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Opportunities to Improve Oil Productivity in Unstructured Deltaic Reservoirs

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Technical Summary and Proceedings of the Technical Symposium

A Public Meeting for
Views and Comments

Conducted by the
Oil Implementation Task Force

Dallas, Texas, January 29-30, 1991
Hyatt Tower East
Dallas/Fort Worth International Airport

OIL RESEARCH PROGRAM

Implementation Plan

U.S. Department of Energy
Office of Fossil Energy
Washington, DC 20545

PREFACE

In August, 1990, Robert H. Gentile, The Department of Energy's Assistant Secretary for Fossil Energy, appointed a Task Force, comprising technical and management expertise, to put into place the Department's new Oil Research Program Implementation Plan, (DOE, 1990). This new plan grew out of DOE's continuing effort to formulate a National Energy Strategy.

Research directed toward near- and mid-term results has been added to the previous program emphasis on long-term, high-risk research, in order to address the needs of current conditions in the petroleum industry. The 1986 price collapse, falling domestic production, and increased well abandonments that threaten future access to reservoirs containing a vast potential of recoverable oil were the major factors that led to this new direction.

In 1987 the Department initiated a study that highlighted the risk to National energy security posed by rising imports and pointed to the need for greater efforts in research. This recommendation was reinforced in an independent study by the Energy Research Advisory Board, which emphasized greater integration and coordination of geoscience and extraction research.

DOE sent a team of technical and management experts across the country to canvass the entire petroleum industry—majors, independents, consultants, service companies, universities—to obtain input on what they thought was needed to increase domestic production. Information gained from this effort led to a DOE Enhanced Oil Recovery (EOR) initiative that recommended expansion of the research program to include near- and mid-term measures to improve domestic production, inclusion of mobile as well as immobile oil, and emphasis on technology transfer, particularly in relation to the independent producer.

In 1988, Congress directed DOE's Office of Fossil Energy to create, as part of a Hydrocarbon Geoscience Research Strategy, a plan to refocus oil research programs with a specific goal of increasing domestic oil production. In late 1989 and early 1990 the Department held a series of public hearings throughout the U.S., heard hundreds of witnesses and gathered thousands of pages of testimony from a cross-section of the Nation. These meetings provided the background material for the formulation of a National Energy Strategy that seeks to strike a balance between competing resources and national priorities in arriving at a sensible, cohesive approach to a national energy policy.

Other concurrent studies emphasized additional facets of the energy security situation. Analysis by DOE's Tertiary Oil Recovery Information System (TORIS), an extensive compilation of petroleum-related information, disclosed the urgency posed by the increasing rate of well abandonment. The Hydrocarbon Geoscience Research Coordinating Committee, in cooperation with the Geoscience Institute for Oil and Gas Recovery Research, published a strategy document and urged a balance of near-, mid- and long-term research, and stressed the need to increase our understanding of reservoir complexities.

In response to these studies, on January 31, 1990, DOE announced its new Oil Research Program Implementation Plan. It recommended a program of field-based research on prioritized classes of reservoirs to rapidly demonstrate cost-effective advances in recovery technology. Under this new plan, a balance of near-, mid-and long-term research will pursue the goals of better reservoir knowledge and improved recovery technologies. Research results will need to be evaluated at reservoir scale to be of value.

Building upon its predecessor, the plan establishes a program of highly targeted research, development, and demonstration in collaboration with the states, industry, and the academic community. It focuses on the reduction of technical and economic constraints on producibility to realize the enormous potential of the resource remaining in known domestic reservoirs. The program sets 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.

The primary goal of the new Oil Research Program is to improve the economic producibility of domestic oil and preserve access to those reservoirs containing the largest volumes of oil that are at the greatest risk of being abandoned.

A vast resource remains in existing reservoirs after conventional recovery. Of the more than 500 billion barrels of original oil-in-place in the U.S., less than one-third has been produced, and a mere 5%—less than 30 billion barrels— remains as proven reserves. With well-designed research and effective technology transfer, reserve additions of 76 billion barrels are possible within the next 10 years—15 billion barrels in the near-term (within 5 years), at present economic conditions with currently available and proven technologies. For the mid-term research component (5 to 10 years), reserve additions of 61 billion barrels are possible with the application of currently identified, yet-to-be-proven technologies.

The top priority for the Task Force is to preserve access to those reservoirs that have the largest potential for oil recovery. TORIS analysis shows that the present abandonment rate of 17,000 to 18,000 wells a year threatens future access to a significant portion of our oil resource. Calculations based on the principal reservoirs in nine states, representing over 75% of the remaining resource in the Lower-48, indicate that by 1987 access to 40% of the remaining oil-in-place has been abandoned. Even at $35 per barrel, nearly 60% of the resource could be abandoned by the year 2,000, and more than three-fourths would be lost by the early 21st century if lower prices persist and technology advances are delayed (DOE, 1989).

The first step in preserving reservoir access is identifying those reservoirs that have significant production potential—oil technically recoverable with advanced, but as yet not proven, technology. Information relating to the 3,700 reservoirs contained in TORIS's reservoir database is being expanded and refined. Using TORIS in an ongoing Multi-State Study, BPO and the Interstate Oil Compact Commission have classified nearly 2,000 of the Nation's 2,500 largest reservoirs, covering 25 of the 29 oil-producing states and 65% of the original oil-in-place. The reservoirs have been grouped into classes based on common geologic characteristics, and their associated production potential has been estimated. An engineering evaluation of the recovery potential and risk of abandonment showed deltas to be the most important types of reservoirs.

Deltas are river-fed systems that deposit sediment along the shorelines of oceans, lakes or bays, forming a sediment wedge. The shape of the delta is dependent on the dynamic interplay of a number of processes. The primary depositional process in delta formation is fluvial, however the final geometry of the sandbody may be affected to varying degrees by wave and tidal currents. Deltaic deposits are broadly classified into three types: fluvial-dominated, tide-dominated and wave-dominated deltas. Deltaic reservoirs can also be subdivided on the basis of structural compartmentalization due to faults and fractures.

Based on a preliminary classification of reservoirs that stressed the structural aspects of deltaic reservoirs, unstructured deltaic reservoirs were selected as the first high priority reservoir class. An industry technical symposium was scheduled in Dallas, TX based on this classification.

A subsequent peer review of the classification determined that the deposystem is more significant to recovery processes than structural character of a reservoir. As a result, a four-fold classification was finalized: fluvial-dominated deltas, wave-dominated deltas, tide-dominated deltas and undifferentiated deltas. Fluvial-dominated deltas are designated the first class for the RD&D under the oil program, based on the largest potential for improved recovery and the largest risk of abandonment of the revised classes.

The revised classification results in varied terminology appearing in this report. The synopsis of the industry symposium in Dallas, TX targets unstructured deltas, whereas Chapters 2 and 3 employ the depositional delta subdivisions.

The analysis, ranking and selection process has been adopted by the Task Force as a method of prioritizing its efforts and focusing on real problems with real potential. All work done under the Task Force research, development and demonstration program will be done on specific leases in functioning reservoirs.

Industry and other public comment on the reservoir selection process and the research needs of each class will be used along with other data to make the final selections and to design research keyed to the needs of the particular reservoir class. Field demonstrations of both currently existing and promising new recovery techniques will be implemented in reservoirs where they are deemed applicable. Successful results will be made available through DOE's Technology Transfer Program, and will be directed particularly to operators in the reservoirs where the results are applicable.

The Task Force is proceeding with these multiple approaches. Data are being collected, refined, and analyzed to provide criteria for ranking and selection of reservoir classes. The first of a series of meetings to obtain comment from the oil industry, academia, and government on the ranking and selection process has been held; its results are reported in this report. Other similar meetings are being planned, and the reports for all of the sessions will be published to provide a consistent, comprehensive reference to this effort.

Questions regarding the meeting or information concerning the general activities of the Task Force may be addressed to:

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This document consists of three chapters and one appendix. Chapter 1 contains summaries of the presentations given at the Department of Energy (DOE)-sponsored symposium and key points of the discussions that followed. The 2-day meeting consisted of four half-day sessions which included both formal presentations and discussion periods. An introductory session was presented by the Department of Energy and contained a brief explanation of the light oil RD&D plan, the reservoir classification system and selection methodology, and a summary of the general characteristics of unstructured deltaic reservoirs. Three technical sessions followed which addressed the topics of integrated geological and engineering reservoir characterization in deltaic reservoirs, extraction technologies, and operational constraints including environmental and regulatory constraints.

Chapter 2 characterizes the light oil resource from fluvial-dominated deltaic reservoirs in the Tertiary Oil Recovery Information System (TORIS). An analysis of enhanced oil recovery (EOR) and advanced secondary recovery (ASR) potential for fluvial-dominated deltaic reservoirs based on recovery performance and economic modeling as well as the potential resource loss due to well abandonments is presented.

Chapter 3 provides a summary of the general reservoir characteristics and properties within deltaic deposits. It is not an exhaustive treatise, rather it is intended to provide some basic information about geologic, reservoir, and production characteristics of deltaic reservoirs, and the resulting recovery problems. The following topics are addressed: 1) a general review of the sedimentological aspects of deltaic systems; 2) a discussion of reservoir heterogeneities related to deltaic depositional processes and their effect on fluid movement within the reservoir; 3) a review of geological factors affecting recovery in 26 enhanced oil recovery (EOR) pilot projects; and 4) average reservoir properties and production characteristics derived from data from 229 fluvial-dominated, unstructured deltaic reservoirs in the Tertiary Oil Recovery Information System (TORIS) database.

Appendix A contains over 300 annotated deltaic references that are divided into the following five subtopics:

1) Twenty-seven key geological references that include references important to understanding the classification, controlling processes, depositional facies, and resulting models of modern and ancient deltas.
2) Fifty-five general geological references that include references that supply important information about the sedimentation, distribution of facies and depositional environment, geometry, geological characteristics of reservoirs, and examples from modern deltas.
3) Nineteen reservoir characterization references that include selected references concerning examples and applications of geological and engineering aspects of reservoir characterization.
4) Fifty-one engineering technology references that include references to technologies for discovery, drilling, and recovery of oil in deltaic reservoirs.
5) One hundred and sixty-seven references on the geology and engineering aspects of reservoirs occurring in six plays. The plays were selected on the basis of geographic distribution, delta type, and availability of data so that a broad, representative sample of deltaic reservoirs would be presented. The plays are as follows: a) Cherokee sands, primarily fluvial-dominated type deltaic deposits in Oklahoma and Kansas (46 references); b) Dakota Formation including the D sand and J sand, mixed wave- and fluvial-dominated deltaic deposits in Colorado and Nebraska (24 references); c) Frontier Formation, undifferentiated deltaic deposits in Wyoming (30 references); d) the Robinson Formation, a fluvial to fluvial-dominated deltaic reservoir in Illinois (8 references); e) Strawn Formation, primarily fluvial-dominated deltaic deposits in Texas (20 references), and f) Wilcox Formation, mixed but predominantly fluvial-dominated deltaic deposits in Texas, Louisiana, and Mississippi (39 references).

References

U. S. Department of Energy, Bartlesville Project Office, 1989, Abandonment Rates of the Known Domestic Oil Resource, DOE/BC-89/6/SP, November 1989.

U.S. Department of Energy, 1990, Oil Research Program Implementation Plan, DOE/FE-0188P, April 1990.

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The following individuals from the U.S. Department of Energy contributed to the symposium program Robert H. Gentile, Assistant Secretary for Fossil Energy; Robert L. Folstein, Office of Oil, Gas, Shale Technology; Thomas C. Wesson, Edith C. Allison and R. Michael Ray, Bartlesville Project Office; and E. B. Nuckols, Metarie (LA) Site Office. We would particularly like to thank all the authors who presented papers at the conference, without whose cooperation the symposium could not have occurred. E. Allison of the DOE Bartlesville Project Office is project manager for Class I Reservoirs.

The analysis of the symposium, the overview of characteristics of deltaic reservoirs and the annotated

deltaic reference sections were prepared by the following people from the National Institute for Petroleum and Energy Research: Thomas E. Burchfield, Ming Ming Chang, Michael P. Madden, Susan R. Jackson, Viola M. Rawn-Schatzinger, Richard A. Schatzinger, and Min K. Tham.

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Chapter 1

ANALYSIS AND SUMMARY OF THE DEPARTMENT OF ENERGY-SPONSORED SYMPOSIUM "OPPORTUNITIES TO IMPROVE OIL PRODUCTIVITY IN UNSTRUCTURED DELTAIC RESERVOIRS"

MEETING SUMMARY

The purpose of the Department of Energy (DOE)-sponsored symposium, entitled "Opportunities To Improve Oil Productivity in Unstructured Deltaic Reservoirs," held January 29-30, in Dallas, Texas, was: (1) to define opportunities for improved light oil production from domestic unstructured deltaic reservoirs; (2) to discuss technical constraints affecting producibility and the research needed to overcome them; and (3) to encourage communication between different segments of the petroleum industry and DOE. Unstructured deltaic reservoirs are reservoirs that were formed in a deltaic environment and whose production is not severely impeded or controlled by structures resulting from faulting, folding, or fracturing at the interwell scale (IOCC, 1990).

The total attendance at the meeting was nearly 250 people and represented a broad cross-section of the petroleum industry. The largest portion (~30%) consisted of independent operators, followed by consultants (~20%), university professors (~15%), technical staff from major oil companies (~10%), and service company employees (~10%). The remaining 15% consisted of domestic and foreign government employees.

Deltaic reservoirs were identified as an important class of reservoirs because they account for about one-fourth of the remaining light oil (gravity greater than 20° API) resource in the United States (fig 1.1). Most of this resource is in unstructured deltaic reservoirs. The DOE estimates that more than 49 billion barrels of light oil were originally contained in unstructured deltas of the onshore United States. Of this, 17.4 billion barrels have been produced, and 580 million barrels are considered proven reserves under current oil prices. After these reserves are produced, more than 31 billion barrels will remain in these reservoirs, which comprises a significant target for advanced oil recovery techniques.

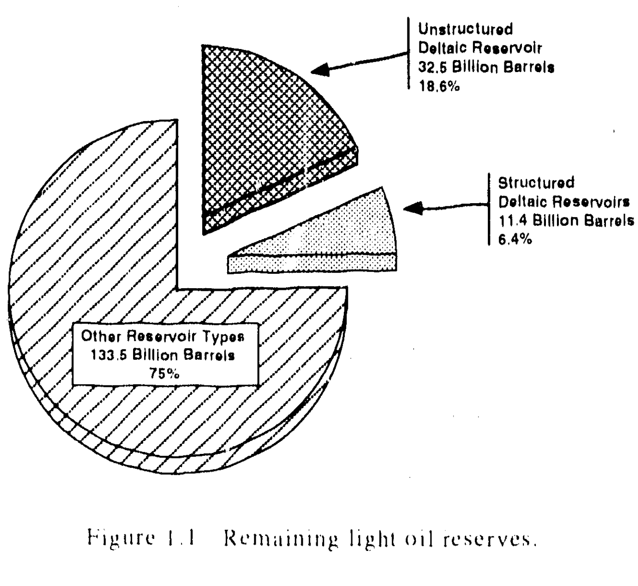

Figure 1.1 Remaining light oil reserves.

The symposium consisted of four half-day sessions. An introductory session was presented by the Department of Energy and contained a brief explanation of the Department of Energy's light oil RD&D plan presented in the Oil Research Program Implementation Plan (DOE/FE-0188P, April, 1990), the reservoir classification system and selection methodology, and a summary of the general characteristics of unstructured deltaic reservoirs. Three technical sessions followed which addressed the topics of integrated geological and engineering reservoir characterization in deltaic reservoirs, extraction technologies, and operational constraints including environmental and regulatory constraints.

Summaries of the presentations and the ensuing discussions were prepared from abstracts submitted by the authors as well as notes taken at the meeting. The authors reviewed the summaries and provided valuable comments and suggestions. The following authors elected to submit manuscripts, which were used in lieu of summaries: Don Oltz, "Reservoir Characterization of the Illinois Basin Including Deltaic Sands;" Gary Pope, "Reservoir Modeling: Advanced Reservoir Simulation -- Experience in the Big Muddy Field, Wyoming;" James E. Russell, "Economic and Regulatory Constraints;" and William C. Maurer, "Drilling Technology: Advances in Directional Drilling."

The major points which emerged from the meeting are outlined below:

- Operators voiced confidence in the capability of technology to improve productivity, but the technology must be delivered in an understandable format and style.
- Reservoir characterization is critical for data interpretation and effective reservoir management. The interpretation and application of sophisticated technologies such as horizontal drilling or seismic cross-well tomography require detailed reservoir models.

- Opinions on the impact of plugging and abandoning wells on oil reserves varied; however, the negative effects are primarily due to the dismantling of oil field infrastructure (manifold systems, storage, power, etc.) and the consequent cost of reinstallation. It was generally agreed that regulations that allow a longer period before required plugging would be helpful to oil producers.
- Methods to evaluate the risks and benefits of implementing specific advanced recovery processes are needed.
- New and improved tools to measure in situ reservoir properties are required to enhance characterization of reservoir properties and heterogeneities and thereby maximize resource exploitation.
- The degree to which reservoir properties can be generalized across basins which have undergone different histories must be carefully evaluated.
- Recommendations for future activities to encourage communication among and between different segments of industry include: 1) additional workshops with an agenda focused on specific topics relative to deltaic reservoirs; 2) seminars on reservoir characterization and methods of utilization of existing data; and 3) further encouragement to consortia and cooperative efforts.

ANALYSIS OF SYMPOSIUM

I. Technical Constraints

The formal and informal discussions among the diverse group of people at the meeting emphasized the fact that different segments of the industry have varying technological needs and levels of technical sophistication. It was widely agreed that much additional oil could be recovered by better or more widespread use of conventional technology. The major cause of under utilization of conventional technologies was attributed to the lack of knowledge of the benefits of the technology and where to obtain it. Many independent operators, however, voiced confidence in the capability of technology to improve their productivity, but the technology must be delivered to them in a format and style that they understand. Many of the smaller operators stated that they could not afford to implement technologies, even though they appreciated the benefit they would bring.

The importance of reservoir characterization in data interpretation and effective field development was widely agreed upon and underscored in a number of papers presented. Detailed reservoir characterization is important to the utilization of sophisticated technologies such as horizontal drilling, where knowledge of geometries and reservoir architecture is essential to optimum well location and profile, and cross-well tomography, where the interpretation of tomogram images relies heavily on the reservoir model.

Opinions about the impact of plugging and abandoning wells on oil reserves varied. Some companies felt the impact was minimal since new wells were drilled for EOR projects. Other operators, however, pointed out that the cost of plugging severely impacts them and does deter future secondary or tertiary recovery. Regulations that permit a longer period before forced plugging were suggested.

The importance of assessing a reservoir for application of advanced recovery methods was highlighted. Not all reservoirs are worth the manpower and cost required to enhance productivity, so it is important to determine the risks and benefits of implementing a specific advanced recovery technique. Typically, the industry does only the minimum analysis necessary to implement a project. Methods to evaluate the risk of implementing advanced recovery techniques are needed.

A parameter critical to the evaluation of a reservoir for application of advanced recovery processes is an estimation of the amount of unrecovered mobile oil (UMO) present in the reservoir. Estimates of the amount of mobile oil are often based on the assumption that the reservoir is water-wet when in actuality many reservoirs are intermediate to oil-wet. This assumption results in overestimation of the amount of mobile oil. On the other hand, several examples discussed in the meeting showed that sweep efficiency in heterogeneous reservoirs may be better than previously thought, and the amount of UMO has been overestimated.

II. Required Technological Advancements

The requisite technological advancements to improve producibility from deltaic reservoirs that were defined at this symposium are in the following areas: 1) reservoir data aquisition and analysis; 2) numerical simulation; 3) chemical recovery processes; and 4) directional drilling technology.

New and improved tools to measure in situ reservoir properties are required to enhance characterization of reservoir properties and heterogeneities and thereby maximize resource exploitation. Logging and other tools which record reservoir properties at greater distances away from the well bore and higher-resolution cross-hole siesmic methods are required. The current ability to collect large amounts of detailed data, however, has preceded the ability to integrate and process that data. Equipment and software to process and integrate large amounts of data from diverse sources in a timely and cost-effective manner are needed.

Within the field of numerical reservoir simulation, four main areas for improvements were identified: 1) numerical problems which include numerical errors (numerical dispersion), limitations on problem size, and reliability; 2) process description problems which include phase behavior, physical property models, chemical reaction models, and surface phenomena; 3) design and application problems including new processes or new combinations of chemicals, heat and solvents, mobility control with foams or microbes, and design optimization; and 4) reservoir description problems including translation of geological descriptions into gridblock properties, estimation of effective gridblock properties from petrophysical data, uncertainty in geostatistical estimations, and the cost of the numerous solutions required.

A major challenge for improving directional drilling technology is cost reduction by development of improved drilling tools. The DOE-sponsored research on measurement while drilling (MWD) and polycrystalline-diamond-compact (PDC) bits has provided major advances in drilling technology. The next major development is predicted to be in the area of slim-hole drilling which can reduce drilling and completion costs by as much as 50 to 60%. Other improvements needed are: more efficient drilling bits, more powerful downhole motors, and improved resolution in MWD and survey tools.

Economic requirements for the petroleum industry were voiced by independent operators who called for relief, or at least consistency, from regulatory agencies. Currently the American Petroleum Institue is working on this, but DOE assistance is also solicited. James E. Russell, president of the Texas Independent Producers and Royalty Owners Association (TIPRO) outlined the following three areas necessary to resolve the current domestic energy dilemma: 1) price stability in the form of a floor and ceiling price on oil ($20 to $30/bbl); 2) greater tax incentives for applying enhanced recovery methods; and 3) less restrictive environmental regulations.

III. Technological Advances

Reservoir Characterization

The area of reservoir characterization has received much attention in the past decade, and considerable progress has been made in developing techniques and methods. It requires the continuous interactive cooperation between engineers, geologists, and geophysicists. The case study presented at the meeting by Needham et al. on Hugoton field, Kansas illustrated how the effectiveness of an infill drilling program was evaluated by the analysis and integration of geological, engineering, and reservoir performance evaluation data. The conclusions of that study were that no additional reserves would result from an infill drilling program although production rates would increase.

The importance of identifying directional flow trends and designing the well pattern to account for them was illustrated in a presentation of a surfactant flooding project in the Robinson sand.

The importance of a detailed reservoir model in the interpretation of the cross-well seismic tomographic images from the deltaic Cromwell sandstone reservoir was presented. This study stressed that reservoir characterization is the key to interpreting the tomographic images and that sedimentology is the key to understanding the distribution of reservoir quality.

Significant advances have been made in tools which measure in situ reservoir properties such as cross-borehole seismic and well logging techniques. Advances in cross-hole tomographic methods allow: 1) identification of high-porosity zones; 2) selection of infill well locations; 3) monitoring of reservoir dynamics such as the movement of the gas cap during primary production and fluid front advancements in EOR projects; and 4) collection of information for structural and stratigraphic mapping on the interwell scale.

Advances in logging techniques include the development of the laminated sand analysis (LSA) tool that has increased resolution and enables the detection of hydrocarbons in thinly bedded intervals, a feature common in deltaic reservoir facies such as crevass splay, tidal flat, and prodelta deposits. In the past, a potentially large number of wells drilled in marginal types of reservoirs have remained unexploited due to insufficient resolution of conventional dual induction logs. In one case studied, a 33% increase in reserves was indicated by using LSA techniques vs. conventional logging. Other logging tools which overcome saturation measurement problems in reservoir intervals with textural variations are the electromagnetic propagation tool (EPT), the geochemical logging tool (GLT), and the nuclear magnetic log (NML). The array induction imager tool (AIT) overcomes problems due to drilling mud invasion.

The importance of the environment in which the reservoir was formed was illustrated by Finley and Tyler who showed that differences in delta type facies affect recovery efficiency in Texas reservoirs. Wave dominated deltas tend to be less compartmentalized and have higher recovery efficiencies than the more highly compartmentalized fluvial-dominated deltas. Wave-dominated deltas with good lateral communication may provide the best opportunities of EOR, whereas the more compartmentalized fluvial-dominated deltaic reservoirs may be targets for directional and infill drilling. Knowledge of these relationships enables design and implementation of effective reservoir management strategies.

Recovery and Extraction Methods

Recent advances in surfactant process design can significantly increase production and reduce costs. Simulation studies presented by Pope indicated that by creating a better salinity gradient between injected chemicals and formation waters, nearly twice as much oil can be recovered. Conclusions from a surfactant flood project in Robinson field, Illinois indicated that chemical costs can be lowered significantly when the design of an optimum slug size is tailored to the volume of reservoir which can be swept, instead of the total volume, as typically is done. Experiences in surfactant polymer projects in Loudon field Illinois illustrated a technically and economically successful field-scale surfactant polymer project in a deltaic reservoir, but also pointed to the need for reservoir characterization, better polymer transport, and cost reduction by recycling used surfactants. Significant progress has been made in the development of numerical simulators that account for all the complex phenomena that occur in the reservoir during a polymer surfactant flood.

Advances in directional drilling enable drilling of slant and horizontal wells that can increase production by overcoming reservoir problems of lenticular, disconnected pay zones; high degree of internal compartmentalization; highly layered reservoirs consisting of pay zones separated by impermeable shale layers; and water and gas coning problems. Although drilling costs for horizontal wells are about two times greater than that of vertical wells, oil production can potentially be increased by 3 to 8 times. Horizontal wells are not the answer for all reservoirs, however. In low-permeability reservoirs (<1 md), hydraulically fractured vertical wells often produce more than horizontal wells. In highly permeable, relatively homogeneous reservoirs, vertical wells efficiently drain the formations. An advantage of directional drilling techniques is the invaluable geological information available from horizontal cores. One horizontal core may provide information equivalent to that from 50 vertical cores.

Infill drilling has received much attention lately as a lower cost alternative to other advanced recovery techniques and may be an alternative to horizontal drilling for improved production. As in all recovery processes, however, the special characteristics of the reservoir must be considered before implementation. The importance of rigorous reservoir analysis was illustrated in an evaluation of an infill drilling program for a gas reservoir in Hugoton (KS) field. In this study, the current 640-acre well spacing provided ample drainage of the gas reservoir because of good lateral communication with flow units.

Recent advances in well completion and well stimulation technology (both vertical and horizontal) can overcome near-wellbore damage by acidizing and fracturing techniques, and sand production can be stopped with gravel packs. Increased awareness of the effect of near-wellbore organic formation damage on reducing production in older reservoirs (many of which are deltaic) will contribute to early recognition, monitoring, and reversal of the damage. In many cases, formation damage can be remedied by inexpensive wellbore cleanup techniques, and costly stimulation treatments can be avoided. These techniques may provide a relatively cost-effective way to increase the ultimate recovery from mature reservoirs.

Abundant data are currently available from commercial sources which include digitized data, integrated commercial databases, and new technologies such as Geological Information System (GIS) and scanned image data. The types of information available are reservoir data; production data; core, well test, and completion data; as well as numerous digitized well logs and seismic data.

IV. Communication Between Different Segments of Industry and DOE

Comments from the nearly 250 registrants were supportive of the Department of Energy's R&D strategy and the choice of deltaic reservoirs as the first target of study. Large and small operators, service companies, and research organizations expressed interest in participating in cost-shared projects with DOE.

Some questions were raised about the concept of self-similarity -- the hypothesis that reservoirs deposited in the same depositional environment will have similar characteristics. The concept of reservoir similarity, if true at all, must first be tested in groups of reservoirs that formed in the same basin or geologic province and have been subjected to similar sediment sources and similar tectonic and diagenetic histories.

It was suggested that caution needs to be exercised to avoid over-generalization of reservoir properties across basins of contrasting depositional history. Don Oltz of the Illinois Geologic Survey pointed out that reservoir characteristics in deltaic reservoirs in the Illinois Basin may differ from those of Gulf Coast basins because of different reservoir histories.

slopes, geothermal gradients, sand thicknesses, vertical sequences of reservoirs, and the maturity of source rocks.

V. Recommendations

Recommendations for future activities to encourage communication between different segments of industry and the Department of Energy include: a) additional workshops with an agenda focused on specific topics relative to deltaic reservoirs; b) seminars on reservoir characterization and methods of utilization of existing data such as old logs and production data; and c) further encouragement to consortia and cooperative efforts.

SESSION SUMMARIES

Introductory Session

DOE'S R&D Approach: Focusing on Problems Encountered in Specific Reservoir Classes

Robert H. Gentile, Assistant Secretary for Fossil Energy, U.S. Department of Energy

The following is a transcript of the keynote address presented by Robert Gentile.

I speak for all of us at the Department of Energy in welcoming you here today. We are aware that many of you have taken valuable time away from your company duties to be here. And I can assure you that we appreciate your willingness to share your expertise and experience.

I'm going to adhere strictly to the expressed intent of this meeting -- namely that it is a meeting intended to elicit your participation, your comments, your active discussion. That means my remarks this morning will be very brief.

But I don't want any of you to equate brevity with a lack of priority.

In fact, I believe I can honestly say that this meeting, if it is carried out as we envision -- and if it leads to the kind of positive results we hope for -- can be one of the most important activities we've undertaken at the Department of Energy. I spoke to the Secretary about this effort last week, and I can tell you that he concurs in that opinion.

And the reasons are quite obvious.

Today, we can't help but be transfixed by the events in the Middle East. I know that some of you, like myself, may have colleagues or family serving in the Persian Gulf. They deserve, and have, our fullest support, our pride and our continuing prayers for a safe return to families and friends.

It tears our heart out to again see Americans in harm's way. But they have a job to do. They are well trained, and they are prepared.

It is our duty here at home to be prepared also.

Because of the obvious impacts of world energy markets, Admiral Watkins and the Department as a whole are taking an active role in the policy and planning that is going into the allied response to the crisis.

Our principal role is coordinating the U.S. energy response -- part of a preparedness effort that involves all of the 21 member nations of the International Energy Agency plus three other OECD countries.

At the center of that response is a coordinated international drawdown of strategic stocks. Fourteen nations are involved in this aspect of the IEA response.

The U.S., at the direction of the President, has begun its first-ever emergency drawdown of the Strategic Petroleum Reserve (SPR).

Our action is not meant to drive down prices. It is an exercise in precaution -- an effort to ensure that world oil markets have a cushion of supply in the event oil flow from the Middle East is disrupted.

And we have been pleased that markets have responded positively. Prices did not soar as so many had predicted. In fact, just the opposite occurred. And while I know that many people in the oilpatch don't want to see prices nosedive, I don't think we -- and myself included -- want to see them skyrocket either.

A roller-coaster oil market doesn't help anyone. Price stability must be our objective, and that is our purpose in commissioning an early drawdown of our strategic stocks.

Yesterday, we announced the list of bidders for Strategic Reserve oil -- 26 companies in all, submitted bids for nearly 45 million barrels of crude, about 11 million barrels above what we offered. Tomorrow, we expect to announce the successful bidders, and we could be ready to begin moving the first oil out of the SPR in the first of the month.

As I said, this is part of a coordinated international effort. All 21 nations of the IEA and 3 more OECD nations are either releasing some of their government-controlled stocks or other supply options or exercising demand restraint.

And that bodes well for the international alliances that are being strengthened by this war against a common enemy.

We are watching incredible tragedies of almost unimaginable scale, both in human and ecological terms. But we are also watching a group of nations uniting in their belief that a new world order can begin only when old traits of aggression and tyranny are eliminated.

I think the last few days have shown us -- the American people -- that the conflict in the Middle East is much more than "blood for oil." The terrorist tactics of indiscriminately-fired missiles, the gut-wrenching barbaric treatment of downed pilots, the massive environmental pollution of the Persian Gulf -- all of these have revealed the true portrait of the evil of Saddam Hussein.

And because of this, we've not heard much these last few days about this being a war for cheap oil or cheap gasoline. Americans now know the stark realities of what this war is all about.

They know the threat is much greater than just a disruption of tanker flow or the up-or-down movement of oil prices. We now see the true face of a ruthless tyrant, with apparently little human conscience or respect for the dignity of man or nature.

And yet ultimately, this tyrant will be defeated. And the war will be over. And Americans will again turn inward, hopefully recognizing that, no matter how just the cause, our future cannot be left solely to military might.

National strength will be dictated largely by economic strength, and economic strength in turn will be drawn largely from the strength of our energy supplies and our energy industries.

So, although the Persian Gulf war is more than a war over oil, it will certainly elevate energy and energy policy in the American consciousness and in turn, receive more emphasis in this Nation's domestic agenda.

Now some will still preach the incredibly naive view that we can make massive changes to our energy mix overnight. Some will undoubtedly say that we can remove the threat of future Saddam Husseins simply by bringing in alternative energy sources with the wave of some magic wand.

Others -- those with more realistic views of reality -- will understand that massive, overnight changes to our economic machine are neither possible nor desirable. They will understand that first, and foremost, oil is the lifeblood of our economy. And any sound, realistic, well-thought-out energy policy must begin with oil and with the domestic oil industry.

You are all probably aware that the Department is in the final stages of formulating a National Energy Strategy (NES). Many of you may have attended the public meetings we held to obtain input on the wide range of oil issues covered by the NES.

Now your contributions have been compiled, analyzed and woven into a narrative document. Many decisions have been made.

But some options remain on the President's desk, and of course as you can well imagine, his thoughts are on the Persian Gulf right now and his agenda is quite full. So I can't give you a timetable on exactly when the Strategy will be released, but I can say that our best guess is that it will be in a matter of a few weeks.

And I can tell you that the NES is not an isolated exercise. It is building on several activities that have already taken place. Our Oil Research Plan that forms the backdrop for this meeting will be part-and-parcel of the National Energy Strategy. Another part of it will be the recently passed tax incentive legislation - sometime that many of us worked long and hard on, as did several of you.

We estimate that this legislation will lead to an increase in domestic production by nearly a half million barrels per day in the next decade. That is important. But it obviously is not everything that we can do. Tax policy is an ongoing give-and-take process. We got some needed benefits in the budget package last year. Perhaps we can work toward an even better package in the future.

But I think many of you recognized that tax incentives are only one part of the effort. Today, here at this meeting, we are dealing with the other major aspect. We are moving from the policies of Washington to the practices you are using in the oil field.

This symposium is the next stage of an effort we began a year ago to drastically restructure our oil recovery program -- making it more directly meaningful and hopefully, more useful to those of you who are working today in high-potential reservoirs.

It has become obvious to us that our emphasis on laboratory-oriented research was not addressing the very critical issues affecting domestic production. It was doing nothing to buy us the time we needed to get new, better recovery technologies into practice.

And, as a result, we were rapidly losing access to substantial quantities of oil in known reservoirs. The numbers are stark. At the present rate of abandonment, we could see 65 percent of our remaining lower-48 oil resource abandoned in just the next few years.

Even the best research was going to have very little impact if we had no place to apply it. And I need tell you least of all that once a reservoir is abandoned, the difficulties in re-establishing titles to the mineral rights, or reworking or redrilling wells virtually eliminates the future use of enhanced oil recovery (EOR) technology.

That is why we have changed our focus. That is why I've told Bob Folstein and his crew that there is nothing more important to the short-term priorities of the Office of Fossil Energy than the effort he has put together -- the effort we are discussing here today.

We see our role as a catalyst -- bringing together a multidisciplinary fabric of reservoir engineering and geoscience efforts. Our goal is to define commonly recognized reservoir problems and find solutions that you can use -- that are appropriate and familiar to the way industry operates.

We've begun with a systematic assessment of domestic reservoirs. More than 2,000 have been classified on the basis of geologic factors that influence oil recovery. They are being ranked according to the twin criteria of the volume of recoverable oil and the risk of abandonment.

As reservoirs are selected for consideration, we hope to identify technologies that can prolong the life of the fields -- not pie-in-the-sky laboratory ideas, but technologies that have been shown to work in the field, that are producing results in one corner of a reservoir and may be useful in other corners or in reservoirs of similar geology.

We wish we could do this on a scale resembling a Project Apollo commitment -- with the same funding and personnel resources. We wish we could work on all at-risk reservoirs, all at the same time.

But fiscal constraints make that impossible. So we must be selective. We must focus on groups of reservoirs that have specific, addressable problems and offer realistic opportunities for additional recovery.

Our selectivity will largely come from meetings like this -- where we interact directly with you to define the problems and determine what opportunities appear most attractive.

Today's session is the pioneer effort in this approach. It is considering unstructured deltaic reservoirs.

We chose this category of reservoir because it has potential for significant recovery and it faces a high risk of abandonment in the near future. We chose it because it is common over a wide geographic area -- it exists in more than 15 states.

And in this category of reservoir, we see both common problems and common potential. Oil recovery is generally low. But these fields offer good targets for infill drilling, and polymer floods are abundant. There are many operators working in similar environments. And from them, we hope to stimulate an interchange of ideas across a broad geographic spectrum.

So that is what we are beginning here today -- an interchange of experience and expertise. Working with you, we hope to clarify our understanding of the problems of working in unstructured deltaic reservoirs. And at a similar meeting in the near future, we will ask for your comments on moving ahead with field demonstrations in these reservoirs.

This is an iterative process. As new reservoir classes are selected, similar meetings will be held. By the time we have finished, we hope to have encompassed most of the recoverable oil resource in this country.

So I urge you today to participate, to comment, to offer suggestions. This is not DOE's meeting. This is DOE setting up a forum for you to begin sharing knowledge and real-life experiences. This is an opportunity for you to begin working with the government and with your colleagues with the sole purpose of increasing production and maintaining reservoir access.

We at the Department of Energy will not produce a drop of oil because of these meetings. We can't do a single thing to boost production of our own. This is something that you in industry must do.

If we can help, so much the better. But we are not going to tell you how to run your fields. We are going to give you an opportunity, however, to talk to others, to share your ideas and discuss possible approaches for prolonging the life of our domestic resource.

My background, as some of you may know, is primarily in coal. I haven't spent most of my career, like you have, trying to understand the geoscience of the oil patch.

But I think we still share a common link. Energy geology and energy production are also in my lifeblood -- they are second nature to me. And I understand their significance to this country's past, and more importantly, to the prospects for this country's future.

Today we are defining that future -- in terms of world leadership and in terms of domestic commitment. This Nation stands tall today not only because of the vision of past Americans but because of their dedication and sacrifice. Now today's generation is being asked for the same measure of vision, dedication and sacrifice.

The importance of this meeting obviously pales in comparison to events half a globe away. But in terms of the long-term future of this country -- in terms of our future growth and in terms of our future security -- I can't imagine a more significant domestic action than what we are about here today.

So thank you for your attendance, and thank you for your cooperation.

DOE'S Oil R&D Plan and Objectives of the Symposium

Edith C. Allison, Reservoir Class I Manager, DOE Bartlesville Project Office

The overall goal of the plan is to maximize the economic producibility of the domestic oil resource. The objectives are: (1) to preserve access to domestic reserves within the near-term (5 years) with a target of 15 billion barrels of oil; (2) to demonstrate currently defined advanced technologies within the mid-term (5 to 10 years) with a target of 61 billion barrels; and (3) to develop new technologies in the long-term (over 10 years) with a target of 265 billion barrels (fig. 1.2).

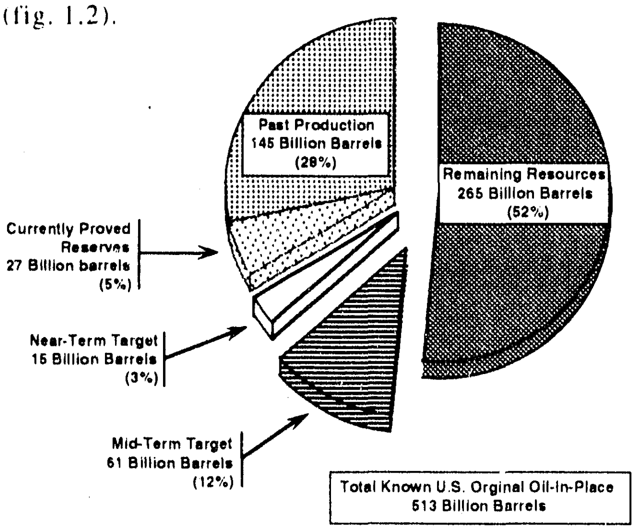

Figure 1.2 - Total known U. S. original barrels of oil-in-place.

A major element of the near-term objective is to sustain production within high-potential reservoir classes that are approaching their economic limit. This will be obtained through broader application of currently available, economic technologies and will include field demonstrations of underutilized technologies and technology transfer workshops and field visits. Research focused on methods and technologies that will reduce environmental constraints on production will also be implemented.

The mid-term objectives to develop and transfer the best currently defined, advanced technologies to operators of high-priority reservoirs will be achieved by concentrating on integrated multidisciplinary reservoir characterization; implementing tests of advanced technologies in field pilots and demonstrations; and transferring successful results to operators, consultants, and service companies.

Pursuit of the long-term objectives to develop new recovery technologies for reservoirs not amenable to conventional or advanced processes will entail fundamental crosscutting research in geoscience and engineering characterization of reservoirs and novel extraction technologies. Focused university research will be an important element in this activity.

Reservoir Classification System and Selection Methodology

R. Michael Ray, Deputy Director, DOE Bartlesville Project Office

The classification system was developed by a group with diverse areas of expertise from industry, government and academia. Reservoirs are classified on the basis of lithology, depositional system, diagenetic overprint, and structural compartmentalization (fig. 1.3). The major clastic depositional systems are presented in figure 1.4, and the major carbonate depositional systems, in figure 1.5. More than 2,000 major reservoirs have been classified. Selection of priority reservoir classes was based on ranking by remaining oil-in-place (figs. 1.6 and 1.7); abandonment potential (figs. 1.8 and 1.9); and advanced technology recovery potential for the selection. The advanced technology recovery potential of unstructured deltaic reservoirs is presented in figure 1.10.

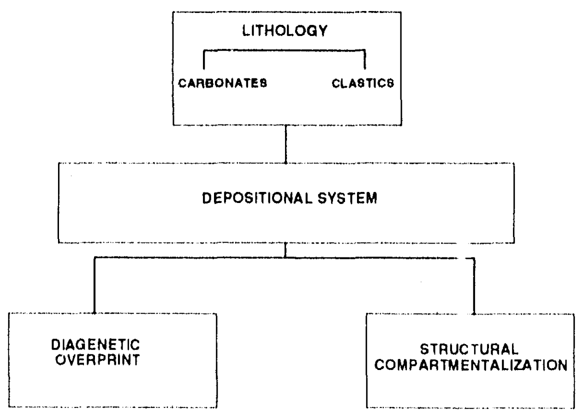

Figure 1.3 - The structure of the classification system.

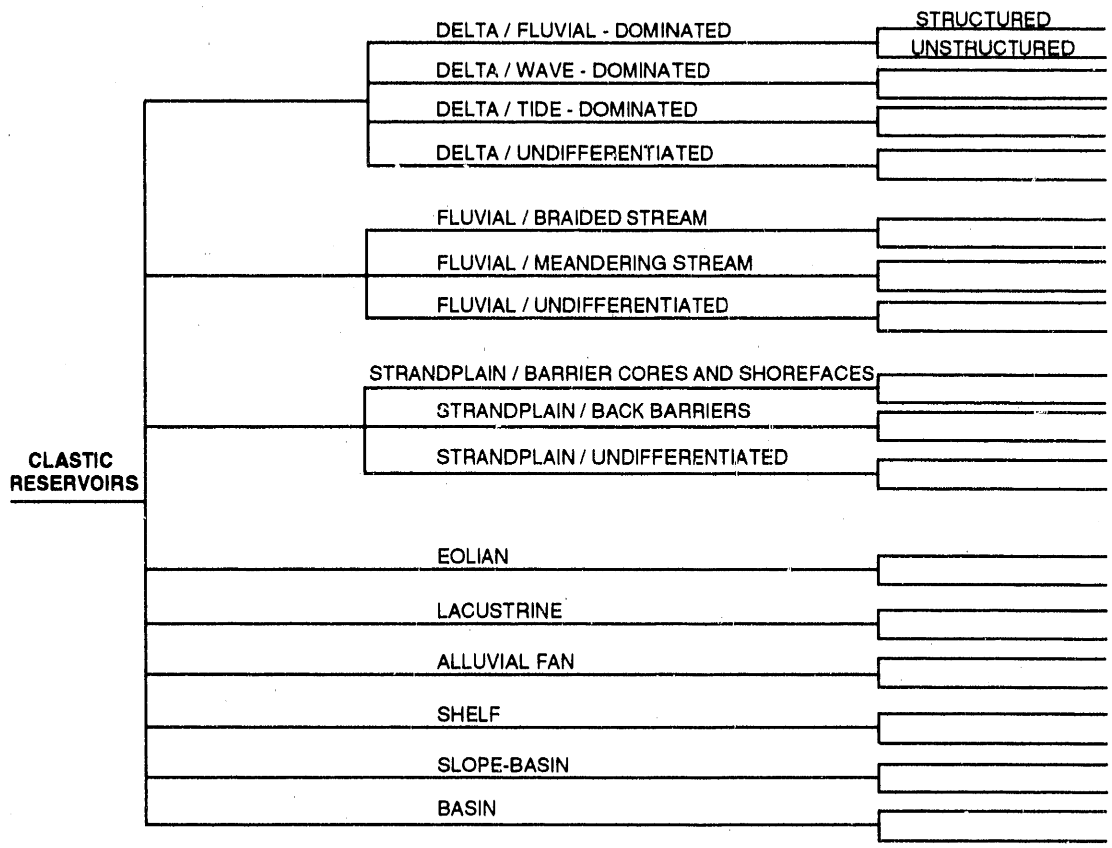

Figure 1.4 - Classification of clastic resevoirs.

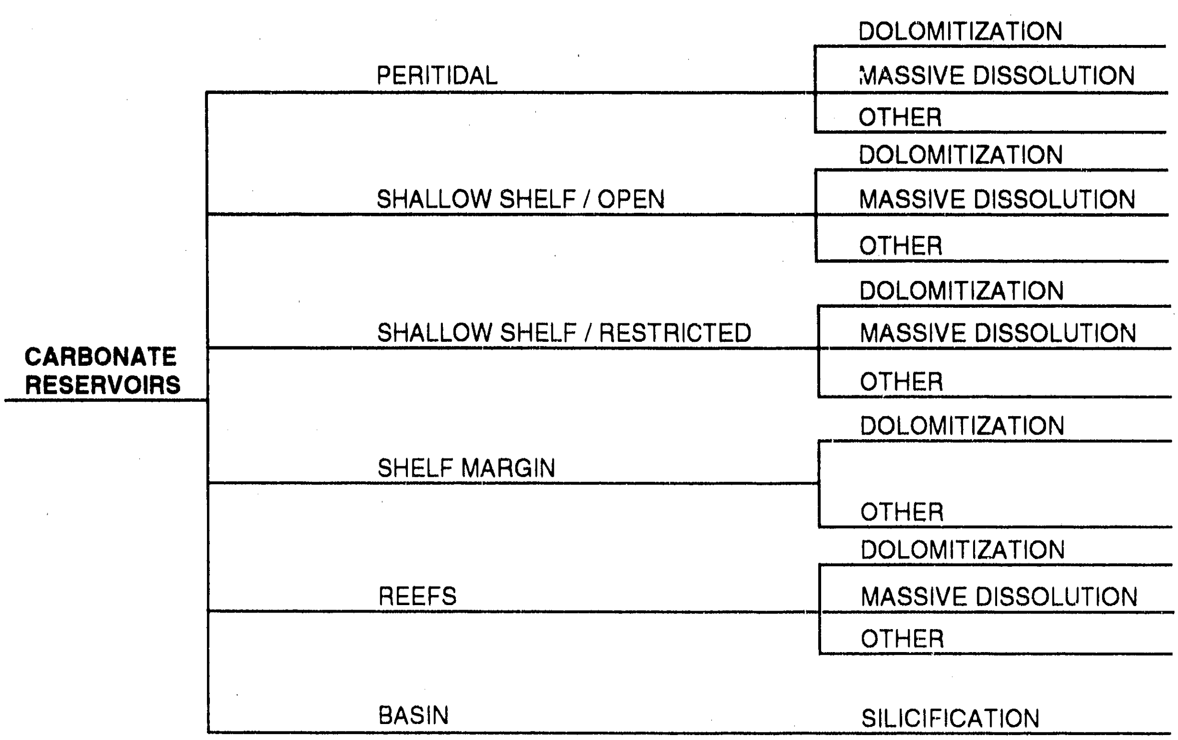

Figure 1.5 - Classification of carbonate reservoirs.

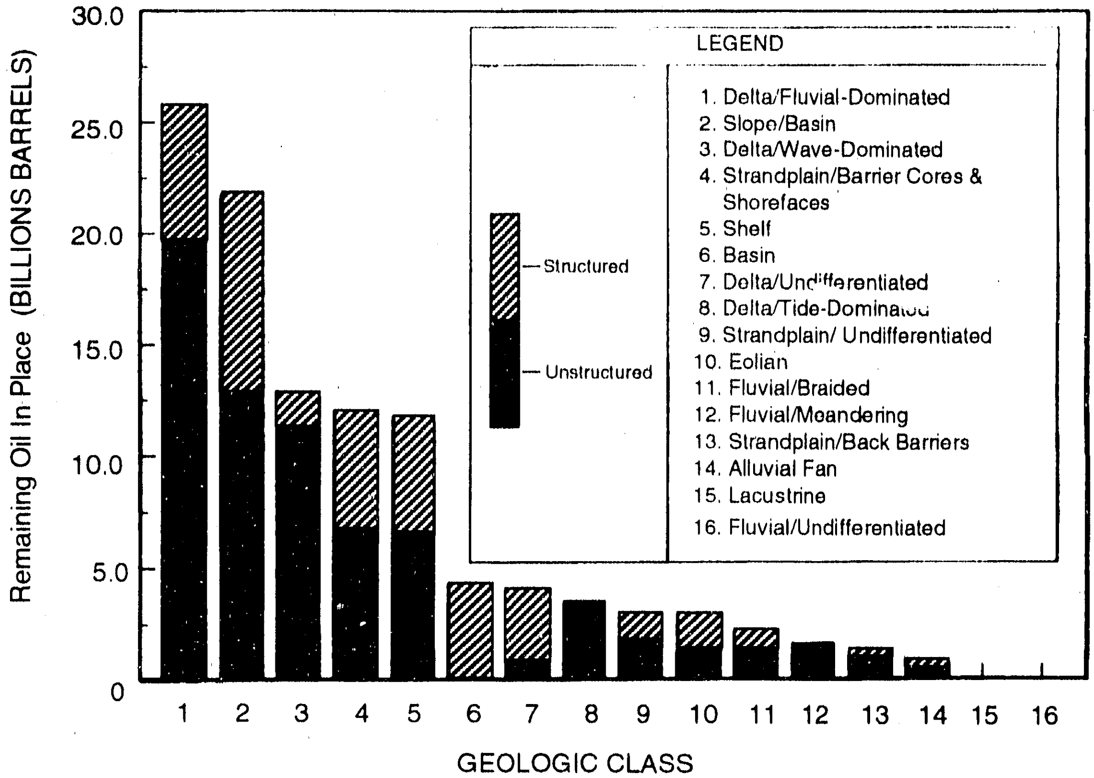

Figure 1.6 - Rank of clastic reservoir classes by remaining oil-in-place.

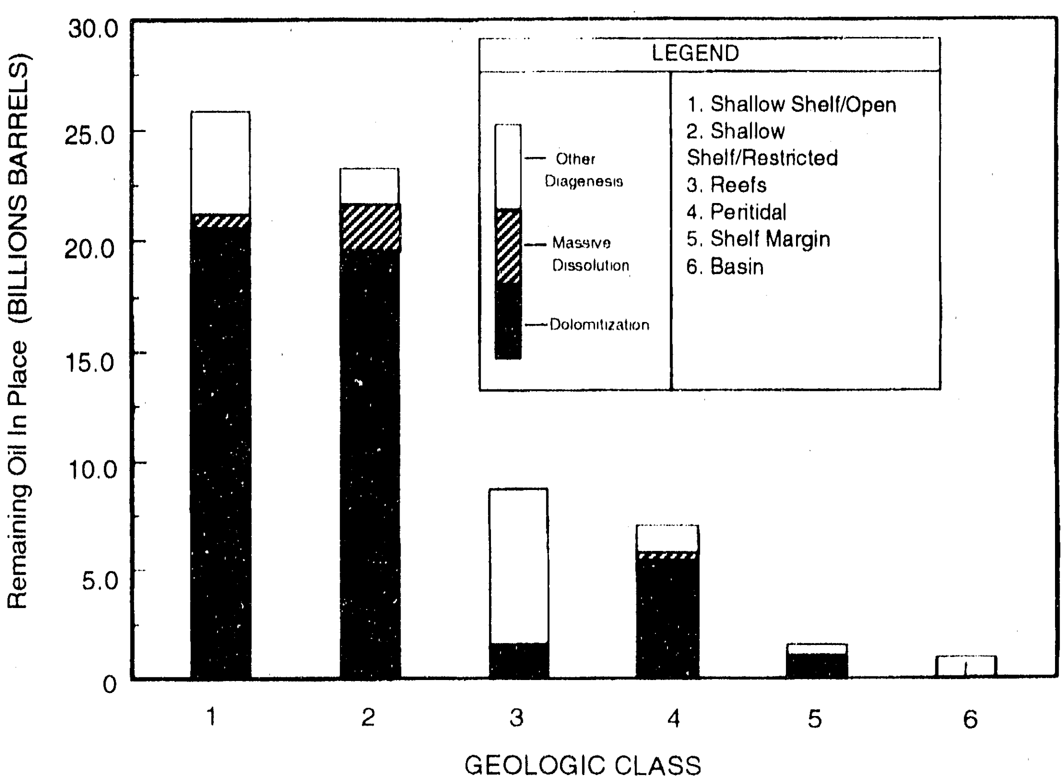

Figure 1.7 - Rank of carbonate reservoir classes by remaining oil-in-place.

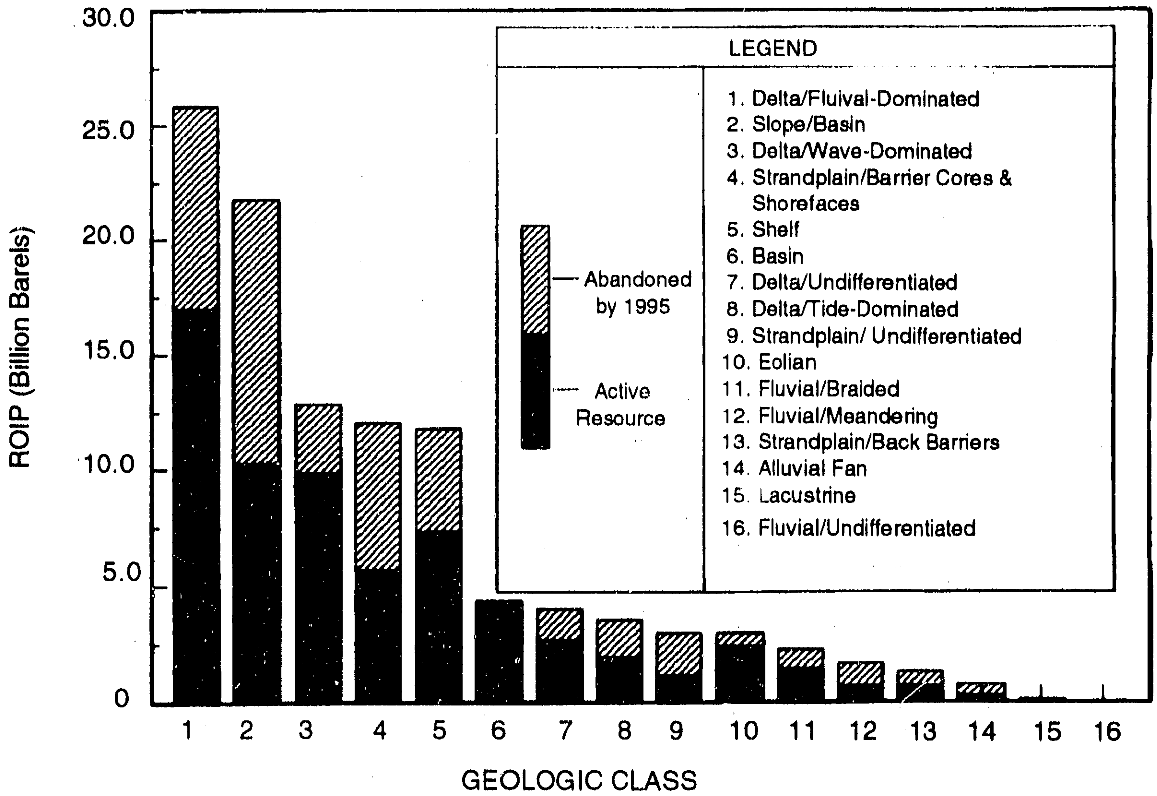

Figure 1.8 - Histogram of abandonment potential for clastic reservoirs.

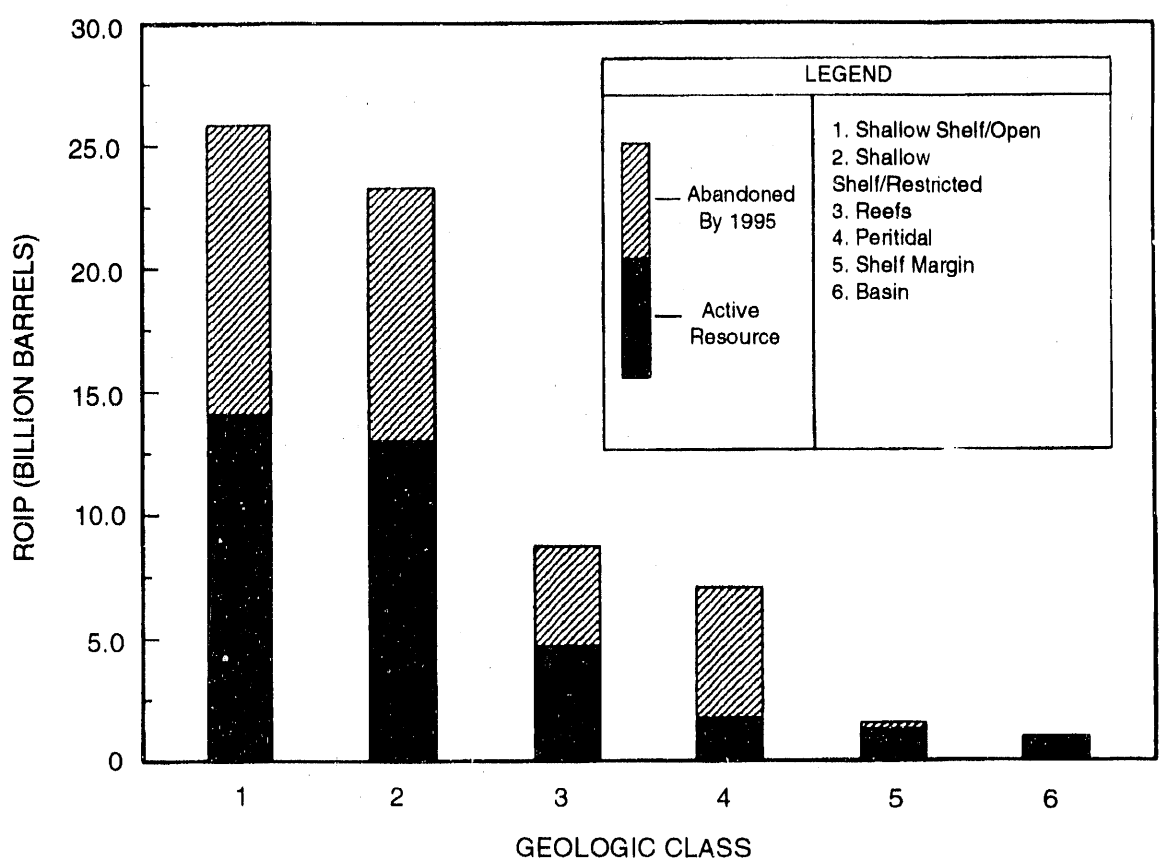

Figure 1.9.- Histogram of abandonment potential for carbonate reservoirs.

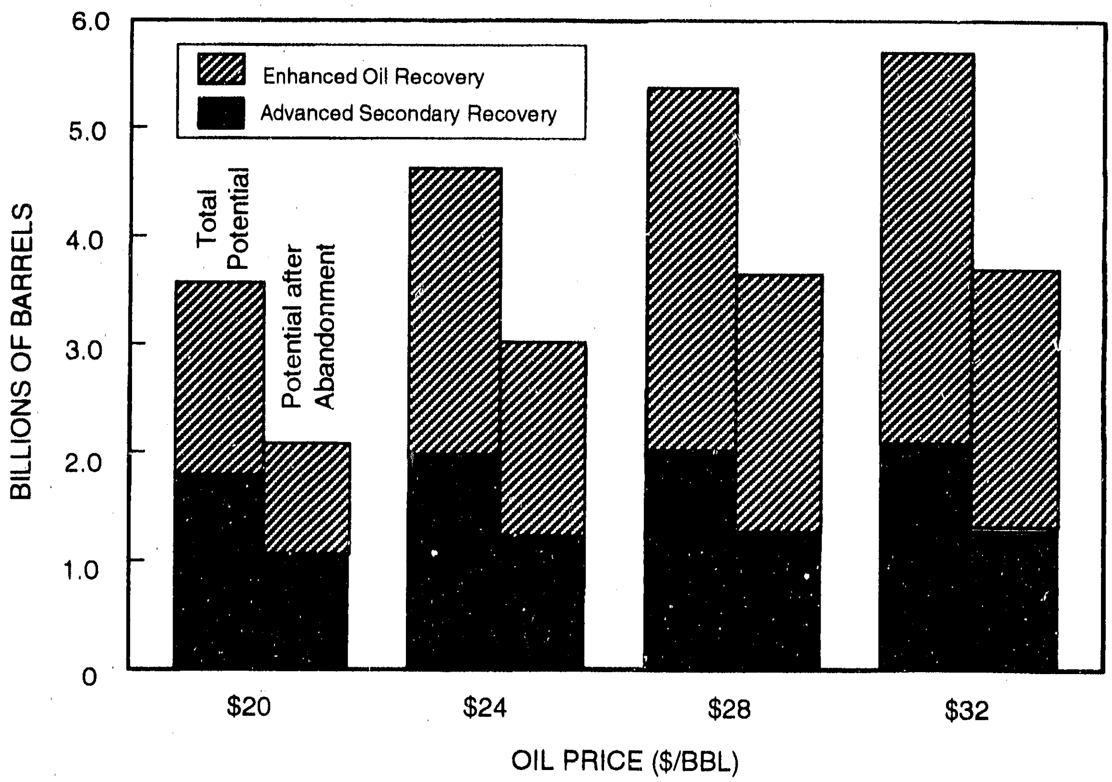

Figure 1.10 - Histogram of advanced technology recovery potential for unstructured deltaic reservoirs.

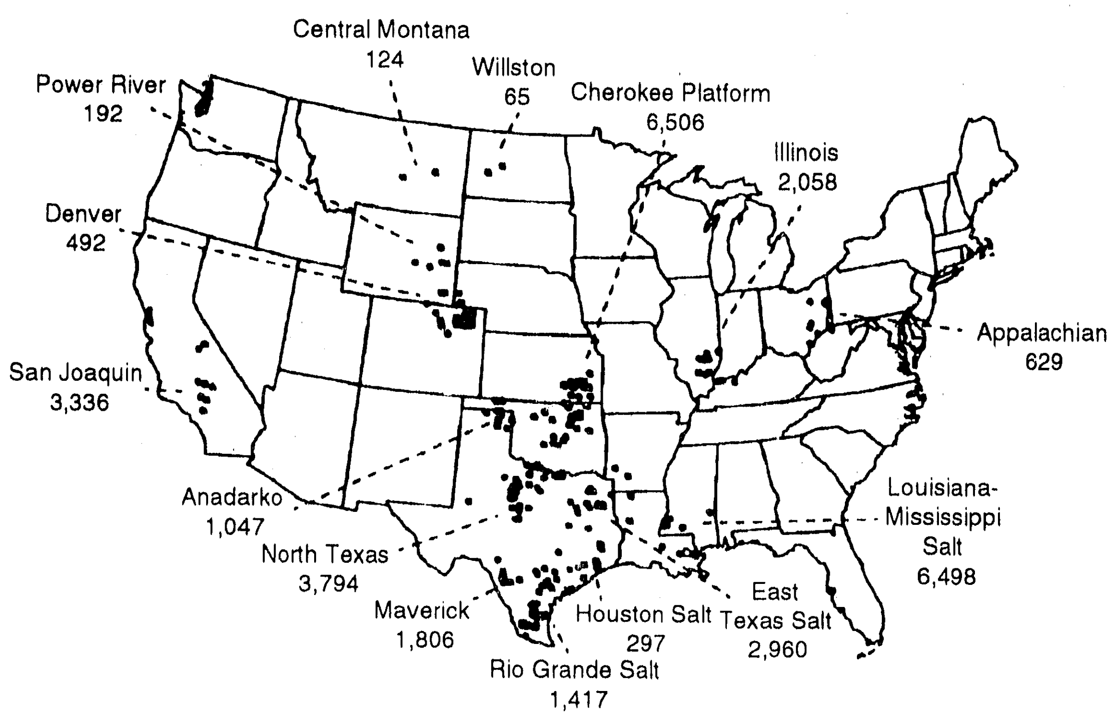

Figure 1.11.- Map of unstructured deltaic reservoirs in major basins in the United States.

Geologic and Engineering Characteristics of Deltaic Reservoirs

E.B. Nuckols, Reservoir Class 2 Manager, DOE Metairie, Louisiana Site Office

This presentation included an overview of geological and engineering characteristics of deltaic reservoirs, the magnitude and geographic distribution of the light oil resource, and the enhanced oil recovery activity in unstructured deltaic reservoirs. The talk emphasized that the reserves-to-production ratio of 5.8 in mature deltaic reservoirs indicates a high risk for abandonment and that timely application of enhanced oil recovery techniques could produce as much as 6 billion barrels of incremental reserves.

Most unstructured deltaic reservoirs are concentrated in a few provinces: in the Cherokee Platform of Oklahoma and Kansas, the Gulf Coast of Louisiana and Mississippi; North Texas, San Joaquin Valley, CA, and in the East Texas Salt Dome province (figs. 1.11 and 1.12).

Currently there are 43 active enhanced oil recovery (EOR) projects in unstructured deltaic reservoirs which include 17 polymer, 12 surfactant, 9 gas injection, 3 thermal, and 2 other projects with a total 1989 production of 3,999 bbl/d. Although the light oil from deltaic reservoirs comprises 20% of the Nation's remaining oil-in-place, it accounts for less than 1% of the U.S. EOR production.

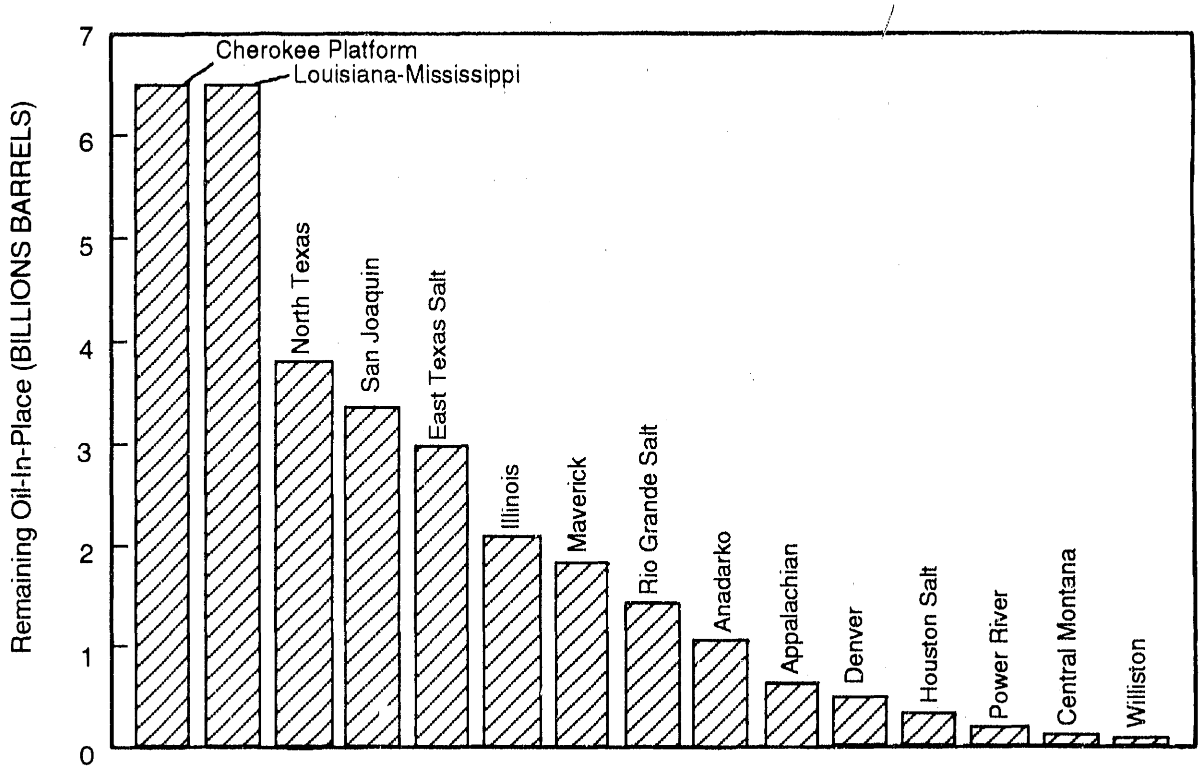

Figure 1.12 - Histogram of remaining oil-in-place by major basin.

Technical Session 1: Reservoir Characterization in Deltaic Reservoirs

Reservoir Characterization of the Illinois Basin Including Deltaic Sands

Donald F. Oltz, Illinois State Geological Survey

Introduction

The Illinois State Geological Survey (ISGS) is one of the largest state geological surveys in the country and is currently dedicating 18 members of its technical staff to a state-federal cooperative reservoir characterization program. The program is reviewed twice each year by two industry advisory committees and was most recently reviewed this past December. In preparation for this symposium, part of the December review meeting was used to solicit input on depositional systems (including deltas) and the influence of delta characteristics on production.

The Illinois program receives continued support from industry individuals and organizations; it has been covered in TV and newspaper media and in regional trade journals. Results are presented at regional and national professional organization meetings. The initial publication based on work done in this program describes an alternative technique for log analysis using the old E-logs that comprise a significant portion of the Illinois oil and gas database.

The ISGS reservoir characterization program (fig. 1.13) is broad-based and interdisciplinary. It relies heavily on operator cooperation for geologic and engineering data and access to leases for brine and oil sampling. Reservoir selection is based, in part, on hydrocarbon volume and sample availability. Initial reservoir characterization employs multiple hypotheses concerning the deposystem and facies. Thin sections, cores, drill cuttings, and logs allow focus and refinement of the multiple hypotheses into a reconstructed deposystem model. An integrated geologic and engineering appraisal provides information about the internal architecture and general flow regimes within the reservoir facies. Exploitation recommendations developed in the current project include geologically targeted infill drilling programs, improved waterflood designs, and recommendations regarding the selective application of acids in certain facies to improve standard stimulation techniques.

Production history in Illinois is characteristic of most mature, producing basins (fig. 1.14). Peak production occurred in the early 1940s following the introduction of seismic, and later, fracturing technology. Subsequent production has been sustained by waterflood. The decline in drilling activity, as measured by the number of permits issued by the state's regulatory authority (fig. 1.15), is a reflection of the domestic industry downturn.

Estimates by DOE of remaining mobile oil-in-place rank Illinois among the top nine coterminous states having significant targets for improved recovery research (fig. 1.16). Illinois' hydrocarbon resources total about 9.5 billion barrels.

Cratonic Basins as Hydrocarbon Containers

The Illinois Basin is one of a large number of intercratonic basins. This classification groups the Michigan, Williston, Paris, Baltic, Parana, Carpentaria, post-rift N. Sea, and others in one class (Leighton and Kolata, 1991). These basins share similar characteristics that separate them from other basin types. Cratonic basins can be quite productive, and the Illinois Basin is among the most productive (Bally, 1980). The project focuses on Mississippian- and Pennsylvanian-age sediments which may illustrate characteristic differences between intracratonic and pericratonic depocenters.

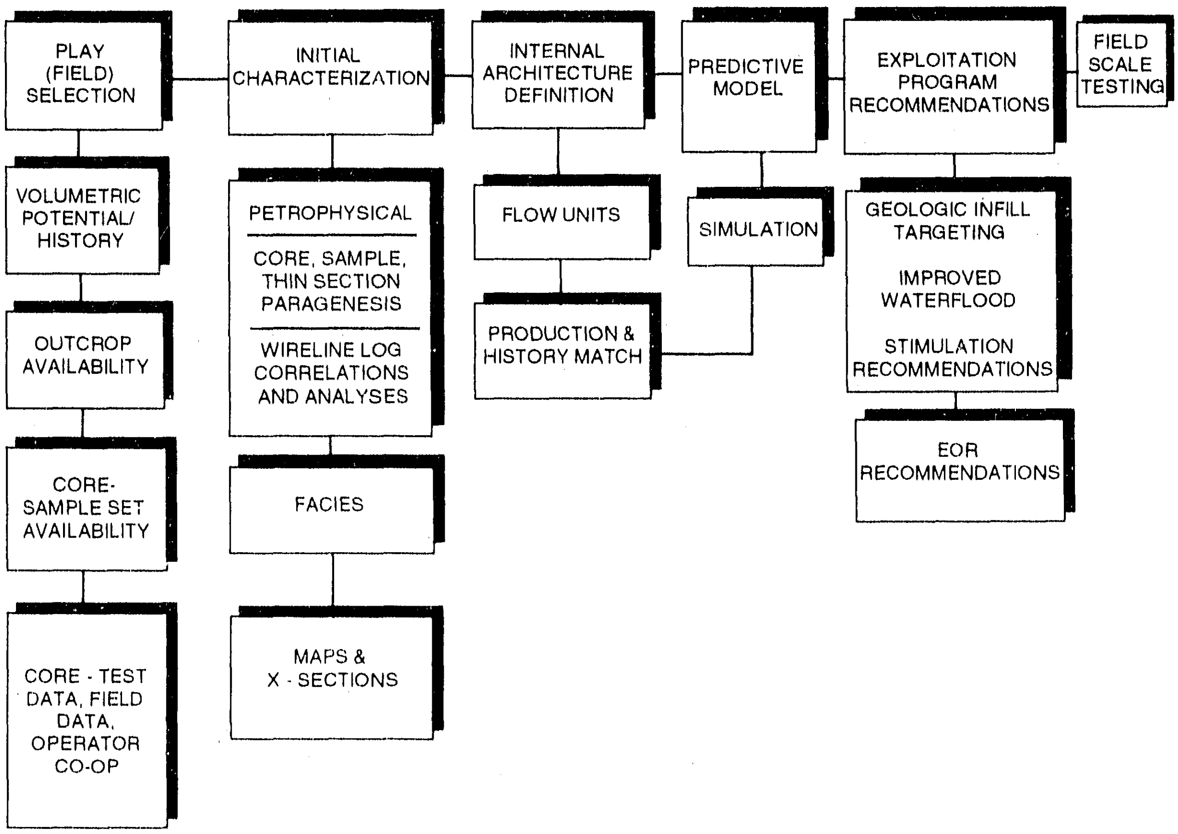

Figure 1.13 ISGS reservoir characterization program flow diagram.

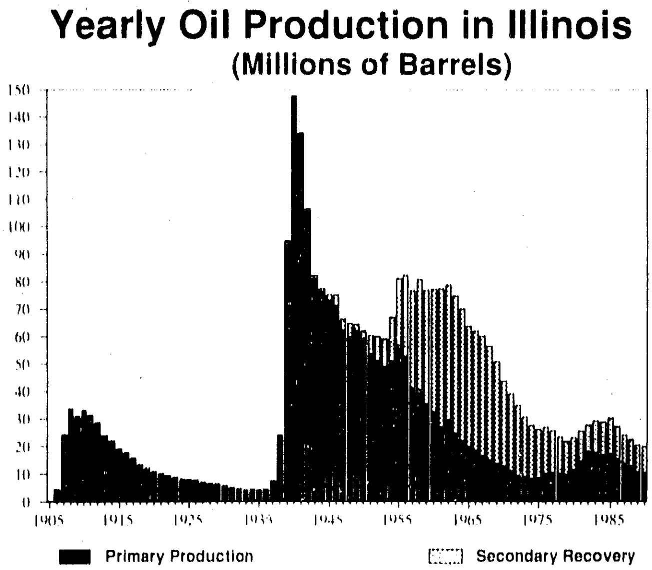

Figure 1.14 - History of production in the Illinois Basin, note peaks at 1940, 1955-65 due to introduction of new technologies.

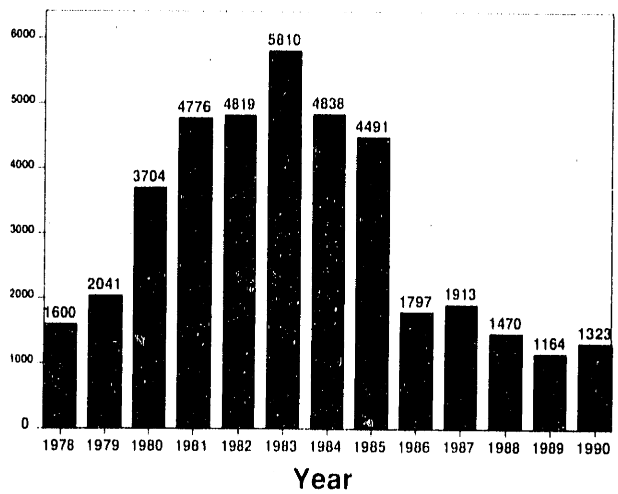

Figure 1.15 - Number of oil well permits issued in Illinois.

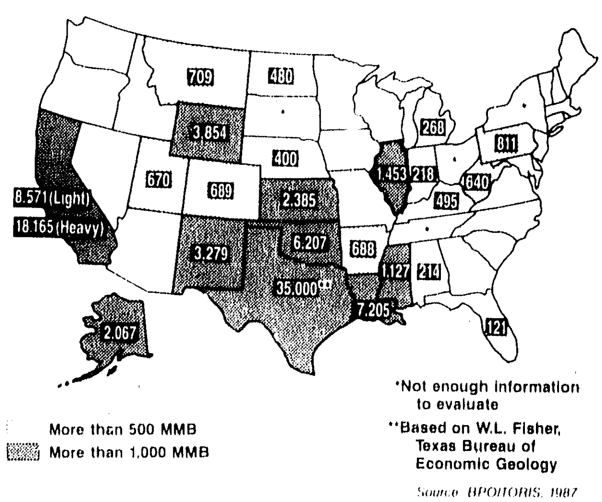

Figure 1.16 - DOE estimates of remaining mobile oil-in-place. Illinois has 1.453 billion barrels of unrecovered mobile oil.

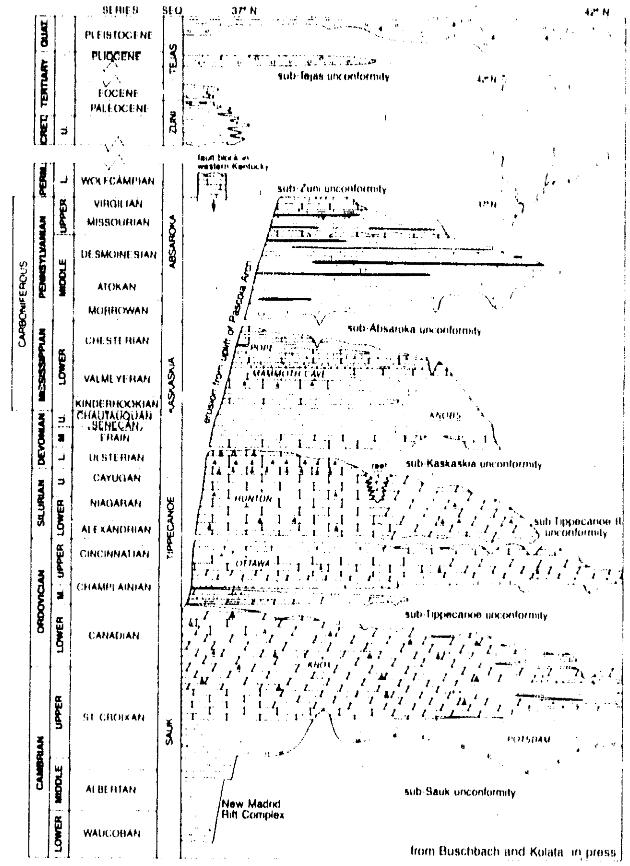

Figure 1.17 - Generalized stratigraphic column for Illinois.

During the Kaskaskia Sequence, for example (fig. 1.17), which includes most of the deltaic reservoirs used here for illustration, the Michigan Basin was isolated, whereas the Williston and Illinois Basins were open to tidal influences. However, sedimentation rates in all three of these intracratonic basins were only slightly less than that at the cratonic edge. During deposition of the Absaroka Sequence, however, sedimentation rates in the pericratonic depocenters were much greater than those on the craton. Rapid accommodation at the continental edge allowed accumulation of hundreds of feet of thick deltaic sands with well-defined peripheral shale boundaries and without major shifts in the distributary channel systems. In contrast, deltaic sands on the craton are measured only in tens of feet. Tidal reworking has locally erased expected deltaic environments, and otherwise characteristic signatures have been modified.

Caution needs to be exercised to avoid overgeneralization of reservoir properties across basins of contrasting depositional history. In contrast with pericratonic basins, interior basins such as the Illinois Basin characteristically have gentle depositional slopes (<0.5 degree), lower geothermal gradients, multiple thin stack pays (generally comprising shallow water deposits), several unconformities (major and minor), and unique deltaic reservoirs. This cratonic basin scenario imparts reservoir characteristics significantly different from those in other basin settings. Sediments commonly show abrupt lateral and vertical changes (although basin-wide units are recognized). Sands can be less mature. There are multiple opportunities for hydrocarbon plays (fig. 1.18). A generalized stratigraphic section illustrates several major deltaic reservoirs in the Illinois Basin.

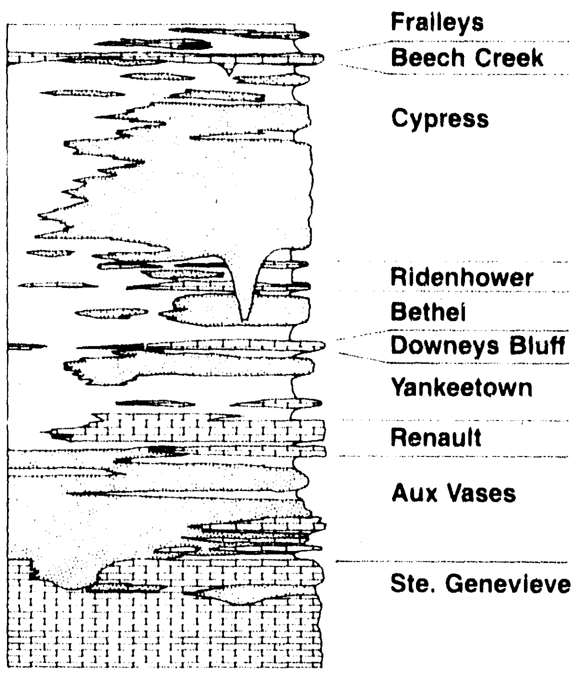

Figure 1.18 - Generalized stratigraphic interval of interest illustrating the depositional setting of the Cypress and Aux Vases Formations.

Deltaic Reservoirs in Illinois

Deltaic plays contribute a significant portion of the oil production in the Illinois Basin. The Tertiary Oil Recovery Information System (TORIS) data include 31 fields and 11 formations following the classification criteria used in screening TORIS reservoirs in the recent Interstate Oil Compact Commission (IOCC) study (IOCC, 1990). Diagenetic factors in these reservoirs include compaction, cementation, and authigenic clays. All traps are combination structure/stratigraphic.

TORIS deltaic reservoirs in Illinois have been categorized as follows:

1. The Upper Valmeyeran Tide-Dominated Deltaic Play comprises nine fields and two producing horizons, the Aux Vases and the Spar Mountain (Rosiclare) (fig. 1.19). Porosity/permeability cross plots of Aux Vases formation reservoirs are shown from Dale Consolidated field (fig. 1.20) and Clay City Consolidated field (fig. 1.21).

Fields In The Upper Valmeyeran Tide-Dominated Delta Play

- Aden Consolidated (Aux Vases)
- Clay City Consolidated (Aux Vases)
- Dale Consolidated (Aux Vases)
- Johnsonville Consolidated (Aux Vases)
- Lawrence (Aux Vases)
- Main Consolidated (Aux Vases)
- Salem Consolidated (Aux Vases)
- Tonti (Aux Vases)
- Tonti (Rosiclare)
- Walpole (Aux Vases)

Figure 1.19 - Fields and formations in the play.

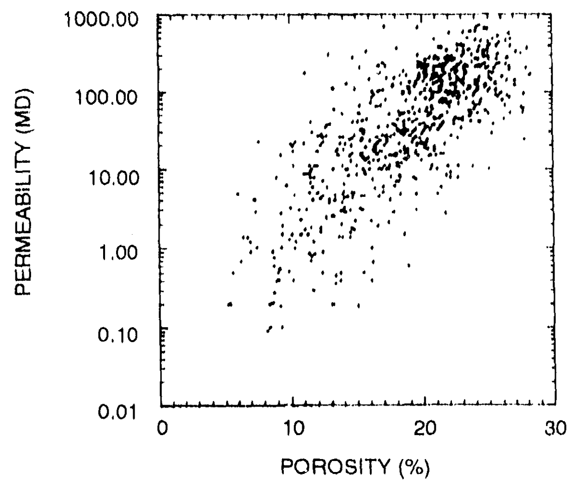

Figure 1.20 - Upper Valmeyeran tide-dominated deltatic play location, Dale consolidated field, Aux Vases Formation.

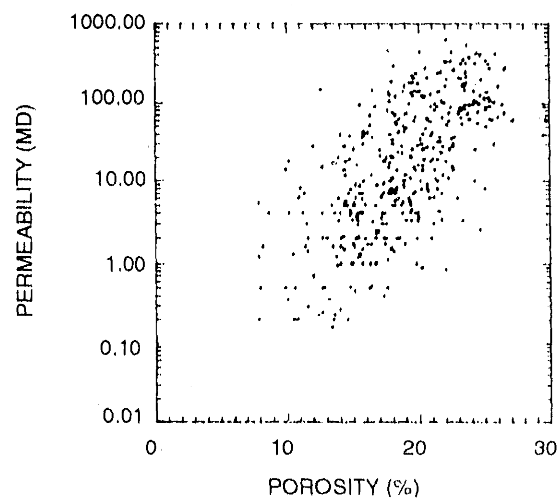

Figure 1.21 - Porosity/permeability cross-plots from Clay City Consolidated field, Aux Vases Formation.

2. The Chesterian Tide-Dominated Deltaic Play includes 16 fields and five formations: the Waltersburg, Hardinsburg, Benoist, Bethel and the Cypress (Weiler) (fig. 1.22). Cypress Formation porosity/permeability cross-plots are shown from New Harmony Consolidated field (fig. 1.23) and Sailor Springs Consolidated field (fig. 1.24).

Fields In The Chesterian Tide-Dominated Delta Play

- Albion Consolidated (Waltersburg)
- Boulder (Benoist)
- Centralia (Benoist)
- Cordes (Benoist)
- Dale Consolidated (Bethel)
- Lawrence (Benoist)
- Lawrence (Bethel)
- Lawrence (Cypress)
- Lawrence (Hardinsburg)
- Main Consolidated (Bethel)
- Main Consolidated (Cypress)
- Mt. Carmel (Cypress)
- New Harmony Consolidated (Cypress)
- Sailor Springs Consolidated (Weiler)
- Salem Consolidated (Benoist)
- Tonti (Benoist)

Figure 1.22 - Fields and formations in the play.

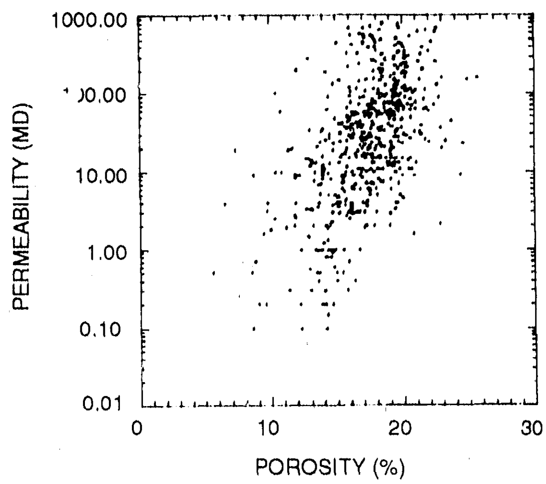

Figure 1.23 - Porosity/permeability cross-plots from New Harmony Consolidated field, Cypress Formation.

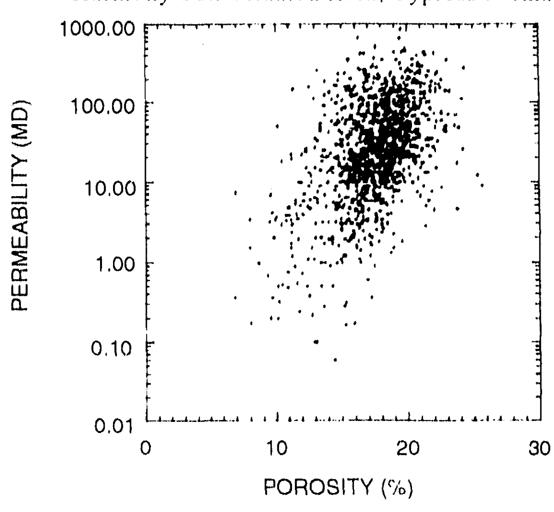

Figure 1.24 - Porosity/permeability cross-plots from Sailor Springs Consolidated field, Weiler-Cyprus Formation.

3. The Chesterian Fluvial-Deltaic Play is represented by two fields and two formations, the Cypress and the Tar Springs (fig. 1.25). Porosity/permeability cross-plots are shown from the Cypress Formation at Dale Consolidated field (fig. 1.26) and Tar Springs Formation at Benton field (fig. 1.27).

Fields In The Chesterian Fluvial-Deltaic Play

- Benton (Tar Springs)
- Dale Consolidated (Cypress)

Figure 1.25 - Fields and formations in the play.

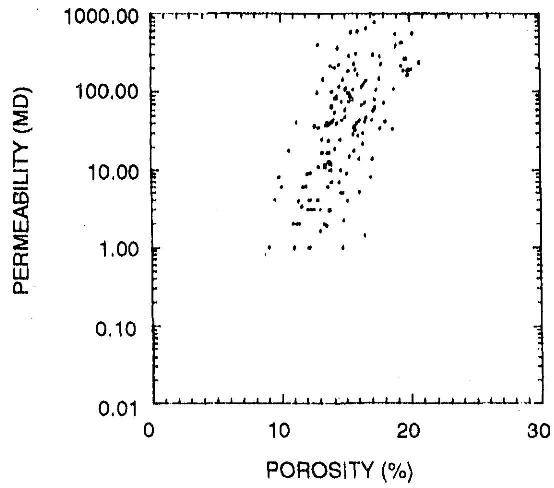

Figure 1.26 - Porosity/permeability cross-plots from Dale Consolidated field, Cypress Formation.

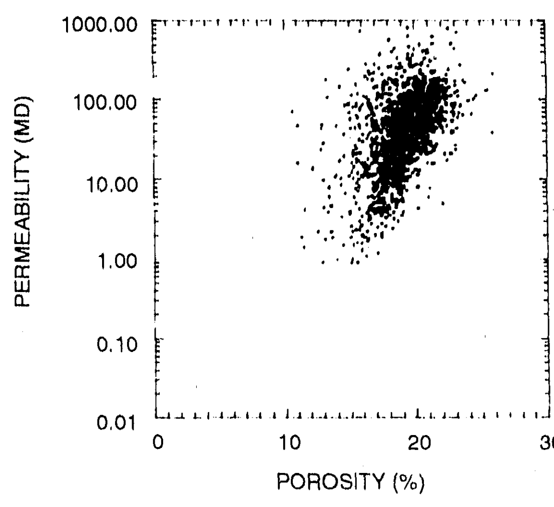

Figure 1.27 - Porosity/permeability cross-plots from Benton field, Tar Springs Formation.

4. The Pennsylvanian Fluvial-Deltaic Play has been documented in three fields and occurs in the Ridgley, Bridgeport, and Robinson sand units (fig 1.28). Porosity/permeability cross-plots are shown from the Robinson at Main Consolidated field (fig. 1.29) and the Bridgeport at Lawrence field (fig. 1.30).

Fields In The Pennsylvanian Fluvial-Deltaic Play

- Lawrence (Ridgley)
- Lawrence (Bridgeport)
- Main Consolidated (Robinson)

Figure 1.28 - Fields and formation in the play.

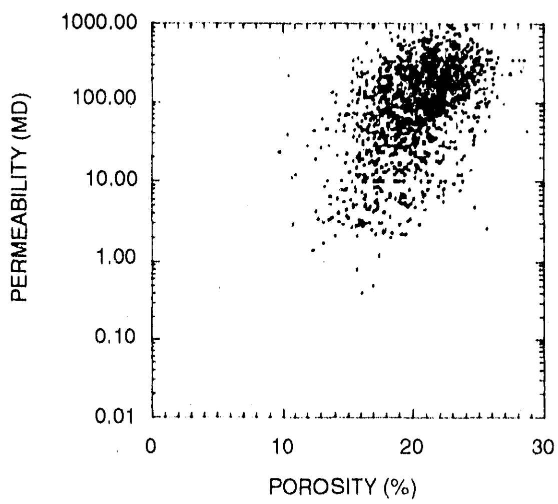

Figure 1.29 - Porosity/permeability cross-plots from Main Consolidated field, Robinson Formation.

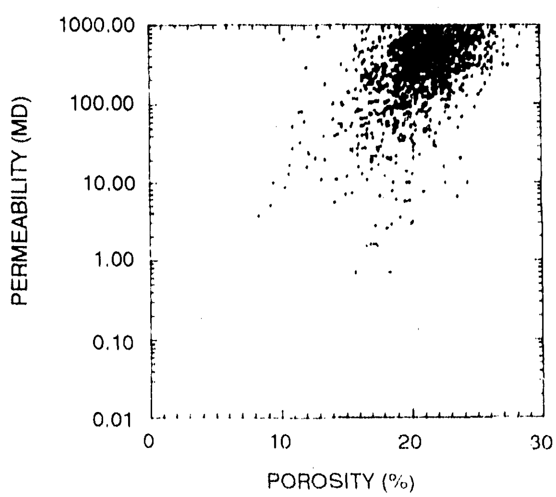

Figure 1.30 - Porosity/permeability cross-plots from Lawrence fields, Bridgeport Formation.

Current DOE-ENR (Illinois State Departments of Education and Natural Resources) investigations show different trends in the respective porosity/permeability distributions of the Cypress and Aux Vases Formations. The Aux Vases data show a linear trend toward increased permeability with increasing porosity (figs. 1.20 and 1.21). The Cypress in contrast is characterized by porosities not greater than about 22% with a typical, narrow range of 18-22% (fig. 1.26). The relationship of the variation in porosity with facies has not been determined.

Examples

Two Cypress Formation reservoir studies in progress include the Parkersburg area (B. Syler) and Bartelso Field (S. Whitaker).

The Parkersburg area is a 30-section study area originally drilled for St. Genevieve (Upper Valmeyeran) targets. The study uses 506 wells, 107 of which produce from the Cypress Formation: 29 from the lower, 70 from the middle, 8 from the upper. Three basic SP signatures are recognized and mapped regionally. One of the three response types, also representative of the largest production, was further divided into upper, middle, and lower Cypress. Isopach maps were constructed for each of the lower, middle, and upper intervals, and the resultant topology was interpreted. The lower Cypress mapped unit characterizes lower delta plain environments including distributary channels, interdistributary bays, and a possible crevasse splay. The middle Cypress mapped unit comprises the best reservoir and has the best production. It represents re-worked, well sorted, thicker, laterally persistent, subaqueous deltaic sands. The upper Cypress map may be indicative of a tidal flat or tidal channel environment. The Cypress in the Parkersburg area is highly variable.

Bartelso field, located in Clinton County, Illinois, produces from the Mississippian Cypress Formation and the Silurian. The Cypress here has been divided into four intervals. Problems exist in the data for this field; e.g., many wells in the field were not logged, the Cypress section was not penetrated by every well, and production figures are comingled. Porosity ranges from 16 to 22%; permeability ranges from 50 to 600 md (based on core). Silica cement and quartz overgrowths are common. Feldspars make up 3 to 6% of the rock and show varying stages of dissolution. Clays comprise less than 2% of the sandstone. Calcite cement is rare.

The four Cypress intervals at Bartelso field are separated by shales and represent different depositional environments. Compartmentalization of the reservoirs is variable depending on the environment of deposition. From oldest to youngest, these intervals represent:

1. Delta: blocky, clean, 40 to 50 ft thick sands, numerous discontinuous shale beds. Regional mapping suggests that this sand extends across the entire area.
2. Upper shoreface: 10 to 15 ft thick sands, shales rare, relative homogeneity based on one oil-water contact.
3. Lagoonal, estuarine: siltstones and shales, thin sandstones.
4. Offshore bars: well-formed, discontinuous lenses, can be locally stacked and may comprise several smaller shingled lenses. For example, one of the bar complexes represents at least two individual stacked bars separated by a thin shale; there is gas in the lower, but only oil in the upper.

Clays are not abundant enough in the Cypress at the Bartelso field to cause production problems. Ten-acre spacing is adequate for recovery except in the upper shoreface facies. The offshore bar-complex shows a tendency for shingling; off-pattern producers drilled for waterflood may have contacted undrained oil.

Individual Study Goals

The integrated ISGS studies require a detailed interpretation of the depositional environment to improve the predictability of the following:

1. Reservoir rock quality.
2. Lateral reservoir boundaries (gradational versus abrupt).
3. Preferred spatial direction and continuity of barriers in each depositional environment.

Because most independents work at the scale of a single prospect, their perceptions of regional deposystems and the variations in those deposystems that control or affect production may be inadequate. The ISGS reservoir and depositional studies are designed to demonstrate the effects of deposystem variation of production and to make this practical information available to independent operators in a usable format.

Overall Project Goals

The three underlying principles of the program are to:

1. Improve understanding of controls on reservoir heterogeneities.
2. Increase and improve (effective) technology transfer.
3. Improve efficient recovery of oil and gas from Illinois reservoirs.

Anticipated Results

As the total study progresses, the following results are anticipated:

1. Characterize reservoirs in sufficient geologic and engineering detail to be able to recommend appropriate improved oil recovery (IOR) and enhanced oil recovery (EOR) technologies.
2. Test some of the drilling and completion fluids commonly used in the basin in core-flow experiments. Both lateral and vertical variations in a single formation across the basin as well as within one field have been demonstrated;; variations in response to introduced fluids are expected.
3. Refine assessment of the State's remaining oil resource for use in planning documents, including the DOE and Illinois energy policy.
4. Enhance the Illinois data base by increasing its size, accessibility to the independent operator, and user friendliness.
5. Expand the use of old E-logs, the common denominator for Illinois Basin data analysis.
6. Document characteristics of brines, oils, and clays for use in geochemical and reservoir models and refinement of drilling, stimulation, and completion practices.

Technology Transfer

In the Illinois Basin, most of the exploration, development, and production is accomplished by independent operators. These companies do not maintain research staffs. They will benefit from having access to new data, recent technological advances, and new ideas about the habitat of oil from the service-oriented environment that a state survey can provide.

Seismic Applications to Reservoir Characterization

Jim H. Justice and M.E. Mathisen, Mobil Oil Corp.

As large commercial oil fields become increasingly difficult to find in North America, attention has turned to the enormous oil reserves which still remain unproduced in existing domestic oil fields. Many of these fields are in decline, and continued economic production may depend on the development and application of new tools which more clearly delineate reservoir characteristics and/or fluid flow patterns.

Seismic tomography is a new tool which can play an important role in reservoir characterization. Cross-hole seismic data have been successfully acquired and processed into tomographic images of the velocity field between wells. These images have been interpreted based on an integrated analysis of all geoscience and production data. Initial results indicate that single tomograms provide additional data for reservoir surveillance.

Tomograms across a midcontinent waterflood document that seismic tomography can be used to image deltaic reservoir sands of the Pennsylvanian Cromwell Formation. Integrated geoscience interpretations indicate that tomograms define cross-hole stratigraphy, structure, facies variations, and reservoir properties. These interpretations enable more accurate reservoir characterization and should help guide reservoir management.

Key Points of the Presentation

1. Applications of cross-hole tomography include (1) identification of high-porosity zones; (2) location of well sites for infill drilling; (3) monitoring of EOR fluid front advancement; (4) information for structural and stratigraphic mapping; (5) monitoring reservoir dynamics such as the movement of a gas cap; (6) additional information for reservoir characterization and modeling.

2. Any feature which effects the velocity will be reflected in the tomogram and includes porosity (lithology), temperature, gas saturation, and pore pressure. Therefore the interpretation of the images requires correlation with a reservoir model constructed from reservoir data such as core analyses, engineering data, petrophysics, and geology.

3. An example of a cross-borehole tomographic study was presented from the Pennsylvanian-aged, deltaic Cromwell sandstone in the Arkoma Basin. The study was conducted in rather ideal conditions where the distance between wells was about 400 feet, and the sequence investigated was about 40 feet thick at a depth of 4,500 feet and consisted of limestone and sandstone layers which provided good velocity contrasts. Faults with a displacement of 20 feet could be recognized.

It was found that (1) reservoir characterization was the the key to interpreting the tomograms and (2) that sedimentology was the key to understanding the distribution of reservoir quality. The presence of sedimentary features of clay drapes and biogenic features resulted in lower reservoir quality sand.

Key Points of the Discussion

1. Currently the technology of cross-borehole tomography is proprietary and is not commercially available. The cost of one tomographic survey currently ranges from \$70,000 to \$100,000 which limits the availability of this technology to smaller oil companies. It is predicted, however, that the costs will drop significantly after the technology is perfected.

2. The technique has limitations and is not a panacea for all reservoir description problems. It is stressed that these data must be integrated with other sources of reservoir data including petrographic analysis.

Petrophysical Challenges, Unstructured Deltaic Environments

Scott Jacobsen, Schlumberger

Wireline logs are routinely used to determine the location of the reservoir in each well and to derive the formation parameters that are critical to the selection and design of the recovery process. Log evaluation consists of three activities: (1) data acquisition, (2) computation, and (3) interpretation.

Because of the mature stage of many domestic fields, the production of hydrocarbons is beginning to require the accurate evaluation of marginal reservoirs. This means that effects previously thought to be unimportant become critical to the evaluation and production of these reservoirs. Three important effects on petrophysical log evaluation are (1) thin bedding, (2) textural variations, and (3) drilling fluid invasion.

Thin bedding and both vertical and lateral textural variations are very common in deltaic deposits. These features occur in the tops of upper delta plain channel deposit sequences in the form of ripple-laminated, small-scale bedding, and clay drapes; in lower delta plain bay fill deposits; and in lower delta plain abandoned distributary fill and basal distributary mouth bar deposits. High-permeability zones susceptible to mud invasion are common in the lower portions of channel deposits--both upper delta plain channel deposits and lower delta plain distributary channels; and the upper parts of distributary mouth bars.

Thin beds, often less than 6 inches thick, distort conventional dual induction log analyses which have a resolution of about 8 feet. The thin beds mask the expression of hydrocarbon presence in the logs and result in leaving a potentially large number of marginal types of reservoirs underdeveloped. Porosity tools have slightly higher resolution, but similar problems of resolution also exist. Several techniques have been developed to address this problem. These include a scheme called "alpha" processing for nuclear porosity measurements, enhanced resolution Phasor™ processing, and the LSA™ (laminated sand analysis) product.

Textural variations create errors in the calculation of irreducible water saturation and permeability. Some success in solving this in selected areas has been seen by utilizing three different types of log measurements. The electromagnetic propagation tool (EPT) provides flushed zone saturations from which a petrophysical textural parameter can be derived. Mineral analysis of the formation, as provided by the geochemical logging tool (GLT), lends itself to a permeability answer in shaley sands and the nuclear magnetic log (NML) will give a measure of the amount of moveable fluid in sandstone lithologies.

Log analysis problems due to drilling fluid invasion are corrected by newer resistivity profiling logging tools such as the array induction imager tool (AIT). Also, advances in low-pressure drilling may help to mitigate mud invasion problems.

Key Points of the Presentation

The following technical developments are required to overcome these problems.

1. Increased analytical capabilities. The ability to collect large amounts of extremely detailed reservoir data has preceded the ability to integrate and process these data in a timely and cost-effective fashion. In 1970, logs recorded 200 kilobits of information per 100 ft of interval. In 1978, the amount of information collected jumped to 160,000 kilobits, and currently in 1990, 2,300,000 kilobits of information is collected per 100 ft of interval.
2. Regardless of the amount of information obtained, many of the resolution problems in petrophysical log data will not be resolved, and we will be required to look to other disciplines for the information needed. For example, interwell heterogeneity may be determined by a new technique called "sonic imaging", which has imaged bed boundaries from the well bore out to 40 feet away in the some experimental cases. Logging of horizontal wells will also provide a wealth of information about the lateral variations of reservoir properties.
3. Finally, the evaluation of these complex reservoirs will be costly and may be difficult to justify for the often marginal return from these areas. However, in one case study cited, a 33% increase in reserves was indicated by utilizing LSA techniques to analyze thin laminated sands versus conventional lower resolution methods. These developments will be critical if we are to be able to produce the remaining oil and gas from these reservoirs.

Reservoir Modeling: Advanced Reservoir Simulation -- Experience in the Big Muddy Field, Wyoming

Gary Pope, Center for Petroleum and Geosystems Engineering, University of Texas at Austin

The presentation consisted of two parts. The first part was a brief summary of a simulation study (Saad et al., 1989) made several years ago of the original Big Muddy surfactant pilot conducted by Conoco in the 1970s. The second part was an overview of some of the significant advanced reservoir simulation topics.

Simulation Study of Big Muddy Field

The objective of this study was to investigate the effects of some design factors on the performance of the Big Muddy pilot project using UTCHEM. The oil cut from the central producer of the Big Muddy five-spot pilot was successfully matched. The observed and simulated polymer, salinity, alcohol, and tracer data were also compared. The reservoir description was based upon cores, logs, and tracer data from Conoco. The process data were based upon a multi-year research project at University of Texas to measure the micellar phase behavior and IFT of the petroleum sulfonate, polymer properties, three-phase relative permeability, and trapping characteristics. The key factor in the good match of the oil bank breakthrough was the inclusion of a thin, high-permeability layer above the main sand separated from it by shale. With enough effort, even very complex processes such as surfactant flooding can be simulated.

After achieving a good history match of the pilot, a design study was made to see if the simulator could be used to suggest design changes that would increase the oil recovery with little or no cost. These factors included salinity gradient, preflush, injection rates, and polymer concentration in the surfactant slug. The capability to do this study did not exist until the mid-1980s.

The combined results of all of the changes showed that oil recovery more than doubled from 31 to 66%. Most of this increase was due to a better salinity gradient at essentially no extra cost. The increased calcium concentration in the injected slug actually improved oil recovery. Phase behavior was improved by changing the salinity gradient in the post pilot design. This and other design changes suggest that the oil recovery could have been doubled at no additional cost. The results of this work are published in Saad et al., 1989.

Overview of Reservoir Simulation Research Topics

An overview of some of the most important reservoir simulation research topics was presented. The four categories presented were: Numerical Problems, Process Description Problems, Design and Application Problems, and Reservoir Description Problems.

Numerical Problems

- Numerical Errors
- Limitations on Problem Size and Optimum Use of Computers
- Reliability Problems
- Human Interface Problems

Each of these was broken down into several general topics, such as: numerical errors, that result from truncation errors, numerical dispersion, and grid orientation. The need for more research was emphasized. As useful as simulation is it still requires considerable engineering judgement. This issue is closely related to limitations on problem size, and optimum use of computers. There are alternatives under investigation such as: higher order finite difference techniques and adaptive mesh refinement to improve computer simulation.

Process Description Problems

The process description problems can be broken down into the following four sub-categories with some examples:

- Phase Behavior
  - Phase equilibrium calculations with three or more phases
  - Characterization of heavy fractions of crude oil
  - Incomplete equilibrium or mixing during displacement
- Physical Property Models
  - Three- and four-phase relative permeabilities
  - Interaction of gel kinetics with fluid flow
  - Rheology of weak gels
  - Description of multiple tracers during steam drives
- Chemical Reaction Models
- Surface Phenomena

Design and Application Problems

The four subcategories and examples of design and application problems are:

- New Processes or New Combinations of Chemicals, Heat, and Solvents
  - Low-tension polymer floods
  - Surfactant-alkaline-polymer floods
  - Profile control with polymer gels during CO_2 floods
- Mobility Control with Foams or Microbes
- Chemical Signal Processing
  - Inverse problems of how to infer geostatistics of reservoirs from tracers
  - Use of tracers for in situ measurements of wettability
  - Combined use of pressure, tracer, and cross-borehole seismic data
- Design Optimization
  - Effective use of horizontal wellbores in EOR
  - Grading of polymer drives
  - Gravity-assisted surfactant flooding
  - Mobility control with steam
  - Mobility control with CO_2

Reservoir Description Problems

Four sub-categories of reservoir description problems are:

- Translation of Geological Description into Gridblock Properties
- Estimation of Effective Gridblock Properties from Petrophysical Data
- Uncertainties in Geostatistics
- Cost of Many Realizations

Reservoir description is an important topic which quantifies reservoir properties and heterogeneities for use in numerical simulation. The challenge is to translate a geological description into gridblock properties. Problems in estimating effective gridblock properties arise from the use of core plug-scale data to determine the properties of much larger volumes of rock. Effective methods of averaging properties but also retaining the important features are necessary to "scale-up" petrophysical data to the larger volumes of gridblocks.

The current practice in reservoir simulation uses a deterministic approach which predicts one outcome only. The geostatistical approach can be divided into stochastic approach and conditioned approach. The stochastic approach requires running a series of simulations based on a set of geostatistical realizations to derive a probability curve for prediction. The conditioned approach is similar to the stochastic approach except data from one or more sources such as core, electric logs, production logs, geology, well tests, tracers, seismic surveys, and history matching of production are used to condition the problem.

The significant issues remaining to be addressed include how to: 1) generate stochastic field based on geology, 2) incorporate conditioning, 3) deal with finite block sizes, and 4) reduce overall effort.

Key Points of the Presentation

The most important conclusion is that there are many diverse and different research opportunities remaining in reservoir simulation. These span the entire range from generic to research specific. We need to work simultaneously on both specific reservoir applications and the cross-cutting problems within reservoir classes and among all classes.

Variability in Deltaic Reservoir Heterogeneity: Implications for Mobile and Residual Oil Recovery

R. J. Finley and N. Tyler, Bureau of Economic Geology, University of Texas at Austin

Based on a 1983 study of 450 major Texas oil reservoirs, 29% of original oil-in-place (OOIP) was found in fluvial-deltaic reservoirs and 30% in other types of deltaic reservoirs. Estimated ultimate recovery (EUR), however, is not in the same proportions for both groups. EUR from fluvial-deltaic reservoirs comprises 28% of recovery from sandstones. EUR from other deltaic reservoir types comprises 49% of recovery from sandstones. The latter disproportionality results primarily from the high recovery efficiency in the East Texas field, a wave-dominated deltaic reservoir. Deltaic deposition and the resulting framework architecture of deltaic reservoirs are determined by the interaction of fluvial processes and waves, currents, and tidal processes in the receiving basin. Classification of deltas relates to overall geometries (elongate to cuspate) and to associated processes (river-dominated to marine-dominated). Critical reservoir heterogeneities vary according to the type of delta. For example, in elongate (Mississippi type) deltas, sand deposition is primarily in fluvial and distributary channels and at the distributary mouth bar which builds seaward to form a "bar finger" sand body with narrow, lenticular geometry in cross section. These types of deltas historically display low to average recoveries. Channel sandstones foster water invasion and are rapidly waterflooded, whereas mouth bar sandstones tend to be more uniformly or top flooded. For example in Daqing field, China, where typical permeability in distributary channel facies varies widely between 200 and 2,000 md, the highest water cut is in the fluvial channels. Stacked sandstone bodies result in multizone waterfloods, and the potential for intra-reservoir entrapment of unrecovered mobile oil is high.

In contrast, laterally continuous sandstones of cuspate deltas, dominated by wave and current processes, exhibit recovery efficiencies that are well above average. Beach-ridge plain sandstones comprise most of the reservoir and are typically syndepositionally reworked resulting in good lateral continuity as well as textural and compositional maturity. These sandstones tend to be top flooded, although vertical heterogeneity and overlapping of sandstones can result in multizone waterfloods. Reservoir compartmentalization is minimal, and most of the remaining oil is true residual oil requiring enhanced oil recovery (EOR).

In Texas, recovery efficiencies (primary and secondary) range from 80% of OOIP for the wave-dominated Woodbine deltas of East Texas field (average reservoir properties include 1.3 darcies permeability, 25% porosity, 14% water saturation, and expected ROS of 15%) to 28% recovery efficiency for fluvial-dominated deltas of the Morrow Sandstone in the Texas Panhandle. Oil recovery efficiencies for reservoirs intermediate between these two types, such as the fluvial-deltaic reservoirs of the Frio Sandstone of South Texas, average 48% of OOIP for that play. Although not affected by structure, some wave-dominated deltas can have a low recovery efficiency where diagenesis and fine grain size determine recovery efficiency. Such is the case for Big Wells field producing from the San Miguel Formation in South Texas which has a primary and secondary recovery efficiency of only 28%. The San Miguel Formation at Big Wells is commonly bioturbated and has 21% porosity, an average of only 6 md permeability (0.1-6 md range), and 30% ROS, although 80% of the mobile oil has been recovered. Big Wells field is virtually strike elongate due to significant reworking of delta front sands by waves and currents. Lacking compartmentalization, and with a large fraction of unrecovered original oil-in-place, such reservoirs offer good opportunities for EOR.

The Bureau of Economic Geology, The University of Texas, Austin, is currently involved in an ongoing project using outcrop exposures of fluvial dominated delta settings in the Ferron Sandstone to evaluate the hierarchy of geological heterogeneities and their effect on reservoir parameters.

Key Points of the Presentation

- Volumetrically significant incremental oil and gas reserves remain within deltaic reservoirs.
- Internal facies architecture is related to the type of delta and the balance of fluvial and marine processes.
- The fundamental flow units follow and are controlled by the distribution, geometry, and type of depositional facies.
- Cuspate deltas dominated by wave and current processes tend to be less compartmentalized and have higher recovery efficiencies than the more highly compartmentalized fluvial-dominated deltas. Because of their good lateral communication, wave- and current-dominated deltas may provide good opportunities for EOR when a large fraction of unrecovered original oil remains in place.

Key Points of the Discussion

- Horizontal wells may prove useful if they could be contained within a single productive sand stringer at Big Wells field.
- It was asked how "mobile oil" was determined, particularly because sands were generally assumed to be water-wet. The answer was that the the mobile oil data were really more useful for comparative purposes and that the relative value of the numbers has validity although the estimates may be twice as large as the actual resource.
- The Bureau of Economic Geology had begun to investigate with Mobil Oil Corp. cross-borehole tomography of subsurface Frio sandstones. It was noted that such work may be useful in interpreting sand-sand contacts.
- The speaker was asked to provide an estimate of the time or manpower needed for a study of a field such as Big Wells field, where there were several hundred wells. The speaker responded by saying that one fully supported experienced geologist could produce such a study in about 1 year at a cost of about $125-150 K/yr in direct costs, depending on the quality of the data (e.g. the age and availability of the wireline logs). Such a study would have to incorporate all production data, and the final cost would be higher if such records were not reasonably well organized and in machine-processable format at the start of the study. Special core analyses and other types of data acquisition could raise the final costs. In all cases, however, total study costs would be well below the cost related to infill or development wells drilled without the benefit of a detailed field study.

Technical Session 2 -- Extraction Technologies

Drilling Technology: Advances in Directional Drilling

William C. Maurer, President, Maurer Engineering Inc., Houston, Texas

Horizontal well drilling may be the largest breakthrough in the oil industry since hydraulic fracturing was developed in the 1950s. Directional drilling technology is advancing at a rapid rate due to the increased use of horizontal drilling. The number of horizontal wells drilled annually increased from 5 wells in 1980 to 1,000 wells in 1990 (fig. 1.31). These horizontal wells are the proving ground for new directional drilling equipment.

Basic Well Profiles

Horizontal wells are drilled in many different shapes, as shown in figure 1.32. In clean reservoirs, horizontal wells are typically drilled horizontally. In "dirty" reservoirs containing impermeable stringers, horizontal wells are often slanted upwards or downwards or drilled in an undulating shape to intersect the impermeable stringers and drain all sections of the reservoir.

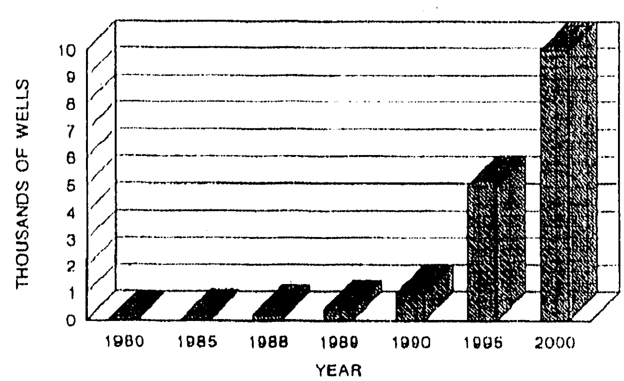

Figure 1.31 Histogram of the estimate of number of future horizontal wells.

Multibranch wells are used to increase horizontal well length and to allow use of existing vertical wells. Drain holes are often drilled upwards into depleted reservoirs where gravity drainage is the only drive mechanism.

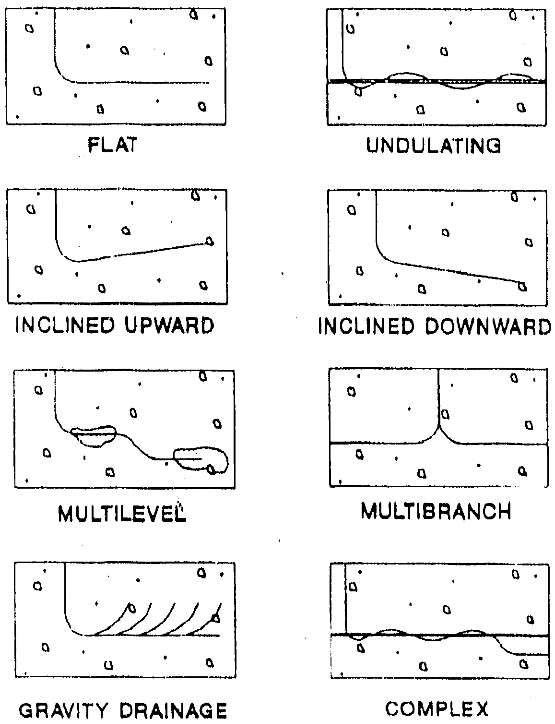

Figure 1.32 - Illustrations of basic well profiles.

Horizontal Well Applications

Horizontal wells are used to increase oil and gas production rates in reservoirs with water and/or gas-coning problems. In reservoirs with gas-coning problems, horizontal wells are drilled along the bottom of the reservoirs, whereas with water coning, horizontal wells are drilled along the top of the reservoir (fig. 1.33). Approximately one-third of the horizontal wells drilled in Canada are used to overcome water-coning problems.

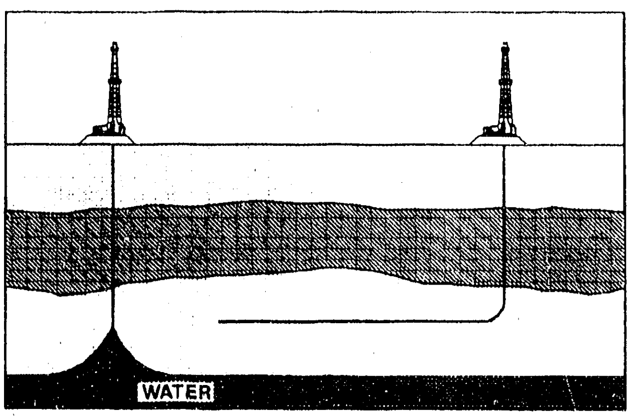

Figure 1.33 - Diagram of water coning application.

Horizontal wells can also be used to improve sweep efficiency. Parallel floods of horizontal wells create line drives which overcome cusp problems with vertical well floods (fig. 1.34). Vertical flooding of horizontal wells can achieve good vertical sweep efficiency for enhanced oil recovery (EOR) processes (fig. 1.35). With heavy oil, steam would be injected into the top horizontal well and heated oil produced from the bottom horizontal well.

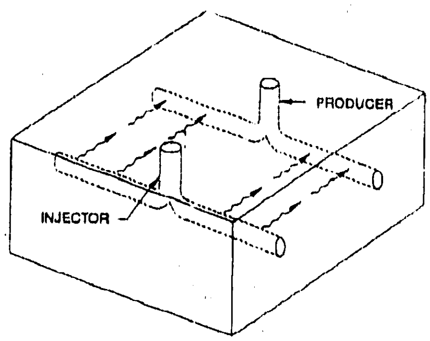

Figure 1.34 - Diagram of horizontal flood movement.

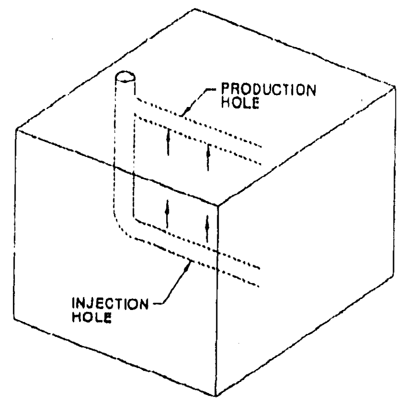

Figure 1.35 - Diagram of vertical flood movement.

Multibranch wells are finding increased use in oil and gas wells because they allow increased horizontal well length at reduced cost (fig. 1.36). A recent multibranch well in the Austin Chalk that utilized 2,200-ft and 3,300-ft laterals was very successful, initially producing 2,200 barrels of oil per day.

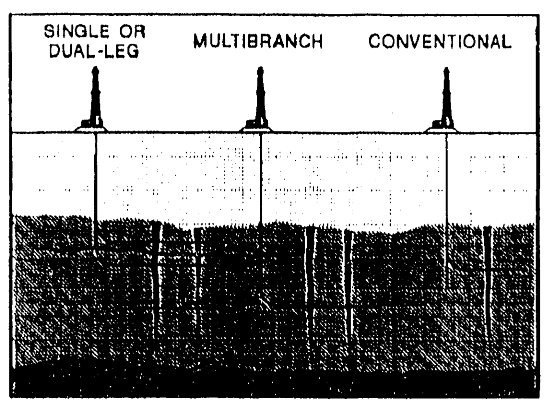

Figure 1.36 - Diagram of well design options.

Multibranch wells are also used to drain pay zones divided by impermeable shale stringers, as shown in figure 1.37. Horizontal wells are also used in low-permeability and naturally fractured reservoirs (fig. 1.38). Horizontal wells typically cost 1.5 to 2 times more than vertical wells, but in current applications, they produce 3 to 8 times more oil and gas than vertical wells.

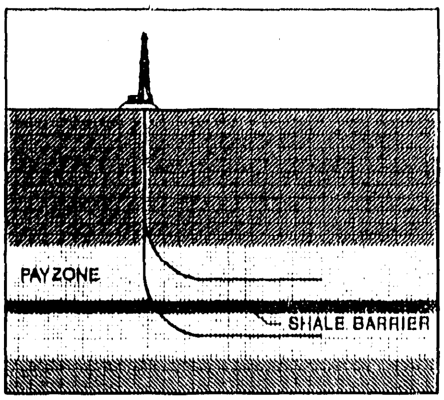

Figure 1.37 - Illustration of dual bore well.

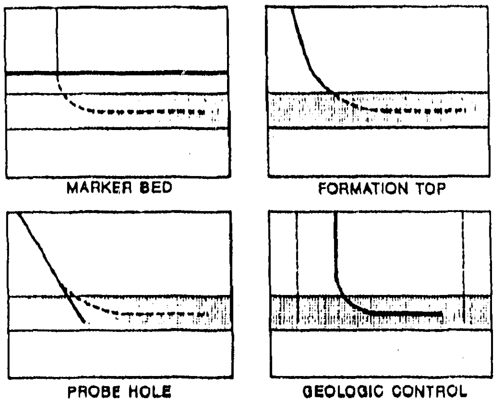

Figure 1.38 - Illustration of naturally-fractured reservoir.

Horizontal wells are not the answer for all reservoirs, being applicable in 20 to 40% of reservoirs. Horizontal well production can be very effective in reservoirs with permeabilities ranging from 1 to 1,000 md. In low-permeability reservoirs (< 1 md), hydraulically fractured vertical wells often produce more than horizontal wells. In highly permeable reservoirs (1,000 md), vertical wells efficiently drain the formations, and horizontal wells are often not needed. An exception is highly permeable reservoirs containing heavy oil where flow rates are low due to the high viscosity of the oil.

Target Location

The four techniques normally used to locate the pay zone with horizontal wells are illustrated in figure 1.39 and are as follows: (1) drill vertically until a known marker bed above the pay zone is identified; (2) drill at a high angle until the top of the formation is identified; (3) drill at a high angle through the pay zone, plug back to the top of the pay, and initiate horizontal well; and (4) drill vertically to a depth determined by nearby vertical wells.

Horizontal wells provide invaluable geological

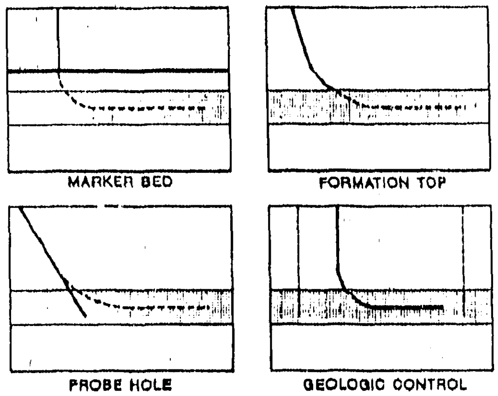

Figure. 1.39 - Illustrations of different target locations.

information about target reservoirs. Coring in horizontal wells is not a serious problem. Information from coring, logging, and production from the first horizontal wells in a field can often tell more about the reservoir geology than 50 vertical wells.

Recent Developments

Recent directional drilling improvements include: (1) improved sidecutting horizontal well bits that drill 20 to 40 ft/hr compared to 3 to 5 ft/hr in 1985; (2) downhole motors that last 100 to 200 hours, whereas 5 years ago failure of motor drive shafts, universals, and bearings was common after 30 to 50 hours; (3) measurement-while-drilling (MWD) tools "hardened" to last 200 to 400 hours under severe vibrations compared to 50 to 100 hours a few years ago; (4) sophisticated directional drilling software that allows directional assemblies to hit targets within 3 to 5 ft, whereas a few years ago hitting targets within 10 to 20 ft was difficult; (5) flexible short-radius motors that can make 40-ft radii turns and be accurately guided by MWD tools over horizontal distances in excess of 1,000 ft; and (6) multibranch medium-radius wells that drain larger areas than single branch wells and reduce drilling costs significantly.

Desired Improvements

Horizontal well drilling costs will decrease rapidly in the next several years. The key factor to reducing drilling costs is the development of improved drilling tools. DOE research programs were instrumental in the development of two important technologies: MWD and polycrystalline-diamond-compact (PDC) bits. The next major development will be slim-hole drilling which can reduce drilling and completion costs 50 to 60%.

Improvements are needed for other tools including bits, motors, MWD, and survey tools. Improvements are needed for bits to drill hard rock at high temperatures and high pressures. Three types of bits are available for horizontal well drilling: conventional roller, PDC, and thermally stable diamond (TSD). Roller bits do not operate effectively at high rotary speeds (due to bearing failures) and often drill slowly in hard formations. PDC bits have high drilling rates but wear out rapidly in hard formations because of high temperatures generated at the cutting edge. TSD bits overcome the high-temperature problem and drill many hard rocks faster than roller or PDC bits. High-power bits suitable for air drilling are also needed.

Improved motors are critical to successful horizontal well drilling. Advanced motors which deliver 3 to 5 times more power than current motors are needed. These motors should deliver high power and operate at high temperatures. Motors for short-radius drilling and air drilling are also needed.

Current MWD systems have sensors located 50 to 80 ft from the bit. This causes problems because the bit often drills out of the pay zone in horizontal wells before the survey sensors detect the change in well path (fig. 1.40). In this case, the bits drill 200 to 300 ft before they can be turned back up into the pay zone, resulting in long, unproductive intervals in the well.

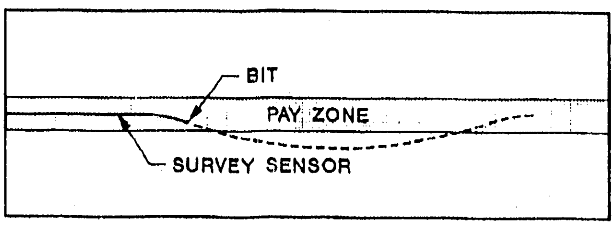

Figure 1.40 - Illustration of borehole guidance problem.

Several companies are developing advanced MWD tools with survey sensors located directly behind the drill bit. They utilize acoustic or electromagnetic transmitters to send signals back to the MWD tool which then relays the data to the surface (fig. 1.41). When developed, these MWD tools will allow more accurate control of the horizontal well trajectories.

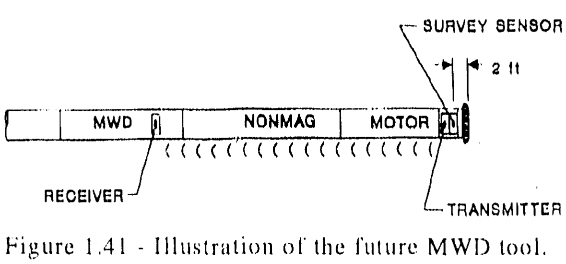

Figure 1.41 - Illustration of the future MWD tool.

Improvements needed in MWD tools include:

1. Survey sensor located near the bit;
2. Two-way communication;
3. Compatibility with shorter radius drilling;
4. Compatibility with air drilling.

Improvements are needed for survey data on azimuth, inclination, tool-face orientation, and electromagnetic systems. Direction control improvements required include joy-stick guidance systems, downhole adjustable assemblies, and downhole thrusters to overcome friction and increase horizontal well length (now limited to about 5,500 ft). Improved production logging techniques are needed for better evaluation of the performance of horizontal wells.

Key Points of the Presentation

More advances have been made in directional drilling in the past 2 to 3 years than in the previous 20 years. This rapid development rate should continue. In 1990, 1,000 horizontal wells were drilled at a budget of $1.5 billion. This is expected to increase to 10,000 horizontal wells annually by the year 2,000, corresponding to an annual budget of $15 billion. This large market will provide the incentive and financial resources for service companies to develop the tools and services needed to increase the use of horizontal wells.

Key Points of The Discussion

1. Horizontal wells have been successfully utilized in a number of oil-bearing formations other than the Austin Chalk. Recently, horizontal wells have been successfully drilled in the Wilcox Formation in Louisiana and Mississippi and the Smackover Formation in Alabama. Horizontal wells have also been applied to offshore gas reservoirs.
2. Horizontal wells have been used to overcome water coning problems. Amoco drilled wells along the top of the Wilcox Formation in Mississippi, guided by resistivity readings from MWD tools. This technique has been used in Canada where wells are also drilled along the bottom of the formation to overcome gas coning.
3. In spite of numerous successes, horizontal wells have failed in some cases (e.g. two horizontal wells in Kansas). Reasons cited for failure were that the wrong reservoirs were selected.
4. Reservoir simulators for horizontal wells have been developed by several institutes including NIPER and the Computer Modeling Group. These reservoir simulators account for wellbore hydraulics and the pressure loss due to friction within the horizontal well.
5. Core recovery within horizontal wells is relatively easy, whereas the technology to evaluate petrophysical properties is lagging. Casing of horizontal wells in fractured, North Sea formations has been successful.
6. Comparisons of the cost-effectiveness of infill drilling vs. horizontal wells are not well understood and are currently being investigated. Preliminary results from a current study by the DOE and Chevron Oil in the Stevens sand in Naval Petroleum Reserve No. 1, CA, indicate that horizontal wells may have a slight cost advantage over infill drilling.

An Analysis of Infill Drilling in the Hugoton Gas Field

Riley Needham, Phillips Petroleum Company

Hugoton field is the largest gas field in the lower 48 states. This study provided an opportunity to test the methodology used to evaluate growth potential for the field. Previously reported studies using the reserve growth potential methodology estimated that infill drilling would yield increased reserves of 25% of the original gas-in-place. Phillips Petroleum used an integrated approach, stressing active simultaneous interaction between specialists from diverse backgrounds to show infill drilling does not add gas reserves in this field. Results have been published in a series of five SPE papers (McCoy, T. F. et al., 1990; Fetkovich, M. J. et al., 1990; Ebbs, D. J., Jr. et al., 1990; Siemers, W. T. and W. M. Ahr, 1990; and Fetkovich, M. J., et al., 1990).

The scope of the study included geological characterization, reservoir modeling, replacement wells, a five-well test in the Kansas portion of the reservoir in 1977, and analysis of performance of 659 infill wells in Kansas. Pay zones include the Winfield limestone, and the Krider and Herrington limestone members of the Nolans limestone, all within the Chase Group. The Chase Group within the field consists of interlayered carbonates, siliciclastics, and evaporites deposited in regionally extensive cycles. Typically a depositional cycle is underlain and overlain by paleosols. There is good lateral continuity of pore types within the carbonate layers because of well-developed intercrystalline porosity which formed as the result of pervasive, area-wide dolomitization. Multiple flow units are separated by barriers deposited at the end of each depositional cycle. The barriers (interbedded redbeds and paleosols) consist of facies which have high threshold entry pressures, are argillaceous, have low permeabilities, and have good areal continuity. Laterally the flow units are continuous and cross facies boundaries. The well-developed pore system within the carbonate layers is related to the diagenetic conversion of limestone to dolomite resulting in isolated dolostone layers with well drained flow units.

During the reservoir study, it was found that modeling single wells with multiple pay zones did not provide a correct history match. The work referred to in this talk was based on a 3-D reservoir model derived from a 12-section portion of the field. A critical part of the work was calibrating new wireline logs to the older logs in order to develop the reservoir model. Other parameters in the study included matching cumulative production history, matching pressures from pay layers based on drill bit tests (DST's) and comparing that data to the model, the deliverability of each well, and maps of porosity and permeability from each zone.

Of the replacement wells drilled in 72 sections, none encountered virgin reservoir pressures. New wells continued to perform at the same rate as that of the original wells. Because of the good lateral communication, it was found that the current 640-acre spacing is sufficient to adequately drain the reservoir. Pressure continued to drop in wells in abandoned sections of the field while gas was being withdrawn elsewhere. Such behavior was offered as further proof of the good lateral continuity within the flow units and the lack of need for infill drilling.

Statistical analyses of more than 600 infill wells drilled of the 3,000 wells which had been permitted, provided no evidence of new or additional reserves.

This study provided conclusive evidence that recovery efficiency was 88% regardless of whether infill wells were drilled or not. Additional infill wells provided no additional reserves but would allow increased production rates. It was also decided that any integrated reservoir study such as this must validate the model by history matching of production.

Key Points of the Presentation

- In cyclical Chase Group sediments at Hugoton field, the diagenetic alteration of limestone to dolomite created multiple laterally extensive intercrystalline pore networks. Interlayered redbeds and paleosols provided barriers to vertical fluid flow resulting in areally extensive, multiple flow units that cross laterally equivalent facies boundaries.
- Reservoir modeling of single wells did not provide a good history match of production within the field. More accurate modeling was based on a number of wells from a series of cross sections and was cross checked with cumulative production history, pressures from distinct pay layers based on DST's, well deliverability, and maps of porosity and permeability from each zone.
- Infill wells in Hugoton field would provide no additional reserves but could be used to increase production rates. Current 640-acre spacing provides sufficient drainage because of good lateral communication within flow units.
- Based on this study, Hugoton field provides classic behavior for a layered, no crossflow reservoir with productive zones exhibiting widely different permeabilities.
- Truly integrated field studies are required in order to produce meaningful conclusions.

Key Points of the Discussion

- It was mentioned that one cannot say that infill drilling will not work unilaterally. The interaction of fluid behavior and what most people refer to as "geology" are the principal causes of heterogeneities that may create problems with infill drilling as well as EOR processes. Thus the same results that were obtained in this study may not necessarily be reached if the reservoir were producing oil.
- The results of this study could not have been forecast by a geological study alone. Needham reported that a prior study had produced a less accurate prediction of infill reserves due to inadequate reservoir performance evaluation, but it was found that there was a need to include reservoir performance evaluation.
- It was suggested that the depositional/diagenetic system controls production regardless of whether gas or oil is produced, even though gas is generally less sensitive to geological heterogeneities.
- It was further suggested that the geological heterogeneities inherent in any particular type of depositional system are the key to understanding the performance of a reservoir. This paper shows where infill drilling may not be useful. In a reply to these statements, it was noted that because all available reservoir data had not been used previously, the results and conclusions of this current study were not previously predicted. The author stressed the need for interactive use of engineering and geologic data above and beyond what is often considered an integrated multidisciplinary study.

Review of Surfactant Flooding in the Illinois Basin -- Robinson Sand

Ron Smith, Manager, Petroleum Recovery Technology, Marathon Oil Company

The M-1 Project, partially funded by the Department of Energy, was a commercial-scale test of the Maraflood™ enhanced oil recovery process (DOE/ET/13077). The project location was in southwestern Illinois near the town of Robinson. The M-1 Project reservoir, the Robinson sand, is a meandering river deposit with migrating point bars occurring between depths of 750 and 1,000 ft. Sand thickness varies from zero feet on the eastern edge of the project to about 60 ft in the center. Both multiple sand bodies stacked one above another and isolated sand lenses, found above and below the main sand, are found in the M-1 Project. A summary of the average parameters for the net reservoir section is as follows: thickness of 28 ft, geometric mean permeability of 77 md, and porosity of 19%. After connate water saturation was determined from electric log data, material balance calculations estimated the post-waterflood oil saturation to be 40% of the reservoir pore volume. The 407-acre project was split into two areas: one area of 248 acres was developed with 2.5-acre patterns, and the other 159-acre area was developed with 5.0-acre patterns. The two pattern sizes were utilized to examine the effect of well density on the economics of the micellar-polymer process.

The injection of a 10% PV of micellar slug began in February 1977. The micellar slug was followed by a partially hydrolyzed polyacrylamide mobility buffer in a tapered concentration sequence. Approximately 100% PV of mobility buffer was, in turn, displaced by drive water. The 2.5-acre pattern area became uneconomic at the end of 1986 and was terminated. The 5.0-acre pattern area was terminated in August of 1989.

The true initial production response in the 2.5-acre pattern area was observed in March of 1979 at 18.6% PV injected. Production peaked in October 1980 (44.5% PV injected) at 577 bbl/d and a 12% oil cut. The 5.0-acre pattern area showed a significant increase in oil cut in May of 1980. Production peaked in October 1982 (45.6% PV injected) at 283 bbl/d at a 13.3% oil cut.

The total project ultimate recovery was about 1.4 million barrels of oil or about 21% of the 40% post-waterflood oil saturation. This recovery is significantly lower than the original total project prediction of 36.6% (38% from the 2.5-acre area, and 35% from the 5.0-acre area). Poor vertical and areal sweep efficiencies caused by reservoir heterogeneities were primarily responsible for the lower than anticipated oil recovery.

Induction logging of observation wells showed the movement of fluid over several intervals, indicating the presence of stacked-sand bodies. The fluid banks advanced at different rates controlled by the reservoir properties within each interval. The advancement of the polymer bank was greatest in the Upper Robinson sand where reservoir quality is superior to that of the lower intervals.

A geological interpretation indicates that the meandering stream channel was deposited in a northeast to southwest direction. Directional permeability should be greatest in this direction due to the orientation of sand grains and sedimentary structures during deposition. Six of ten wells studied with a radioactive tracer program showed a flow trend nearly parallel to this northeast-southwest depositional direction.

An economic analysis of the M-1 Project shows a $4.3 million profit resulting in a 6.1 year payout and an 8% rate of return. This analysis includes the $14 million in investment funds recouped from the Department of Energy as part of a tertiary recovery incentive program.

Key Points of The Presentation

- Sweep efficiency can be improved by either orienting the well pattern to correct directional flow trends or use of horizontal wells or linedrive fluids.
- Chemical costs can be reduced by designing more efficient and lower cost slugs.
- Optimum slug size design is one that uses just enough surfactant to recover oil from the part of formation that can be swept, and not for the total reservoir pore volume.
- Development costs can be minimized by using existing wells.
- The efficiency and success rate can be improved by integrating (1) reservoir sampling, (2) reservoir description, (3) reservoir engineering, (4) laboratory evaluation, (5) modeling, (6) pilot tests, (7) evaluation, and (8) project implementation steps.

Completion Engineering - Where We Are Today/Needs For The Future

Gerald Coulter, Division Completion Engineer, Oryx Energy Company

A brief overview of the completion engineering discipline as it is today, along with some of the potential needs for the future, was presented.

A general definition of completion engineering is "work in the wellbore after pipe is set - which includes the initial completion, as well as workovers later in the life of the well." The problems encountered and solutions used today were discussed as follows.

Current

Formation Damage and Perforating -- We continue to see poor initial production after completion on some wells. It is thought that much of this is due to significant formation damage and/or poor perforating performance.

Stimulation -- Acidizing and, in some cases, a small fracturing treatment, are utilized to overcome near-wellbore damage. These small fracturing treatments can be very effective. Advances in the state-of-the-art in massive hydraulic fracturing are allowing the industry to assess viability of these large treatments. The determination of in situ stresses and application of 3-D frac geometry models let us predict success of fracturing treatments. An area for improvement in hydraulic fracturing is a better understanding of the fluids used. The fluids are not as clean or non-damaging as we would like.

Sand Control -- The industry is very efficient at stopping sand production with gravel packs. Some formation damage still occurs from the use of gravel packing but can be overcome by acidizing.

Horizontal Well Completion -- Horizontal wells are being considered more and more in non-partitioned reservoirs, placing more demands on the completion of these wells. All of the potential problems mentioned above can be magnified in horizontal wells.

Technology Advancement Methods -- The industry has shown a strong interest in cooperative research efforts in the past few years. This cooperative effort is an efficient approach to advancing technology in various disciplines. An example of an association formed to encourage this type of cooperation is the Completion Engineering Association, currently made up of approximately 22 oil and gas producing companies. This association has taken a proactive approach to surfacing industry needs in the area of completion engineering. To further address those subjects receiving the most interest, committees have been formed. These committees will surface specific needs in each of the following areas.

Environmental and Safety

Horizontal Well Completion

Sand Control

Stimulation

Perforation

Water Shut-Off

Future Needs

Many areas within the completion engineering industry need additional research work. For this presentation, the focus was on horizontal well completions. Horizontal wells may be used in deltaic reservoirs to address water coning problems and perhaps replace hydraulic fracturing. There are those situations where bottom water is a problem and hydraulic fracturing may be detrimental to the completion.

As mentioned above, many problems encountered in vertical wells may be magnified in horizontal wells. The problems include formation damage, proper liners for zone isolation, and sand control.

Key Points of Discussion

In a way, a horizontal well can be considered equivalent to a long hydraulic fracture. However, due to vertical permeability variations, a true horizontal well may not adequately drain the interval of interest. Hydraulic fractures from horizontal wells can be beneficial in overcoming vertical permeability barriers, as well as giving additional reservoir stimulation.

Completion/Maintenance Technologies Organic Formation Damage

Kenneth M. Barker, Petrolite Inc.

Long-term productivity from deltaic reservoirs can be affected by a number of factors. A lack of understanding of the relationships of formation fluids, the formation, and production methods often creates problems. Near-wellbore organic formation damage is one of these factors. Paraffins and asphaltenes are the main components of crude oil that generally cause organic formation damage. Precipitation of asphaltenes may drastically change the wettability of the formation near the wellbore, thereby increasing the water cut and negatively affect productivity. Paraffins in the strict chemical sense may be defined as straight-chain alkanes and include methane. They are crystalline, with melting points up to 240° F. Only 10 ppm of C100 paraffin is soluble at 100° F in xylene. Asphaltenes are dispersed by asphaltic resins in the crude oil, and because they are the most polar component of crude oil, they are highly attracted to charged surfaces such as clays or metals. Asphaltenes are not crystalline and will slowly flow after adsorption onto surfaces. Formation damage caused by the precipitation and deposition of paraffin and asphaltenes particles has been a recurrent problem in all types of reservoirs.

Organic damage may be naturally occurring or more frequently the result of common oilfield maintenance operations. Hot oiling to remove downhole paraffin deposits and acid jobs to remove inorganic deposits can cause severe formation damage. These operations may result in the loss of oil production immediately or over a period of years. If the damage accumulates slowly, it may be mistaken for natural depletion of the reservoir.

Older fields and many deltaic reservoirs have cooled to the point that paraffins may precipitate. Hot oil treatments to remove precipitated paraffins often involve the worst stock tank oil because it is drawn from the bottom of the tank which contains crude oil relatively enriched in paraffins and asphaltenes. Upon heating to greater than 200° F, the stock tank crude oil is further degraded by driving off volatile components.

Acidizing has become so well accepted that its implications are often ignored. Acid reacts with asphaltenes in the oil to produce sludge problems in all types of oils. Clearly, compatibility of acid with the crude oil must be checked.

Most organic damage is located near the wellbore (<6 ft), so that alleviation by solvent/surfactant treatments may be a rather simple process. Service companies usually start with a treatment designed to fill 1 foot outside the perforated interval. If this treatment pays for itself in 5 days with increased production, increasingly larger treatments should be tried. The lack of a 5-day payout after a treatment will indicate when the majority of the damage has been removed.

Key Points of the Presentation

- Near-wellbore organic formation damage is an often overlooked cause of decreased productivity.
- Paraffins and asphaltenes are the primary components of the crude oil that create the damage.
- Many older reservoirs, including a good number of deltaic reservoirs, have depleted pressures and have cooled enough to permit precipitation of paraffins. Recognition, monitoring, and reversal of organic formation damage may provide a relatively cost-effective way to effect the ultimate recovery from these older "at risk" reservoirs.
- Organic formation damage may be naturally occurring or it may be brought about by common oilfield maintenance operations such as hot oil treatments and acidization. The formation damage usually accumulates gradually, however, it may occur rapidly, for example after a single hot oil job.

- Organic formation damage may be suspected if productivity declines in a given well faster than in the rest of the field. Damage created by acid jobs may be recognized if the water cut goes up after the acid job. Such occurrences are commonly reported and may provide a measure of the widespread nature of the problem.
- Alleviation of certain types of organic formation damage by multiple solvent/surfactant injection jobs is recommended if each job pays out in about 5 days.

Key Points of the Discussion

- Asphaltenes are often precipitated by injection of liquid petroleum gas(LPG)-enriched natural gas or CO_2. Most CO_2 projects, especially the large ones, have asphaltene problems. In addition, surfactants for chemical floods should be carefully selected to avoid organic formation damage. The use of some surfactants may cause emulsions.
- Gas production will create downhole cooling. For every 40 psi of pressure drop at the perforations during gas production from oil wells, the formation cools approximately 1° F.
- It was noted that paraffins are generally harder to remove than are asphaltenes. Because solvents (such as xylene) are relatively inefficient in removing paraffins from around the wellbore, it would be very useful to develop new or more efficient ways to heat the downhole region, such as by applying microwave radiation to the formation. Continuous monitoring for organic formation damage may be required if there is a natural source of CO_2 in the formation. In other cases, it may take a single treatment to remove the damage if subsequent acidization is not required.
- The effects of treatment for organic formation damage may last up to 2 years for paraffin and up to 6 months for asphaltenes.
- A tip was offered for recognizing organic formation damage caused by gas cooling. Production may increase after a shut-in/workover if the formation temperature is sufficient to melt any paraffins that have precipitated. Production may then slowly decease as paraffin damage recurs.
- It was suggested that a chemical pad might be placed ahead of acid-frac fluids to protect the oil from asphaltene problems created by acid-crude oil contact or paraffin problems caused by formation cooling.
- Because of the affinity of asphaltenes for iron and the abundance of iron sulfide in many water-injection wells, organic formation damage may need to be cleaned up in these wells.
- Further information about organic formation damage is available in the following SPE papers: (Newberry, M. E. and K. M. Barker, 1985; Jacobs, I. C. and M. A. Thorne, 1986; Barker, K. M., 1987; and Addison, G. E., 1989).

TECHNICAL SESSION 3 -- OPERATIONAL CONSTRAINTS

Lessons Learned at Loudon Surfactant Pilots

Edward D. Holstein, Reservoir Engineering Coordinator, Exxon Co., USA

Loudon (IL) field which was discovered in 1940, has a total acreage of 30,000 acres. The primary recovery mechanism was solution gas drive, and some gas reinjection was performed. Waterflooding was begun on a small part of the field in the 1950s, and then was expanded to the entire field. The field is at an advanced stage of depletion after nearly 40 years of waterflooding. Water cut is 99% and the total primary and secondary recovery is expected to be 50% OOIP. Five surfactant pilots were conducted in this field. The first one was performed during the period 1969-1971, and 15% of waterflood residual was recovered. The second small pilot recovered nearly 60% of the waterflood residual. Success of this small pilot led to a series of three pilots to be discussed today. Four SPE papers (Bragg, J. R. et al., 1982; Maerker, J. M. and W. W. Gale, 1990; Reppert, T. R. et al., 1990; and Huh, C. et al., 1990) were published on these pilots.

The pilots were in the Chester (Mississippian) aged Weiler sand. The deposition environment is deltaic resulting in stream-mouth bar and delta fronts. The sands are medium to fine to very fine grained.

The average reservoir properties are as follows:

Depth, ft	1,500
Thickness, ft	50
Temperature, °F	78
Porosity, %	20
Permeability, md	160
Salinity, ppm	104,000
Oil viscosity, cP	5

The rock properties are excellent for the application of a surfactant process. A chemical system had to be developed to work in the high brine salinity environment. The southern part of the reservoir was chosen for pilot tests because it was thought that the geology is less complex and, therefore, easier to interpret the results.

The three pilots were described as follows:

1. a 0.7-acre five-spot pilot,
2. a 40-acre project with 2.5-acre five-spot pattern, and
3. an 80-acre project with 5.0-acre five-spot pattern.

The objectives of the 0.7-acre five-spot pilot were to determine the proper microemulsion slug size and to test the technology for treating macroemulsion in produced fluid.

The second and third projects were initiated at the same time after the successful completion of the small pilot. Nine inverted five-spot patterns were used in these projects. All of the wells in these pilots were new wells. The 40-acre pilot area consisted of an Upper Weiler zone and a Lower Weiler zone separated by an impermeable shale. The thicknesses of both the Upper and Lower Weiler sands change dramatically across the 40-acre project. A number of low-permeability streaks were distributed throughout these sands.

The 80-acre project consisted of three zones, the Upper Cypress, the Upper Weiler, and the Lower Weiler. The Upper Cypress is very tight and pinched out within the project area. It was thought that the Upper Weiler and Lower Weiler were not completely isolated from each other, and communication in certain areas was thought to occur.

The injection sequence and slug sizes were as follows: Slug 1, 0.3 pore volume of microemulsion (viscosity = 28 cP) which consisted of 2.3% surfactant, 1.2 to 2.7% white oil, and biopolymer; Slug 2, 0.7 pore volume of biopolymer drive (viscosity = 38 cP); Slug 3, brine.

Initial oil saturations in the pilot areas varied from 24 to 55%. The variation was caused by sand quality and distance from existing injectors. The waterflood residuals in the initial producing oil cut in the pilot averaged 2%. This result also indicated the lack of infill drilling potential in the field.

The 0.7-acre pilot recovered 68% of waterflood residual oil, and the 40-acre and 80-acre project recovery efficiencies were 27 and 33%, respectively.

The reasons for the recovery efficiencies for the 40- and 80-acre field projects being lower than that of the 0.7-acre pilot were considered to be due to loss of mobility control as a result of problems with polymer transport and the higher degree of heterogeneities in the areas of the larger projects (Dykstra Parson coefficients were 0.43, 0.59, and 0.5 for the small pilot, 40-acre, and 80-acre projects, respectively). Additional core and log measurements after the tests confirmed the heterogeneities of this deltaic reservoir. The recovery efficiencies of various patterns in the project areas varied widely, with the highest being 40%. The loss in mobility control was not due to polymer degradation; the recovered polymer was as effective as the original. Phase separation from surfactant slug and loss of mobility of the higher molecular weight polymer in the formation were thought to be the cause of the loss of mobility.

An interesting conclusion from the laboratory coreflood experiments is the relationship observed between permeability and recovery efficiency for a given set of surfactant formulation and rock -- the higher the rock permeability the higher the recovery efficiency. The conclusion is that the applicability of surfactant flooding is limited to reservoirs with permeabilities greater than 100 md.

The calculated chemical flooding costs for a commercial project, assuming 30% recovery of waterflood residual saturation, are as follows:.

	$/additional bbl of oil
Chemical cost (no recycled surfactant)	28-32
Chemical cost (recycled surfactant)	18-22
Emulsion treating cost	<<1
Facilities	4-8
Drilling wells	??

The ability to break the emulsion without adding chemicals would allow recovery of surfactant. This surfactant is reusable, and it is as effective as new stock. The chemical cost is partially indexed to crude oil cost with the remainder a function of manufacturing equipment.

For future work, the project could be designed to take advantage of recycling the surfactant.

The conclusions that can be drawn from these field projects are as follows:

Successes:

- Mobilization of significant amounts of residual oil
- Successful operation of a large-scale surfactant flood
- Confirmation of many chemical design principles

- Breaking produced emulsion at low cost
- Recovering usable surfactant
- Development of reliable simulation capability

Remaining challenges:

- Solving the polymer transport problem: better use of currently available polymer
- Developing better polymer
- Finding lower cost chemical systems: lower concentration formulations
- Achieving volumetric sweep with wider well spacing.

Key Points of the Discussion

1. A suggestion was made that it would be interesting to compare oil recoveries and costs of a second pilot conducted in the same field using horizontal wells instead of five-spots. In the second pilot, a more detailed facies analysis and more realistic reservoir model should be used.
2. It was commented that an analysis of energy balance should be made for EOR pilots to determine whether there is a net energy gain.

Economic and Regulatory Constraints

James E. Russell, Russell Petroleum Co.

Instability in the price of oil and unrestricted imports of foreign oil are the most devastating factors in solving our domestic energy dilemma. During the 1970s and 1980s, oil prices fluctuated between a low of about $3.00 per barrel prior to the oil embargo in 1973 to a high of $40.00 a barrel in 1981. After a gradual decline to about $25.00 in 1985, OPEC shocked the world in 1986 by flooding the world with oil and driving the price down to less than $10.00 per barrel. Subsequent to this, many oil companies and service companies went out of business. Oil properties were shut-in or abandoned, domestic oil production started to decline, and oil imports began to increase. By the end of 1990, the U.S. had lost nearly 2,000,000 barrels per day in producing capacity, and imported oil now stands at nearly 50% of our needs -- an alarming situation!

Other factors that have impacted the survival of the domestic industry are restrictive environmental regulations and unfavorable tax treatment. With the advent of EPA many rules and regulations have been written and implemented that adversely affect the oil and gas industry. A clean and healthy environment is essential to the public domain and should be preserved. The oil industry is very cognizant of this and it has taken great strides in correcting many of the "sins" of the past. On the other hand, over regulation and discriminations against certain segments of the oil industry may not be in the long term best interest of our society. For example over 16,000 wells were abandoned in 1989, representing 10,000 more wells abandoned than in 1980. Certainly many of these wells needed to be abandoned, but far too many were abandoned because of economic and regulatory constraints. It is recognized that many of these, once abandoned, can never be used in any type of EOR program and that much of the potential reserve will be lost. If this trend is not reversed, we could lose more than 50% of our reserve base in the next decade. Some relief should be built into the regulations for appeal from mandatory plugging and automatic fines. Far too many wells are being abandoned because of tough regulations even though they are not a threat to the environment. There must be a way for industry, the environmentalists, and regulatory bodies to work together in a reasonable and realistic manner that will preserve the environments, but not cripple domestic production.

During President Carter's administration (1976-1980), the byword was that this Nation was running out of oil, that most oil fields had been discovered and were rapidly being depleted, so there was no need to grant incentives to find new oil or improve efficiency of recovery. At the same time, prices were rising and a "boom" in drilling was occurring. President Carter thought oil companies were making too much money, and he referred to it as "obscene profits". As a result, a windfall profits tax was passed by Congress, percentage depletion allowances were reduced or eliminated, expensing of intangible drilling costs was reduced, and other restrictive taxes and regulations were imposed. All of these factors together with the oil price collapse in 1986, the tragic failure of banks and S&L's, real estate evaluation, bankruptcies, etc. have taken their toll on the domestic oil industry.

Oil prices have improved since 1986 and some signs of a partial recovery have appeared, but we are still a long way from reestablishing a viable domestic industry particularly for the independent producer. Many studies have been made by various institutions (DOE, AAPG, University groups, ICF, and others) over the past several years that indicate we do have significant undiscovered oil and gas reserves in the lower 48 states and Alaska. Also, some 350 billion barrels of unrecovered oil will remain in known reservoirs that could be a target for advanced recovery technologies. The purpose of this symposium is to concentrate on the "Unstructured Deltaic Reservoirs" that are a significant part of this unrecovered reserve.

The DOE should be commended for the work it is doing and the new approach to transferring known technology to industry to improve productivity in the near term. A partnership between government and industry is essential if we are going to recover these known reserves in a reasonable time frame. A stabilized pricing scenario, tax incentives, and methods of funding projects are all integral parts of the equation to accomplish this important goal.

The DOE has recently submitted to President Bush recommendations for a meaningful National Energy Strategy. This report points out much of the strategy needed to coordinate all energy sources such as oil, gas, coal, hydroelectric and so on to maintain adequate energy supplies for this Nation for many years ahead. The Texas Independent Producers and Royalty Owners Association (TIPRO), has long advocated a "core supply" energy policy that would maintain supply at a minimum of 20 million barrels of oil or equivalent per day from all energy sources for many years. However, adequate and stabilized pricing and favorable regulations will be necessary to do this.

It is doubtful that a variable import fee is being considered at this time. Such a fee has long been advocated by the Texas Independent Producers and Royalty Owners Association (TIPRO). Most of the other oil and gas associations throughout the U.S., including Independent Producers Association of America (IPAA), support such a fee. However, the Administration and Congress have not approved such a fee in the past. In order to develop and supply this Nation with adequate oil, we cannot rely entirely on the free market to work when in fact the international energy market is almost exclusively government driven -- particularly in the Middle East. An import fee, or other similar options, should be implemented immediately to stabilize oil prices in the range of $25-$30 per barrel. This should cause more drilling and the implementation of improved oil recovery processes that will help lessen dependence on uncertain foreign supplies. Such a price range adjusted for inflation should be fair and reasonable for both the industry and consumers.

As discussed above, the industry has been restricted by certain regulations that amount to disincentives for exploration and initiation of advanced or EOR projects. Recently the Congress passed the Budget Reconciliation Act of 1990. In this act are newly enacted energy-incentive provisions that should be beneficial toward the goals that DOE and industry are trying to achieve. These incentives are as follows:

Tax Credit for Enhanced Oil Recovery

Enhanced Oil Recovery Credit. A credit equal to 15% of qualified costs attributable to qualified enhanced oil recovery (EOR) projects. The qualified EOR costs include: 1) tangible property which is an integral part of the project and with respect to which depreciation or amortization is allowable; 2) intangible drilling costs (IDC); and 3) the costs of tertiary injectants with respect to which a Section 193 deduction (relating to the expensing of tertiary injectants) is allowable.

Qualified EOR Methods. Qualified EOR methods include the nine tertiary recovery methods listed in the June 1979 DOE energy regulations. The nine tertiary recovery techniques are: 1) miscible fluid displacement, 2) steam drive injection, 3) microemulsion or micellar emulsion flooding, 4) in situ combustion, 5) polymer augmented flooding, 6) cyclic steam, 7) alkaline, 8) carbon dioxide augmented waterflooding, and 9) immiscible carbon dioxide displacement. In addition, immiscible non-hydrocarbon gas displacement is considered a qualifying method even if the gas injected is not carbon dioxide. The Secretary of Treasury may also add to the list of qualifying methods. Some of these that are being advocated include 1) in-fill drilling, 2) major workover and/or recompletion, 3) improved waterflooding by pattern change to correct for heterogeneity, 4) new seismic methods and techniques, 5) horizontal drilling, and 6) microbial.

Effective Date. The EOR credit is effective for taxable years beginning after December 31, 1990, with respect to costs paid or incurred in EOR projects begun or significantly expanded after that date. It is not clear what "significantly expanded" really means and needs further definition.

Phase-Out of Credit. The amount of the credit is reduced in a taxable year following a calendar year during which the average national price of oil exceeds $28 (adjusted for inflation). The credit is reduced over a $6 phase-out range (between $28 and $34).

Amendment of Percentage Depletion Rules for Independent Producers

The Act makes three modifications to the percentage depletion rules under Section 613A.

Net Income Limitation. The prior law limitation on the allowance of percentage depletion to an amount not in excess of 50% of the taxpayer's net income from the property is increased to 100%.

Transferred Property Limitation. The prior law denial of percentage depletion for properties transferred after they have been proven is repealed.

Percentage Depletion for Marginal Production. Increase in percentage depletion for marginal production and marginal production are covered here. The statutory percentage depletion rate of 15%is increased by 1% (limited to a maximum increase of 10%) for each whole dollar that the domestic wellhead price of crude oil for the immediately preceding calendar year is less than $20 per barrel (not adjusted for inflation).

Marginal production is defined as:

(a) crude oil and natural gas produced from a domestic stripper well property. A stripper well property is any property which produces a daily average of 15 bbl or less per producing well on such property in the calendar year during which the taxpayer's taxable year begins. The determination whether a property is a stripper well property is to be made separately for each calendar year. This apparently repeals the "once a stripper always a stripper" rule.

(b) Oil from a domestic property substantially all of the production of which is heavy oil (having a weighted average gravity of 20° API or less).

Effective Dates. The amendments relating to the net income limitation and the percentage depletion rate for marginal properties are effective for taxable years beginning after December 31, 1990. The amendment repealing the transfer rule is effective for transfers of property occurring after October 11, 1990.

The IRS is currently reviewing and will be writing regulations on these incentives in the near future. Correspondence with the IRS in Washington, D.C. is invited to support these regulations and proper implementations.

Other incentives included in the tax package cover changes in the Alternative Minimum Tax (AMT) and extension for 2 years of the tight sand (Sec. 2a) credit for tax years after 1-1-91.

Because transfer of technology and application to field projects are of utmost importance to our improving oil recovery, basic means of funding such projects have been a problem in the past for many small- to medium-sized independents. Capital requirements usually are high "up-front" with deferred returns over a longer period of time than primary production. However, in most cases, the risk is much lower. Price stabilization at levels between $25 and $30 per barrel and the tax incentives in the Budget Act should be beneficial in developing these projects. However, in order to ensure that qualified projects are continued and fully developed to maximize recovery, the ability to finance such projects properly is an important consideration. Perhaps some relationship between the operator, government, and financial institutions for guaranteed loans could be developed.

It is apparent that we may have improved our position on tax incentives included in the Budget Reconciliation Act of 1990, but we still need to achieve a reasonable stabilized price high enough to stimulate and accommodate the cost of development and application of technology to recovery the oil we know is out there. Without this, much of the technology transfer will not be economically available to the independent segment.

I disagree with those in government and our Administration, as well as some economists, that $25-$30 oil ($0.60-$0.70/gal.) would be devastating to our GNP when a gallon of Coke™ or a gallon of milk costs two to three times more. When you factor in the cost of protecting our foreign supplies, the hidden cost to our taxpayers per gallon of gasoline is unbelievably high (according to Kent Hance, former Texas Railroad Commissioner). Mac Wallace (also a former Texas Railroad Commissioner) once said, "If it's worth fighting for, it's worth drilling for."

Actions necessary to stimulate production and reduce the number of well abandonments:

1. Establish an appeal mechanism for abandoned wells and other regulation issues.

2. Work with the EPA to reduce environmental regulation restraints which contribute to premature abandonment of wells. Leniency on shut-in times would reduce the need to plug and abandon wells and allow the option of re-entry and application of EOR processes.

3. Avoid windfall profits tax that could devastate many oil producers and would be counter to DOE's objectives of implementation of known technology.

4. Stabilize oil prices at $25 to $30 per barrel by imposing an import fee. This stability is necessary for oil companies to invest in producing oil from

domestic oil fields rather than foreign production and would ignite industry into domestic activity.

5. Offer tax incentives for 15% of qualified costs such as property and equipment, drilling costs, workover costs, use of new technology such as seismic methods, EOR implementation costs, and other enhanced recovery techniques such as improved waterflood methods, infill drilling, and horizontal drilling. The following processes are considered EOR processes: miscible, steam, micellar, in situ, polymer-augmented waterflood, cyclic steam, alkaline flood, CO_2 waterflood, CO_2 miscible. Also, a plea was submitted for relief from depletion allowance.

6. Change the public perception that low oil prices are good for the economics of the country and increase awareness of what is involved in the production of a barrel of oil.

Key Points of the Discussion

1. Problems for the oil producer are: the costs of oil production and the subsequent refining to gasoline are high, a fact not appreciated by the public. Since gasoline is not subsidized, (the United States is one of the few countries where it is not) the public is subjected to the full cost of the energy resource and feels that oil companies are making "obscene profits." If the media and government would work with the oil companies, they could correct this public misperception.

2. Many of the participants claimed they were free market advocates and did not think that price regulation is a long-term solution to the problem. However, U.S. operators are at a disadvantage in the world market because they are competing against government subsidized companies.

Environmental Constraints

Cheryl Stark, Milpark Drilling Fluids Company, Houston, Texas

The topics of the past 2 days have covered the technical restraints to development of U.S.A. oil productivity. The technical restraints may be easier to forecast, develop, and commercialize than to anticipate the future of environmental regulations. Legislation is imposed from the federal, state, and local level, and may be more a factor of public opinion than environmental protection. Federal laws under which petroleum and gas industries operate cover the entire gamut of Environmental Protection Agency (EPA) Occupational Health and Safety Act, (OSHA) Minerals Management Service (MMS), Bureau of Land Management (BLM), and others with less widespread impact. The EPA has the greatest number of regulations and covers all aspects of operations from air, water, groundwater, land, coastal zone/wetlands, and waste management. The acts have been in place for some time, but each is reauthorized on a 5 to 10 year cycle, and may at each reauthorization become more restrictive and contain more reporting requirements. All aspects can eventually become restrictive and expensive to actual drilling and production operations.

The federal laws briefly are:

Clean Water Act (CWA) which contains the National Pollutant Discharge Elimination System (NPDES) concept of water discharge permitting and storm water testing/regulation and is being reauthorized this year. The reauthorization will probably set tighter restrictions on use of coastal zone and wetlands and contains the idea of "no net loss."

Clean Air Act (CAA) which was recently reauthorized (1990) and contains newer restrictions for ozone, global warming, and acid rain control.

Resource Conservation and Recovery Act (RCRA) which contains the concept of "cradle to grave" waste management, controls for underground storage tanks, and is being reauthorized this year (1991). Reauthorization could lead to the loss of the oil, gas and geothermal industry exemption to disposal of drilling fluids, produced water, and associated wastes.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) which entails Superfund identified toxic chemicals, and in the reauthorization as Superfund Amendments and Reauthorization Act (SARA) expanded included the reporting requirements of "Community-Right-To-Know."

Safe Drinking Water Act (SDWA) which regulates underground injection control, the placement, classification and construction of injection wells.

States also have water, waste and air disposal restraints, and in many cases, these regulations are more restrictive than the federal laws. For instance under RCRA, each state was given primacy in setting the regulations for handling of drilling fluids, cuttings, produced water, and associated waste. Complications occur in dealing with different agencies in each state, the varying laws, and overlapping jurisdictions. All the various laws and regulations require operators to have large environmental support staffs, spend increasing sums to comply, and constantly review and educate local personnel. The environmental arena is certainly not static. The speaker can offer no positive assurance that these environmental restrictions will become less complicated, or that the effect on drilling and production operations will lessen. One can only assume that environmental regulations must be factored into all operations for production of oil and gas.

DOE Oil Research Program - Data Constraints

Philip H. Stark, Petroleum Information Corporation

There are abundant data collections to support the DOE's Oil Research Program. The major constraints appear to be the availability of ready-to-use computerized data and the cost to generate computerized databases from disaggregated hard copy archives that are essential for the program. Integrated commercial databases and new technologies such as Geologic Information System (GIS), scanned image data capture, and desktop applications workstations provide an excellent platform to create an information system for the program. Commercial databases are being integrated through entry of API well numbers and standard field, operator, and geologic formation codes to all well entities. Complete (all wells) well and production histories are available in the Rocky Mountains, Anadarko and Permian Basins. Pre-1965 field development wells are being encoded at the rate of 5,000 per month in Texas, Oklahoma, and Louisiana. The objective is to provide a well history for all current and abandoned producers. Thus, commercial databases soon will provide well core, test and completion data plus production volumes and performance test data for all wells associated with about 60%(16 billion bbl) of the resources in the program. Substantial commercial databases also are available for the balance.

Other commercial databases also are important. More than 2.2 million well logs are available from commercial sources. Few logs are digitized, but new scanning technologies allow one to economically capture and display logs. In the Gulf Coast, geologic databases provide correlated tops, sand counts, hydrocarbons and pressure data for about 30,000 onshore wells. Regional geologic characteristics of deltaic systems can be mapped from these data. Digital indexes also allow one to retrieve and map more than 500,000 miles of commercially available seismic lines in the Gulf Coast. Digital land grid from USGS 7.5 minute quads -- the graphic foundation for digital maps -- soon will be available for all major U.S. producing provinces.

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Chapter 2

CHARACTERIZATION OF THE LIGHT OIL RESOURCE FROM IDENTIFIED FLUVIAL-DOMINATED DELTAIC RESERVOIRS IN THE UNITED STATES

INTRODUCTION

Deltaic reservoirs are by many measures the predominant type of light oil reservoir in the United States. Considering only the light oil (gravity greater than 20° API) contained in the 2,540 reservoirs in the Tertiary Oil Recovery Information System (TORIS) data base, deltas account for about one-third[1] of U.S. oil recovery to date (Figure 2.1). The application of additional recovery technologies to these deltaic reservoirs before they are abandoned could yield nearly 6.7 billion barrels of new reserves at foreseeable prices. However, 2.3 billion barrels of this 6.7 billion barrels of oil is at risk of abandonment by 1995. Fluvial-dominated deltaic reservoirs contain up to 3.4 billion barrels of the potential 6.7 billion barrels of incremental reserves. Of the 2.3 billion barrels of the oil from deltaic reservoirs which is at risk of abandonment by 1995, 900 million barrels is contained within fluvial-dominated deltas. Based on their historical importance, large recovery potential, and impending abandonment, the U.S. Department of Energy (DOE) is focusing a significant portion of its R&D program on fluvial-dominated deltaic reservoirs.

TERTIARY OIL RECOVERY INFORMATION SYSTEM

The analysis of enhanced oil recovery (EOR) and advanced secondary recovery (ASR) potential is based on recovery performance and economic modeling using the Tertiary Oil Recovery Information System (TORIS). This system was adopted and validated by the National Petroleum Council (NPC) in 1984[2] and is maintained and updated by the U.S. Department of Energy's Bartlesville Project Office. TORIS consists of comprehensive oil reservoir data bases and detailed engineering and

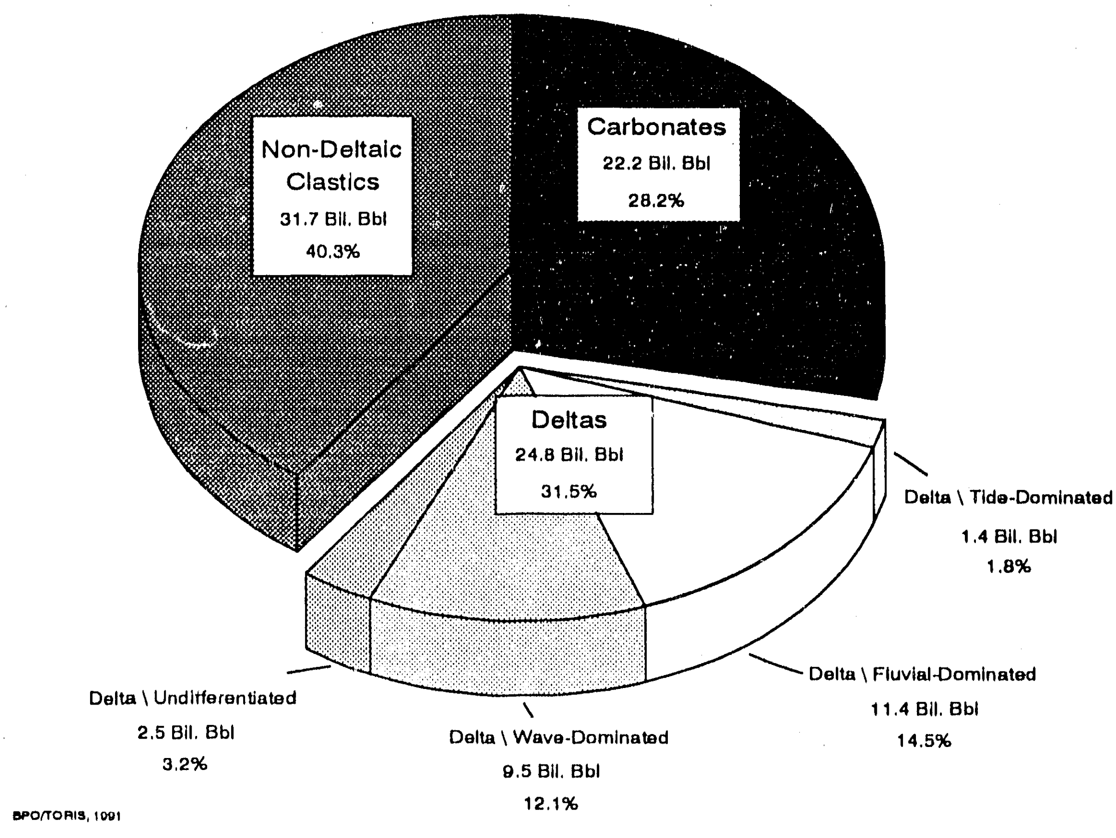


Figure 2.1 - Cumulative Light Oil Recovery from TORIS Reservoirs

economic evaluation models for a variety of EOR and ASR technologies. The models address individual reservoirs separately to estimate costs and production, as well as to evaluate the applicability and anticipated performance of various recovery technologies. The models are also used to predict project economics and, ultimately, the potential crude oil resource. Decline curve models predict reservoir abandonment dates and ultimate recovery. This analysis of fluvial-dominated deltaic reservoirs is based on 410 such reservoirs represented in the TORIS data base as of this writing.

TORIS was originally designed to evaluate EOR potential which targets remaining immobile oil. The capabilities of TORIS have since been expanded to incorporate the evaluation of the unrecovered mobile oil resource (UMO). Unrecovered mobile oil, the target for advanced secondary recovery operations, consists of uncontacted or bypassed oil that is physically displaceable by water. "Uncontacted" oil is oil trapped in isolated portions of the reservoirs not in contact with wells at the current spacing, while "bypassed" oil is in pressure communication with existing wells but remains unswept by secondary processes.[3]

The resource potential documented within TORIS is estimated for two technology levels: *implemented technology*, which assumes the more extensive application of currently available technology, and *advanced technology*, which assumes that the scope and the application of existing technology is extended to overcome current technical and economic limitations. These cases were originally defined by the NPC (1984) for immobile oil (EOR), and were expanded by the DOE (1990)[4] to include unrecovered mobile oil (UMO). Examples of technological improvements include increased injectant sweep efficiency, increased injectant tolerance to "severe" reservoir conditions (temperature, salinity, etc.), decreased chemical retention, improved process displacement efficiency, and reduced injectant costs. A more detailed description of advanced technology assumptions is given in the NPC (1984) report on *Enhanced Oil Recovery*. Tables 2.1 and 2.2 show examples of the implemented and advanced technology screening criteria for selected EOR and ASR processes.

GEOLOGIC CLASSIFICATION SYSTEM

The geologic characteristics of reservoirs influence the volume, distribution, and potential recovery of remaining mobile and immobile oil. The primary geologic factor affecting recovery potential is the origin of the reservoirs, the conditions under which the sediment packages were originally deposited. These processes of deposition yield distinct spatial relationships between and within reservoirs. "Deposystem" is the term used to encompass the environment of deposition and the resulting distribution of sediments.

A major constraint to oil production is reservoir heterogeneity, variations in rock properties within the producing interval which affect fluid flow at the interwell scale. Reservoir heterogeneities result from the processes of deposition or by the subsequent alteration of the reservoir rocks by diagenesis or tectonic activity. Noting that future production of light oil (>20° API) in the United States could be significantly augmented by better definition of reservoir units, the U.S. Department of

Table 2.1 - Screening Criteria for EOR Candidates.

	Miscible	Surfactant		Alkaline	
Screening Parameter	Implemented & Advanced Technologies	Implemented Technology	Advanced Technology	Implemented Technology	Advanced Technology
Oil Gravity (oAPI)	≥25	--	--	<30	<30
Oil Viscosity	--	<40	<100	<90	<100
Reservoir Temperature (oF)	--	<200	<250	<200	<200
Permeability (md)	--	>40	>10	>20	>10
Reservoir Pressure (psia)	≥MMP*	--	--	--	--
Brine Salinity (ppm)	--	<100,000	<200,000	<100,000	<200,000
Rock Type	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone	Sandstone

*MMP denotes minimum miscibility pressure, which depends on temperature, crude oil composition, and injectant gas

Table 2.2 - Screening Criteria for ASR Candidates

	Polymer*		Profile Modification	
	Implemented	Advanced	Implemented	Advanced
Reservoir Temperature (°F)	<200	<250	<180	<250
Formation Brine Salinity (ppm)	<100,000	<200,000	<100,000	<200,000
Permeability (md)	>20	>10	>20	>10
Oil Viscosity (cp)	<100	<150	<100	<150

*Source: NPC, 1984

Energy resolved to gain an increased understanding of reservoir heterogeneity by delineating the geologic characteristics of reservoirs. A reservoir heterogeneity classification system for reservoirs in the TORIS data base was developed. Approximately 2200 TORIS reservoirs have been classified.[5]

Similar types of reservoirs have been combined within a geologic framework for focused research into reservoir heterogeneity. Based on extensive discussions of lithology, depositional system, diagenesis, and structure, a committee of expert geologists grouped the reservoirs from geologically similar deposystems into 22 classes: 6 carbonate and 16 clastic. Reservoirs within these classes were created by like processes and are expected to manifest attendant similarities in reservoir heterogeneity as outgrowths of their similar lithologies and depositional settings.

The structural and diagenetic compartmentalization of a reservoir can have an overriding influence on the flow of oil and other fluids. Recognizing the importance of these modifiers in the description of reservoir behavior, the experts agreed that it was desirable to generate subclasses for each class. They created structural subclasses for the clastic classes and diagenetic subclasses for the carbonate classes. The resultant grouping of reservoirs into classes with subclasses addresses the observation that other geologic factors, in addition to depositional setting, have an impact on reservoir heterogeneity (Figure 2.2).

Among the sixteen clastic classes are four that are deltaic in origin (Figure 2.3). Deltaic reservoirs are created by stream fed systems which deposit sediments rich in organic matter into standing bodies of water (lakes, bays, lagoons, oceans, etc.), resulting in an irregular progradation of the shoreline. In general, all deltas are marked by a thickening wedge of sediment at the interface of land and water formed by the rapid influx, deposition, reworking, and subsidence of sediment at a rate which exceeds its removal and redistribution by wave and tidal action.

The nature of the depositional processes and the internal architecture of deltaic systems justified the delineation of four distinct deltaic classes: Delta/Undifferentiated, Delta/Wave-dominated, Delta/Fluvial-dominated and Delta/Tide-dominated. Undifferentiated deltas are either complex combinations of any or all of the three major types, or deltas for which insufficient information was available with which to place them into any of the other three classes. Each of the four deltaic classes has a "structured" and "unstructured" subclass. Diagenetic processes, specifically the growth of authigenic clays, have a significant effect on heterogeneity. This is particularly important in fluvial-dominated and wave-dominated unstructured deltas. These processes are too widespread to be useful in the differentiation of subclasses within the clastic deposystems.

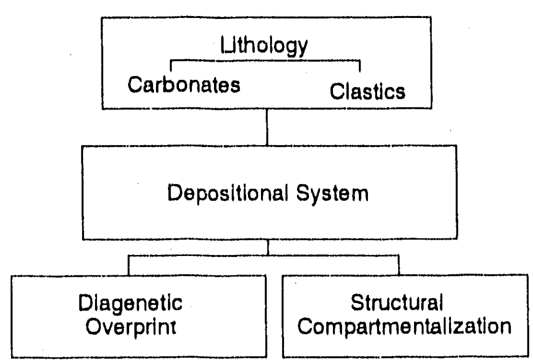


Figure 2.2 - Organization of the Reservoir Classification System

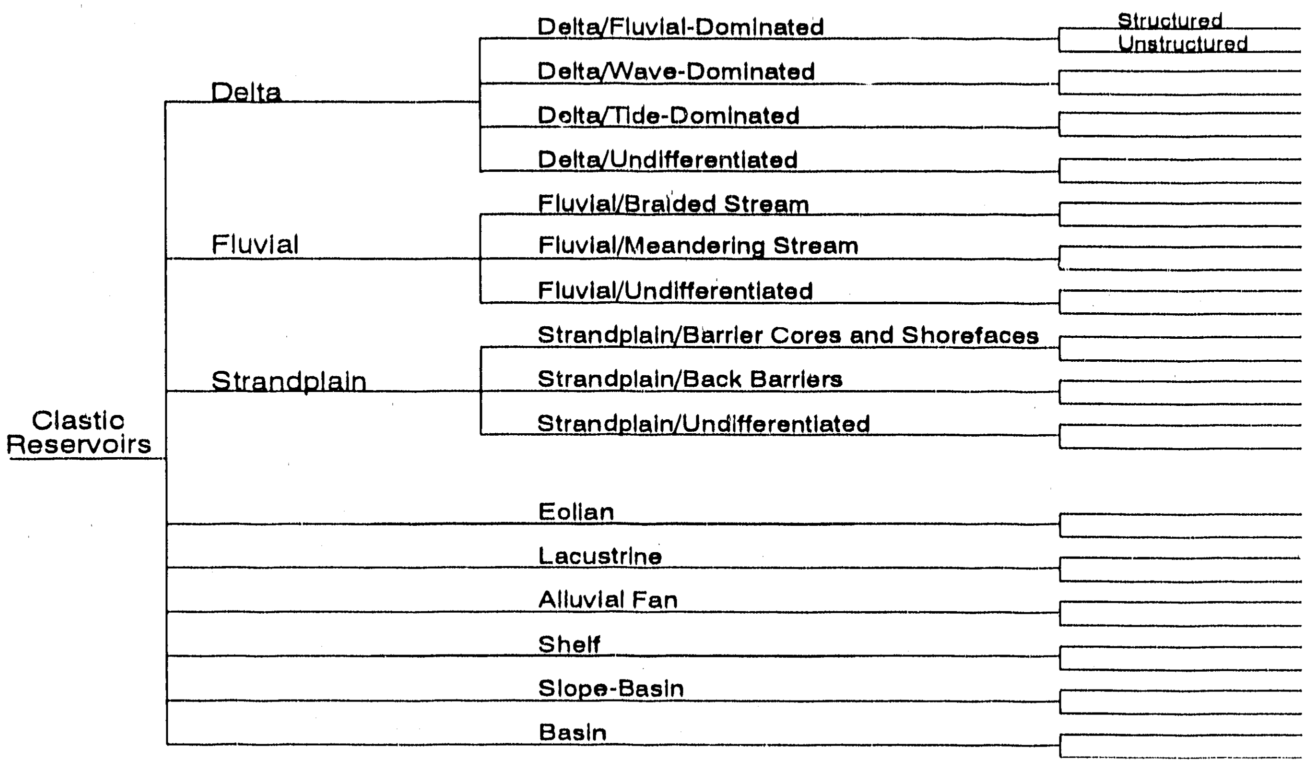


Figure 2.3 - Classification of Clastic Reservoirs.

THE RESOURCE

While TORIS does not include the entire domestic oil resource, it does include 597 deltaic reservoirs. These reservoirs contained 66.5 billion barrels of original oil in place (OOIP). Over one-third, 24.8 billion barrels, of the original oil in place has been produced and 1.2 billion barrels of proved reserves remain. The remaining oil in place (ROIP) equals 40.5 billion barrels (Figure 2.4). The recovery potential of a reservoir can be increased by the application of implemented and advanced EOR and ASR technologies.

The amount of the increase in productive potential over the anticipated recovery through a continuation of current operations is the incremental recovery potential. This incremental recovery potential is estimated under different price scenarios using TORIS.

Preliminary reserve numbers calculated from the data currently in TORIS reveal that the largest deltaic class in terms of OOIP and ROIP is that of the fluvial-dominated deltas. In the "Near-Term" case (at an oil price of $20 per barrel, utilizing implemented EOR and ASR technologies) a potential recovery of 2.1 billion barrels is estimated from deltaic reservoirs (Table 2.3 and Figure 2.5). The majority

Table 2.3 - TORIS Results for Deltaic Reservoirs.
(Millions of Barrels)

Near Term (Implemented Technology, $20/Bbl)

Class	EOR	ASR	Total
Delta/Undifferentiated	79.6	102.8	182.4
Delta/Wave-dominated	34.1	333.4	367.5
Delta/Fluvial-dominated	587.2	909.3	1,496.5
Delta/Tide-dominated	0	60.7	60.7
Total	700.9	1,406.2	2,107.1

Mid-Term (Advanced Technology, $32/Bbl)

Class	EOR	ASR	Total
Delta/Undifferentiated	572.5	232.0	804.5
Delta/Wave-dominated	409.2	700.4	1,109.6
Delta/Fluvial-dominated	1,665.6	1,740.4	3,406.0
Delta/Tide-dominated	1,275.0	83.4	1,358.4
Total	3,922.3	2,7596.2	6,678.5

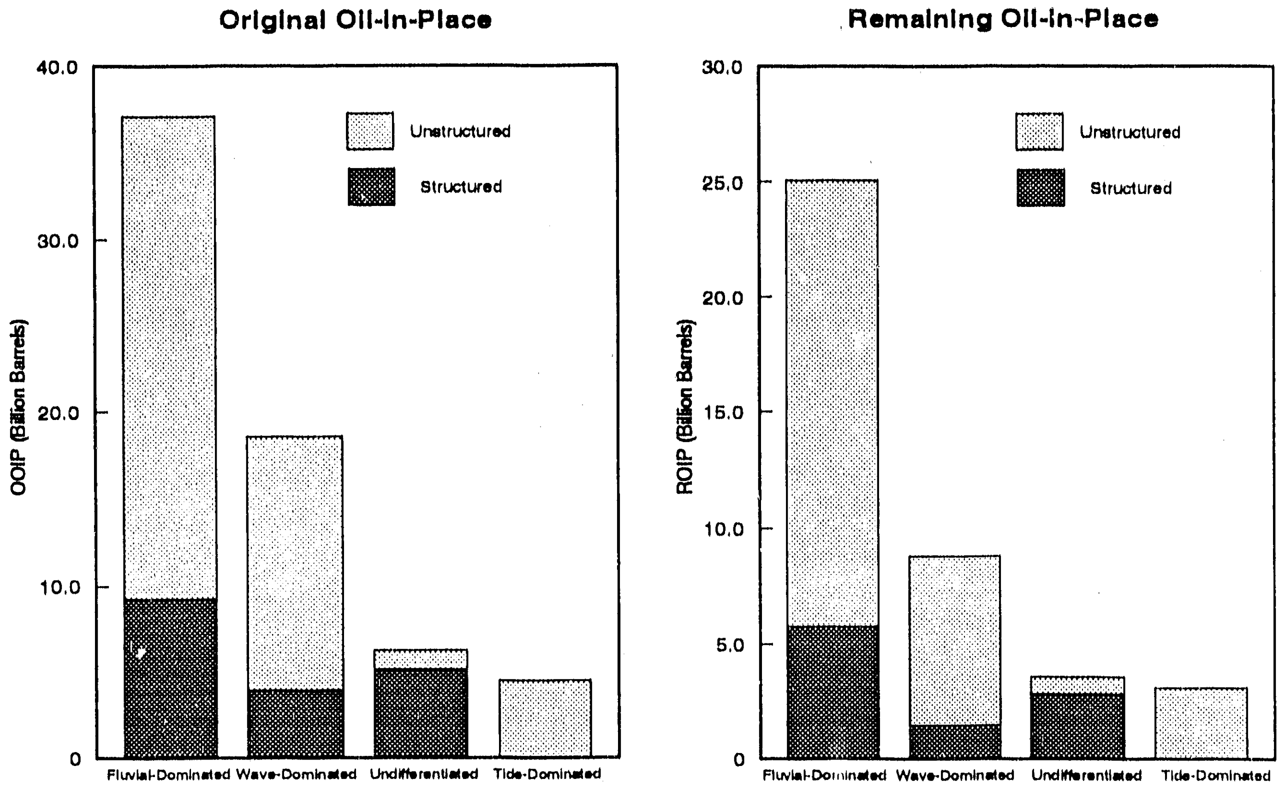
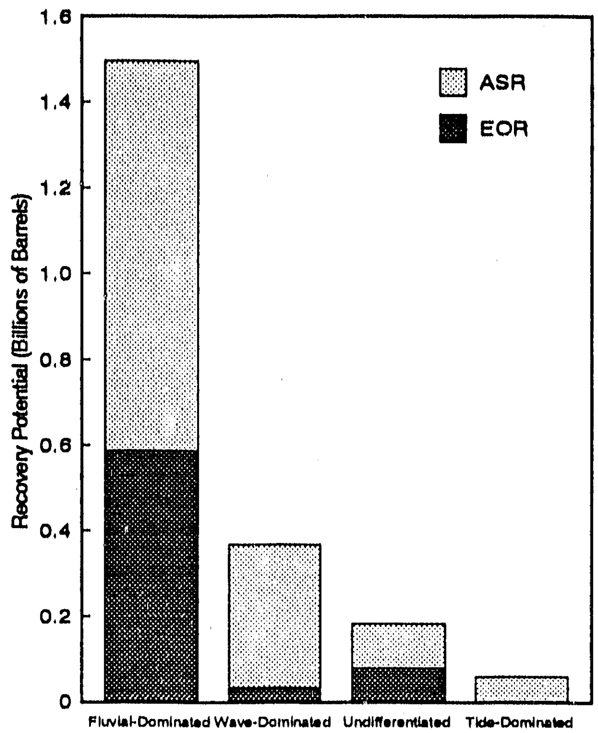


Figure 2.4 - Comparison of Resource Magnitude for All Deltaic Classes.

of this (1.5 billion barrels) is from fluvial-dominated deltaic reservoirs. These reservoirs are predominantly unstructured. Most of the resource potential within fluvial-dominated deltas results from the application of advanced secondary recovery techniques. In fact, while the EOR/ASR potential in all four delta classes exceeds 2.1 billion barrels in the "Near-Term", the ASR portion of this potential is 1.4 billion barrels, two-thirds of the total, indicating that the majority of the "Near-Term" resource potential is mobile oil. Seventy-eight per cent of the EOR/ASR incremental recovery potential from TORIS fluvial-dominated deltaic reservoirs in the "Near-Term" is located within the states of Texas and Louisiana (Figure 2.6).

In the "Mid-Term" ($32 per barrel oil price, utilizing advanced technologies) the incremental recovery potential soars to almost 6.7 billion barrels for the four deltaic classes combined (Figure 2.7). Slightly more than half of this recovery potential (3.4 billion barrels) is from the fluvial-dominated deltas. In fluvial-dominated deltas, incremental potential recovery is attributable to ASR and EOR techniques, equally. However, for deltas as a whole, the resource available through EOR methods exceeds that from ASR techniques, reflecting the overwhelming amount of EOR potential in tide-dominated deltas. The vast majority (about two-thirds) of the deltaic reservoirs described in TORIS are unstructured. The "Mid-Term" incremental recovery potential reflects this distribution with 71% of the potential resource attributable to deltaic reservoirs that are unstructured. Over 90% of the EOR/ASR potential from fluvial-dominated deltaic reservoirs in the "Mid-Term" case are in the states of Texas, Louisiana and Oklahoma (Figure 2.8).

Significant amounts of the light oil resource in deltaic reservoirs are at risk of abandonment by 1995 (Figure 2.9). At $20 per barrel, 800 million barrels of oil potentially recoverable using currently implemented technology is at risk of abandonment in this very short time frame. Nearly 60% of this is in fluvial-dominated deltaic reservoirs. With a $32 per barrel oil price and the use of advanced technologies, the potential recoverable resource at risk of abandonment by 1995 is estimated to be 2.3 billion barrels from these four deltaic reservoir classes alone. Over 40% of this is in fluvial-dominated deltaic reservoirs. In short, access to this resource base is in danger of being lost due to record abandonment rates of wells and fields. However, with broader application of existing ASR/EOR technologies and the development of reasonably attainable advanced technologies, much of this remaining resource could be recovered.



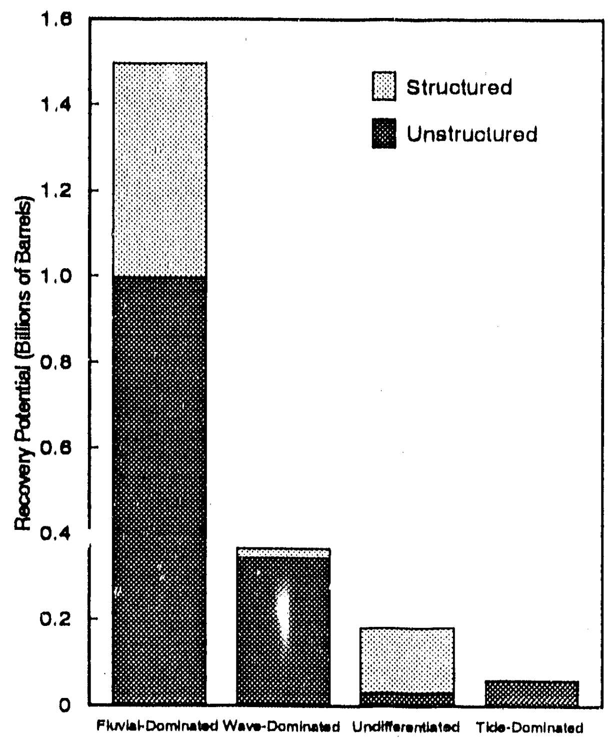


Figure 2.5 - Near-Term Case for All Delta Classes.

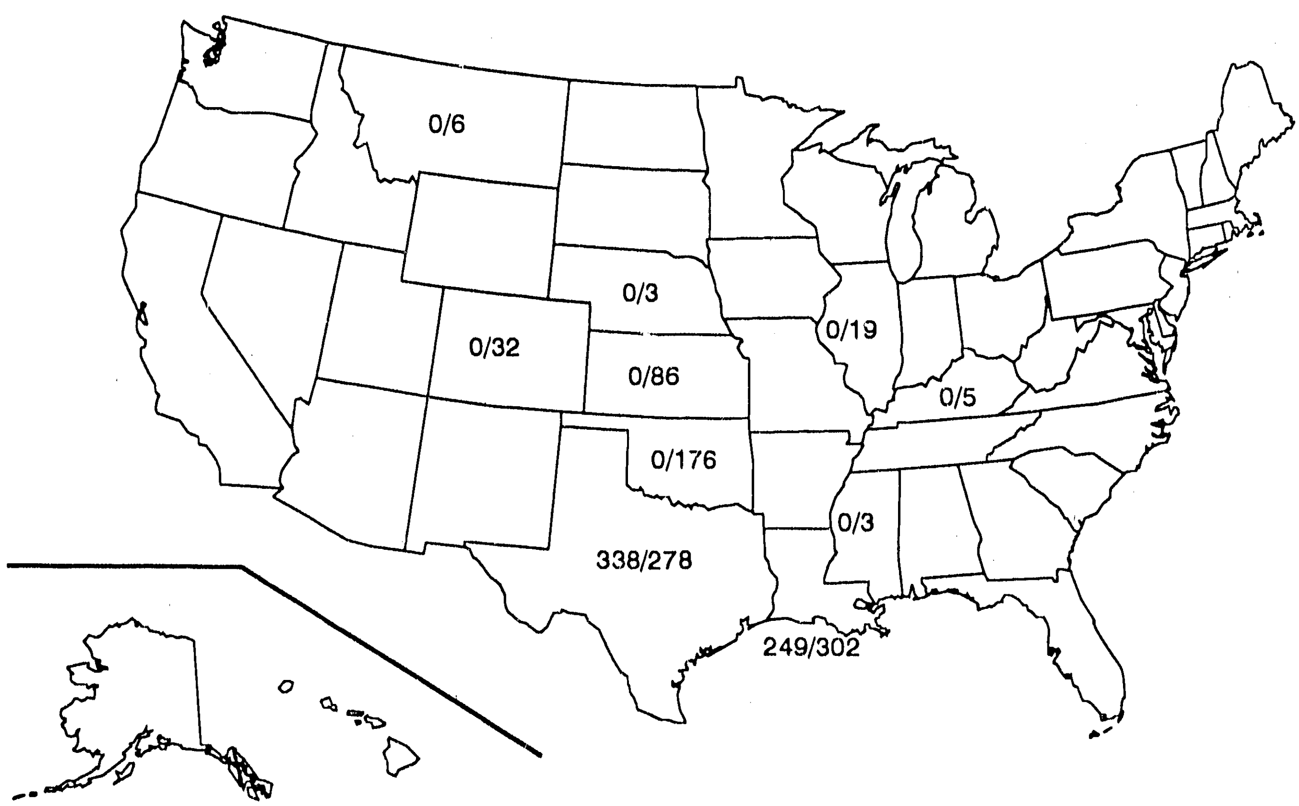


Figure 2.6 - Incremental Recovery Potential of Delta/Fluvial-Dominated Reservoirs, Near-Term Target (EOR/ASR MMBbl).

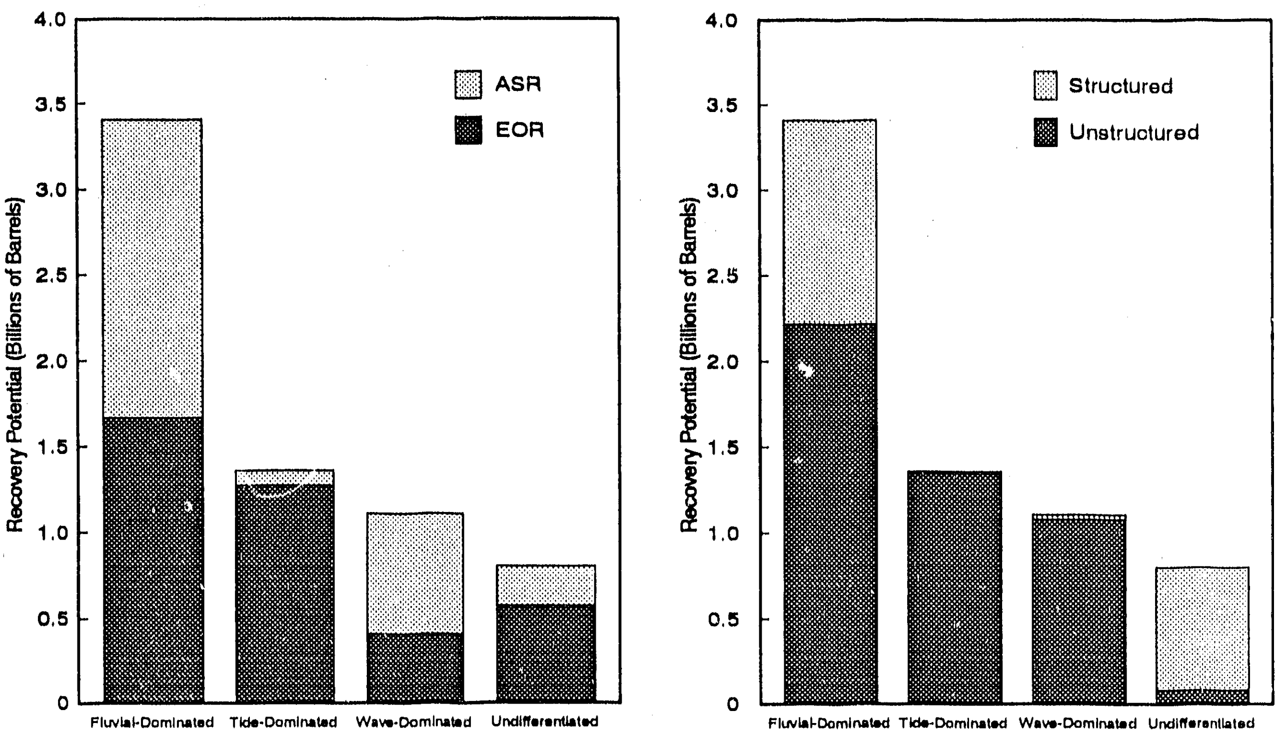


Figure 2.7 - Mid-Term Case for all Delta Classes.

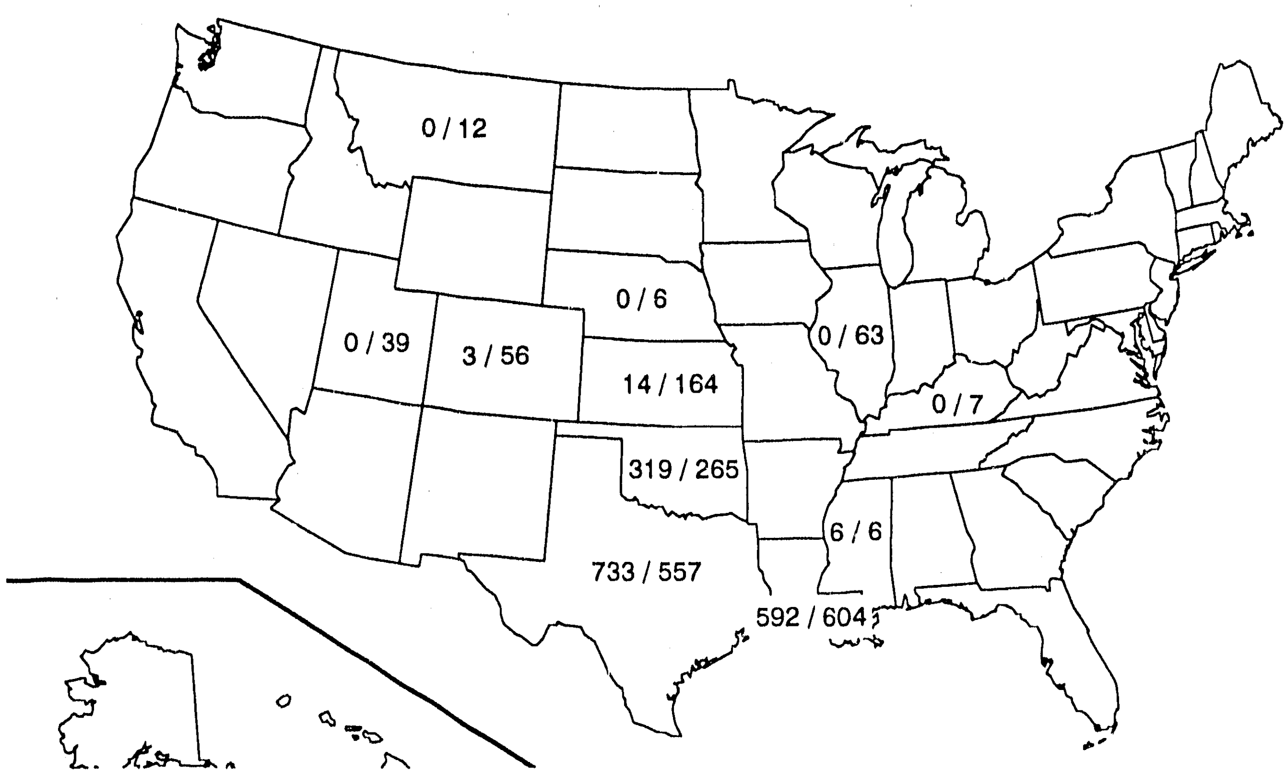


Figure 2.8 - Incremental Recovery Potential of Delta/Fluvial-Dominated Reservoirs, Mid-Term Target (EOR/ASR MMBbl).

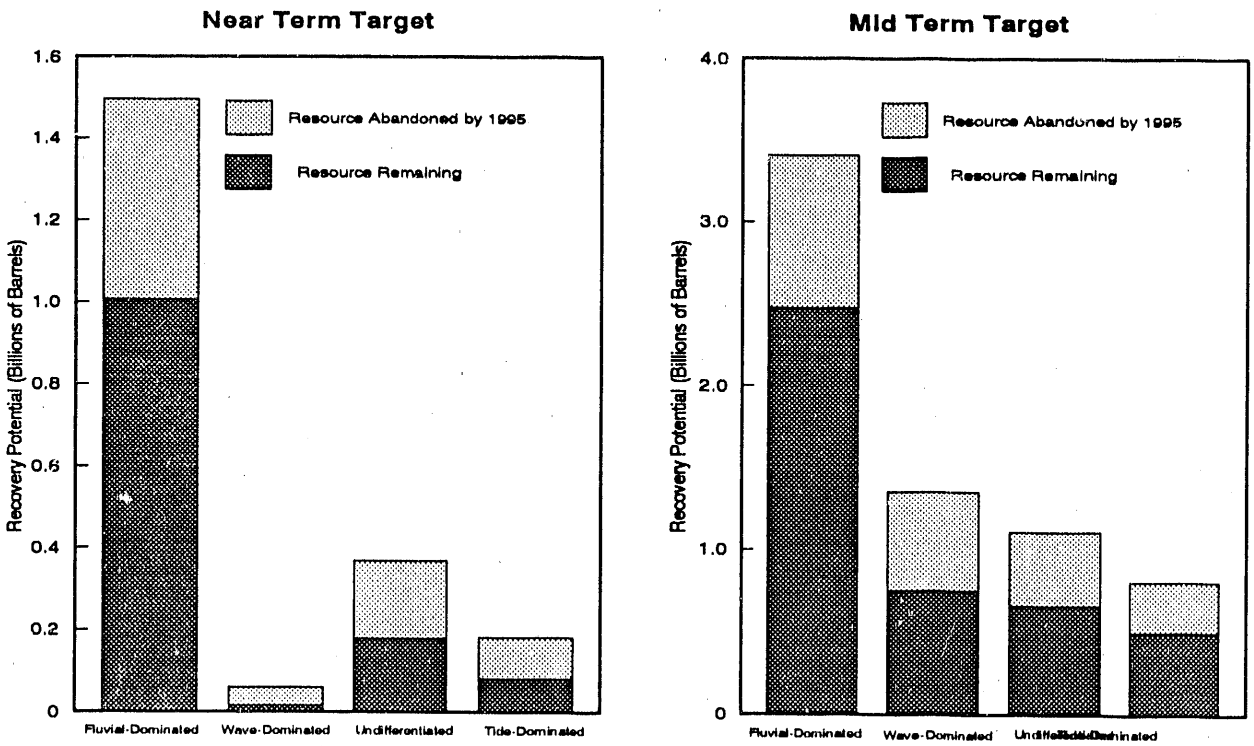


Figure 2.9 - Resource at Risk of Abandonment for All Delta Classes.

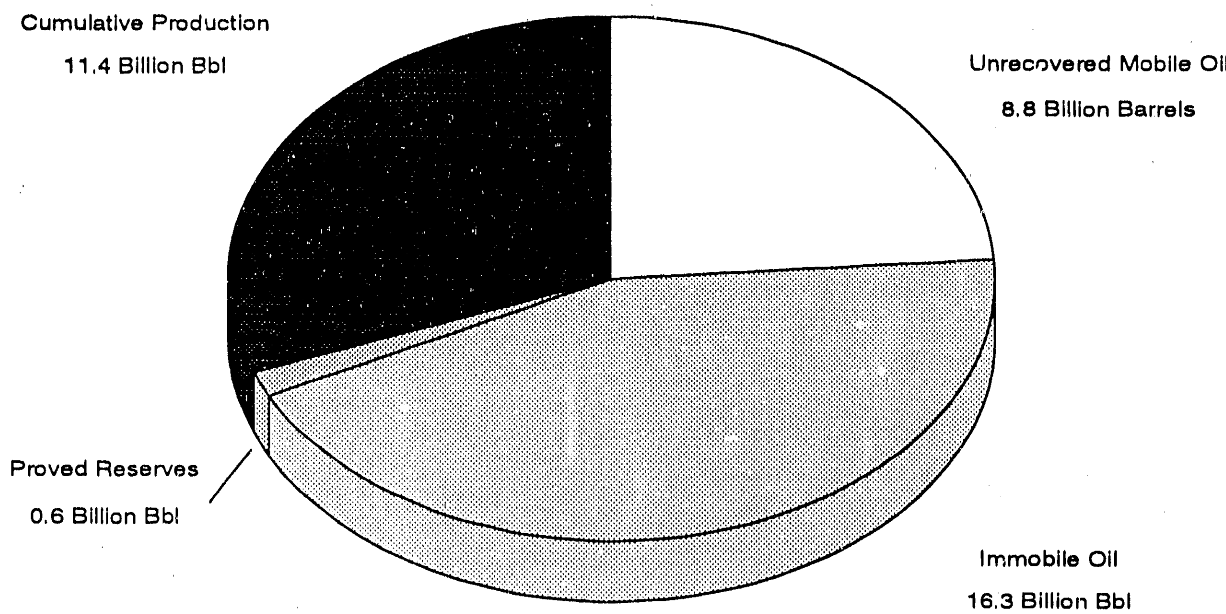
Fluvial-Dominated Deltas

More than 37 billion barrels of light oil were originally contained in the fluvial-dominated deltas of the United States. Of this, a total of 11.4 billion barrels have been produced and 582 million barrels are considered proved reserves under current economic conditions (Figure 2.10). After these reserves are produced, more than 25 billion barrels will remain in these reservoirs, the targets for advanced recovery techniques. Thirty-five percent of the remaining oil (8.8 billion barrels) is mobile to waterflooding, but was bypassed or uncontacted. This unrecovered mobile oil (UMO) is a target for advanced secondary recovery (ASR) techniques such as infill drilling and polymer treatments to increase the proportion of the reservoir swept. The balance of the remaining oil (16.3 billion barrels) is "residual oil" which is immobile to water, being trapped by viscous and capillary forces. Enhanced oil recovery (EOR) techniques can overcome these forces to produce a portion of this oil through the injection of chemicals, gases, or heat. ASR and EOR technologies are frequently employed in combination.

These estimates are recognized to be understated because they rely on the sample of 410 large, mature, fluvial-dominated deltaic reservoirs currently described in the TORIS data base. The reservoirs in this system contain about 70 percent of the total U.S. oil, but it is not possible to know precisely what portion of any particular class of reservoirs the system might contain. Light oil, fluvial-dominated, deltaic reservoirs are found throughout the oil-producing regions of the United States and occur in states and basins other than those currently represented in the TORIS data base. Additional deltaic reservoirs, many from the Gulf Coast region, are expected to be added to the data base in the future.

Current Production and Operators

Currently 3,709 operators are active in fluvial-dominated deltaic reservoirs.[6] In 1989, these operators produced 55.3 million barrels from reservoirs that contain 582 million barrels of proved reserves, a reserve-to-production ratio of 10.5 to 1. Figure 2.11 and the accompanying Table 2.4 show the profile of operators, ranked by size of their total U.S. liquid reserves, relative to their production from fluvial-dominated deltas. The "Majors", thirteen of the largest U.S. operators, produced 48.8% of the total light oil recovered from fluvial-dominated deltas in 1989. The next six largest independent U.S. operators (based on U.S. domestic liquid reserves) account for only 1.0% of the 1989 production from these reservoirs. Twenty-three of the next 40 largest publicly traded U.S. oil companies are represented as mid-



Total OOIP: 37.1 Billion Bbl

Source: U.S. Department of Energy, Bartlesville Project Office, 1990.

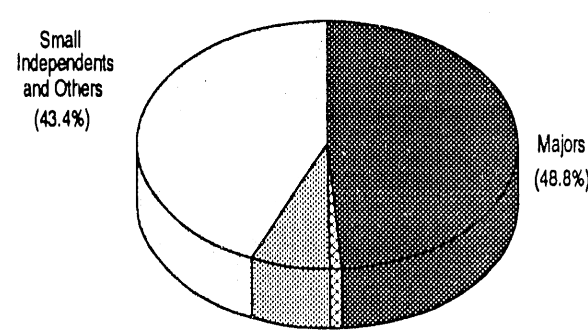
Figure 2.10 - Distribution of Original Oil-In-Place in Fluvial-Dominated Deltaic Reservoirs.

size independent operators with domestic reserves of between 10 million and 100 million barrels. Collectively they have produced 6.8% of the oil recovered from fluvial-dominated deltaic reservoirs in 1989. The remaining 3,667 or so operators, which are small public companies with less than 10 million barrels of domestic liquid reserves or privately held companies of unspecified size, together account for 43.4% of the total oil produced from this reservoir class in 1989. This distribution reflects the diversity in company types that are actively producing from fluvial-dominated deltaic reservoirs.

EOR Applications

Excluding heavy oil (gravity less than 20° API), 76 EOR projects in fluvial-dominated deltaic reservoirs are documented in the combined DOE and Oil and Gas Journal data bases.[7] These include both active and terminated projects. Interest in EOR is clearly tied to the price of oil. Project starts peaked in 1980-82, following the dramatic increase in oil prices that occurred in 1979-80. Conversely, new project starts dropped off significantly after the price collapse of 1986. Currently, 46 light oil fluvial-dominated deltaic reservoir EOR projects are reported as active by the combined data bases. Advanced secondary projects are not as systematically reported as EOR projects, but a number of individual

(Percent of 1989 Crude Oil Production)



1989 Crude Oil Production = 55.3 Million Barrels
Number of Class 1 Operators = 3,709

Majors (13) (>250 million barrels domestic liquids reserves)
Large Independents (6) (>100 million barrels domestic liquids reserves)
Mid-Size Independents (23) (>10 million barrels domestic liquids reserves)
Small independents and Others (3,667)

Figure 2.11 - Fluvial-Dominated Deltas Operator Profile

Table 2.4 - List of Operators Active in Fluvial-Dominated Deltaic Reservoirs.

Majors (public companies > 250 million barrels domestic liquids reserves)				
Amoco	Chevron	Mobil	Shell	USX
ARCO	Conoco	Oryx	Texaco	
BP	Exxon	Phillips	Unocal	
Large Independents (public companies > 100 million barrels domestic liquids reserves				
Amerada Hess	Pennzoil			
Burlington Resources	Santa Fe			
Occidental	Union Pacific			
Other Independents (public companies > 10 million barrels domestic liquids reserves				
Adobe Resources	BHP	Louisiana Land	Noble	Sonat
American Petrofina	Coastal	Maxus	Pacific Enterprises	Union Texas
Anadarko	Enron	Mesa	Parker & Parsley	Wiser
Apache	Fidelity Oil	Mitchell Energy	Presidio Oil	Berry
Kerr-McGee	Murphy Oil	Sage Energy		
Others (public companies < 10 million barrels domestic liquids reserves and private companies)				
3,667 other operators				

reports suggest considerable experimentation with infill drilling and polymer-blocking.

Thermal EOR projects producing from the lower-gravity (20-23° API gravity) light oil reservoirs are relatively uncommon in fluvial-dominated deltas. Only four of the forty-six active EOR projects utilize this technology. Two these thermal EOR projects are steam floods in a single Louisiana field. The other two other are in situ combustion projects in Bartlesville Sand reservoirs in Oklahoma and Kansas.

Active miscible and immiscible gas injection projects, which are primarily in Louisiana (14), represent a significant portion of the total number of EOR projects currently in fluvial-dominated deltaic reservoirs, 16 of the 46 projects. Gas injection projects are also reported in Oklahoma (1) and Texas (1).

The greatest number of reported active EOR projects in fluvial-dominated deltaic reservoirs are chemical, whether surfactant, polymer, alkaline, or microbial projects. Twenty-six of the forty-six reported EOR projects active in fluvial-dominated deltaic reservoirs utilize chemical processes. Fifteen polymer flood projects are operative in five states, Oklahoma (6), Montana (5), Texas (2), Louisiana (1), and Illinois (1). Surfactant projects account for nine of the active chemical projects and are distributed among three states, Oklahoma (4), Illinois (4), and Louisiana (1). An alkaline chemical project is underway in the same field as the thermal steam projects in Louisiana, although in a different reservoir. A single microbial project is active in a fluvial-dominated deltaic reservoir in Oklahoma.

Overall, the currently reported EOR activities in fluvial dominated deltaic reservoirs are restricted to a few states and larger companies dominate operations. Most active light oil EOR projects in fluvial-dominated deltaic reservoirs are located in Louisiana (19) and Oklahoma (13). Only the four other states mentioned above are reported to have active projects in this class of reservoirs. The vast majority (over 80%) of project operators are the major oil companies. This illustrates the potential for further expansion of activities to develop the EOR resource.

Future Potential

Incremental recovery potential resulting from the application of implemented technology is estimated to total 1.5 billion barrels at an oil price of $20 per barrel for fluvial-dominated deltas (the "Near-Term" case). Nearly 61% of this potential results from the application of ASR processes. Over half (53%) of the ASR potential could come from infill drilling alone, while infill drilling in combination with profile modification and polymer flooding ("combination" ASR process in Figure 2.12) accounts for an additional 30%. The remainder of the ASR potential is from profile modification (8%) and polymer flooding (9%), when they are not combined with infill drilling. EOR accounts for 39% of the incremental recovery potential in the "Near Term." Chemical flooding could account for 44% of the EOR potential, miscible gas 31%, and thermal processes the remainder (25%).

The incremental recovery potential from fluvial-dominated deltas when advanced technologies are utilized is estimated to be 3.4 billion barrels at $32 per barrel (the "Mid-Term" case). As in the "Near-Term" case, the majority of the incremental recovery potential in the "Mid-Term" results from the ASR processes, 51%. Of this, infill drilling accounts for 47%, and infill drilling in combination with profile modification and polymer flooding another 45%. Profile modification (2%) and polymer flooding (6%), not in combination with infill drilling, contribute a total of only 8%. EOR processes contribute nearly as much to the incremental recovery potential as the ASR processes, 49% versus the 51% from ASR. Chemical flooding increases in significance as the dominant EOR process (66%), while miscible gas (22%) and thermal (12%) processes continue to contribute substantial amounts.

Well abandonments put at risk a significant portion of the domestic oil resource (Figure 2.9). The extent of well abandonments and their impact on potential recovery has been estimated for fluvial-dominated deltas. If no new technology is applied to the reservoirs by 1995, well abandonments could reduce the incremental recovery potential of 1.5 billion barrels anticipated from the "Near-Term" target ($20 per barrel, implemented technology case) by as much as a third. As with the implemented technology, abandonments will reduce access to otherwise promising reservoirs where advanced technologies could be used. If no new technology is applied by 1995, the incremental recovery potential of the "Mid-Term" target ($32 per barrel oil price, advanced technology) could similarly be reduced by almost a third.

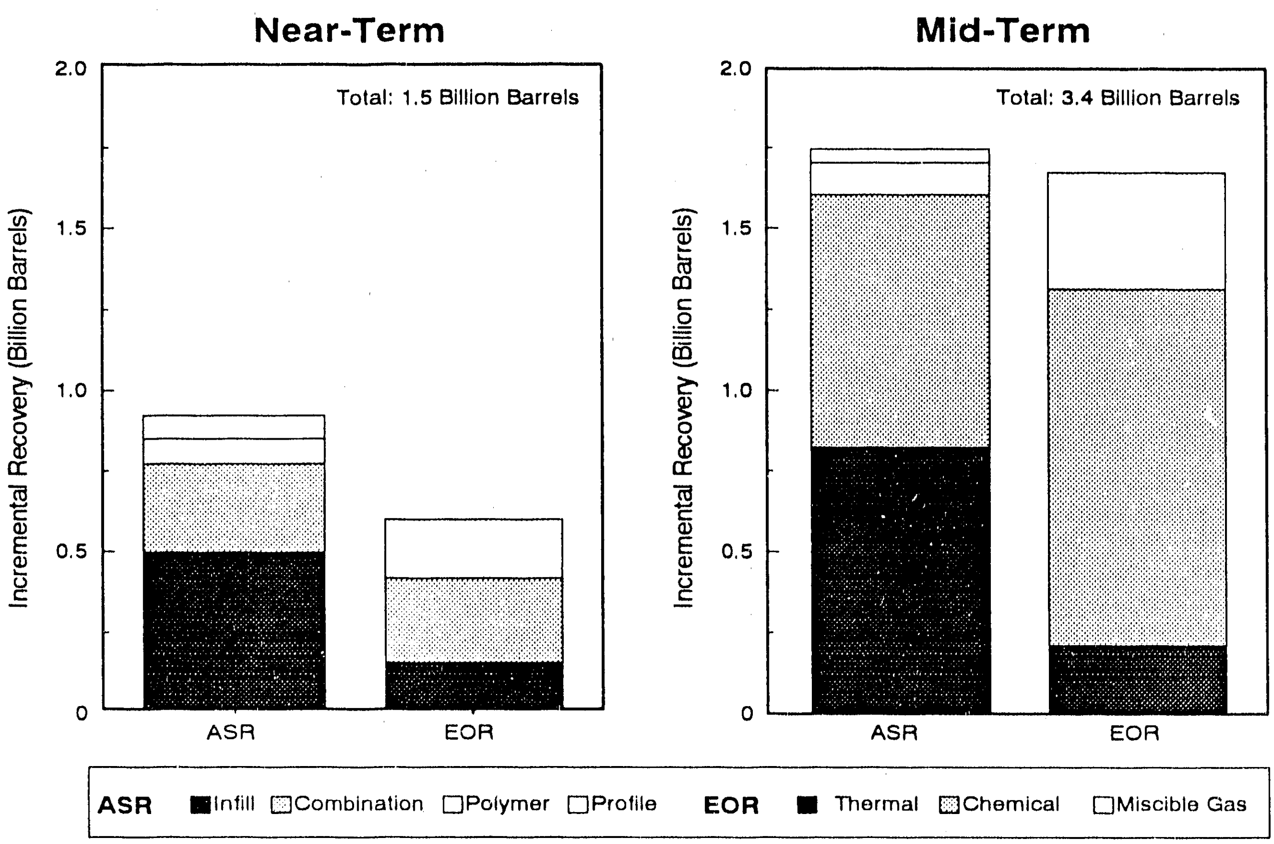


Figure 2.12 - Future Potential from Fluvial-Dominated Deltas by Process

SUMMARY

The amount of potentially recoverable oil endangered by abandonment establishes an urgency in ensuring application of implemented technologies to light oil, fluvial-dominated deltaic reservoirs. The magnitude of the incremental recovery attributable to research-based advanced technology, likewise establishes a substantial target for future R&D. Light oil fluvial-dominated deltaic reservoirs as represented in TORIS are clearly an important component of the nation's energy resource base.

NOTES

[1]U.S. Department of Energy/Bartlesville Project Office TORIS database.

[2]National Petroleum Council, *Enhanced Oil Recovery*, Washington, D.C., 1984.

[3]IOCC Project on Advanced Oil Recovery and the States, *An Evaluation of the Known Remaining Oil Resource in the State of Texas*, 1989.

[4]U.S. Department of Energy/Bartlesville Project Office, *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically recoverable Reserves in Texas, Oklahoma, and New Mexico, Bartlesville, Ok*, 1990.

[5]IOCC Multi-State Study, *Evaluation of the Domestic Oil Resource and Economic Recovery of Mobile and Immobile Light Oil: The Report of the IOCC Multi-State*, forthcoming.

[6]According to an operator survey by Petroleum Information Corporation, November, 1990.

[7]U.S. DOE and The Oil and Gas Journal EOR data bases combined, including the OGJ Terminated Projects data base as reported in "CO_2 and HC injection lead EOR production increase," *The Oil and Gas Journal*, April 23, 1990, pp 49-82.

CHAPTER 3

GENERAL GEOLOGICAL AND PRODUCTION CHARACTERISTICS OF DELTAIC RESERVOIRS

SUMMARY

Deltas form where streams transport large quantities of sediment into bodies of water such as lakes, bays, lagoons, or the ocean, creating potential reservoir facies. Depositional facies are three-dimensional rock bodies whose environmental origins can be inferred from the physical characteristics of the rock. Fluvial processes interact with the sediment-reworking and redistributing properties of tidal and wave processes to varying degrees resulting in three genetic types of deltas that can be recognized based on sand distribution patterns, particularly delta front sands, and lateral and vertical facies relationships. The general area where an active stream enters the ocean or other body of water is called the delta front. Each of the three major types of deltas affects the distribution of the delta front sands, often the best reservoirs, in different ways. Fluvial-dominated deltas tend to build elongate "fingers" of delta front sands, and the general distribution of major sands tends to be perpendicular to the shoreline. The delta front sands on wave-dominated deltas tend to be reworked into numerous coastal barriers that are oriented roughly parallel to the shoreline. Tide-dominated deltas tend to have sand-choked channels and build tidal sand ridges in the delta front area which are oriented perpendicular to the shoreline.

It is because of the link between the genetic type of delta, depositional environment, and rock characteristics that reservoir geologists can predict important information about geological heterogeneities that are critical to production including geometry, trend, scale, and quality of reservoir sandstone facies. An important aspect of maximizing oil recovery from deltaic reservoirs through better understanding of geological heterogeneities is improved geological reservoir characterization. Such characterization may be used as a basis for implementation of appropriate secondary and enhanced oil recovery (EOR) production technologies. Improved, often more detailed knowledge about the depositional framework and the scale and frequency of reservoir heterogeneities may be required, but that detailed knowledge offers the best opportunity to anticipate and alleviate problems commonly encountered by infill drilling, waterflooding, or other enhanced oil recovery processes.

Interwell continuity is often related to the geometry, scale, and lithology of depositional facies. These facies are produced by the interplay of depositional processes which are characteristic of particular depositional environments. Thus, the recognition of facies (the distinguishable rock units) can be tied to genetically related type deltas (fluvial, wave, or tide-dominated), which define the distribution of potential high-quality reservoir sandstones.

Reservoir heterogeneities occur at different scales, which are best detected by different technologies. Sand distribution maps and vertical successions interpreted from electric logs provide means for distinguishing major depositional facies and determining which type of delta created the reservoir sandbodies. Seismic reflections are often used to examine the larger scale aspects of the delta deposystem such as the gross depositional pattern, the presence of erosional surfaces and faults, or about the continuity of sealing strata. Smaller scale heterogeneity problems are often best deciphered by examination of recovered core which can then be calibrated with electric log patterns so that facies distributions can be interpreted. Diagenesis includes the physical and chemical processes including compaction, cementation and leaching that are undergone by sediments as they subside within an active sedimentary basin. Diagenetic features are known to potentially improve or destroy reservoir quality sandstones. However, the processes controlling diagenesis are relatively difficult to predict, particularly on an interwell scale. Diagenetic processes are related to the hydrologic framework of sedimentary basins, but only indirectly related to depositional systems, such as deltas, and may locally create significant differences in the production characteristics of depositionally similar reservoirs.

Production from deltaic deposits generally comes from distributary channel facies or from delta front facies. The size and geometry of distributary channel deposits are related to the overall size of the delta, the substrate over which the delta lobe is deposited, channel mouth processes, and the distance upstream from the delta front. In sinuous distributaries, sand bars deposited on the inside of meander loops (point bars) are common; however, in straight distributaries, point bars are not important facies, and symmetrical channel deposits are flanked by muddy natural levee deposits. Common upward fining channel fill sequences

are caused by lateral migration of channels as well as by channel abandonment, often creating mud seals at the top of reservoir quality sands. Because of the depositional mechanisms controlling the geometry of channel deposits, both lateral extent and depositional continuity of distributary channel sands decreases upward, often creating depositional compartments difficult to contact and drain during secondary and chemical EOR recovery processes.

One study of deltaic facies dimensions indicates that a single genetic cycle of distributary channel meanderbelt deposits averages 30 ft thick, about 1,000 ft wide, and has a width/thickness ratio of 40:1; however, variability is exceedingly large and probably depends on the absolute size of the delta, local structure, and other factors. Great variations in size of distributary channel deposits have been documented for modern as well as ancient settings.

Delta front facies geometry is dominantly related to rate of sediment supply and the relative strengths of wave, tide, and fluvial processes. The resultant facies may, in turn, be modified by several factors at the time of deposition including growth faulting, gravity slumps, and diapirism. Although there is also great variability in delta front facies dimensions, these facies tend to be much larger than distributary channel sandstones. For example, distributary mouth bar (delta front) sands tend to be twice as thick and 10 times wider than distributary channel sandbodies.

Future analysis of distributary channel or delta front sand dimensions should probably be made with respect to the genetic type of delta and the overall delta size. For a given degree of preservation, the geometry of genetic sand units is more predictable than their absolute dimensions.

The presence of shale layers within and between reservoir sandstones can strongly influence production in either a positive or negative manner. Dimensions of shale layers generally correspond to the depositional setting. For example, shales associated with deltaic barrier sands are generally more continuous than are shales in delta front sediments.

There is often a great tendency to assume that thin shales within productive sandstones are more or less planar and extend for only short distances or are discontinuous because they cannot be correlated in adjacent wells. Sweep is often unexpectedly poor in such settings because the depositional geometry of the bedding allows thin shales to merge causing both lateral and vertical barriers to fluid flow and "compartments" of various size that are not contacted during waterflood or chemical EOR operations.

Field-wide, interwell, and microscopic scale heterogeneities are often created as a result of the processes that create deltas. Because the processes which form deltas operate in other deposystems, the heterogeneities common in deltaic deposits are also found in other types of reservoirs. Field-scale heterogeneities are related to the degree of sandbody interconnectedness and the location within the deposystem. Interwell-scale heterogeneities are related to lateral facies changes and the zonation (both laterally and vertically) of permeability between and within depositional facies. Pore level or microscopic-scale depositional heterogeneities are related to bedding style (e.g. lamination, cross lamination, or massive), direction of fluid flow, mineralogy, and textural features such as grain size, sorting, or packing.

Currently available advanced production methods can mitigate the effects of the heterogeneities discussed. In general, the methods of infill drilling, horizontal/slant wells, and hydraulic fracturing are most applicable to larger field-scale heterogeneities, whereas enhanced oil recovery processes are best applied to interwell and microscopic-scale heterogeneities.

Effective application of EOR methods to recover oil remaining after waterflooding will depend on knowledge of both the type and scale of heterogeneities limiting oil recovery as well as their effect on specific EOR techniques. Until now most evaluations have concentrated on the recovery process, with little effort spent on relating the project performance to heterogeneities induced by the geological environment. Most DOE- and industry sponsored chemical EOR pilot tests have been conducted in deltaic reservoirs. A review of the sedimentologically related reservoir heterogeneities found the following to be significant: channeling, when a high permeability zone takes a disproportionate volume of the injected fluids which has a low residual oil saturation due to prior waterflooding; compartmentalization, caused by lateral changes in facies, clay drapes, etc. that prevent communication between injectors and producers or result in unswept areas of the reservoir; directional trend, is generally caused by bedding orientation and creates preferential fluid flow directions; contact with high salinity regions, may reduce the effectiveness of the EOR fluids; and formation parting may be created by high-viscosity fluids injected for mobility control. In the pilots reviewed, recovery efficiency decreased from 70 to less than 30% when well spacing became greater than 1 acre. Geological heterogeneities within the reservoirs were the likely cause for the decreases in efficiency.

Reservoir properties and production characteristics of 229 fluvial-dominated "unstructured" deltaic reservoirs in the Tertiary Oil Recovery Information System (TORIS) data base were analyzed. Median values indicate that fluvial-dominated deltaic reservoirs are generally high-quality reservoirs at moderate depth (4,954 ft), with good porosity (19%), good permeability (128 md), and producing light oil (39° API gravity) with a primary recovery of 26% of OOIP. Based on the TORIS data, the best indicator among formation parameters for primary production is permeability. Low secondary recovery factors recorded for fluvial-dominated reservoirs may be attributed to either poor sweep efficiency or extremely efficient primary production due to a strong drive mechanism that leaves relatively small amounts of oil for secondary recovery. It should be emphasized that the TORIS reservoir data base contains only average values for production, and reservoir parameters and interpretations based on the data must be made with extreme caution.

INTRODUCTION

Deltas are stream-fed depositional systems that occur in lakes, bays, lagoons, or the ocean and create an irregularity on that shoreline. Deltas are created by the rapid influx, deposition, reworking, and subsidence of sediment at a rate which exceeds its removal by wave and tidal action. The scale of deltas can be small; for example, Kanes (1970) showed that the Colorado Delta of Texas was only 1,300 ft wide at the turn of the century, or they may be large; for example, the Nile Delta is about 170 miles wide along the shoreline and nearly 100 miles from its apex to the shoreline.

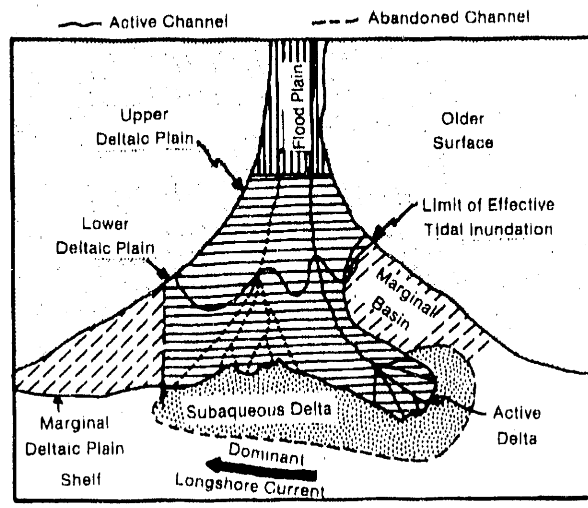
The configuration of deltaic deposits in plan view has been described by Coleman and Prior (1982) (fig. 3.1). Proceeding in a seaward direction, the major depositional settings are:

- The upper deltaic plain, which is dominated by fluvial processes. Representative facies include braided, straight and meandering distributary channels, lacustrine, and floodplain deposits.
- The lower deltaic plain, which lies within the range of high and low tides. The principal facies are interdistributary bay fill, crevasse splays, levees, marshes, and abandoned distributary channel fill.
- The subaqueous delta, which is dominated by marine processes (waves and currents) and tends to consist of reworked sediments. These facies include distributary mouth bars, channel mouth tidal ridges, subaqueous slumps, mud diapirs, and prodelta muds.

PROCESS FRAMEWORK FOR DESCRIBING DELTA MORPHOLOGY

Delta systems are characterized by continual interplay of processes, so that depositional processes are not independent of each other. Basic components which determine the morphology and stratigraphy of a delta include sediment input and energy of the basin or water body. These are modified by climate and basin-specific factors such as tectonic style which will affect subsidence rates (see Swift, 1969; Galloway, 1975). Sediment input is a function of the fluvial contribution to the delta, whereas wave and tidal energy flux are the primary long-term processes affecting the types and geometries of deltaic facies.

Depositional facies are three-dimensional stratigraphic bodies whose environmental origins can be inferred from the physical characteristics of the rock (Fisher and McGowen, 1967; Finley and Tyler, 1986). The facies comprising a deltaic deposit are, there-



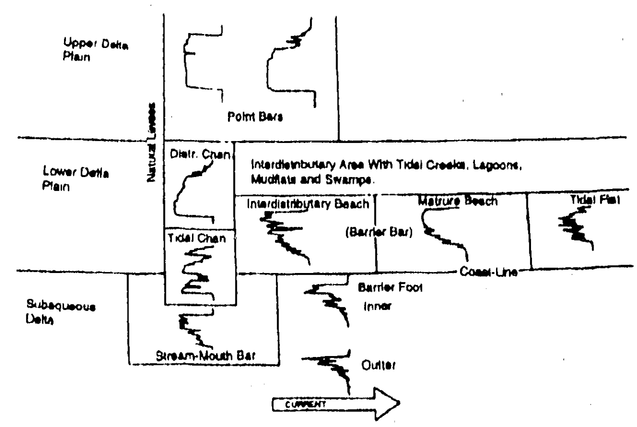


Figure 3.1 - Above. Components of a typical delta system. After Coleman and Prior, 1982. Below. Typical gamma-ray log patterns for major components of a typical wave-dominated delta. After Weber, 1986. The indicated log patterns are representative of the major depositional facies but, in no way, indicate all of the possible variations.

fore, linked by depositional environment to associated depositional processes (Brown and Fisher, 1977). It is the process-related or genetic approach to reservoir characterization that offers the reservoir geologist and engineer the best opportunity to characterize the interwell area using fundamental rock units (Finley and Tyler, 1986).

Galloway (1975) found that of all the processes affecting deltaic sedimentation, only sediment input, wave energy, and tidal currents appear to be capable of transporting and redistributing large volumes of sand. These processes define three end members: 1) fluvial-dominated deltas, 2) wave-dominated deltas, and 3) tide-dominated deltas (fig. 3.2). Fluvial-dominated deltas tend to build elongate fingers of delta front sands at high angles to the shoreline. Reservoir sands are sealed by surrounding impermeable shales. Tide-dominated deltas are characterized by sand choked distributary channels and by tidal sand ridges in the lower delta plain. Wave-dominated deltas are typified by sands which have been reworked into coastal barrier bars perpendicular to the stream inflow. All of these processes operate in all deltas, with one or another predominating at different times, resulting in a wide variety of deltaic configurations.

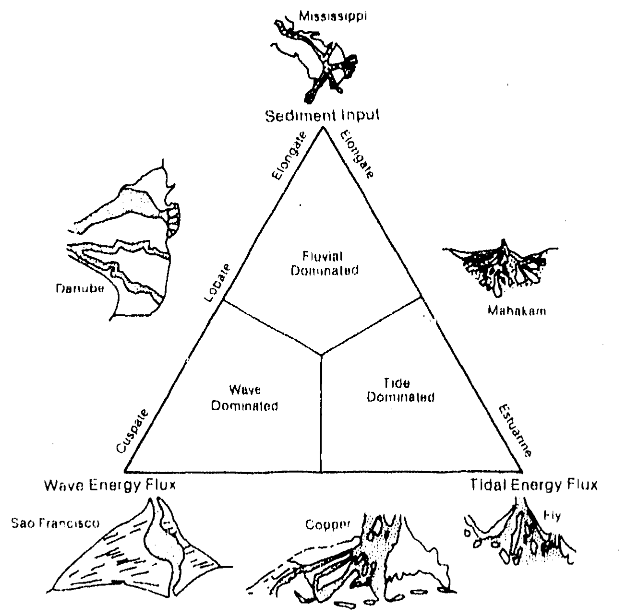


Figure 3.2 - Morphologic and stratigraphic classification of delta systems based on the dominant regime of the delta front (fluvial processes, wave energy flux, and tidal energy flux). After Galloway, 1975.

Galloway noted that because sandy facies form the stratigraphic framework of the delta, a genetic (process oriented) classification of deltas based on relative importance of tide and wave energy flux and rates of sediment input is equally applicable for modern deltas and their ancient equivalents (table 3.1).

Characterization of deltaic reservoirs by truly interactive multidisciplinary reservoir studies is necessary to understand and predict production behavior (Honarpour et al., 1989; also see comments by Needham in this report). These studies must fully utilize all types of data available for geological characterization (Finley and Tyler, 1986), but must also include comprehensive engineering reviews that incorporate geological, petrophysical, and reservoir production/injection field data (Hartman and Paynter, 1979).

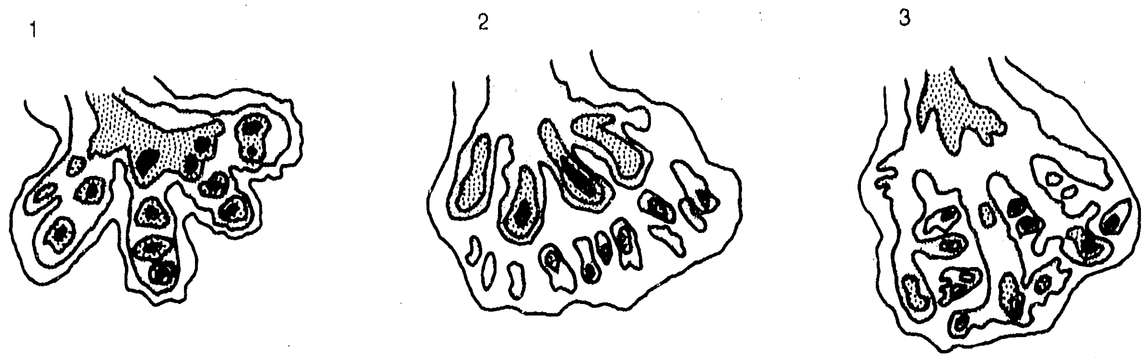
Important information about reservoir facies distribution, lithology, continuity, trend, scale of critical geological heterogeneities, potential reservoir quality, and recovery efficiency may be predicted based on the genetic type of delta to which the reservoir belongs. For example, certain critical heterogeneities within deltaic reservoirs vary according to the generic types of delta. Finley and Tyler (in this report) indicate that elongate, fluvial-dominated deltas historically display low to average oil recoveries. Sand deposition in this type of delta is principally in fluvial and distributary channels and distributary mouth bars which build seaward creating narrow, lenticular sandy "bar fingers" (Fisk, 1961). In contrast, laterally continuous sands in cuspate deltas are dominated by wave and current processes. These types of sandstone bodies are easier to sweep and tend to have good recovery efficiencies. In addition, attributes of deltaic reservoirs can be more realistically simulated once the correct genetic type of sandbody has been ascertained.

DELTAIC PROCESSES AND SAND DISTRIBUTION MODELS

Because of the tremendous complexity within deltas, several authors including Fisher et al. (1969), Fisher (1969), Coleman and Wright (1975), and Galloway (1975) proposed a series of end-member delta types which were related to the dynamic interplay of a finite number of controlling processes. An understanding of these processes and the resulting delta configuration facilitates prediction of reservoir distribution and quality. Coleman and Wright (1975) concluded that, in the geological sense, the most important controlling processes are climate, relief in drainage basin, water discharge, sediment yield, rivermouth processes, nearshore wave power, tides, winds, nearshore currents, shelf slope, tectonics of receiving basin, and receiving-basin geometry. The overall effect of the depositional processes is framework (dominantly sandstone) or nonframework (dominantly muddy) facies that may be either constructional (mostly stream dominated) or destructional (mostly current and wave dominated) (Fisher et al., 1969; Fisher, 1969).

Table 3.1. Stratigraphic characteristics of deltaic depositional systems. Modified from Galloway and Hobday, 1983.

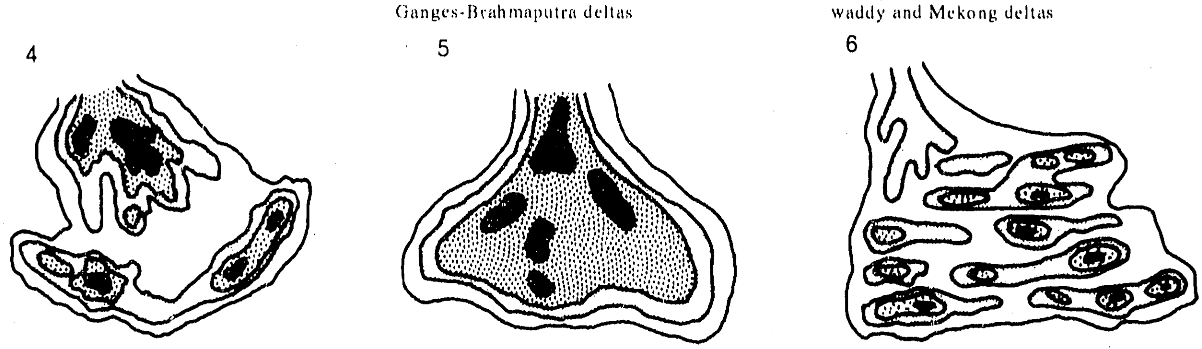
	Fluvial-Dominated	Wave Dominated	Tide-Dominated
Lobe Geometry	Elongate to lobate	Arcuate	Estuarine to irregular
Bulk Composition	Muddy to mixed	Sandy	Muddy to sandy
Framework Facies	Distributary mouth bar and delta front sheet sand; distrib-uatary channel fill sand	Coastal barrier sand; distrib-utary channel sand	Tidal sand ridge sand; estuarine distributary channel fill sand
Framework Orientation	Highly variable, parallels depo-sitional slope	Parallels depo-sitional strike	Parallels depositional slope unless locally skewed
Common Channel Type	Suspended-load to fine mixed-load	Mixed-load to bed-load	Variable, tidally mod-ified geometry
Channel Style	Straight to sinuous	Meandering	Flaring straight to sinuous



Type 1
Conditions: low wave energy tidal range, and littoral drift low offshore slope, fine-grained sediment load.
Characteristics: widespread finger-like channel sands normal to the shoreline
Example: modern Mississippi delta

Type 2
Conditions: low wave energy high tidal range, normally low littoral drift, narrow basin.
Characteristics: finger-like channel sands passing off-shore into elongate, tidal current ridge sands.
Examples: Ord, Indus, Colorado Ganges-Brahmaputra deltas

Type 3
Conditions: intermediate wave energy, high tides, low littoral drift, shallow stable basin.
Characteristics: channel sands normal to shoreline connected laterally by barrier-beach sands
Examples: Burdekin, Irra-waddy and Mekong deltas



Type 4
Conditions: intermediate wave energy, low offshore slope, low sediment yield
Characteristics: coalesced channel and mouth bar sands fronted by offshore barrier islands
Examples: Apalachicola and Brazos deltas

Type 5
Conditions: high persistent wase energy, low littoral drift, steep offshore slope.
Characteristics: sheet-like laterally persistent barrier beach sands with up-dip channel sands.
Examples: Sao Francisco and Grijaiva deltas

Type 6
Conditions: high wave energy, strong littoral drift, steep offshore slope.
Characteristics: multiple elongate barrier-beach sands aligned parallel to the shore line with subdued channel sands
Examples: Senegal delta

Figure 3.3 - Sand distribution models based on multivariate analysis of a wide variety of parameters from modern deltas. Darker shades indicate thicker sands. After Coleman and Wright, 1975.

Deltaic Sand Distribution Models

The interplay of individual processes mentioned above results in specific responses in a particular delta. For example, climate determines that thick coal-forming peats are characteristic of tropical climates, whereas thin peats interfinger with fine clastics in temperate climates; continued high wave energy along delta shorelines results in widespread strike-aligned clean quartzose sand bodies; or high tidal ranges result in sand-choked radiating or dip-aligned channels in contrast to clay-filled channels in areas characterized by lower tidal ranges.

Analysis of 34 major deltas of the world by Coleman and Wright (1975) indicates that in terms of gross sand body geometry, deltas can be broadly classified according to six end members (fig. 3.3). They illustrate that specific combinations of processes, if preserved, exhibit distinctive lateral and vertical sand and reservoir distributions.

Of course sand thicknesses will vary with the absolute size and type of delta as well as the tectonic setting. It should be expected that deltaic depositional geometries occupy a continuum relating the relative contributions of different fluvial and marine transporting and reworking processes. Hence the need to classify deltas according to their genetic type for reservoir characterization studies.

Sand Distribution and Vertical Succession of Facies

Borehole programs in the Mississippi, Rhone, and Niger deltas (Fisk et al., 1954; Fisk, 1955, 1961; Oomkens, 1967, 1974; Weber, 1971) were stimulated by the economic importance of deltaic facies. Based on these studies and others, it became apparent that deltaic successions contain a wide variety of vertical facies sequences and that the type of vertical sequence changes both within the delta at different locations and between deltas.

Conceptual diagrams of principal facies, sand patterns, and geophysical log responses for high constructive and destructive elongate (fluvial dominated), high constructive lobate (fluvial/wave dominated), high destructive cuspate (wave dominated), and high destructive, tide-dominated delta systems are provided for reference in figures 3.4-3.9.

Lateral variations of log patterns within major delta depositional environments must be understood in order to make proper facies correlations, particularly in the absence of core control. Examples of the lateral variability within interdistributary bay fill, abandoned distributary, distributary mouth bar, and river mouth tidal ridge facies geophysical log patterns are given in Coleman and Prior (1982).

Sand distribution maps and vertical successions interpreted principally from wireline logs provide the most commonly used means for distinguishing major subsurface depositional facies, and thereby, the type and extent of the resulting delta and its reservoirs. Geophysical techniques, such as seismic interpretation, are often used to examine the larger scale aspects of the delta system, such as the gross depositional pattern, the presence of unconformities and faults, or the continuity of sealing strata. Cross-borehole tomography is a developing tool that potentially has much to offer in terms of structural and stratigraphic mapping of reservoirs (see Justice and Mathisen in this report). Smaller scale heterogeneities such as bedding type, fine scale interlamination of diverse lithologies, porosity type, mineralogy, and subtle changes in facies are often best deciphered by examination of recovered core, which can then be calibrated with log patterns so that facies distributions can be interpreted.

DELTAIC DEPOSITS

Constructional Delta Framework Facies and Environments

Among these facies, the distributary channels, subaerial levees, and delta front sands comprise the best reservoir quality facies or framework of the delta.

Distributary Channel Facies

Distributary channels of the Mississippi delta, a stream-dominated delta, are low sinuosity, and point bars (sand bars created by meandering streams) are common (fig. 3.10); however, when channels are straight, point bars are insignificant, and the deposits are generally symmetrical in cross section with levees flanking the channel. In contrast to upland channels, delta distributary channels are always influenced by basinal processes such as tides, waves, and marine currents (even in low-energy basins).

Facies sequences within the fluvial-dominated distributary channels tend to comprise erosive channel bases, often with coarse-grained lag, overlain by trough cross-bedded sands which pass upward into ripple-laminated finer sands with silt and clay alternations and finally into silt and clay plugs of abandoned distributaries carried into the channels by successively diminished flow and overbank flooding of adjacent active channels. Overall upward fining of the channel fill results from both lateral migration of the channel, or more often from channel abandon-

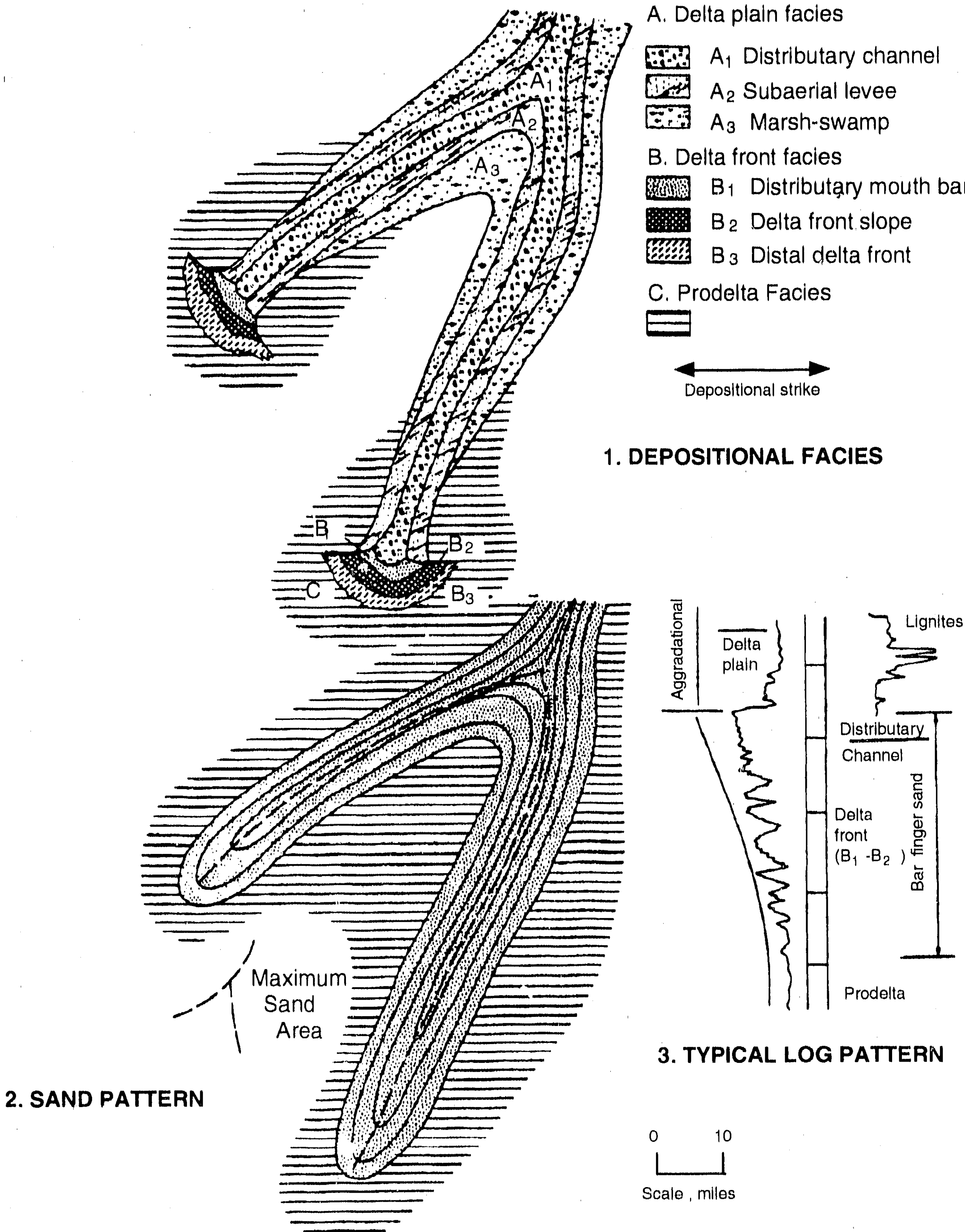


Figure 3.4 - Representative depositional facies, sand distribution, and electric-log patterns based on high-constructive elongate delta systems of the Gulf of Mexico. After Fisher et al., 1969.

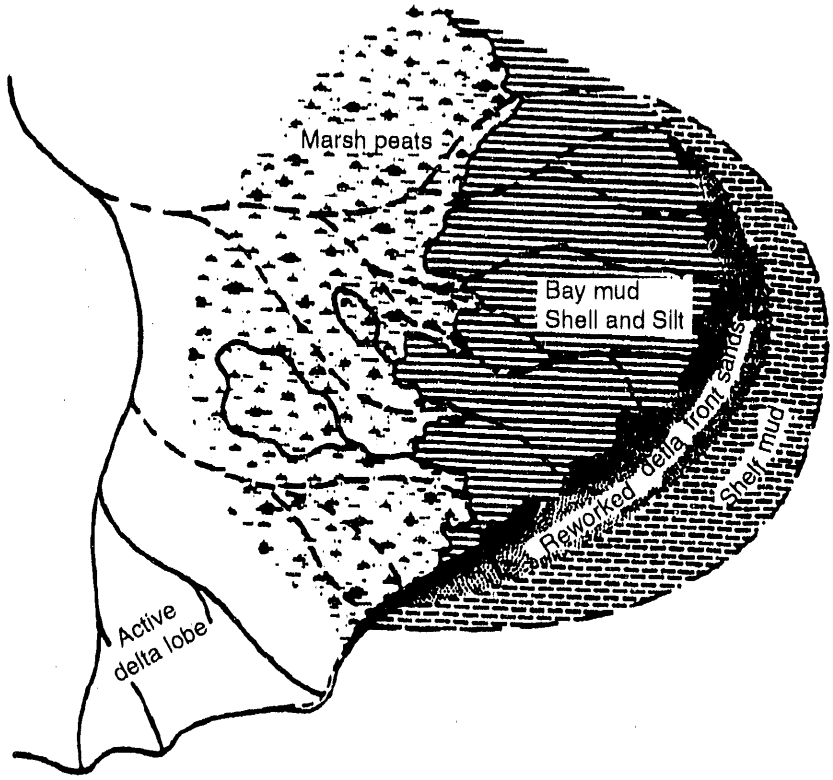


Figure 3.5 - Facies relationships within an idealized facies tract of a fluvial-dominated delta produced by lobe abandonment, subsidence, and transgression. After Galloway and Hobday (1983), originally from Fisher et al. (1969).

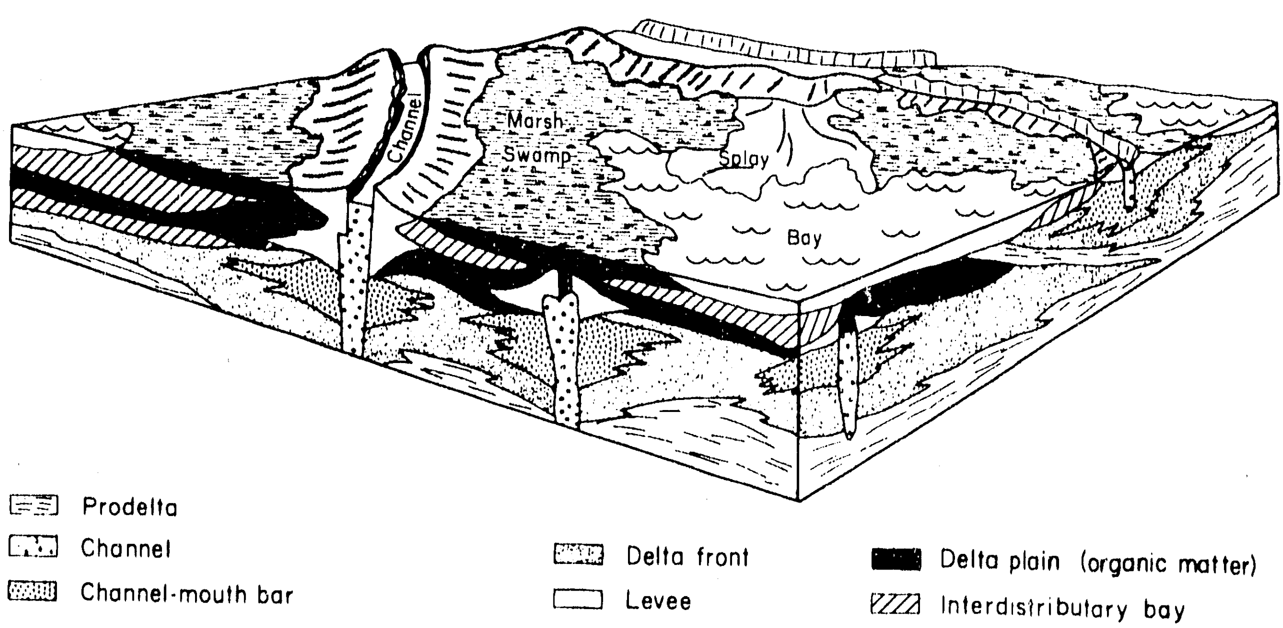


Figure 3.6 - Block diagram of a high-constructive lobate delta. From Erxleben (1975) after Frazier (1967).

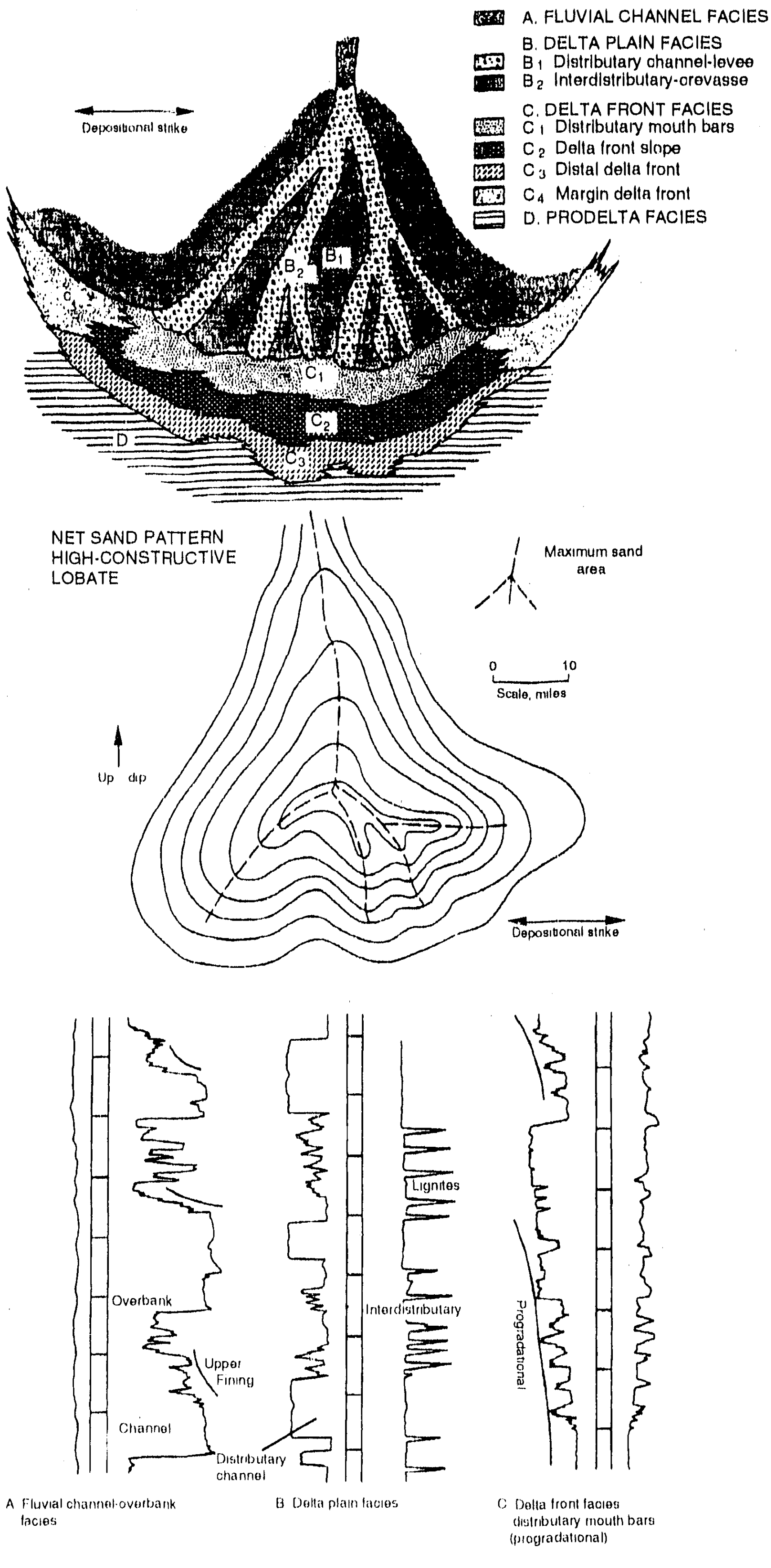
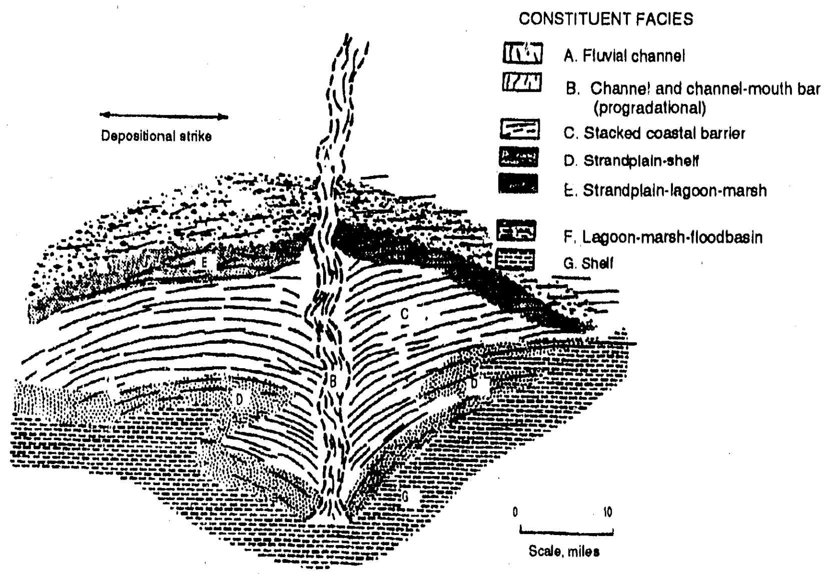
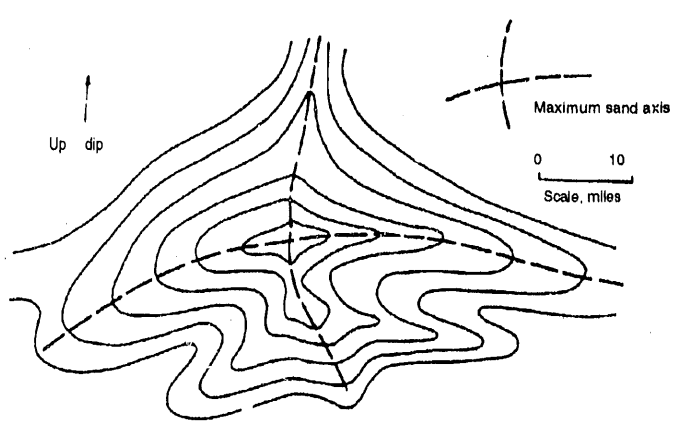


Figure 3.7 - Representative depositional facies, sand distribution pattern, and log patterns based on high-constructive lobate delta systems of the Gulf of Mexico. After Fisher et al., 1969.



NET SAND PATTERN
HIGH-DESTRUCTIVE DELTAS



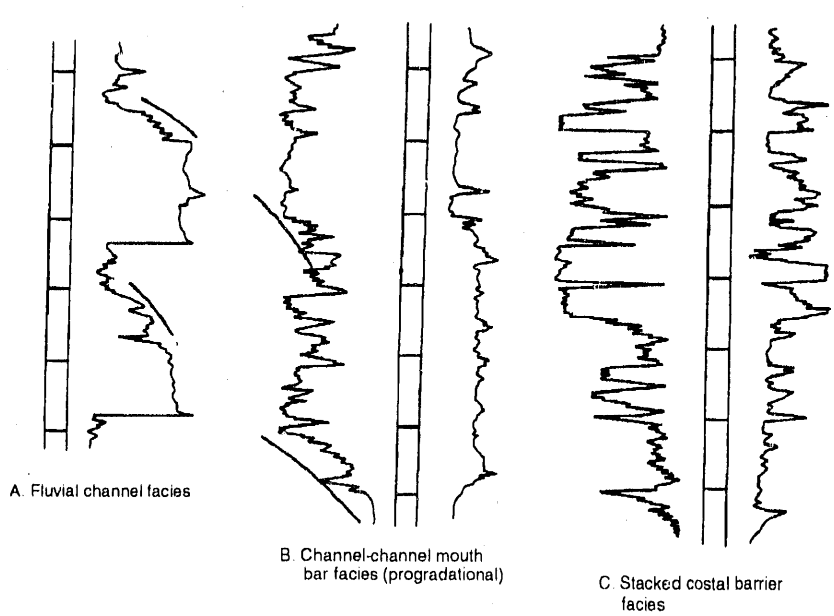


Figure 3.8 - Major depositional fac'..s, sand distribution pattern, and log patterns based on high destructive, wave-dominated delta systems, Gulf of Mexico. After Fisher et al., 1969.

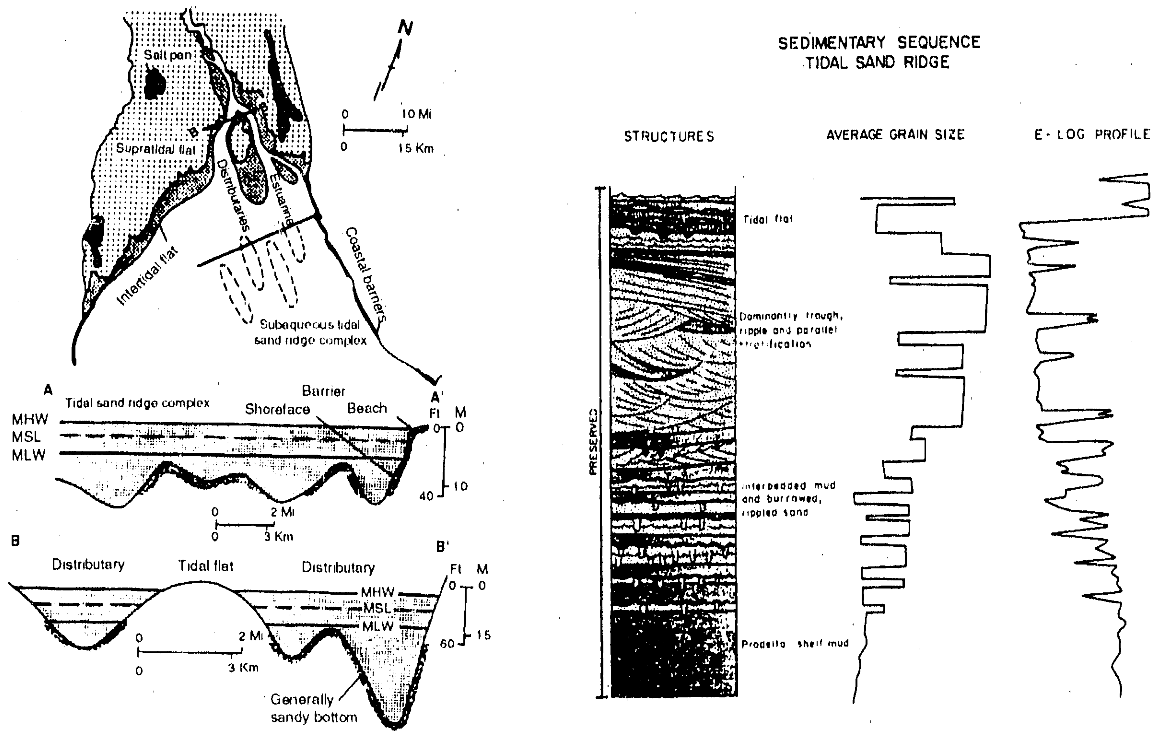


Figure 3.9 - Left. Distribution of environments and major depositional facies in the Colorado delta, a tide-dominated delta, Gulf of California. After Meckel, 1975. Right. Generalized vertical profile through a tidal current sand ridge based on the Colorado delta subaqueous delta-front platform. Grain size increases to the right. After Galloway and Hobday, 1983.

ment. Thickness, lateral extent, and depositional continuity of reservoir quality sands decrease upward through the distributary channel fill sequence.

Tidally influenced distributary channels tend to be low sinuosity and funnel-shaped with high width/depth ratios in contrast to the relatively straight reaches of distributaries in microtidal regions. In the Niger delta, there are more than 20 tidal inlets which cut through the shoreline barrier sands, and depths within the inlets range from 27 to 45 ft. Vertical sequences from tidally influenced distributaries in the Niger delta have a coarse basal lag with a fragmented marine fauna overlain by sands with decimeter-scale trough cross-bedding to centimeter-scale cross-lamination (Allen, 1965). Vertical sequences within the tidally influenced distributary and estuarine channel facies may fine upward (e.g., mangrove swamps at the top of the sequence) or they may remain coarse throughout, as when the distributary cuts through a coastal sand barrier.

Characteristic features of tidal influenced distributary channel facies include bimodality of flow direction and abundance of small-scale facies variations in the vertical sense which reflect fluctuations in tidal current and direction. In the former Rhine delta, elongate tidal channel sands form complexes 12 miles wide and 30 miles long (Oomkens, 1974).

Distributary channels of the wave-dominated Rhone delta are moderately sinuous, forming broad meander belts up to 3 miles wide that tend to branch and narrow basinward. Rhone delta distributary channel deposits fine upward from medium to coarse sand into silts and fine sand. Channel belt width/thickness ratios range from 100:1 to 1,000:1 (Oomkens, 1970).

Subaerial Levee Facies

Subaerial levees form as the result of overbank flow during flood stage; they tend to flank rather than overlie channel fill facies in mud-rich deltas. Although vegetation often destroys primary sedimentary structures, centimeter-scale or finer laminated interbedding of silty sands and mud layers is common.

Delta Front Facies

The delta front sediments include 1) the most-terminal portion of the distributary channel immediately upstream of the distributary mouth bar, 2) the distributary mouth bar sands, 3) the distal bar sands, 4) the subaqueous levee, and 5) the marginal or delta front sheet sands (vary from bar finger to lobate

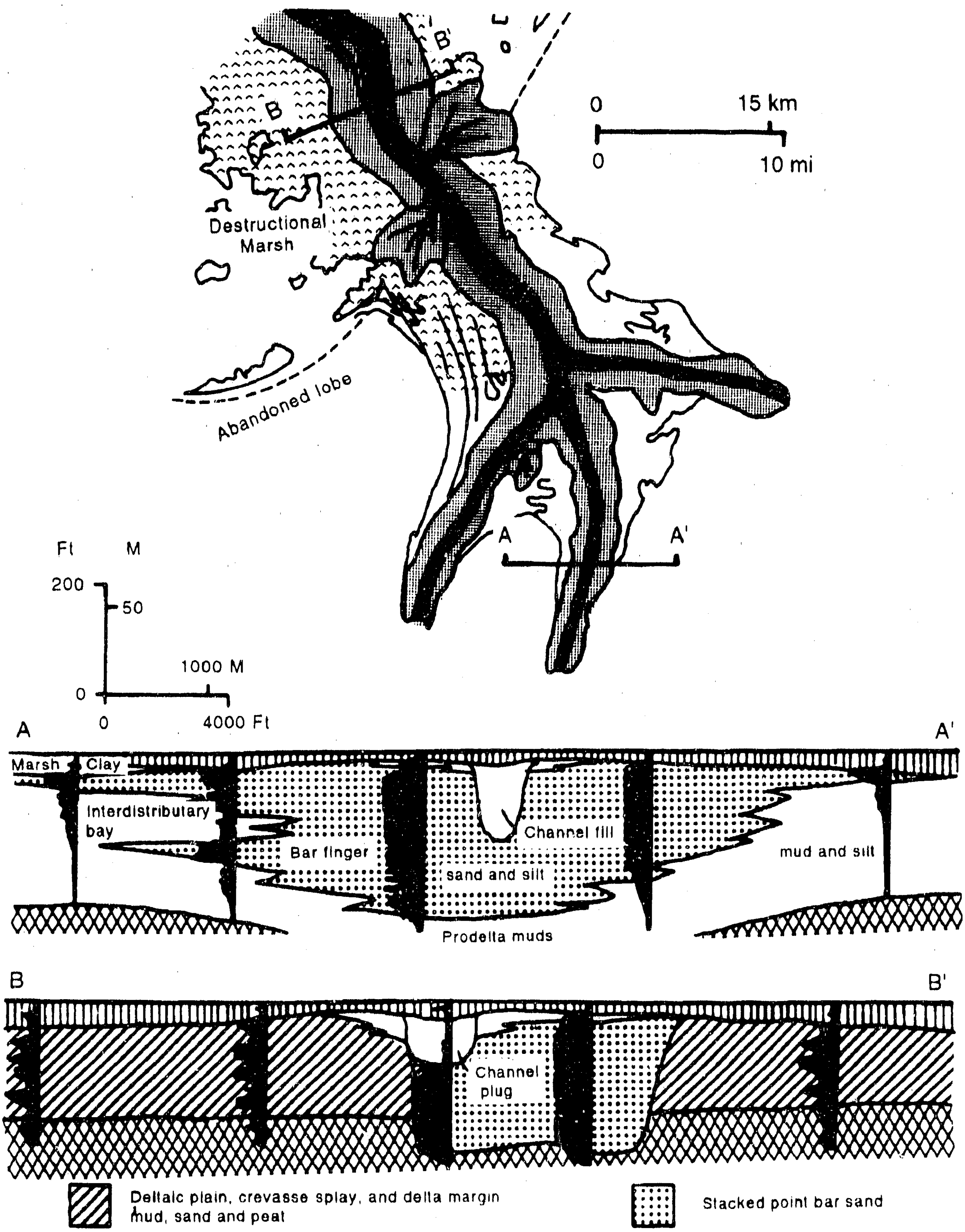


Figure 3.10 - Interpretive cross sections of (A) progradational channel mouth bar and (B) distributary channel fill sand bodies of an elongate, fluvial-dominated delta lobe. From Galloway and Hobday, 1983.

geometry), and include the best potential oil and gas reservoirs (fig. 3.7). These deposits represent the coarsest sediments associated with a prograding delta and may be about 75% sand (Fisher et al., 1969).

Fluvial flow becomes unconfined laterally as the stream reaches the receiving basin and the hydraulic gradient decreases dramatically. In addition, flow separation due to density differences between fluvial and marine waters results in rapid deposition of bedload as a channel or distributary mouth bar. These processes create the maximum sand depositing environment on the entire delta. Winnowing and reworking on the marine face of the delta front and bar crest are largely due to wave assault. These sands are the source of the well-developed coalesced beach ridges which define the characteristic cuspate shape of wave-dominated deltas.

The distal portion of the channel mouth bar contrasts with the bar crest. It is finer grained and often contains graded beds and thin slumped sand beds. Thin, distinct sands or silty sands with overall coarsening up sequences may characterize log patterns developed in the distal bar. Convolute bedding related to loading of the prodelta muds also occurs.

Constructional Delta Nonframework Facies and Environments

This category includes a wide variety of generally muddy and organic-rich facies which are located on both the subaerial and subaqueous portions of the delta plain. Included here are many parts of the delta plain complex such as the abandoned distributary-channel fill, marshes and swamps, lacustrine, crevasse splay deposits, as well as the prodelta muds. Collectively these environments form the most areally extensive, laterally persistent units of many deltas. According to Fisher et al. (1969), marshes and swamps which comprise the organic producing environments typical of large fine-grained constructive delta systems may cover up to 90% of the delta plain. Organic-rich prodelta muds are normally located seaward of the delta front and represent the most widespread, the most homogeneous, and often the thickest depositional environment in the delta system.

Destructive Delta Facies and Environments

Destructive facies include (proximally) widespread nonreservoir marsh deposits and (distally) potential reservoir facies which are dominated by marine processes. Fluvial processes have minimal impact on the destructive delta facies.

Proximal Destructive Facies

The dominant depositional environment on the nonmarine part of the delta plain during subsidence of a delta lobe includes extensive brackish to freshwater marshes. Destructive phase peats exhibit much greater lateral persistence than those deposited during progradational phases (Fisher et al., 1969; Gould, 1970).

Distal or Marginal Destructive Facies

Sediment supplied to the lower delta plain and delta front environments is drastically reduced during periods when the channel switches course to another part of the delta. The prodelta region reverts to a normal marine shelf and a more diverse community of marine organisms returns to the area. Interdistributary regions are characterized by highly organic mud fill of shallow-water bays or sounds. The interdistributary regions may be protected by and grade seaward into barrier island facies formed by the reworking of delta front sands.

By far the most important destructional facies in terms of potential reservoir quality are the reworked delta front sands which may form an arcuate system of barrier islands or shoals on the outer margins of abandoned delta lobes. With additional reworking brought about by continued subsidence, these sands are rolled back in the form of thin sheet sands on the Mississippi delta, where they are volumetrically insignificant. Reworked delta front sands are much more important on more sand rich types of deltas, particularly those building into a wave-dominated setting. In wave-dominated deltas such as the Rhone (Oomkens, 1970), the Grijalva (Psuty, 1967) or the Sao Francisco (Coleman and Wright, 1975), numerous coastal barriers or beach ridges develop and may provide significant hydrocarbon reservoirs. Coastal barrier sands associated with wave-dominated deltas form deposits ranging from several hundred to several thousand feet thick in the Upper Tertiary Nile delta system (Galloway and Hobday, 1983) and in the Tertiary Frio and Oakville formations in the northwestern Gulf of Mexico (Galloway et al., 1982). Cyclic burial of wave-dominated deltas may produce stacked sequences of upward-coarsening coastal barrier sands (Oomkens, 1970) which are potentially excellent reservoirs.

GEOMETRY AND DIMENSIONS OF DELTAIC FACIES

Primary Reservoir Facies

The dimensions and geometry of channel deposits are a function primarily of 1) the size of the delta, 2) the position of the channel in the delta, 3) the type of material being cut into, and 4) to a lesser degree, the forces at the mouth of the channel distributing the sediments (Sneider et al., 1978). For example, the channels of the modern Mississippi River generally are less than 600 ft wide and 35 ft deep where sediment is being dispersed into the Gulf of Mexico, in contrast to channel dimensions of 2,000 to 3,000 ft wide and 150 to 200 ft deep upstream on the upper delta plain (Sneider et al., 1978). Channels can be filled with up to 90% sand or clay/silt material depending on whether it migrates laterally or becomes abandoned. The geometry of the delta front is typically attributed to 1) the rate of sediment supply and 2) the relative strengths of the wave, tide and fluvial processes acting on the sandbody. However, synsedimentary faulting, slumping, clay diapirism and gravity sliding can drastically affect the geometry and structure of delta front and mouth bar deposits (Coleman, 1980). Deformed packets of sediments up to 200 ft thick and over half of all delta front sequences were reported to be disturbed in outcrop exposures of Upper Carboniferous deltaic deposits of the Clare Basin, Ireland (Pulham, 1989). In the same study, large multistory and laterally composite channel sandstones were attributed to rapid subsidence and compaction rates. Another example of growth faulting affecting sandstone geometry is presented for a Niger delta reservoir (Weber et al., 1978) where the sandstone thickness varied from 15 to 45 ft thick across a fault.

Table 3.2 presents data on the dimensions and geometry of deltaic facies of distributary channel, distributary mouth bars, distal bar sandstones and crevasse splay channels. The data include information from nine studies which represent a variety of ancient and modern deltaic settings (Lowry, 1989).

Table 3.2. Facies dimensions for primary reservoir facies in deltaic deposits. Modified from Lowry, 1989.

Facies	**90% less than:**	**50% less than:**	**20% less than:**
Distributary Channels			
width (ft)	2,805	1,073	248
thickness (ft)	60	30	12
width/thickness	130:1	40:1	10:1
Distributary Mouth Bars			
width, dip (ft)	21,120	10,560	3,696
thickness (ft)	99	60	23
length, strike (ft)	31680	21,120	10,560
width/thickness	820:1	280:1	50:1
length/thickness	1240:1	360:1	42:1
length/width	2.7:1	2:1	1.2:1
Distal Bar Sandstones			
thickness (ft)	2	--	--
Crevasse Splay Channel			
width (ft)	838	244	36
thickness (ft)	33	13	1
width/thickness		76:1	34:1 10:1

The data indicate a wide degree of variability in the dimensions and geometry. The median width of distributary channels is about 1,000 ft, but width ranges from less than 250 to over 2,800 ft. The median thickness of distributary channels is 30 ft and ranges from less than 12 to 60 ft for one genetic cycle, and width/thickness ratio is typically 40. Distributary mouth bar deposits are much larger sandbodies with median values for width at about 10,500 ft, thickness 60 ft, and length about 20,000 ft. Width/thickness ratios generally are 280, while length/thickness ratios are about 360.

Distributary mouth bar deposits tend to be twice as thick and 10 times wider than distributary channel deposits. The width/thickness ratio for distributary mouth bars is 7 times greater than that for distributary channels.

Table 3.3 presents dimensions data on channel fill deposits which are further subdivided into non-migrating distributary channel-fills and meandering channel-fills, and point bars. Non-migrating channel-fills are an order of magnitude narrower than the meandering channel-fills, are half as thick and tend to form disconnected, labyrinthine type reservoirs as opposed to the laterally continuous reservoirs resulting from meandering channel-fill deposits.

Table 3.3 Dimensions of channel fills and barrier bar deltaic facies. Modified from Weber, 1986.

Facies	**Width (W) (ft)**	**Thickness (T) (ft)**	**W/T**
Non-migrating distributary channel fills	400-4,000	10-150	50-200
	(larger channels (W>1600) tend to have W/T>40)		
Meandering channel-fills, point bars	4,000-65,000 usually <16,500	30-300 usually 30-100	300-2700 usually <1500
	(larger channels (W>10,000) tend to have W/T > 300)		
Barrier bars	4,500-40,000	25-100	500-1650
	(larger barriers (W>13,000) tend to have W/T >400)		

Shale Lengths

Dimensions of shale layers tend to vary as a function of depositional setting. Figure 3.11 presents probability distribution functions of shale lengths for a number of deltaic settings.

Shales associated with deltaic barrier sand deposits are usually quite continuous and are generally concentrated in the lower half of the sandy interval. The activity of burrowing organisms often creates permeability across shale breaks if they are thinner than 10 cm. Delta-front and delta plain sediments, however, contain shale layers which are usually less

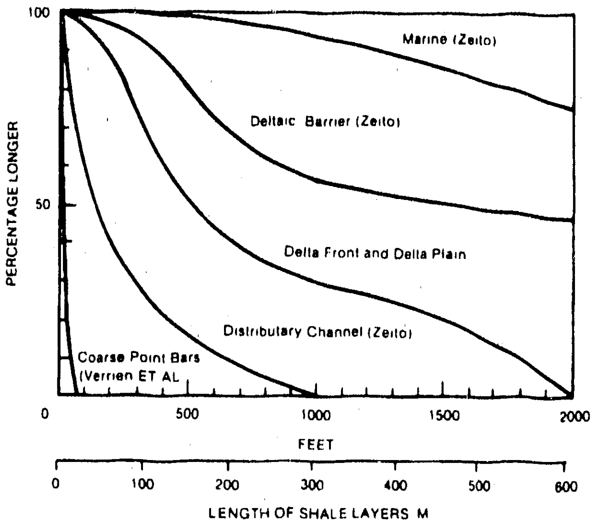


Figure 3.11 - Observed shale lengths as a function of depositional environment. After Weber, 1982.

extensive because of erosion by migrating and nonmigrating rivers and tidal channels. Shale breaks are often less than 30 ft in lateral extent in distributary channel fill deposits. The most common occurrence of laterally discontinuous shale layers is related to trough cross-bedding, where the shale layers often merge causing barriers to horizontal as well as vertical fluid flow (Weber, 1982).

Numerical studies of the effects of shales on production are discussed by Haldorsen and Chang (1986) and can negatively and positively effect production. The negative effects include: gas underrunning shales (cusping), reduced volumetric sweep in gravity drainage, reduced horizontal and vertical (cross-flow) flow and sweep efficiency, and the creation of channeling by confining high-permeability zones. Positive effects on production include reduced coning and, therefore, reduction of early gas or water breakthrough and aid in confining injected water to reduce slumping and improve the vertical sweep efficiency.

DIAGENESIS

Diagenesis refers to the postdepositional physical and chemical (including biologically induced) processes that are undergone by sediments as they subside within a sedimentary basin prior to extreme changes brought about by pressure and heat. Diagenetic processes include compaction, hydration/dehydration, cementation, recrystallization, leaching, alteration, and replacement among others. The driving force for most diagenesis is the chemical instability of minerals within sediments with respect to pore waters (Burley et al., 1985).

Often the higher quality (higher porosity and permeability) depositional facies distribution is mimicked by the resulting diagenetic products such as cements or secondary porosity. Just as often the depositional trend is not followed by diagenetic processes or is destroyed.

There are, however, some basic concepts that tie the often site-specific products of diagenesis to larger scale patterns. Fundamental to the prediction of porosity and permeability distribution is a process-oriented diagenetic model. The process-oriented model is the result of integrated information about both organic and inorganic diagenetic reactions which are placed into a time and temperature framework (Surdam et al., 1989). The general approach to developing such a model, in turn, depends upon recognizing the specific processes responsible for the enhancement and preservation of porosity. Some of the better models have recently begun to recognize the importance of secondary sandstone porosity that originates within deeper subsurface environments (Surdam et al., 1984). Such models demonstrate the dynamic nature of diagenesis during progressive stages of burial which are the consequence of interaction between pore fluids, maturing kerogen, and cements and framework grains comprising the rock.

The effects of diagenesis may be related to the hydrological framework of large, depositionally active sedimentary basins. The hydrological system includes a meteoric regime in shallow portions of the basin characterized by infiltration of surface waters. The shoreline is generally a major discharge area for meteoric waters; therefore, deltaic sands are often deposited within and strongly effected by this hydrological (and diagenetic) regime. The compactional regime is characterized by upward and outward expulsion of trapped pore waters as sediments are continuously loaded onto the accumulating section. Waters produced from this zone may be derived from water originally trapped in the sediments and subsequently modified by rock-water reactions, or they may be meteoric waters which have been buried below the zone of active meteoric circulation. The thermobaric regime is located in the deepest parts of the basin where the pressures and temperatures are the greatest. Here significant volumes of water may be released by dehydration of clays or other hydrated minerals (Galloway, 1984). The low-permeability characteristic of the the thermobaric regime is caused by cementation and compaction and generally creates restricted or slow water circulation.

Both depositional environment and hydrogeologic setting help to define the end result of diagenesis; therefore, distribution of reservoir quality sandstone is indirectly related to facies distribution, but is neither controlled by, nor uniquely associated with, the depositional environment of the reservoir (Galloway and Hobday, 1983).

An example of diagenetic changes that have widespread implications may be taken from the Gulf Coast. It is well known that porosity generally decreases with depth in the Gulf Coast section (Blatt, 1979; Loucks et al., 1977). McBride et al. (1991) showed that much of the loss of porosity in Wilcox sandstones could be attributed to compaction. These sands compacted rapidly to approximately 1,200 ft and appear to have stopped compacting at about 3,000 ft. Total whole rock porosity lost by compaction ranges from 9 to 31%. Porosity in the deeper subsurface environment, however, increases in many Tertiary Gulf Coast sediments at the top of the geopressured zone (Blatt, 1979; Loucks et al., 1984) as secondary enhanced porosity is created, probably by the interaction of organic and inorganic constituents within the sedimentary sequence that is undergoing progressive diagenesis (Surdam et al., 1989). Loucks et al. (1984) noted that the large range of porosity and permeability values at any given depth indicates the complexities involved in understanding the controls on reservoir quality. Frio Formation deltaic and barrier/strandplain systems were found to have distinct suites of diagenetic features for each of the three major basinal hydrologic regimes (Galloway, 1984), thus providing a direct link between diagenetic changes and production capabilities. In a more general sense, Loucks et al. (1984) distinguished similar diagenetic sequences within Lower Tertiary sandstones along the Texas Gulf Coast. The generalized diagenetic sequences may be summarized according to the general diagenetic/hydrologic environments. These include surface-to-shallow-subsurface diagenesis characterized by compaction and cementation; intermediate subsurface diagenesis characterized by continued cementation, but locally significant enhancement of porosity; and deep subsurface diagenesis characterized by carbonate cement precipitation. Loucks et al. (1984) concluded that differences in the intensity of diagenetic events and depths at which they first occurred correspond to the chemical and mechanical stability of the original mineralogy and to regional variations in geothermal gradient.

Diagenesis impacts a number of aspects of production that may be summarized as production/injection anomalies, core analysis, drilling, completion, and stimulation applications, log analysis, and fluid/rock interactions. These topics should be taken into account for each stage of production (primary, waterflood, EOR) in terms of the engineering model of a given reservoir.

Potentially sensitive minerals should be distinguished, and their effects on primary, waterflood, or EOR recovery processes should be evaluated. The pore system is then defined in terms of volume, pore size, distribution, aspect ratio, genetic type and geometry, microporosity, and mineral or organic coatings, fillings, and throat blocking. Petrophysical parameters can be significantly effected by textural properties of clay minerals. For this reason, reservoir rocks must be evaluated in terms of clay mineral texture and morphology as well as the "standard" volume and distribution values.

Petrographic analysis of depositional and diagenetic features can provide basic information for the reservoir engineer including pore size distribution, pore geometry, pore type and complexity, pore lining materials (including clays) and their grain size, abundance, and morphology, framework content and amount, depositional matrix, mineralogy, grain size distribution, sorting, compaction, other textural features, and the mineralogical and textural history of the rock. Each of these parameters is related to production volume, rate, and expected residual oil saturation after each phase (primary, waterflood, EOR) of production.

The study of reservoir diagenesis can be of particular use to waterflood applications. Petrographic studies comprise part of the laboratory studies that can be used to predict waterflood performance. They must be undertaken prior to waterflood implementation (Atwater et al., 1986a and 1986b) in order to help improve design of well patterns and prevent drastic formation damage. Petrographic studies for waterflood performance prediction concentrate on the basic questions of compatibility of injection water and formation water, and the compatibility or reactivity of injection water with the reservoir rock. Detailed knowledge of the chemical composition of the reservoir rocks and the injection water is paramount to the prediction of chemical reactions between the two media.

Just as the potential reactions between water-water and water-rock are considered for waterflood, the potential reactions between EOR injection chemicals and the reservoir rock composition must be evaluated. Theoretical considerations based on a thorough knowledge of the chemical composition and reactivity of injection fluids with reservoir minerals should be supplemented by laboratory tests on cores under reservoir conditions prior to chemical injection into a reservoir.

STRUCTURAL FEATURES IN DELTAIC RESERVOIRS

Introduction

Structural features result from deformation of sediments and rocks and include faults, folds, tilting (dip), and fractures. Structural features can be broadly divided into two classes based on the timing of the deformation: 1) syndepositional deformation which occurs at the time of deposition in unconsolidated sediments, and 2) postdepositional structural features that typically occur in consolidated rock after burial of the sediments. The types and frequency of syndepositional structural features are related to the depositional environment. The conditions in deltaic environments, for example, where large volumes of sediment are rapidly deposited into large bodies of water, are conducive to large scale deformational features. Postdepositional features, on the other hand, are unrelated to the environment of deposition and are controlled by tectonic forces and movement within the earth.

Syndepositional Deformation

Syndepositional deformational processes, which include slumping, mud diapirism and growth faulting, are common in lower delta plain environments and operate during delta formation. Slumping is the downward movement of a mass of sediment caused by slope failure and is due to a combination of processes including high pore-water and methane pressures in the sediment, wave-induced forces acting on the sediments during storms and hurricanes, and oversteepening of a bar front due to differential sedimentation rates during flood periods. Slumping may affect large volumes of sediment. For example, in the Mississippi Delta, it is estimated that 50% of the sediment deposited in the distributary mouth bars is involved in down-slope mass movements which transport upper mouth-bar facies into the deeper parts of the basin (Elliott, 1989). Syndepositionally deformed sediments may locally create significant accumulations. For example, packages of deformed sediment up to 180 ft thick occur in Carboniferous deltaic deposits in Ireland (Pulham, 1989).

A mud diapir is a dome or fold in sediments that is formed by the plastic deformation of mud underlying sand or other sediments. Diapirs, called mudlumps, frequently emerge in distributary mouth bar deposits where they cause steeply dipping bar fronts, slumping and faulting.

Growth faults form a discrete class of syndepositional faults and are defined by characteristics which reflect their genesis. These faults generally form parallel to the shoreline, have a curved concave profile in cross-section which flattens with depth, and the downthrown side of the fault is basinward. The thickness of sediments is appreciably thicker on the downthrown side and also contains a significantly higher sand proportion (Reading, 1978). The amount of vertical displacement can be as large over 3,000 ft (Busch, 1975). Although many mechanisms have been proposed for the formation of growth faults, it is generally accepted that differential compaction is an important mechanism, where large masses of sediment are rapidly deposited on water-saturated shales (Carver, 1968). Sediment continues to accumulate on the downthrown side of the fault, thus perpetuating downward movement of the fault.

Structural features can modify the sandstone body geometry to such an extent that it has been suggested that delta classification schemes should include deformational processes as well as tidal, wave, and fluvial processes (Pulham, 1989). Deformation by diapirism has been reported to transform distributary mouth bar deposits from uniform, linear bodies 40 to 60 ft thick, to a series of discrete sand packages up to 300 ft thick separated by areas of thin sands (Coleman et al., 1974). Sand thicknesses vary from 15 to 45 ft across a growth fault in a Niger Delta reservoir (Weber, 1978).

The upper Wilcox deltaic reservoirs of the Texas Gulf Coast attain thicknesses of 3,000 ft and are examples of growth-faulted deltas. The growth faults were activated by progradation over unstable prodelta muds at the shelf margin (Edwards, 1981). In contrast, syndepositional growth faulting does not play an important role in the reservoirs of the lower Wilcox deltaic reservoirs which were deposited on a stable substrate (Fisher, 1969; Fisher and McGowen, 1967). The lower Wilcox Group in East Texas, central Louisiana and Mississippi is not subject to the extensive growth faulting of the south Texas Coast. However, in some areas of southern Louisiana faulting related to diapirism and upward movement of salt piercement domes into the overlying sediment is evident. Salt dome formation causes fracturing and displacement of the hydrocarbon in the effected reservoirs.

Postdepositional Deformation

Postdepositional features include folding, tilting, faulting, and fracturing and result from tectonic forces and consequent movement of the earth's crust. These features are important in the migration, accumulation and trapping of petroleum. Migration of hydrocarbons from the source rock is enhanced by faults and fractures. The accumulation or trapping of oil is caused by permeability barriers which prevent further migration of the petroleum. When the permeability barrier is a structural feature, the reservoir is considered a structural trap. Structural traps may be created by folding, faulting, fracturing, or tilting of strata as well as intrusion (or withdrawal) of salt plugs or a combination of these features. Fractures and faults are important on an interwell scale where they control the movement of both injected and naturally occurring reservoir fluids and may significantly affect the production of hydrocarbons.

Deltaic reservoirs within the Frontier Formation in the Rocky Mountain region are examples of reservoirs formed by structural traps. Deposition of the Frontier Formation was widespread and relatively uniform across much of what is now north-central Wyoming and parts of southern Montana. Mountain building caused extensive folding and faulting that modified the uniform sand and created many structural traps and fractured reservoirs. Of the 65 oil and gas fields in the Bighorn and Wind River Basins, only five recognized reservoirs are not structural traps (Cardinal, 1989). In the Powder River Basin, however, the Frontier reservoirs are were not strongly modified by tectonic forces and are not structural traps.

In the Burbank sandstone of the Cherokee Group of Oklahoma, no major thrust faulting or regional growth faulting occurs; however, minor faulting and fracturing has resulted in a highly compartmentalized reservoir in North Burbank field and affects production patterns (Trantham et al., 1980). The joint system affecting the Burbank sandstone at depths up to 3,000 ft can be traced on the surface by vegetative changes using aerial photography (Hagen, 1972).

HETEROGENEITIES RELATED TO DELTAIC DEPOSITIONAL PROCESSES

Introduction

Heterogeneities that occur as a result of delta genesis or depositional processes may cause significant recovery problems on scales ranging from field-scale to pore-scale. Heterogeneities that are not directly caused by depositional processes such as structural faults and fractures, diagenetic features, and rock-fluid interactions will not be discussed here although they exert significant affects on fluid flow.

The types of heterogeneities found in deltaic reservoirs are presented in figure 3.12 in a decreasing order of scale. Although these heterogeneities are common in deltaic deposits, they may also apply to other depositional systems because the processes which formed them operate in a number of environments. For example, channelized flow occurs in fluvial systems as well as in delta distributary channels, and wave and tide processes shape coastal beaches, sand ridges and shoreface sediments as well as delta front sediments.

Field-Scale Heterogeneities

Interconnectedness of sandbodies. On the field scale, the lack of interconnectedness of distributary sandbodies may present a major problem to sweep efficiency. Fig 3.12a illustrates three different degrees of distributary channel interconnectedness separated by shale. Statistics of the widths, thicknesses, and lengths of distributary sandbodies presented above indicate that dimensions of sandbodies can vary over an order of magnitude. Depositional controls on channel sandbody interconnectedness are primarily related to the amount of sand in the depositional regime and the lithology of the underlying unit being cut into. If the underlying unit is shale, the channels do not tend to migrate laterally, resulting in deep, straight channels. If the underlying unit is sand, which is not as easily eroded as shale, the channels are shallower and wider, and the tendency to migrate laterally is increased. Lateral migration results in greater channel sandbody interconnectedness. Theoretical studies on lateral migration patterns of river channels have shown that the channel sandstone interconnectedness increases substantially when the sand/shale ratio exceeds 0.50 to 0.55 (Allen, 1978).

Figure 3.13 is a conceptual model of the effect of sandstone body interconnectedness on waterflood sweep efficiency. The reservoir model in figure 3.13a is similar to the Statfjord reservoir in the North Sea (Van de Graff, 1989) and consists of three units separated by shales. Each unit consists of different sand/shale ratios and degree of interconnectedness of sandbodies. Figure 3.13b presents the fluid distribution after waterflood showing that the middle unit remains unswept and illustrates the importance of sandbody connectedness on waterflood sweep efficiency.

Location within the deposystem. A second type of field-scale heterogeneity is the variability of reservoir quality due to location within the deposystem. Previous studies have shown a generally good correlation between facies type and permeability in a number of different environments (Dreyer, 1990; Jackson et al., 1990; Jackson et al., 1987; Stalkup and Ebanks, 1986; Jones et al., 1987). The facies distribution, therefore, can be used to indicate the permeability distribution within a reservoir. Figure 3.6 illustrates the reservoir complexity due to the lateral variations of facies that occur within a lower delta plain area.

This scale of variability has been the cause for numerous problems in enhanced oil recovery (EOR)

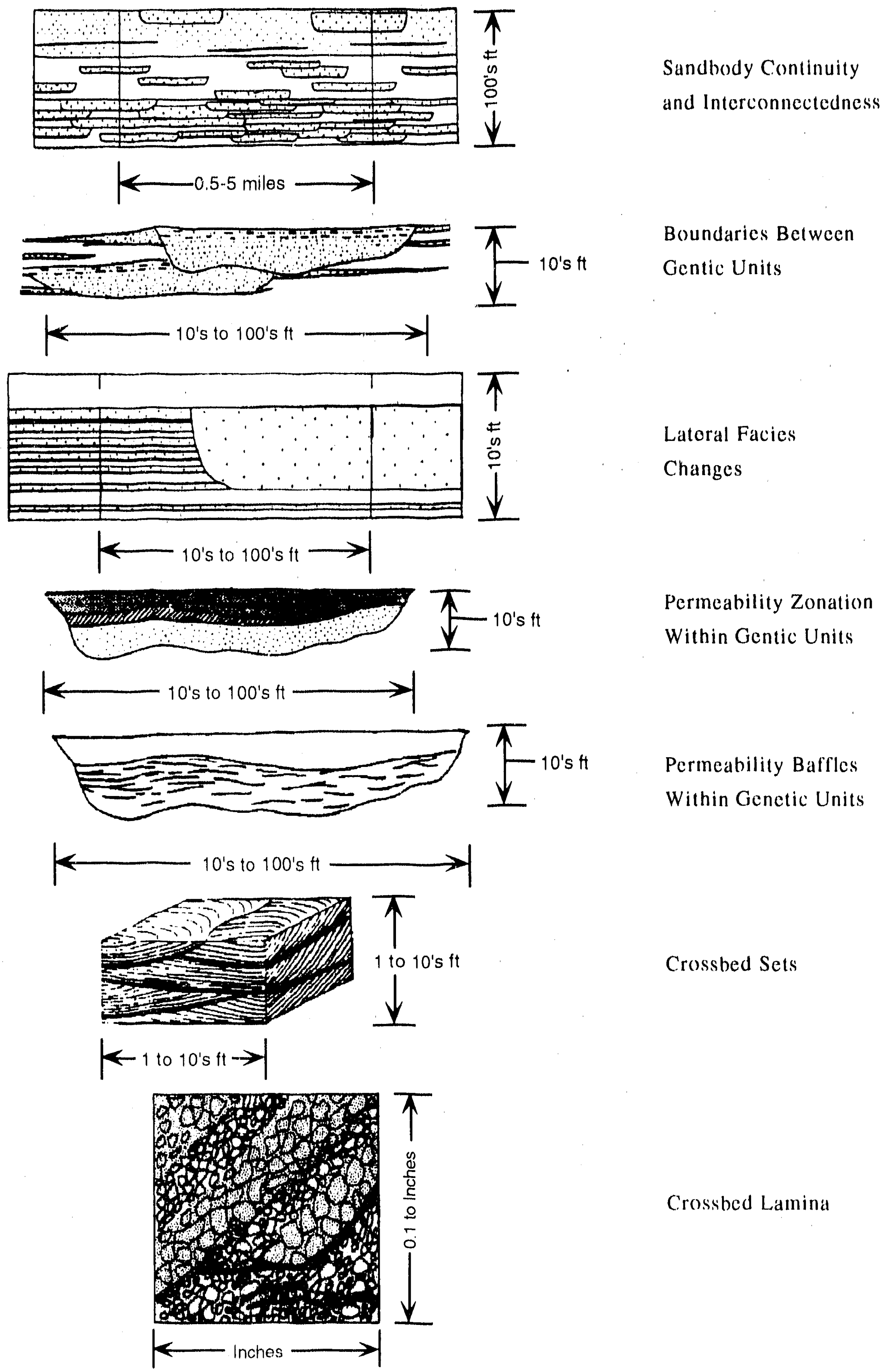


Figure 3.12 - Heterogeneities related to deltaic depositional processes. Modified from Weber, 1986.

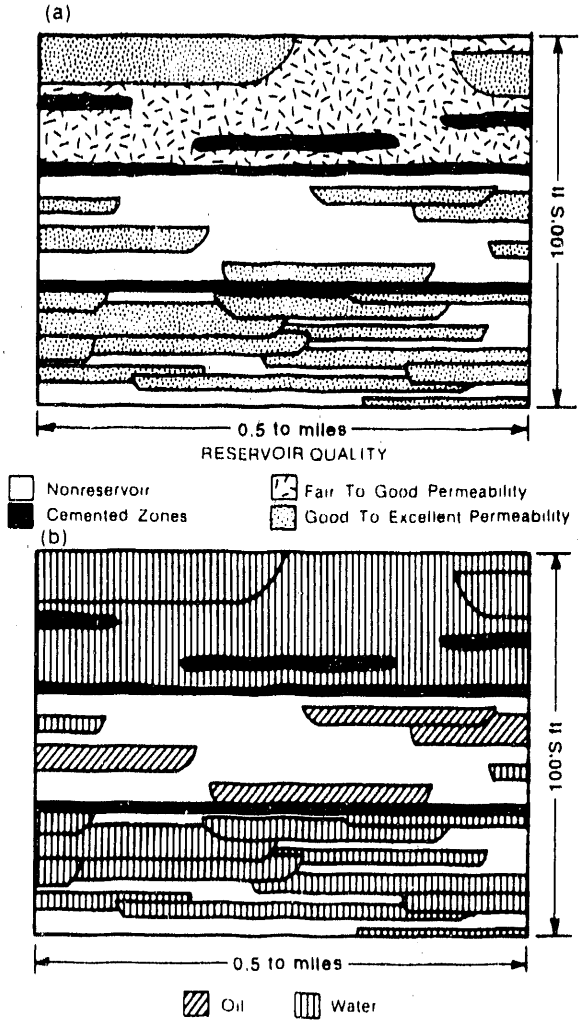


Figure 3.13 - (a) Various distributions and degrees of interconnectedness of distributary channel sandbodies, (b) Conceptual fluid distribution after waterflood illustrating the effect of sandbody distribution on sweep efficiency. After van de Graaff and Ealey, 1989.

pilots. In Sloss field, for example, a five-spot micellar polymer pilot was located in interdistribuary crevasse-splay sands, which are discontinuous and have poor areal and vertical communication (Basan et al., 1978). Performance data collected during preflush water injection could not be matched with mathematical model results because they were based upon more favorable distributary channel sand properties recorded in another part of the field.

Another example of mislocated pilots in deltaic reservoirs is discussed in Szpakiewicz et al., (1987). In El Dorado field, Kansas producing from the Admire sand, two pilots were initiated with the objective to compare two separately designed tertiary oil recovery methods (Van Horn, 1978). Comparison of the two methods was not valid because the pilots were located in different parts of the deltaic system — one pilot was located in interdistributary bay shales, crevasse splays and beach sands, and the second was located within distributary channel sand and crevasse splay deposits (Van Horn, 1983).

Field-scale heterogeneities can often be recognized deterministically by detailed well log correlations and through sedimentological models derived from core descriptions and outcrop information. Recent advances in imaging technology and geostatistics have been applied to outcrop exposures which allow quantification of the spatial distribution of facies and sandbodies in a fluvio-deltaic deposit (Ravenne et al., 1989; Ravenne and Beucher, 1988; Matheron et al., 1987). Detailed seismic studies may also be of value in delineating field scale variations in reservoir quality.

Interwell Scale Heterogeneities

Boundaries between genetic units such as channel deposits (fig 3.12b) often consist of clay drapes or mud-pebble conglomerates which range from low to zero permeability. These permeability barriers strongly affect horizontal and vertical sweep and contribute to compartmentalization of the reservoir. The lengths of these shales are usually less than 1,000 ft (fig. 3.11).

Examples of lateral facies changes on the interwell scale are distributary channel cutting into an adjacent, thinly bedded bay fill or crevass splay (fig. 3.12c) or of a distributary channel prograding out over thinly bedded pro-delta deposits. These heterogeneities tend to cause channeling, strongly affect horizontal sweep efficiency, and moderately affect vertical sweep efficiency.

An example of reservoir-scale heterogeneity is presented in figure 3.14a which depicts a single channel sandstone which has cut down into thinner sandstones interbedded with shales. The laterally equivalent thinner sandstones are commonly formed in crevasse splay or sub-aerial levees and have lower permeabilities and poorer vertical communication than the adjacent channel sandstone. Figure 3.14b shows the expected fluid distribution after waterflooding which results from the permeability contrast, influence of gravity and sand continuity. A field example similar to this is presented by Hartman and Paynter, (1979).

Another example of the effect of lateral facies changes is from the Mississippi delta area. The M_6 sandstone in the South Pass Block 27 is discussed by van de Graaf and Ealey, (1989). This reservoir consists of a distributary channel which has prograded over and cut into delta front sands. Figure 3.15a shows the fluid distribution within the M_6 sandstone at the time of field development in 1959. Figure

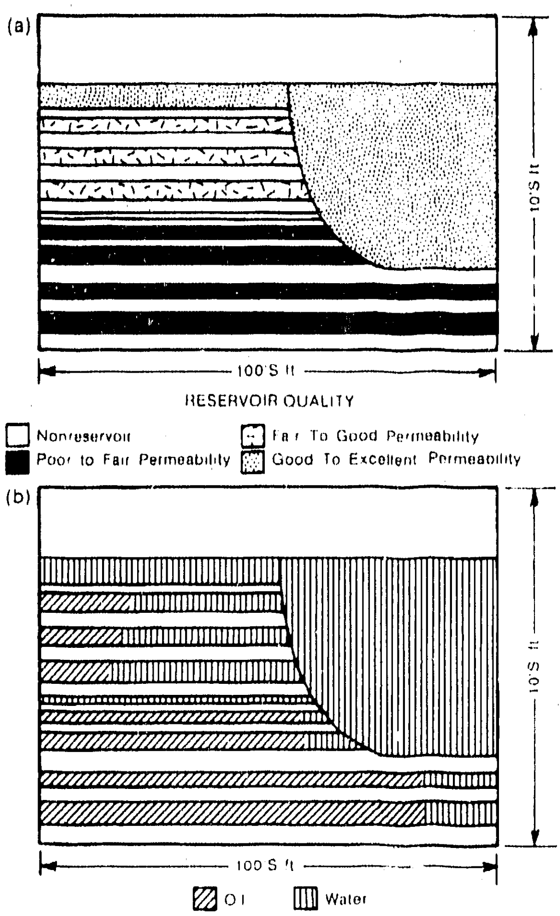


Figure 3.14 - (a) Distributary channel sandstone and its lateral facies equivalents illustrating reservoir-to-genetic sand-body scale heterogeneity, (b) Conceptual fluid distribution after waterflood showing unswept layers. After van de Graaff and Ealey, 1989.

3.15b depicts the fluid distribution after 15 years of waterflood production and illustrates the preferential sweep of the high-permeability zones.

Permeability zonation within genetic units (fig. 3.12d) can consist of decreasing permeability upward as occurs in distributary channel deposits, or increasing permeability upwards as in delta front distributary mouth bar deposits. These heterogeneities strongly affect vertical sweep efficiency, moderately effect horizontal sweep efficiency, and cause non-uniform residual oil saturation (ROS) in swept zones.

The effect of this type of heterogeneity on oil recovery was investigated by simulation studies by van de Graaff and Ealey (1989). Figure 3.16 shows the percentage of oil cut vs. dimensionless oil recovery (equal to cumulative produced oil divided by moveable oil) resulting from simulation studies. The two cases considered are a fining-upward (decreasing permeability) channel deposit typical of distributary channels, and a coarsening upward (increasing permeability) barrier/bar typical for distributary mouth bars and delta front deposits.

The same parameters for both scenarios were used: uniform porosity, oil viscosity of 20 mPa•sec (i.e. an unfavorable mobility ratio) and three layers of equal thickness with cross flow and with the same average permeability and absolute permeability. Only the position of the high-permeability layer is different.

Simulation results show that in the channel sandstone, a 5% oil cut (economic limit) is reached after

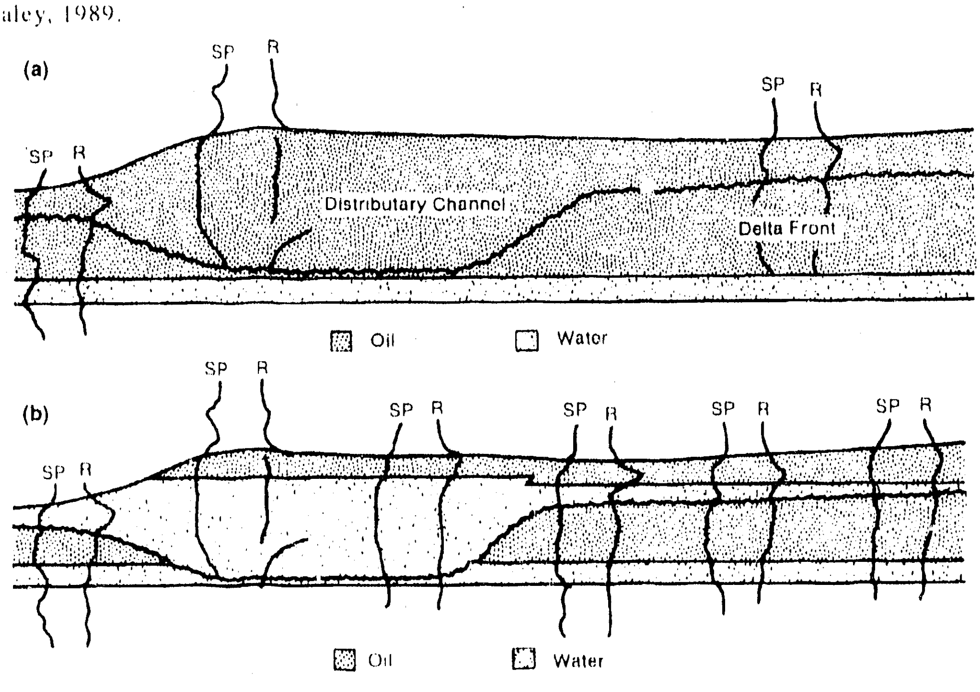


Figure 3.15 - (a) Fluid distribution in M_6 sandstone in 1959 at time of field development, (b) Fluid distribution in M_6 sandstone in 1974 after 15 years of production. After Hartman and Paynter, 1979.

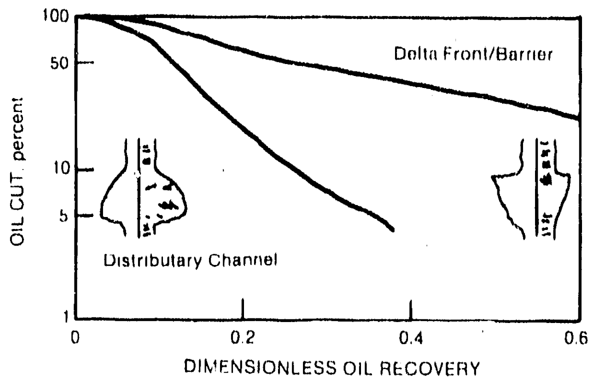


Figure 3.16 - Influence of vertical distribution of permeability on oil recovery. Permeability profiles typical for the distributary channel (decreasing permeability upward) and distributary mouth bar (increasing permeability upward) delta facies result in different oil cut vs. oil recovery curves even with identical absolute permeability values. After van de Graaff and Ealey, 1989.

approximately 35% of mobile oil has been produced (fig. 3.16). By contrast, in the barrier sandstone, oil cut is still 20% after 60% of mobile oil has been recovered. The reverse response may occur in a gas or steam injection scheme, however, because of the combined effect of gravity and presence of a high-permeability zone at the top of the sandstone. A barrier in a sandstone reservoir will give an unfavorable sweep as compared to a channel sandstone.

A field example from the North Sea Brent formation of the effect of an upward decreasing permeability profile on injected water movement is discussed by Archer (1983). At the location where injected water channeled along the base of distributary channel fill deposit, sweep efficiency was lower and much less oil was recovered than expected.

Lateral permeability zonation within genetic sandbodies is most strongly influenced by sedimentary structures and stratification type, clay content, and grain size distribution. Permeability variations within distributary channel sandbodies were documented in an analysis of permeability data from outcrop exposures (Dreyer, 1990). The study indicated that the sandbodies consist of numerous interlocking permeability lenses that rarely exceed 3 ft in thickness or 60 ft in length or width. The lense-shape geometry of these zones is attributed to the channel depositional processes of infilling of scours and migration of bed forms along the channel bottom. Semivariogram analyses and correlation of permeability profiles indicated that permeability measurements tend to be unrelated at distances exceeding 6 to 10 ft. These heterogeneities strongly affect both horizontal and vertical sweep efficiency and cause non-uniform residual oil saturation in swept zones.

Permeability baffles within genetic units (fig 3.12e) are typically caused by clay drapes between cross-bed sets and along scoured surfaces. Their presence strongly affects vertical sweep efficiency and moderately affects horizontal sweep efficiency and non-uniform ROS in swept zones.

Crossbed sets (fig. 3.12f) are a source of anisotropy in the reservoir. Emmet et al. (1971) described the influence of cross-bedding on infill drilling and secondary recovery in the Tensleep Formation in Wyoming. They found that permeability parallel to the cross-bed laminae is about 4 times higher than that perpendicular to the laminae. The effect of the permeability contrast is dependent on the viscosity of the fluid, where the higher the viscosity of the oil, the greater the affect on waterflood recovery. Jones et al. (1987) document permeability ranges and the degree of anisotropy for the stratification types of trough cross-bedding, as well as ripples and dewatering structures in outcrop exposures of the Mesaverde Formation in Colorado.

Weber et al., (1972) determined the permeability distribution in an unconsolidated, trough cross-bedded distributary channel-fill deposit and developed a model for calculating permeability anisotropy. In situ flow experiments were performed in the channel-fill sand body to check the permeability anisotropy calculations. They concluded that permeability anisotropy in unconsolidated distributary channel-fill deposits is negligible; however, in consolidated sands, the anisotropy is expected to be very large.

Core-Plug and Microscopic-Scale Heterogeneities

Permeability variations caused by grain size variations within cross-bed laminae are a small-scale heterogeneity common in distributary channel deposits (fig. 3.12g). The permeability contrasts between cross-bed lamina can range from very slight differences to great differences where impermeable shale laminae are interlayered with sandstone laminae and may impart a significant effect on residual oil saturation and log response.

Kortekaas (1983) analyzed the effect of permeability variations on the displacement of oil by water within cross-beds with a permeability contrast of 5 between laminae. His work shows that when fluid flow is perpendicular to the cross-bed laminae and the rock is water-wet, oil within the higher permeability laminae may be initially bypassed due to the higher capillary pressures in the lower permeability (finer-grained) laminae (fig. 3.17). His simulation study also showed that low-tension (dilute surfactant) and polymer floods would improve recovery in these cross-laminated zones.

These results are consistent with those of Tomutsa et al., (1990) who used CT scanning techniques to monitor fluid distributions while flooding a cross-bedded rock sample first with oil and then with water. They found that the lower permeability laminae accepted less oil than the higher permeability layers after flooding, as expected. After flooding with water, however, the water entered the lower permeability layers first. This response can be partly explained by the higher water saturations in the lower permeability layers, which result in higher initial relative permeability to water than the higher permeability, oil-saturated zones. As flooding continues, the relative permeability to water increases in the lower permeability zone with an increase in water saturation.

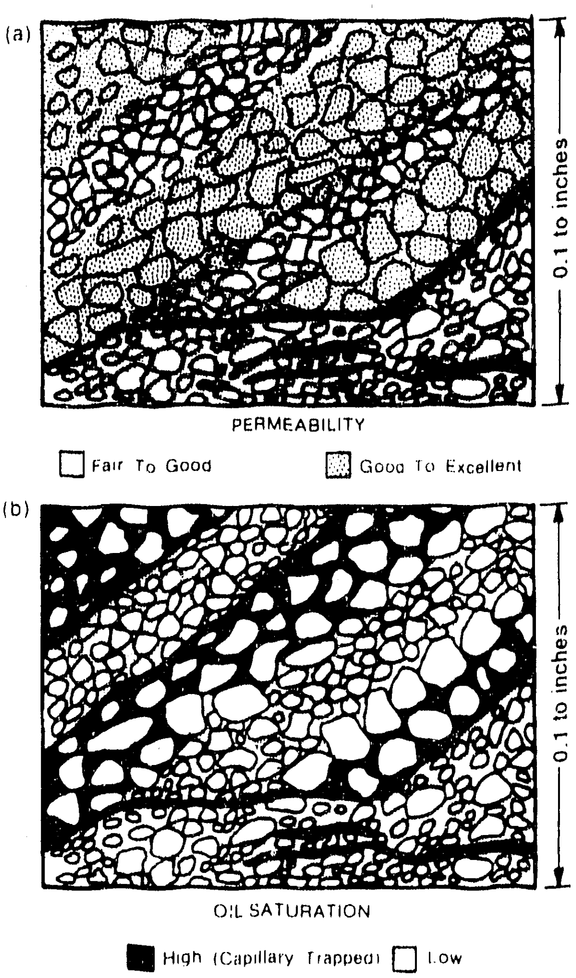


Figure 3.17 (a) Conceptual model of permeability heterogeneity in crossbed laminae. After van de Graaff and Ealey, 1989. (b) Hypothetical fluid distribution after waterflood. After Kortekaas, 1983.

Jacobsen (this report) stressed that textural variations may create errors in the calculation of irreducible water saturation and permeability. This error may be increased by diagenetically altered, cross-bed laminae which result in erroneously high water saturation measurements. In a case where laminae with high kaolinite content, plugged pores and low permeabilities alternate with laminae with moderate amounts of kaolinite and permeability in the darcy range, the average log-derived water saturations were as high as 50 to 60%, but the reservoir maintained water-free production of up to 6,000 b/d (Salle and Wood, 1984). The kaolinite forms a microporosity system which is filled by immobile water in the low-permeability layers, while oil can flow through the cleaner, higher permeability laminae. Advances in logging techniques such as improved dipmeter (Salle and Wood, 1984) and the dielectric (EDT) approach along with geochemical methods (GLT log) are showing much promise in the analysis of thin bedded rocks (Jacobsen, this report).

APPLICATION OF ADVANCED PRODUCTION METHODS TO MITIGATE TO DEPOSITIONALLY RELATED HETEROGENEITIES

In general, the methods of infill drilling, horizontal/slant wells, and hydraulic fracturing are most applicable to larger field-scale heterogeneities, whereas enhanced oil recovery processes are most applicable to interwell and microscopic-scale heterogeneities. Table 3.4 summarizes the enhanced production methods which may be applicable in overcoming the heterogeneities related to depositional processes described in the previous section.

Sandbody Continuity and Interconnectedness

For sandbodies that are separated both laterally and vertically by large distances, (as in the top third of figure 3.12a), the only recourse for increased oil production is to infill drill. As the connectivity between sandbodies increases (as in the middle part of fig. 3.12a), the application of both vertical infill wells and horizontal wells should be investigated to overcome this field-scale heterogeneity. The degree of lateral connectedness of the sandbodies will determine whether a horizontal or infill well would be most effective. Horizontal wells are best applied in reservoirs with interconnected sandbodies. Horozontal wells can cut across flow barriers between stacked sandbodies and reduce the effect of compartmentalization. Hydraulic fractures would increase produc-

Table 3.4. Application of enhanced production methods to heterogeneities related to deltaic depositional processes

	Infill	Horizontal/ slant	Hydraulic fracturing	Gel polymer	Polymer	Surfactant alkali-surf.	CO_2	Steam	In situ combustion
Field scale sandbody continuity									
continuous	X	X	X						
semicontinuous	X		X						
separated	X								
Boundaries between genetic unit	X	X	X						
Lateral facies changes	X	X		X					
Permeability zonation				X	X				
Permeability baffles			X						
Crossbed sets			X			X	X	X	X
Crossbed laminae					X	X	X	X	X

tion from a horizontal well by connecting two or more neighboring sand bodies providing the shale layer in between will propagate a fracture.

For an offshore reservoir with similar field-scale permeability barriers but an inverse pattern as that illustrated in figure 3.12a, Johnson and Krol (1984) illustrated through simulation studies the possibility of simultaneous miscible gas flooding in the top laterally continuous (transgressive) unit and that waterflooding of the lower individual and multistory channel sandstone unit would improve recovery efficiency in the top unit by 14%.

Boundaries Between Genetic Units

Infill drilling would be best applied to overcome permeability barriers caused by boundaries between genetic units with dimension in the 10's to 100's feet in the (x-y directions). The use of hydraulic fracturing or short laterals from the vertical well may be desirable to provide better flow.

Lateral Facies Changes

The residual oil after waterflood indicated in figure 3.14 suggests that thin laminae adjacent to a channel with good permeability will not be swept efficiently. One effective technique to overcome directional permeability or channeling is to apply a linedrive pattern so that the injected water flows perpendicular to the direction of the permeability trend. The linedrive pattern has been successfully applied in numerous reservoirs including North Burbank field in Oklahoma (Trantham et al., 1980). [illegible] where there are significant quantities of oil in [illegible] another effective method to correct for lateral facies changes will be the use of infill wells (vertical or high angled slant well) in the tight thin zones, or in some instances, the use of polymer gel may be used to modify the flow profile.

Permeability Zonation Within Genetic Units

Heterogeneity caused by the vertical arrangement of permeability can usually be mitigated through properly designed improved waterflood methods such as polymer flooding or profile modification or a combination of the two methods. Crosslinked polymers including chromium acetate, chromium proprionate, and aluminium acetate polymers in profile modification and polymer flooding have been successfully used to improve the sweep efficiency in high-permeability zones in deltaic reservoirs such as North Burbank and North Stanley Units of Burbank field (Zornes, 1986; Harpole and Hill, 1983). These methods reduce drive water mobility and decrease the degree of water channeling, thereby improving conformance and overall waterflood volumetric sweep efficiency. Profile modification and polymer flooding may not be an economic solution in large, high-permeability zones, or when the the ratio of vertical to horizontal is greater than 0.01, where the water will revert back to the high-permeability zone after it flows past the gel-polymer slug (Gao et al., 1990). In these cases, targeted infill drilling may be a better solution.

In cases where the permeability contrast between zones is not large, polymer flooding can compensate for the imbalance in water intake due to the differences in fluid conductivity. However, polymer flooding cannot completely correct for permeability zonation induced flow imbalances as indicated by post surfactant polymer flooding pilot evaluation studies, where higher residual saturations in tighter zones were reported (Taggart and Russell, 1981; Smith, 1991). Mechanical methods such as flow baffles, selected perforation have also been used with some success.

Permeability Baffles Within Genetic Units

Horizontal permeability baffles reduce vertical permeability and may effect horizontal wells more adverseiy than vertical wells. Hydraulic fracturing stimulation will improve injectivity or productivity around the wellbore.

Crossbed Sets

As indicated in the previous section, waterflooding in crossbedded intervals can be highly inefficient due to trapping of oil by capillary forces and bypassing zones due to shale layers. In this situation, the recovery efficiency can be improved by using a miscible displacement (CO_2, hydrocarbon gas, etc.) process which reduces the capillary forces that trap the crude oil and overcomes the viscous forces that tend to retard crude oil flow (Hornof and Morrow, 1988). A dilute surfactant or alkali-surfactant process may be a candidate process and should be investigated. However, the use of polymer for mobility control may not be desirable due to the potential filtering effect of the shale streaks which occur between the cross-bed sets. This phenomenon may be the cause of problems encountered in a number of pilots where only the surfactant slug but not polymer reached an observation well or evaluation well (Lorenz et al., 1986; Cole, 1988 a and b; Huh et al., 1990).

Crossbed Laminae

Pore size variation in crossbed laminae tends to promote nonwetting phase trapping. For water-wet rock, rapid imbibition of water into the tighter laminae leaves the higher permeability laminae unswept and with a high residual oil saturation (immobile oil). This was shown in the simulation work of Kortekaas (1983) and theoretical review of Stegemeir (1976).

The only way to overcome this type of heterogeneity is by increasing the capillary number and improving the displacement efficiency via one of the EOR methods. Any of the conventional EOR methods of chemical, gas miscible (reduction of interfacial tension), and thermal (reduction of viscosity) can overcome the effect of cross-bed laminae induced oil trapping.

REVIEW OF GEOLOGICAL FACTORS AFFECTING RECOVERY IN EOR PILOT PROJECTS

Introduction

After primary and secondary recovery, an average of about 69% of the original oil-in-place will remain unrecovered in deltaic reservoirs (see the section on General Reservoir Characteristics from TORIS Data Base). This remaining oil will be the target of improved oil recovery. Improved oil recovery methods include advanced secondary methods such as targeted infill drilling, profile modification (chromium or aluminium crosslinked polymer, foams, etc.), and polymer flooding. These methods improve the sweep efficiency of a waterflood and mitigate reservoir-scale and small-scale heterogeneities that cause unrecovered movable oil to be left behind even after extended waterflooding. The other improved oil recovery methods usually identified as enhanced oil recovery processes are steamflood, cyclic steam, in situ combustion, miscible and immiscible gas (CO_2, natural gas, enriched natural gas and N_2), microbial, alkaline, surfactant, and alkaline-surfactant methods. These methods improve displacement efficiency and can mitigate micro- and small-scale heterogeneities. Mobility control agents such as polymer, and steam and CO_2 foam can, to a certain degree, mitigate bypassing phenomenon caused by reservoir scale heterogeneities. Unfortunately, as can be seen from the discussion below, using mobility control agents will not totally eliminate the tendency for fluid to follow a path of least resistance. Inefficient sweep is especially detrimental to EOR projects that inject less than 1 pore volume of slugs. The smaller the slug used, the greater the importance of proper mobility control.

The DOE Bartlesville Project Office EOR Project Database showed 129 EOR projects in 37 fields producing from deltaic reservoirs. Of these 129 projects, 46 are steam (cyclic or steamdrive), 4 in situ combustion, 10 gas injection, 38 polymer, 32 surfactant, 1 alkaline, and 1 microbial EOR projects. Forty-four of the 46 steam prejects are in Coalinga, Lost Hill, and Elk Hills fields which have crude oils in the 20.5° to 22.8 °API gravity range. Most interestingly, the number of gas injection projects is small, most probably due to the lack of availability of CO_2. From these historic data, chemical flooding (surfactant, alkaline-surfactant, and polymer flooding) appears to be the prime EOR method to be applied in the deltaic reservoirs considered.

To maximize the economic recovery of oil by waterflooding, application of an optimum advanced secondary recovery method (infill drilling, profile modification, and polymer flooding) will be needed to mitigate the effects of different scales and types of heterogeneities that affect waterflood efficiency. The effective application of EOR methods to recover remaining oil after waterflooding will depend upon a knowledge of the type and scale of heterogeneities limiting oil recovery. Venuto (1989) advocates tailoring EOR processes to geologic environments. Geoscientists and engineers should work together to design an EOR process to mitigate inefficient recovery due to geologic (rock and rock/fluid properties) and production induced heterogeneities. As an example, geologic and engineering studies at the Sloss field, Nebraska surfactant-polymer pilot site have identified changes in depositional environment as the cause for the restricted communication between two injection wells, which are located in the distributary channel facies, and the central producing well, which is located in a interchannel deposit (Basan et al., 1978).

Polymer flooding has been effectively applied to recover additional oil economically in North Burbank field, Oklahoma, a deltaic reservoir, by mitigating channeling caused by field-scale heterogeneities (Zornes et al., 1986). In the same field, a more cost-effective method is being applied in which freshwater preflush is not required. The successful pilots at Loudon field, Illinois (Bragg et al., 1982, Reppert et al., 1990) also demonstrate the successful application of surfactant-polymer technology to improve displacement and sweep efficiencies and to mitigate small-scale heterogeneity. The alkaline-surfactant-polymer process may be a viable and less expensive process complementing the surfactant-polymer process (French and Burchfield, 1990). Application of the gravity stable CO_2 miscible method in a tilted deltaic reservoir (Palmer et al., 1981) is another example of tailoring EOR processes to geologic environments.

Effects of Sedimentological Factors on EOR Pilot Projects

The influence of sedimentological factors on waterflooding was discussed in previous sections. Since most EOR processes involve injection of fluid to mobilize and displace residual oil, the same sedimentological factors are expected to influence EOR recovery efficiency. Any effect is amplified because of the small pore volume of the EOR fluid injected.

Since the early 1970s and until recently, many EOR pilots and commercial field tests were performed, and a significant number of papers and reports evaluating the causes and reasons for successes and failure of these projects have been reported. Unfortunately, most of the evaluations concentrated on the recovery processes, and even when the geological factors were evaluated, little effort was expended in relating the project performance to heterogeneities induced by the depositional environment.

In an attempt to determine the effect of these heterogeneities on EOR recovery efficiency, reports and publications on EOR projects performed in deltaic reservoirs were reviewed. It is interesting that almost all DOE-sponsored and a large proportion of industry-sponsored chemical EOR pilots tests were conducted in deltaic reservoirs. In this review, only the effects of sedimentologically related reservoir heterogeneity were considered. Although the efficacy of the recovery process is also important, it is outside the scope of this report and will not be discussed here.

Table 3.5 is a compilation of the observations reported in the literature from 17 fields and 27 chemical EOR projects conducted in deltaic reservoirs. The fluid flow problems most often reported were channeling, directional trends (preferential direction of fluid flow), and compartmentalization. Although fractures or faults may cause similar flow anomalies, they were not reported to be the cause in the examples listed.

Channeling

A project is considered to be affected by channeling when a high-permeability zone affects the distribution of fluids or when a zone is taking a disproportionate volume of the injected fluid. Vertical permeability zonations within genetic sandbodies are common in deltaic reservoirs, with higher permeabilities (and therefore preferred conduits for fluid flow) occurring at the bases of distributary channel deposits and at the tops of distributary mouth bar and delta front deposits.

The high-permeability channels reduce the effectiveness of the designed slug because most of the injected EOR fluid will flow in the high-permeability zone, which has low residual oil saturation due to waterflood sweep efficiency. The lower than expected recovery reported for the M-1 surfactant pilot was attributed to a similar situation (Smith this report), where only a small fraction of this report the slug contacted the zone with high oil saturation. This phenomenon was observed in 20 of 27 (74%) of the field tests listed in table 3.5.

Compartmentalization

Compartmentalization was documented when geologic studies of the EOR projects reported the presence of compartments or barriers to flow of EOR

Table 3.5. Geologic factors affecting EOR recovery

Field name	EOR type	Well spacing acre	Recov. efficiency %	Chan-neling	Compart-ments	Contact high salinity	Formation parting	Direct-ional trend	Facies
Benton, IL[1]	S/P	1	27	yes	yes	yes			
Big Muddy 1, WY[2]	S/P	1	36				yes		dc,dfr
Big Muddy 2,WY[3]	S/P	10	14	yes			yes		
Delaware Childer,OK[4]	S/P	2.5	7	yes		yes		yes	
El Dorado, KS[5]	S/P	6.4	0			yes			
Glennpool, OK[6]	S/P			yes	yes		yes	yes	
Loudon 1, IL[7]	S/P	0.625	15.3			yes			
Loudon 2, IL[8]	S/P	0.68	60	yes		yes		yes	dmb,mb,df
Loudon 3, IL[9]	S/P	0.71	68	yes	yes				
Loudon 4, IL[10]	S/P	2.5/5	27/33	yes	yes				
Main Consolid.1, IL[11]	S/P	0.75	63	yes			yes		dc,pb
Main Consolid.2, IL[12]	S/P	10	39	yes					
Main Consolid.3, IL[13]	S/P	3	27 to 33						
Main Cons.4, IL[14,15]	S/P	2.5/5	20/17	yes	yes	yes	yes		
Manvel,TX[16]	S/P								
North Burbank, OK[17]	S/P	10	25	yes	yes	yes	yes	yes	fc,mmtl
North Burb., OK[18,19]	P	20		yes			yes	yes	fc,mmtl
North Stanley, OK[20]	P		1.4	yes					
Ranger, TX[21]	S/P	40	25		yes				dc
Salem 1, IL[22,23]	S/P	5	14	yes	yes	yes			df
Salem 2, IL[24,25]	S/P	5	47	yes		yes			
Sloss, NE[26]	S/P	9	yes	yes	yes				
Bay St. Elaine, LA[27]	CO_2M	-	-	-	-	-	-	-	obs
Garber, OK[28]	CO_2M	10.4	14	yes	yes				dc,df
Rock Creek 1,WV[29]	CO_2M	10	3	yes	yes				
Rock Creek 2,WV[30]	CO_2M	1.55	11	yes	yes				
Grann Creek, WV[31]	CO_2M	0.85/6.7	37/6	yes	yes				

S/P Surfactant (including microemulsion, low tension and soluble oil)-polymer
P Polymer
CO_2M Carbon dioxide miscible

dc= distributary channel | df = delta front | mmtl = marginal marine tidal or lagoonal deposit
obs = overbank splay | pc = point bar | dfg = delta fringe
fc = fluvial channel | mb= mouth bar | dmb = distal mouth bar

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fluids and occurred in 13 of 27 (48%) projects reviewed. Compartmentalization may result from boundaries between genetic units, lateral facies changes, and clay drapes between cross-bed sets (discussed above) which prevent communication between injectors and producers or result in unswept areas of the reservoir. In certain cases, barriers to flow were not detected when low viscosity fluids such as preflush, tracer, or surfactant solutions were injected. However, when polymer solution was injected, the progress of polymer slug was impeded. Compartmentalization could reduce the effectiveness of an otherwise well designed EOR project.

Directional Permeability Trends

Directional trends of permeability may be caused by orientation of cross-bedding or higher permeability channel deposits which have cut down into lower permeability facies, both of which generate a preferential direction of flow. Tracer tests or recovered surfactant and polymer are often able to confirm the presence and directions of high-permeability trends (Holley et al., 1990). This feature was observed in six (22%) of the projects reviewed.

Contacting High Salinity Region

Channeling, compartmentalization, and/or directional trends may result in by-passing of areas within a reservoir and preservation of the original formation brines. As a consequence of better mobility control of the EOR process, these high salinity pockets are contacted during an EOR project. This phenomenon was reported only in chemical EOR projects where high salinity was found to reduce the effectiveness of the EOR fluids.

Formation Parting

This phenomenon is not related to the depositional environment of a deltaic reservoir; however, it is included here because it occurred in eight of the projects reviewed. Formation parting was reported in many of the chemical flood projects where high-viscosity fluids were injected for mobility control. Formation parting may be caused by the presence of fractures or low in situ stresses in shallow reservoirs. Natural fractures, however, were not cited as the cause of formation parting, even though fractures were present in some of the fields.

Discussion

Lower than expected oil recovery was partially attributed to heterogeneity related to depositional processes in the projects listed in table 3.5. Quantification of the effects on recovery, are not possible at this point. However, comparison of performance to well spacing may indicate the scale of the features controlling production. Figure 3.18 is a plot of recovery efficiencies against well spacing for a number of micellar-polymer field tests performed in Loudon, Main Consolidated (Robinson), and Big Muddy field. These fields were chosen because several projects were performed with varying well spacing and similar chemical slugs. The 1973 pilot test at Loudon was not included because the slug was different from that of subsequent field tests, and pilot '119' at Main Consolidated (Robinson) field was also excluded because of the different well pattern used (it was a linedrive pilot with 10-acre spacing between injectors and producers and 2.5-acre spacing between injectors).

Figure 3.18 shows that the recovery efficiency decreased from 60 to 70% to less than 30% for well spacings greater than 1 acre. Although other explanations can be advanced, reservoir heterogeneities are the likely cause. In a number of the presentations at the Class I Symposium on EOR pilot projects, sedimentologically related heterogeneities were cited as the cause for poor performance. For example, Smith (this report) showed that poor vertical and areal sweep efficiencies within Main Consolidated (Robinson) field, caused by the presence of stacked-sand bodies and directional permeability are the probable reason for the lower than anticipated oil recovery. He suggested that a linedrive pattern may alleviate these geologic problems. The higher recovery efficiency of the 119 projects using a linedrive pattern supports this hypothesis. In another case, Holstein (this report) in his discussion of Loudon field, attributed the lower recovery efficiency in larger well spacing pilots to poor polymer transport. The probable causes for poor polymer transport are: 1) disassociation of polymer from surfactant slug (Holstein, this report); 2) low permeability rock (Huh et al., 1990); and 3) reservoir compartmentalization.

GENERAL RESERVOIR CHARACTERISTICS FOR DELTAIC RESERVOIRS IN THE TORIS DATA BASE

Introduction

TORIS, which stands for Tertiary Oil Recovery Information System, was developed by the National Petroleum Council (NCP) and is maintained by the Department of Energy (DOE). TORIS is a collection of a reservoir data base, an EOR data base, EOR screening models, and reservoir simulators. For several years, DOE and the Interstate Oil Compact Commission have been jointly collecting data on major U.S. reservoirs for TORIS. In 1983, it was decided to seek additional data for all reservoirs having 20 million bbl of OOIP or greater and crude oil gravities of 10° API or greater (National Petroleum Council, 1984). Requests were sent to each major operator in

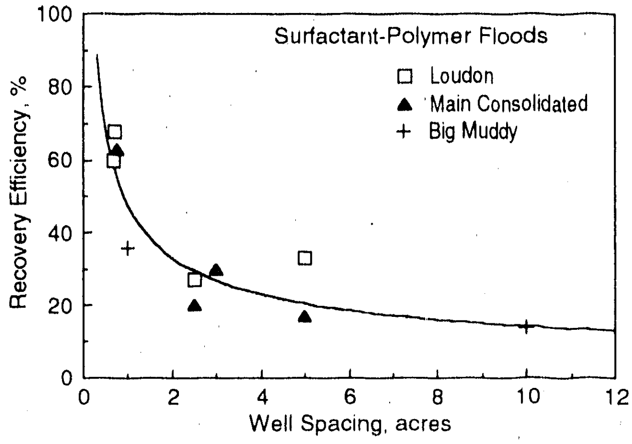

Figure 3.18 - Relationship between well spacing and recovery efficiency in EOR pilot projects.

1,300 identified reservoirs for reservoir data and production data of primary and secondary recovery. The collection effort was a reiterative process with continuous requests to research organizations and operators for additional information on reservoirs which are not limited to OOIP equal to or greater than 20 million bbl. The end result of this effort is a reservoir data base far larger and more complete than had previously been available.

A total of 229 fluvial-dominated deltaic reservoirs were identified among 359 unstructured deltaic reservoirs contained in the TORIS data base. Eighty-one wave-dominated and 24 tide-dominated deltaic reservoirs were identified. The TORIS reservoir data base contains only average values of production and reservoir parameters (such as porosity, permeability, and recovery factor). The detail of data is not suitable for a rigorous statistical analysis; however, it is presented here to illustrate the range of reservoir properties and production characteristics in deltaic reservoirs. Interpretations based on these data must be made with extreme caution.

Reservoir properties and production characteristics of 229 fluvial-dominated unstructured deltaic reservoirs in TORIS data base were analyzed. As the median values suggest, fluvial-dominated deltaic reservoirs are generally high quality reservoirs at moderate depth (4,954 ft), having good porosity (19%) and permeability (128 md) and produce light oil (39° API gravity) at a reasonable primary recovery factor (26%). Among four individual fluvial-dominated deltaic plays analyzed, Bartlesville sands have the shallowest depth (2,000 ft) and the highest original oil-in-place (82.7 million barrels), while Wilcox sands show the highest permeability (524 md) and the highest primary recovery (479 bbl/acre-ft). Rock permeability values were found the best indicator among formation parameters for the primary production in such reservoirs. Fluvial-dominated deltaic reservoirs showed a low secondary recovery which might be due to the permeability contrast in the vertical direction.

Reservoir Properties

General statistics of formation and production characteristics of fluvial-dominated deltaic reservoirs are listed in table 3.6. Median values are used for comparison because determination of significant mean values requires that the data be distributed normally, which is rarely the case. A "median" fluvial-dominated deltaic reservoir has a net pay of 16 ft (fig. 3.19), porosity of 19% (fig. 3.20), permeability of 128 md (fig. 3.21), and a reservoir size of 1,840 acres. The logarithmic values of permeability show a somewhat linear relationship with the porosity values in figure 3.22. Fifty percent of the fluvial deltaic reservoirs studied have more than 26.6 million barrels of original oil-in-place (fig. 3.23) and have produced more than 205 bbl/acre/ft (fig. 3.24). Fluvial dominated deltaic reservoirs produce light oil with a median gravity of 39° API (fig. 3.25). The reservoir depth ranges from 580 to 10,246 ft with a median value of 4,954 ft (fig. 3.26). Neither the permeability value nor the original oil-in-place showed a correlation with the reservoir depth. The median value of primary recovery factor is 26%, and the median value of primary and secondary recovery factor is 30% (fig. 3.27).

General statistics of wave- and tide-dominated deltaic reservoirs contained in TORIS data base are listed in tables 3.7 and 3.8 for comparison. Fluvial-wave-, and tide-dominated deltaic reservoirs have similar values for porosity, permeability, initial oil saturation, and oil gravity. Tide-dominated deltas have a median depth of 2,065 ft in contrast to median depths of over 4,000 ft for fluvial- and wave-dominated deltas.

Analysis of reservoir and production data was conducted for four individual plays within fluvial-dominated deltaic reservoirs as a sample of this group of reservoirs. The following plays were selected on the basis of geographic distribution and availability of data: 1) Cherokee or Bartlesville sands in Oklahoma and Kansas; 2) Dakota Group including the D sand and J sands in the Denver-Julesburg Basin in Colorado and Nebraska; 3) Strawn Group in Texas; and 4) Wilcox Group in Texas, Louisiana and Mississippi. The general statistics of formation and production properties of fluvial-dominated deltas in Bartlesville, Dakota, Wilcox, and Strawn sands are listed in tables 3.9 to 3.12, respectively. Histograms of porosity, permeability, depth, net pay, original oil-in-place, primary production in bbl/acre-ft, and ultimate recovery factor of these four plays are shown in figures

Table 3.6. Statistics of reservoir properties of fluvial-dominated deltaic deposits (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	219	0.4077	735	75.47	41.03	85.87
Net pay, ft	229	2	201	22.71	16	21.99
Gross pay, ft	228	2.4	241.2	31.05	22	28.87
Porosity, %	229	7.5	35	20.16	19	5.667
Initial oil saturation, %	229	41	90	67.32	68	7.454
Current oil saturation, %	228	10.01	68.79	41.61	42.67	12.11
Depth, ft	227	580	10,250	4,684	4,954	2,027
Permeability, md	229	0.2	3,100	275.4	128	418.9
API gravity	229	21.8	50	38.18	39	4.557
Total disolved solids, ppm	134	300	244,000	83500	50000	73,990
Original oil-in-place, bbl x 10^6	229	0.1685	1,189	89.71	26.6	17.73
Primary recovery factor	228	0.01211	0.836	0.2896	0.26	0.1696
Secondary recovery factor	142	0	0.64	0.08372	0.02122	0.1193
Cumulative recovery, bbl x 10^6	229	0.39	325.4	23.99	65.93	51.76
Primary recovery, bbl/ac-ft	228	6.433	1134	254.5	205.2	193.1
Primary recovery, bbl x 10^6	228	0.02588	348	22.82	59.86	51.39
Ultimate recovery factor	229	0.012	0.836	0.3321	0.302	0.1706

Table 3.7. Statistics of reservoir properties of wave-dominated deltaic deposits (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	81	0.1471	293.6	63.62	40	63.69
Net pay, ft	81	4	272	24.36	12.5	41.41
Gross pay, ft	81	4.8	1,560	48.3	16.8	177.1
Porosity, %	81	6	35	20.42	21	6.715
Initial oil saturation, %	81	28.1	85	64.93	68	12.57
Current oil saturation, %	81	7.928	73.16	39.99	40.55	14.63
Depth, ft	81	400	9,800	4,655	4,423	2,271
Permeability, md	81	0.03467	2,800	335	95	583.1
API gravity	81	21.2	46	37.17	38	5.314
Total disolved solids, ppm	59	31.9	250,000	72,660	68,000	56,020
Primary recovery, bbl x 10^6	81	0.03074	7558	21.26	22.5	92.01
Primary recovery factor	81	0.033	0.84	0.3	0.2479	0.184
Secondary recovery factor	46	0	0.85	0.1238	0.07765	0.1664
Cumulative recovery, bbl x 10^6	81	0.01232	5,004	93.86	5.294	561.6
Primary recovery, bbl/ac-ft	81	11.76	910	267.6	152.5	250.1
Primary recovery, bbl x 10^6	81	0.01232	4,939	84.51	5.173	549.9
Ultimate recovery factor	81	0.08766	0.8604	0.3438	0.307	0.1931

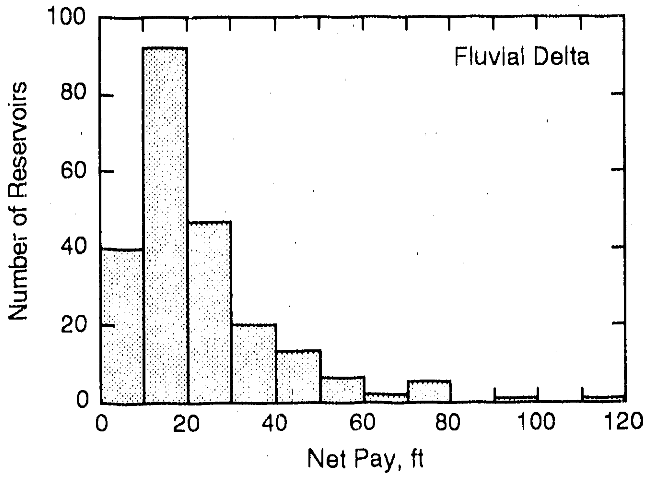

Figure 3.19 - Histogram of net pay in fluvial-dominated deltaic reservoirs studied.

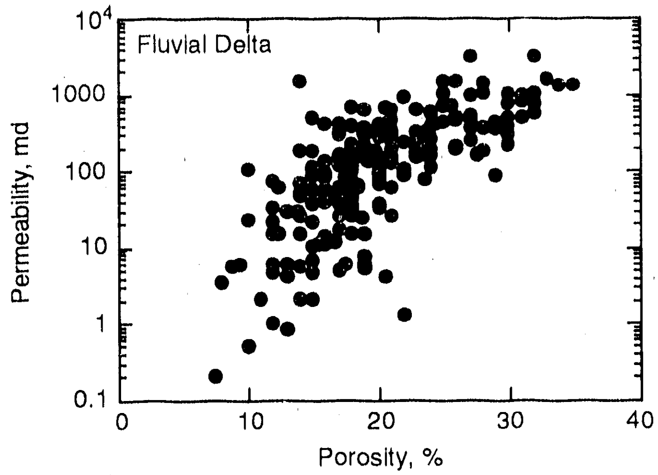

Figure 3.22 - Semilog plot of permeability vs porosity of the fluvial-dominated deltaic reservoirs studied.

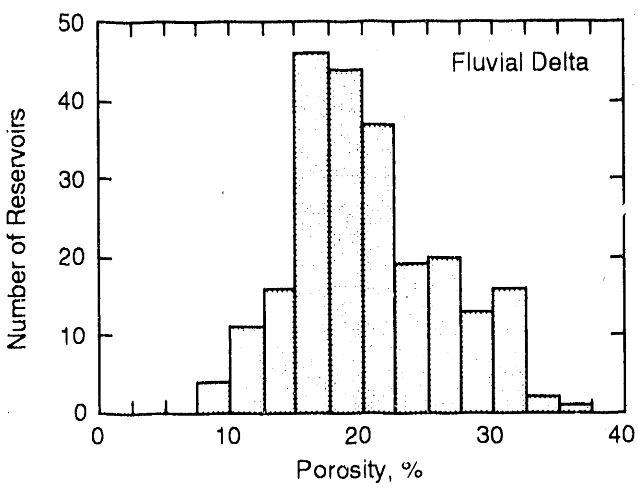

Figure 3.20 - Histogram of porosity of the fluvial-dominated deltaic reservoirs studied.

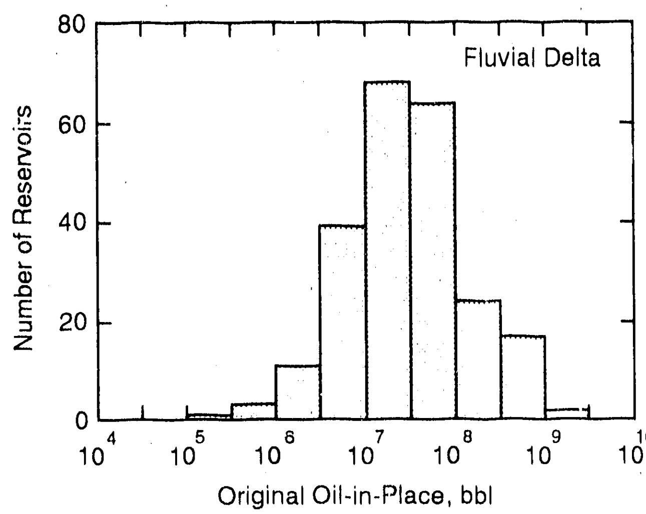

Figure 3.23 - Histogram of original oil-in-place in the fluvial-dominated deltaic reservoirs studied.

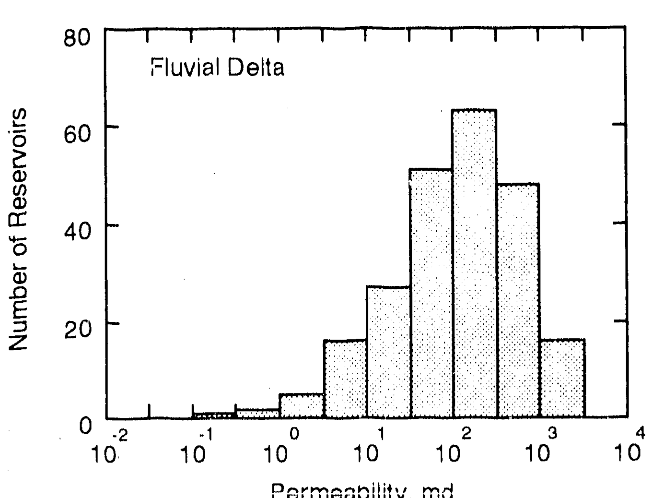

Figure 3.21 - Histogram of permeability of the fluvial-dominated deltaic reservoirs studied.

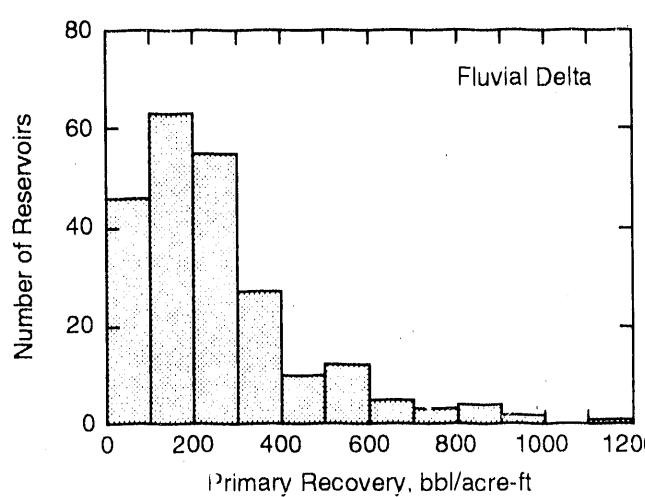

Figure 3.24 - Histogram of primary recovery in the fluvial-dominated deltaic reservoirs studied.

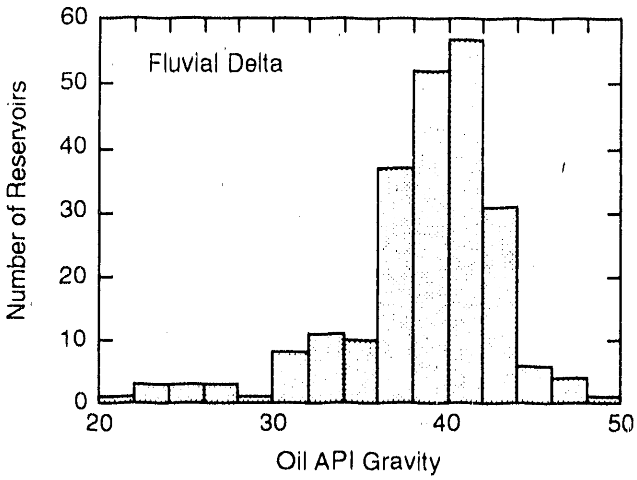

Figure 3.25 - Histogram of oil gravity in the fluvial-dominated deltaic reservoirs studied.

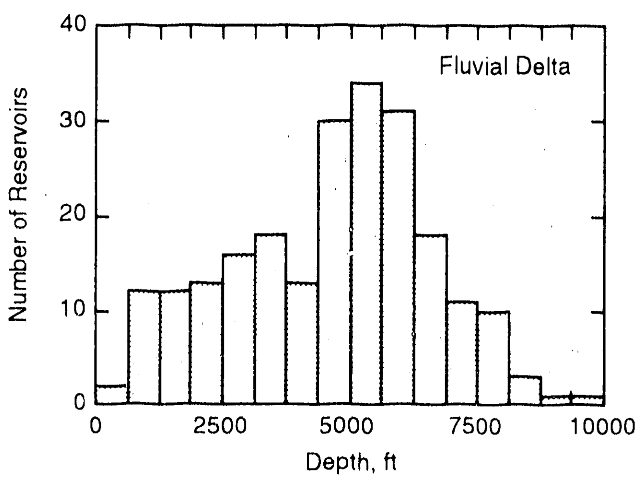

Figure 3.26 - Histogram of reservoir depth in the fluvial-dominated deltaic reservoirs studied.

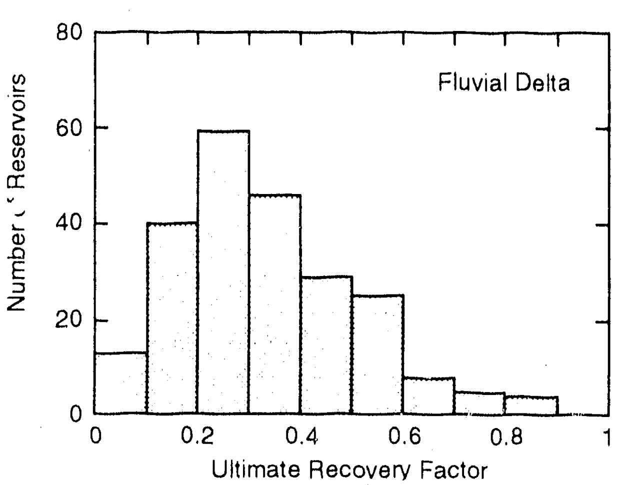

Figure 3.27 - Histogram of cumulative recovery in the fluvial-dominated deltaic reservoirs studied.

3.28 to 3.34. The cross-plots of permeability and porosity of individual plays are shown in figure 3.35.

Table 3.13 lists median values of important formation and production characteristics for Bartlesville, Dakota, Wilcox, and Strawn sands together with those for all fluvial-dominated deltaic reservoirs. The primary recovery value is not necessarily equal to the product of the original oil-in-place and the primary recovery factor because median values are listed in table 3.13. Bartlesville sands have shallow depths of around 2,000 ft (fig. 3.30), relatively thick net pay of 25 ft (fig. 3.31), and high original oil-in-place (approximately 82.7 million bbl) (fig. 3.32). Wilcox sands show the highest median values in porosity (30%) (fig. 3.28), permeability (524 md) (fig. 3.29), and primary recovery in barrels per acre-foot (479) (fig. 3.33) among the four listed individual plays. The primary recovery of Wilcox sands is known to benefit from its bottom water drive. This water drive mechanism helps Wilcox sands achieve high primary recoveries and require no secondary recovery. Oil gravities of all four plays in table 3.13 are about the same as those of fluvial-dominated deltaic reservoirs.

Production Characteristics

Visual analysis of cross-plots indicate that primary production is most strongly correlated with permeability and that the primary recovery factor increases with an increase in permeability in the reservoirs studied (fig. 3.36). According to principles of reservoir engineering, reservoirs of high-permeability values result in high production rates, but not necessarily in high recovery factors. Recovery factor is determined by several factors such as permeability, formation heterogeneity, fluid-rock properties, and reservoir drive mechanisms.

Permeable reservoirs produce greater amounts of oil because lower pressure drawdown is required to produce the same amount of oil, and the larger viscous forces overcome the capillary effects, resulting in lower amounts of remaining oil. High permeability, in addition to the bottom aquifer drive, may explain why the Wilcox reservoirs have produced more primary oil than the average fluvial-dominated deltaic reservoir.

Primary recovery in bbl/acre-ft decreases with increase of well spacing (fig. 3.37). The compartmentalization of fluvial-dominated deltaic reservoirs reduces the drainage area from a single vertical well. Primary production seldom reaches 500 bbl/acre-ft when the well spacing is greater than 160 acres. This relationship suggests that the application of infill drilling or horizontal well drilling may be required to recover additional oil from fluvial-dominated deltaic

Table 3.8. Statistics of reservoir properties of tide-dominated deltaic deposits (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	24	1.616	150.5	36.94	19.45	40.51
Net pay, ft	24	7	100	26.71	16.5	24.75
Gross pay, ft	24	8.4	1,100	96.03	26.85	229.2
Porosity, %	24	13	40	21.25	18.75	6.701
Initial oil saturation, %	24	55	77	67.87	69	4.73
Current oil saturation, %	24	29.43	50.63	38.03	34.73	7.108
Depth, ft	24	765	4,807	2,240	2,065	930.3
Permeability, md	24	10	800	219.6	150	220.6
API gravity	24	17	39.5	34.32	36	6.22
Total disolved solids, ppm	18	152.7	140,000	76,000	65,950	53,170
Primary recovery, bbl. x 10^6	24	2.5	175	215.3	24.5	453.8
Primary recovery factor	24	0.03	0.5597	0.2288	0.23	0.1308
Secondary recovery factor	23	0	0.35	0.1842	0.24	0.1166
Cumulative recovery, bbl x 10^6	24	0.76	46.46	63.94	10.9	121.1
Primary recovery, bbl/ac-ft	24	24.29	1447	369.2	195.4	422.5
Primary recovery, bbl x 10^6	24	0.13	462.2	61.58	5.8	121.4
Ultimate recovery factor	24	0.12	0.565	0.6597	0.4121	0.1205

Table 3.9. Statistics of reservoir properties of the Bartlesville sandstone (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	31	2.4	310.9	28.92	15.41	54.04
Net pay, ft	31	3	74	28.99	25	17.54
Gross pay, ft	31	3.6	88.8	35.39	31.2	20.12
Porosity, %	31	12	28	17.25	17.9	3.097
Initial oil saturation, %	31	47	80	66.12	68	7.012
Current oil saturation, %	31	23.3	66.26	45.43	47.16	11.56
Depth, ft	31	580	7742	2178	1950	1470
Permeability, md	31	4.7	35[illegible]	66.91	43	88.12
API gravity	31	22	4[illegible]	36.06	38	4.546
Total disolved solids, ppm	13	10,000	220,000	98,670	110,000	57,830
Original oil-in-place, bbl x 10^6	31	0.1685	1,058	199	82.76	241
Primary recovery factor	31	0.01211	0.629	0.2598	0.233	0.1693
Secondary recovery factor	7	0.000061	0.309	0.05037	0.000374	0.1151
Cumulative recovery, bbl x 10^6	31	0.039	373.5	51.18	13.54	89.91
Primary recovery, bbl/ac-ft	31	10.26	655.4	206.3	183	156.8
Primary recovery, bbl x 10^6	31	0.04437	414	53.59	13.56	97.16
Ultimate recovery factor	31	0.012	0.629	0.2691	0.233	0.1773

Table 3.10. Statistics of reservoir properties of the D/J (Dakota) sandstone (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	29	0.1628	316.7	135	120	91.4
Net pay, ft	34	2	30	12.46	10	6.99
Gross pay, ft	34	2.4	37	15.55	12	9.48
Porosity, %	34	10	26	19.63	19	2.95
Initial oil saturation, %	34	58	90	71.51	71	6.07
Current oil saturation, %	34	14.14	68.79	41.88	42.1	11.5
Depth, ft	34	3,938	6,731	5,255	5,077	665
Permeability, md	34	17.94	2,238	336.2	234.5	385
API gravity	34	23	43	37.47	38	3.69
Total disolved solids, ppm	17	300	18,000	7,905	7,363	5,110
Original oil-in-place, bbl x 10^6	34	0.02829	135	16.87	8.419	23.5
Primary recovery factor	34	0.153	0.798	0.3628	0.325	0.147
Secondary recovery factor	21	0	0.38	0.07847	0.01744	0.101
Cumulative recovery, bbl x 10^6	34	0.008887	55.35	6.38	3.906	9.61
Primary recovery, bbl/ac-ft	34	15.19	908.3	290.2	277	198
Primary recovery, bbl x 10^6	34	0.008887	55.26	5.157	2.836	9.48
Ultimate recovery factor	34	0.1611	0.798	0.4035	0.3717	0.137

Table 3.11. Statistics of reservoir properties of the Wilcox formation (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	20	22.01	220	84.19	62.58	56.39
Net pay, ft	20	4	70	12.55	9	14.11
Gross pay, ft	20	4.8	84	15.06	10.8	16.94
Porosity, %	20	26	35	30.05	30	2.417
Initial oil saturation, %	20	41	71	59.2	62	8.788
Current oil saturation, %	19	10.55	57.01	33.97	35.85	15.49
Depth, ft	19	4,330	6,666	5,995	6,174	675.3
Permeability, md	20	89.7	1540	644.1	523.9	441.5
API gravity	20	31	47	39.45	39.5	3.364
Total disolved solids, ppm	12	130,000	178,600	147,300	146,000	12,790
Original oil-in-place, bbl x 10^6	20	1.4	36.7	7.81	6.44	7.6
Primary recovery factor	19	0.1	0.84	0.412	0.44	0.24
Secondary recovery factor	11	0.000001	0.000467	0.0001808	0.000147	0.0001792
Cumulative recovery, bbl x 10^6	20	0.2566	5.879	2.662	2.674	1.77
Primary recovery, bbl/ac-ft	19	121.4	1134	484	479	278.1
Primary recovery, bbl x 10^6	19	0.3485	6.403	2.908	2.723	1.903
Ultimate recovery factor	20	0.114	0.836	0.4037	0.427	0.2419

Table 3.12. Statistics of reservoir properties of the Strawn sand (from TORIS database).

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Std deviation
Well space, acres	20	8.5	183.3	58.41	44	42.22
Net pay, ft	21	6	110	24.21	15	26.59
Gross pay, ft	21	7.2	2000	120.8	22.8	431.1
Porosity, %	21	10	23.5	17.41	17	3.002
Initial oil saturation, %	21	60	74	65.9	65	4.158
Current oil saturation, %	21	12.47	61.34	41.55	42.36	11.25
Depth, ft	21	850	6,400	4,043	3,970	1,077
Permeability, md	21	0.5102	335	80.59	55	78.78
API gravity	21	33.7	44	39	40	2.916
Total disolved solids, ppm	11	50,000	240,600	146,600	120,000	84,260
Original oil-in-place, bbl x 10^6	21	2.495	593	70.71	18.17	154
Primary recovery factor	21	0.07	0.812	0.2885	0.2616	0.1856
Secondary recovery factor	11	0	0.29	0.05635	0.03	0.08818
Cumulative recovery, bbl x 10^6	21	0.2911	16.94	21.02	3.688	48.79
Primary recovery, bbl/ac-ft	21	43.86	675.3	204.3	194.6	131.5
Primary recovery, bbl x 10	21	0.2911	171.8	20.4	3.459	50.12
Ultimate recovery factor	21	0.09594	0.812	0.3396	0.302	0.164

Table 3.13. Median values of reservoir and production data of fluvial-dominated individual plays and all deltaic reservoirs. Data from TORIS database.

	Fluvial delta	Bartlesville	D/J	Wilcox	Strawn
Number of fields	229	31	34	20	21
Porosity, %	19	18	19	30	17
Permeability, md	128	43	235	524	55
Soi, %	68	68	71	62	65
Net pay, ft	16	25	10	11	15
Depth, ft	4,954	1,950	5,078	6,174	3,970
API gravity	39	38	38	39.5	40
Original oil-in-place, bbl x 10^6	26.6	82.8	8.4	6.4	18.2
Primary recovery, bbl/acre/ft	205	183	277	479	195
Primary recovery, bbl x 10^6	5.98	13.54	2.84	2.72	3.46
Primary recovery factor	0.26	0.23	0.32	0.44	0.26
Ultimate recovery factor	0.30	0.23	0.37	0.44	0.30

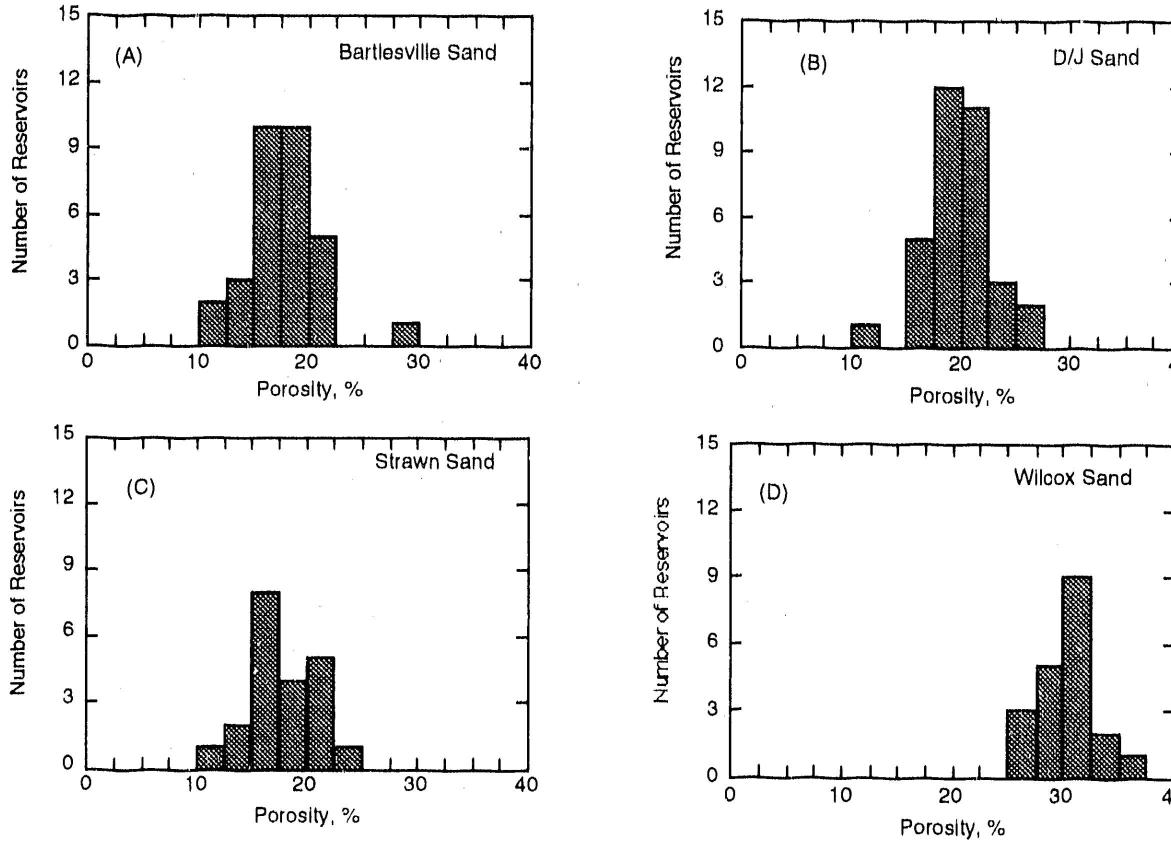

Figure 3.28 - Histograms of porosity for four plays in the fluvial-dominated deltaic reservoirs studied.

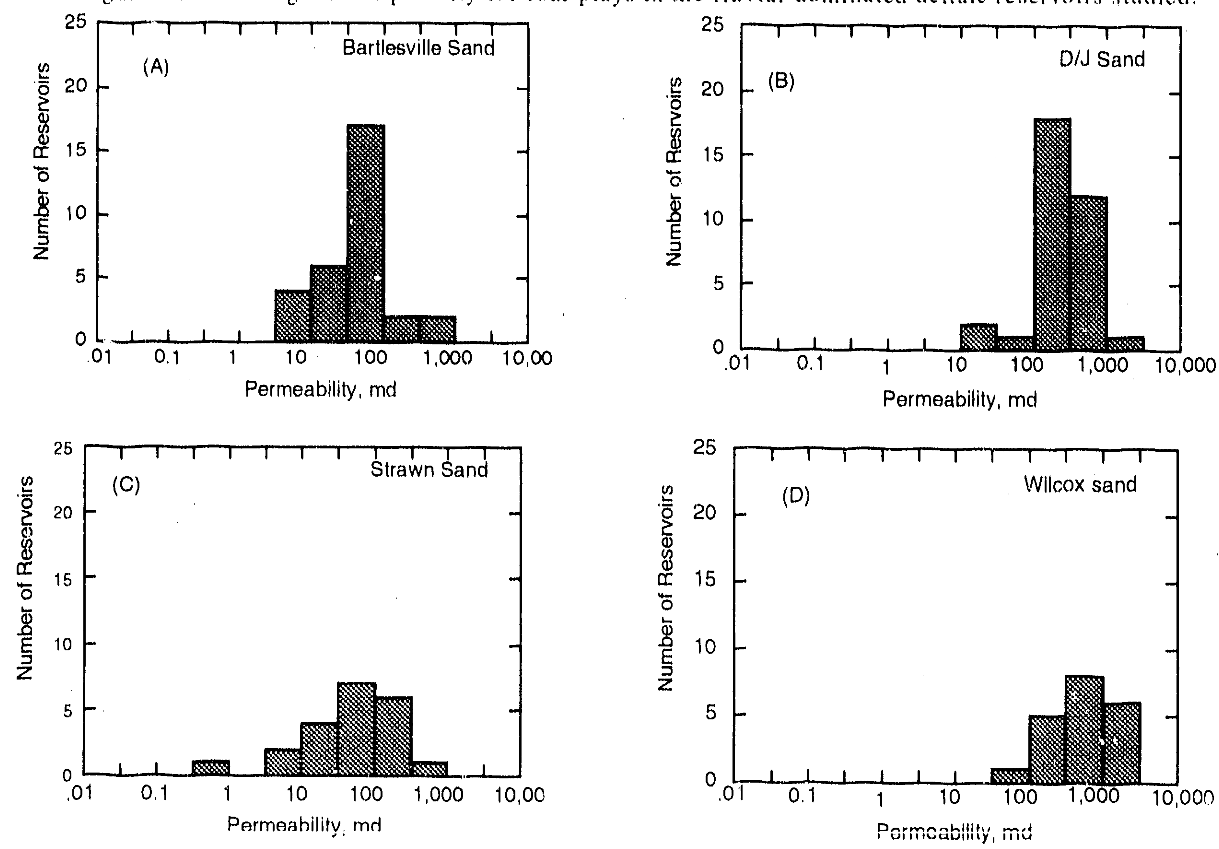

Figure 3.29 - Histograms of permeability for four plays in the fluvial-dominated deltaic reservoirs studied.

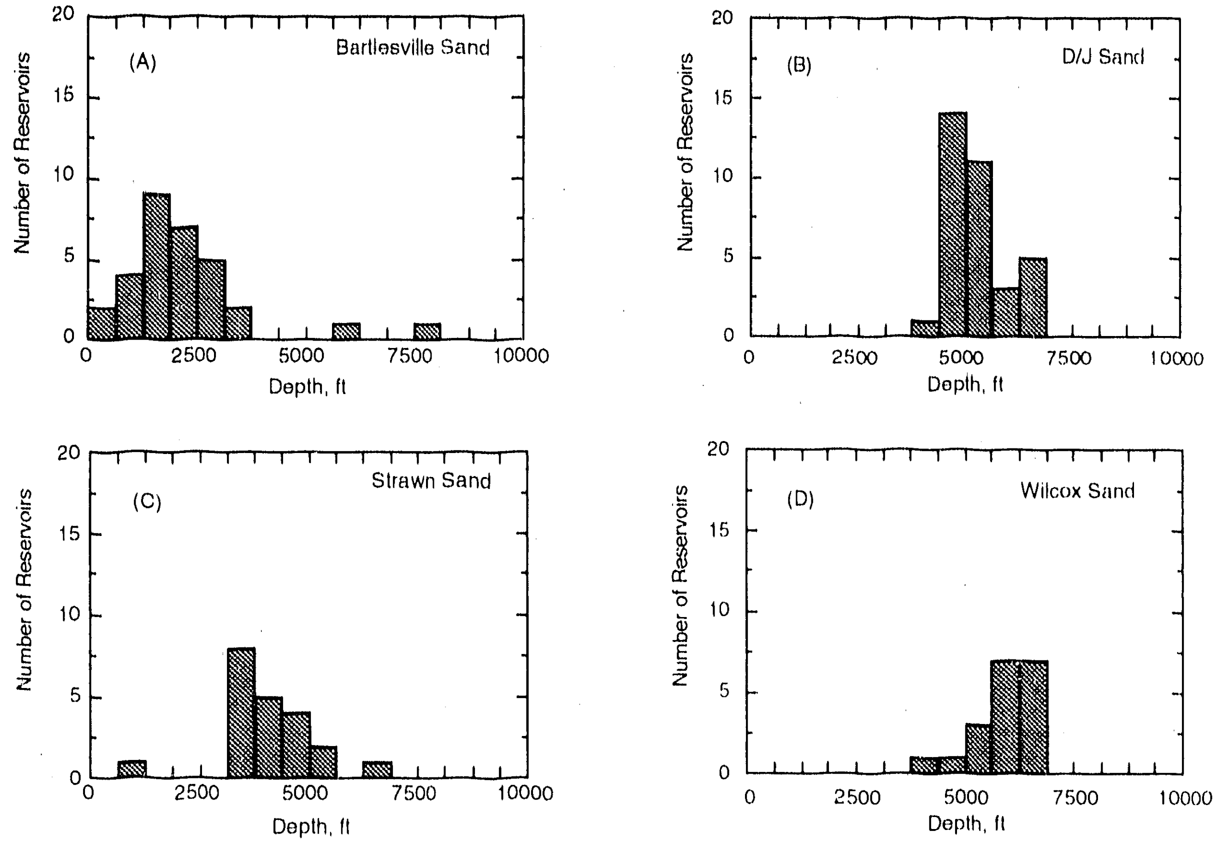

Figure 3.30 - Histograms of reservoir depth for four plays in the fluvial-dominated deltaic reservoirs studied

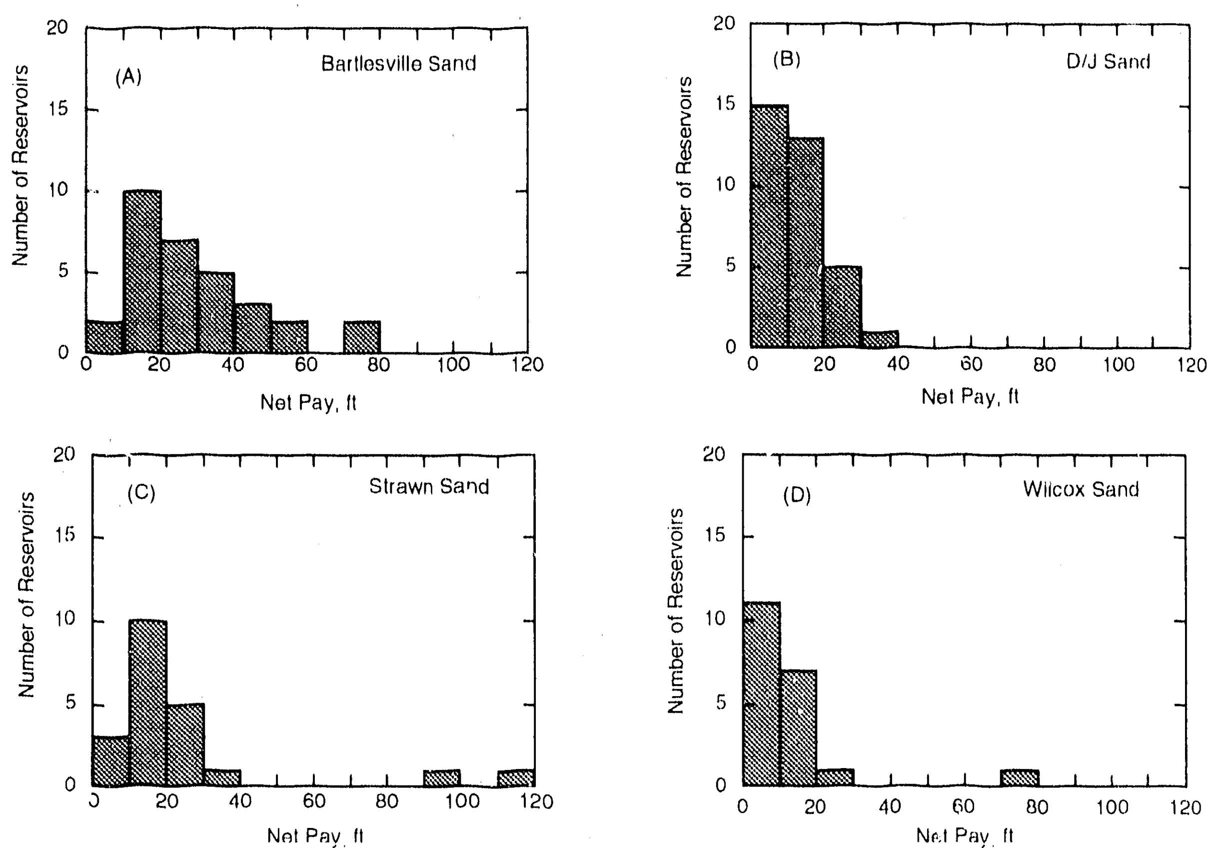

Figure 3.31 - Histogram of net pay for the fluvial dominated deltaic reservoirs studied.

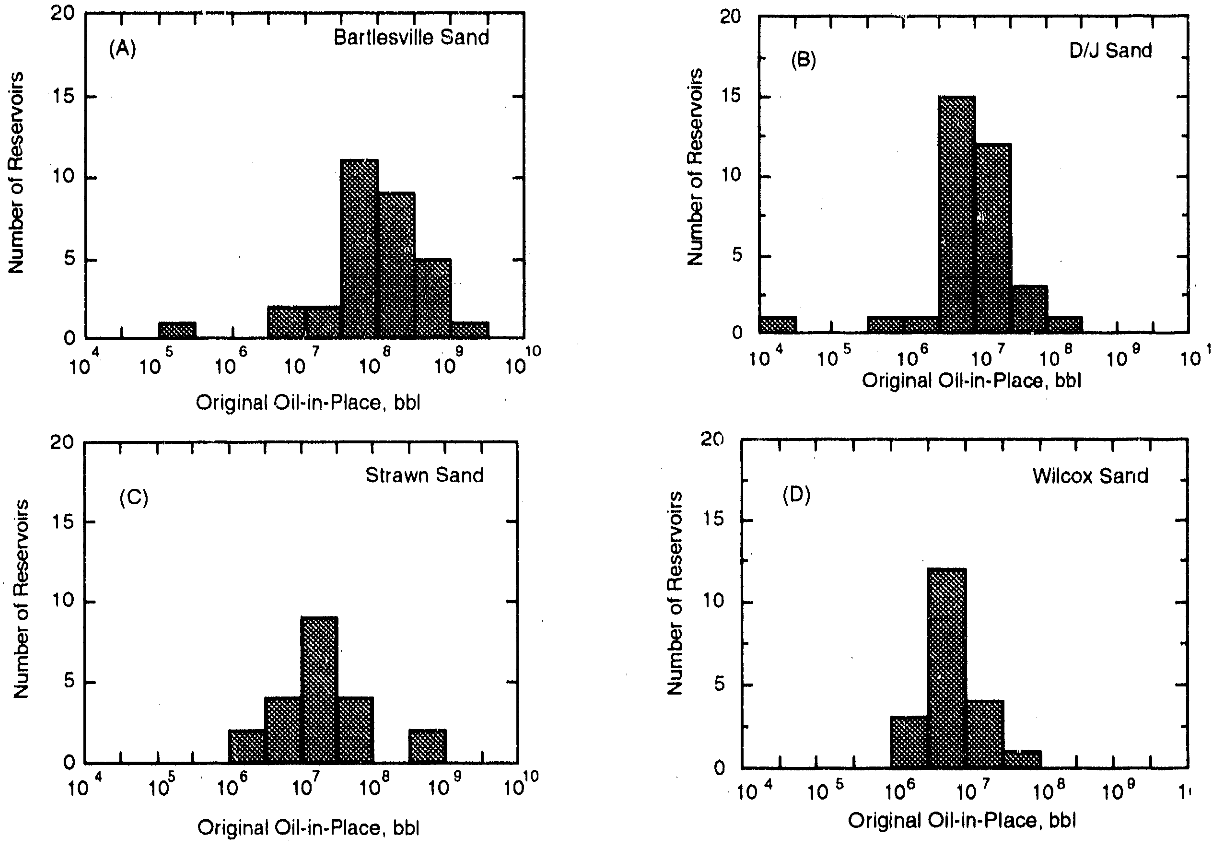

Figure 3.32 - Histograms of original oil-in-place for four plays in the fluvial-dominated deltaic reservoirs studied.

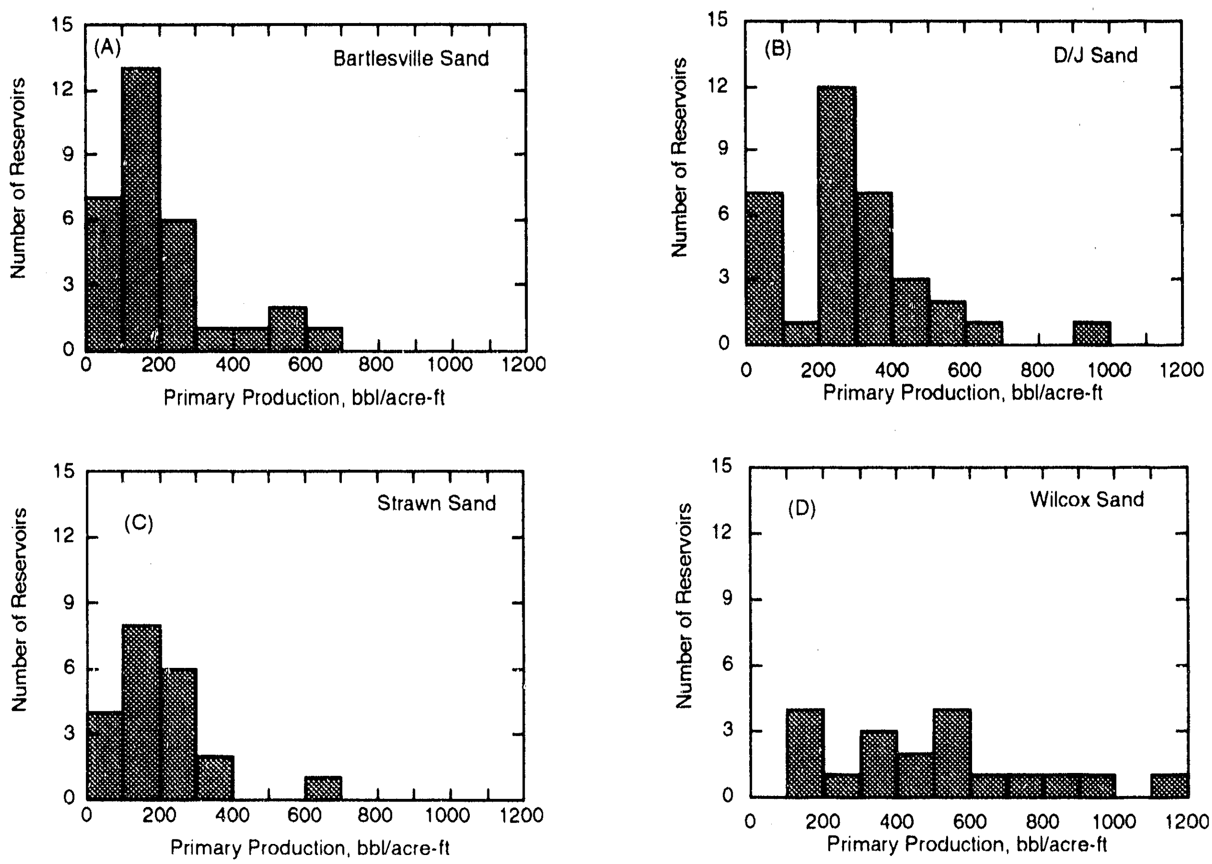

Figure 3.33 - Histograms of primary recovery for four plays in the fluvial-dominated deltaic reservoirs studied.

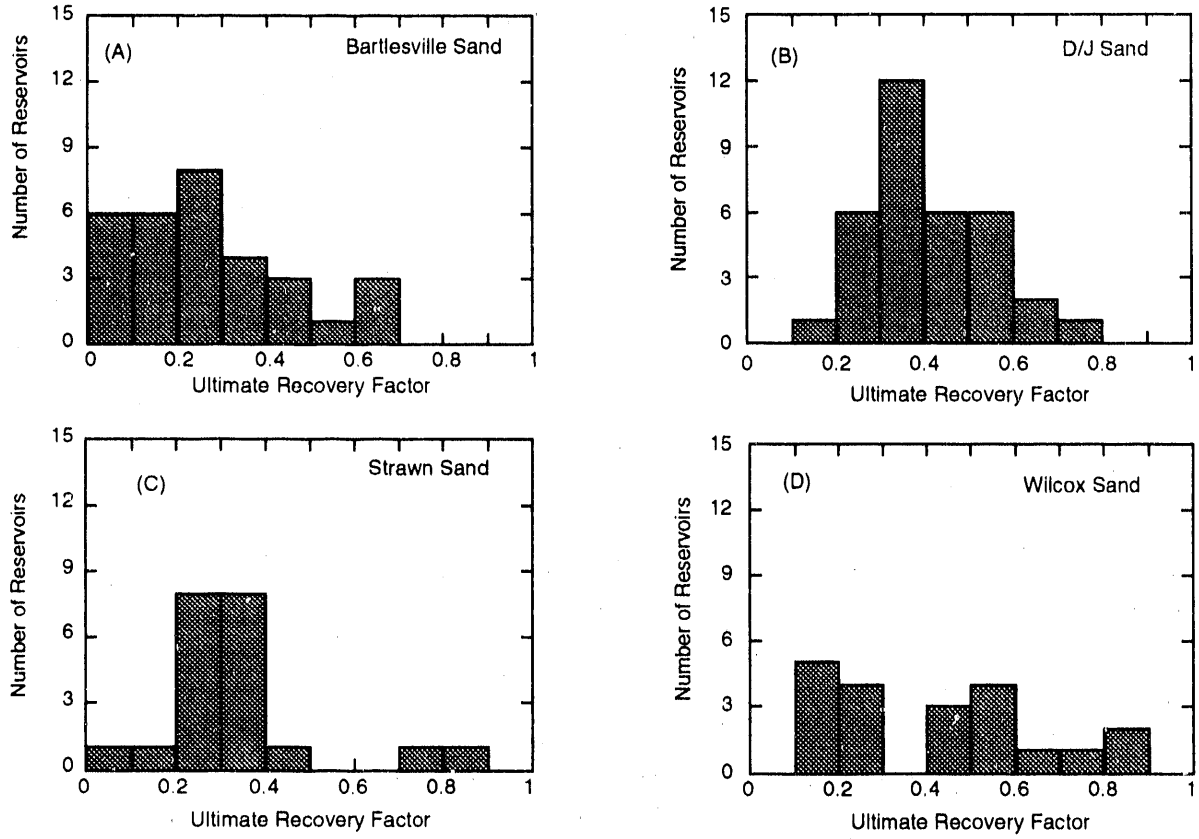

Figure 3.34 - Histograms of dumulative recovery for four plays in the fluvial-dominated deltaic reservoirs studied.

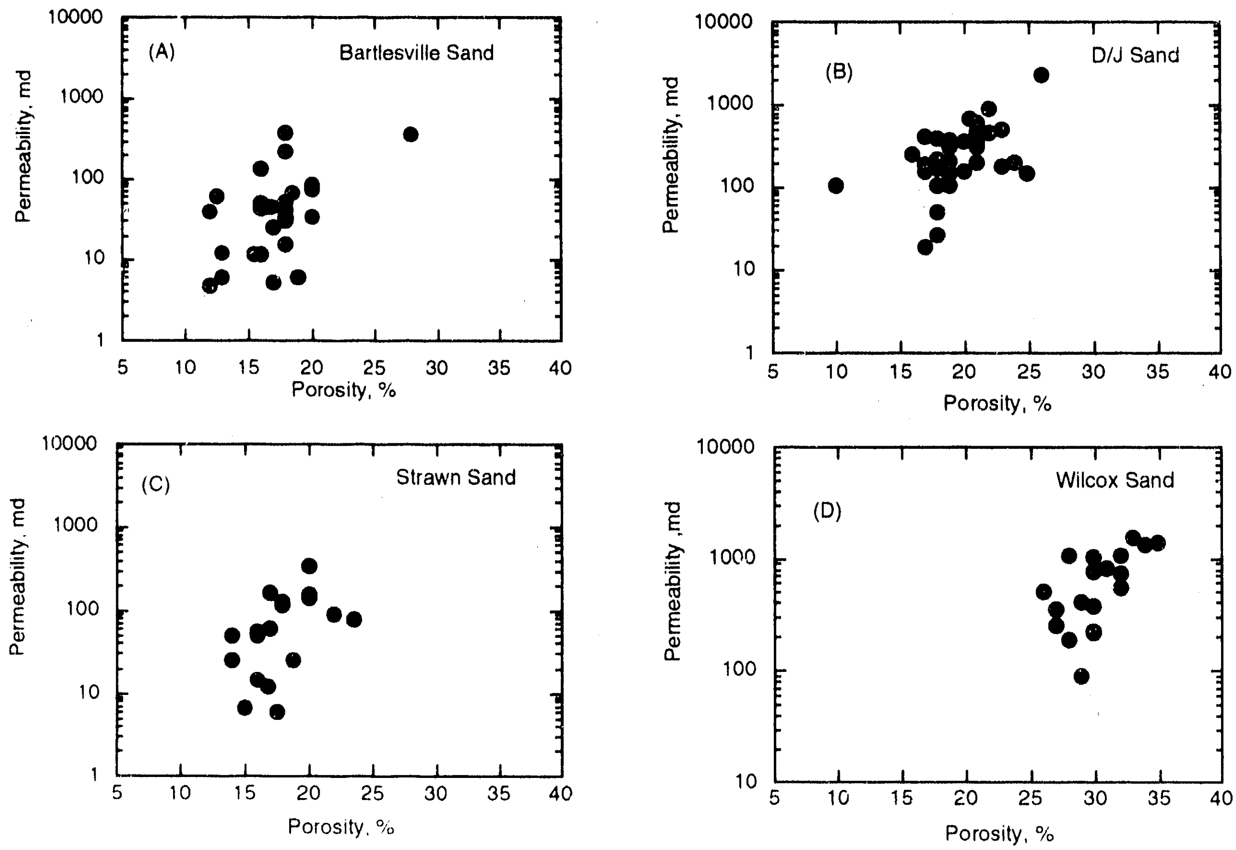

Figure 3.35 - Semilog plot of permeability vs porosity of four plays in the fluvial-dominated deltaic reservoirs studied.

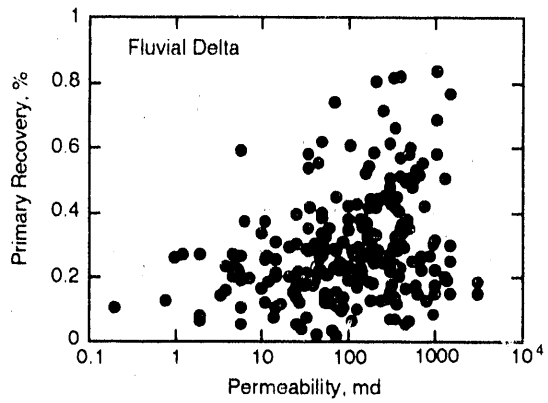

Figure 3.36 - Effect of permeability on primary recovery factor for fluvial-dominated deltaic reservoirs studied.

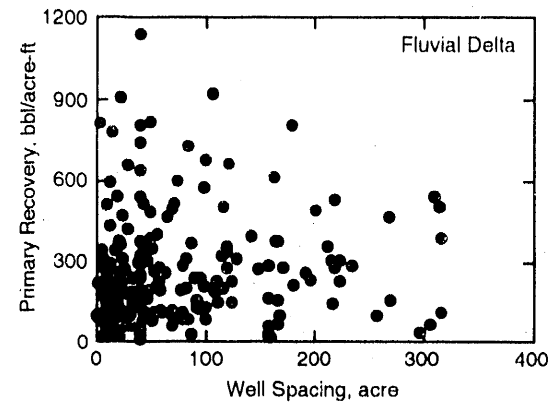

Figure 3.37 - Well spacing vs primary recovery of the fluvial-dominated deltaic reservoirs studied.

reservoirs with well spacing greater than 160 acres. Horizontal wells may be effective in penetrating laterally continuous, multiple reservoirs quality coastal barrier sands from wave-dominated deltas but may be less effective in discontinuous reservoir sands from the same stratigraphic horizon in tide- and fluvial-dominated deltas.

Primary and secondary recovery were analyzed for fluvial-, wave- and tide-dominated deltaic reservoirs. Primary recoveries from the different genetic types of deltaic reservoirs were similar, with median values ranging from 24 to 26% original oil-in-place (OOIP); however, differences in secondary recovery production were apparent. The secondary recovery factor (median value) for fluvial-dominated reservoirs was the lowest at 2% OOIP in contrast to 8% OOIP for wave-dominated and 24% OOIP for tide-dominated deltaic reservoirs. The significantly higher recovery rates for tide-dominated reservoirs may be an artifact of well spacing, where the median well spacing is 20 acres as opposed to 40 acres in the fields producing from fluvial- and wave-dominated deltaic deposits (tables 3.6-3.8).

The low secondary recovery factors recorded for fluvial-dominated deltaic reservoirs (69 of the 142 reservoirs reported less than 1%) can be attributed to either: 1) reservoir heterogeneity which prevents efficient waterflood sweep, or 2) extremely efficient primary production which leaves relatively small amounts of oil for secondary recovery. As discussed, fluvial-dominated deposits tend to have a greater amount of compartmentalization than wave- or tide-dominated deposits which may explain the lower recovery factors.

An example of efficient primary recovery in a fluvial-dominated deltaic deposit is illustrated in the Wilcox reservoirs, where the bottom-water drive production mechanism combined with high permeability resulted in higher primary recovery rates than the average from other fluvial-deltaic plays (table 3.13).

Production characteristics reported for deltaic reservoirs located in Texas also indicate higher recovery efficiency in wave- dominated deltaic reservoirs (Tyler, 1988). This study showed that the unrecovered mobile oil (UMO) remaining in fluvial-dominated reservoirs averaged 43% for water drive reservoirs and 27% for solution-gas drive reservoirs, whereas the UMO in wave-dominated deltas averaged 37% for water drive reservoirs and 10% for solution-gas drive reservoirs.

SYNOPSIS

This chapter provides background information about the general geological and production characteristics of deltaic reservoirs in order to provide a means for information exchange among different segments of the petroleum industry. Tthe main points presented in chapter 3 are as follows:

- Deltas are stream-fed depositional systems that occur in lakes, bays, lagoons, or the ocean and create an irregularity in that shoreline. Three major depositional settings include the upper deltaic plain, which is dominated by fluvial processes; the lower deltaic plain, which lies between high and low tides; and the subaqueous delta, which is dominated by marine processes including waves and currents. Delta front sediments refer to those sandy accumulations at or near channel mouths and those deposits dispersed locally by longshore currents.
- Deltaic reservoirs are created by entrapment of oil and gas within the sandy, generally more porous depositional facies. Depositional facies are three-dimensional stratigraphic bodies whose environmental origins can be inferred from the physical characteristics of the rock. Depositional facies

comprising deltaic reservoirs are, therefore, related to depositional processes. Reservoir quality and geometry of deltaic depositional facies may be altered by three structural features (folds, faults, or fractures) or by diagenesis. Diagenesis refers to the postdepositional physical and chemical processes that are undergone by sediments as they subside within a sedimentary basin. Diagenetic processes include compaction, cementation, and leaching, among others.

- Three types of deltas are defined by the dominant depositional processes capable of transporting and redistributing large volumes of sand, particularly in the delta front area. The resulting classification of deltas includes 1) fluvial-dominated deltas, 2) wave-dominated deltas, and 3) tide-dominated deltas. Fluvial-dominated deltas tend to build elongate fingers of delta front sands at high angles to the shoreline. Tide-dominated deltas are characterized by sand choked channels and tidal sand ridges. Wave-dominated deltas have an abundance of sand that has been reworked into coastal barrier bars oriented perpendicular to the sediment-supplying river.

- Sand deposition in fluvial-dominated deltas builds seaward creating elongate, lenticular bar fingers. Reservoirs from these types of deltas tend to have lower than average oil recoveries. In contrast, laterally continuous barrier and beach sands from wave-dominated deltas are more easily swept and have good recovery efficiencies. Reservoirs from tide-dominated reservoirs are, at this time, poorly known.

- Interplay of a wide variety of depositional processes has been shown to produce a limited number of distinctive sand and reservoir distributions. Understanding of the processes and resulting delta configurations facilitates prediction of reservoir distribution and quality.

- Sand distribution maps and vertical successions interpreted principally from geophysical logs provide the means for distinguishing major subsurface depositional facies, and thereby, the type and extent of the resulting delta and its reservoirs. Geophysical techniques, such as seismic interpretation, are often used to examine the larger scale aspects of the delta system. Smaller scale heterogeneities are often best deciphered by examination of recovered core, which can then be calibrated with log patterns so that facies distributions can be interpreted.

- Of the numerous deltaic depositional facies, perhaps the most important reservoir facies include the distributary channel facies and the delta front facies. The delta front facies includes the best potential oil and gas reservoirs. In addition, reworked delta front sands may become an arcuate system of barrier islands or shoals on the margins of abandoned delta lobes and may also become important reservoir facies. Lobe abandonment occurs when the stream feeding the delta switches to another channel.

- Dimensions and geometry of channel deposits are a function of the size of the delta, the position of the channel in the delta, the type of material being cut into, and the forces at the mouth of the channel.

- Geometry of the delta front sandbody is typically attributed to the rate of sediment supply and the relative strengths of wave, tide, and fluvial processes. However, the geometry can be altered by synsedimentary faulting (growth faulting), slumping, gravity sliding, and clay piercement structures known as diapirs.

- Distributary mouth bar deposits tend to be twice as thick and ten times wider than distributary channel deposits. Width/thickness ratios for distributary mouth bars is seven times greater than that for distributary channels. A wide degree of variability is present in the size and geometry of distributary channel, distributary mouth bars, distal bar sandstones and crevasse splay channels. Distributary bar deposits are much larger sandbodies (average 10,500 ft wide and 60 ft thick) than are distributary channel deposits (average 1,000 ft wide and 30 ft thick).

- Shales associated with deltaic barrier sand deposits are usually highly continuous. Delta front and delta plain sediments, however, contain shale breaks which are usually less extensive because of erosion by fluvial and tidal channels. Effects of shales on production can be either positive or negative. Negative effects include gas underrunning shales, reduced volumetric sweep in gravity drainage, reduced horizontal and vertical flow and sweep efficiency, and the creation of channeling. Positive effects include reduced coning and, reduced early gas or water breakthrough, and aid in confining injected water to improve the vertical sweep efficiency.

- Diagenetic effects may be either positive or negative with respect to reservoir quality. Because diagenesis is related to the hydrological framework, both it and the depositional environment determine the end results. Distribution of reservoir quality sandstones is indirectly related to facies distribution, but is neither uniquely controlled by, nor associated with, any specific depositional environment.

- Geological heterogeneities within reservoirs are related to deltaic depositional processes, may cause significant recovery problems, and occur on a wide variety of scales. Field-scale heterogeneities include the degree of interconnectedness of sandbodies, the location within the depositional system. Interwell-scale heterogeneities include boundaries between genetic units, lateral facies changes, style of bedding, and permeability variations within genetic units. Core-plug scale heterogeneities often include lamination, textural variations, and diagenetic alteration of the mineralogical content or the pore system.

- In general, the methods of infill drilling, horizontal/slant wells, and hydraulic fracturing are most applicable to larger field-scale heterogeneities, whereas enhanced oil recovery processes are best applied to interwell and microscopic-scale heterogeneities.
- The fluid flow problems most often reported from EOR projects of deltaic reservoirs are channeling, directional permeability trends, compartmentalization, formation parting, and contacting high salinity regions.
- Reservoir heterogeneities are the likely cause of poor performance of EOR projects. Comparison of chemical EOR projects in deltaic reservoirs shows that the recovery efficiency decreased from 60 to 70% to less than 30% for well spacing greater than 1 acre.
- As the median values of 229 fluvial-dominated unstructured deltaic reservoirs in the TORIS data base suggest, such reservoirs are generally high quality reservoirs at moderate depth (4,945 ft), have good porosity (19%) and permeability (128 md), and produce light oil (39 degrees API gravity) at a reasonable primary recovery factor (0.26).
- Permeability values were found to be the best indicator among formation parameters for the primary production in fluvial-dominated unstructured deltaic reservoirs. A low secondary recovery from fluvial-dominated deltaic reservoirs might be due to channeling or barriers to flow within the formation, or to efficient primary recovery.

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APPENDIX A. ANNOTATED DELTAIC REFERENCES

Annotated references have been provided for the convenience of the reader who may which to know more about certain aspects covered in this report. The Annotated References section is divided into five areas: Key Geological References; General Geological References; Reservoir Characterization: Examples and Applications; Engineering Technology; and Selected Plays.

1. KEY GEOLOGICAL REFERENCES

Included in the key geological references are those which are deemed essential to understanding the classification, the controlling processes, the depositional facies, and the resulting models of modern and ancient deltas.

Allen, G. P., D. Laurier, and J. Thourenin, 1979, Etude sedimentologique du delta de la Mahakam: Notes et Memories 15, Compagnie Franciase des Petroles, Paris.

Documentation of the tide-dominated Mahakam delta of Indonesia.

Allen, J. R. L., 1965, Later Quaternary Niger Delta, and adjacent areas: sedimentary environments and lithofacies: AAPG Bulletin, v. 49, p. 547-600.

This was the first study of the Niger delta, an arcuate, mixed wave-tide dominated delta type. The summary table of characteristics of environments and lithofacies is very useful.

The Niger delta in the Gulf of Guinea is a large arcuate delta, associated with estuaries and barrier-island lagoonal systems. The late Quaternary delta comprises a minimum of 900 cubic kilometers occupying part of the Nigerian Coastal Plain geosyncline. Sediment is dispersed by river, tidal, wave and ocean current processes.

Growth of the delta began during the Late Wisconsin-age lowstand of the sea. Rivers had become entrenched on the continental shelf above submarine canyons on the continental margin. The oldest preserved feature is a transgressive strand plain sand, called the "Older Sand". As sea level stabilized, deltas advanced forming the "Younger Suite". Lithofacies of the "Younger Suite " grade upward from open shelf clays to pro-delta clays, silts and sands to well-bedded sands of the delta-front, river-mouth bar and beaches. Tidal mangrove swamps occur today behind the beach ridge-barrier island fringe. The swamps contain organic-rich sands and silts. Cross bedded sands are associated with the silts and clays of the delta floodplain.

Maps: sedimentary features, geology of region, sand thickness, sediment transport and distribution, wave and tidal currents, environments, grain size distribution.

Charts: grain size frequency curves for sand, frequency curves for various minerals, sedimentary structures.

Berg, O. R., 1982, Seismic detection and evaluation of delta and turbidite sequences: Their application to the exploration for the subtle trap: in Halbouty, M. T., ed., The Deliberate Search for the Subtle Trap: AAPG Memoir 32, p. 57-75.

Deltas are divided into fluvial-dominated, wave-dominated and tide-dominated deltas. Each delta has a distinct framework, orientation, and depositional pattern which gives a characteristic seismic reflection. Fluvial-dominated deltas have seismic reflection patterns include oblique (tangential), complex oblique (tangential), sigmiod, and complex-sigmoid-oblique. Seismic facies analysis can define sand facies. Wave-dominated deltas are characterized by shingled reflection patterns. Seismic facies analysis for this type is not effective in identifying sand facies. Shingled reflections may define strandline sands. Tide-dominated deltas have not yet been identified by seismic stratigraphic methods. Turbidite fans and submarine canyons can be identified. Examples include regional studies from the North Sea, the Gulf Coast, and the Sacramento Valley.

Maps: models and seismic reflection patterns.

Bernard, H. A., C. F. Major, Jr., B. S. Parott, and R. J. LeBlanc, Sr., 1970, Recent sediments of Southeast Texas- A field guide to the Brazos alluvial and deltaic plains and the Galveston barrier island complex: Guidebook No. 11, Bureau of Economic Geology, The University of Texas at Austin, 16 p.

This field trip guidebook includes stops on the wave-dominated delta of the Brazos River, Texas. Of interest are the historical changes in the shoreline. Well illustrated with "cored" intervals.

Coleman, J. M., and S. M. Gagliano, 1964, Cyclic sedimentation in the Mississippi River deltaic plain: Gulf Coast Assoc. Geol. Soc. Trans., v. 14, p. 67-80.

Based on cores, this paper described the component parts of cyclic deltaic sedimentation.

Coleman, J. M., and D. B. Prior, 1982, Deltaic environments: in Scholle, P. A. and D. Spearing, eds., Sandstone Depositional Environments: AAPG Memoir 31, p. 139-178.

This chapter from the AAPG's volume, Sandstone Depositional Environments, is a good, well-balanced review of all the deltaic subenvironments. The article, and the book, are particularly well illustrated. Highly recommended for a general introduction to the geology of deltas.

Coleman, J. M., and L. D. Wright, 1975, Modern river deltas: variability of process and sand bodies: in Broussard, M.L., ed., Deltas, Models for Exploration: Houston Geological Society, p. 99-149.

This study found that the most significant processes controlling the distribution, orientation, and internal geometry of delta sand bodies include climate, relief in drainage basin, water discharge, sediment yield, river-mouth processes, nearshore wave power, tide, winds, nearshore currents, shelf slope, tectonics of receiving basin, and receiving-basin geometry. The results of this study indicate that no one delta model could be used to predict vertical sequences in all deltas.

Coleman, J. M., S. M. Gagliano, and W. G. Smith, 1970, Sedimentation in a Malaysian high tide tropical delta: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 185-197.

This paper is perhaps the best detailed description of a tide-dominated delta. The compound delta of the Klang-Langat rivers endures mean spring tides of 14 ft which dominate the sediment dispersal patterns. Because of tides and currents in the Malacca Strait the prodelta muds (Angsa Bank) are located lateral to the swampy mouths of the Klang and Langat rivers and are separated from the mainland by a small strait (Klang Strait). Channels that have become established in banks and tidal flats serve dual purposes of accommodating tidal movements in the estuary and directing river discharge.

Donaldson, A. C., R. H. Martin, and W. H. Kanes, 1970, Holocene Guadalupe Delta of Texas Gulf Coast: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM. Special Publication 15, p. 107-137.

This delta is being deposited along a shoreline dominated by barrier islands. Distinctive delta environments recognized include distributary channel, natural levee, marsh, interdistributary bay, delta front, and prodelta. Sands are present only in the distributary channels and as delta-front deposits. The overall configuration of the delta is "birdfoot", but includes small lobate masses where the delta has prograded toward shallow-water bay margins. No species were found to be restricted to a particular depositional environment.

Dott, R. H., Jr., 1964, Ancient deltaic sedimentation in eugeosynclinal belts: in Developments in Sedimentology, v.1, Deltaic and Shallow Marine Deposits: Elsevier, N.Y., p. 105-113.

This paper was the first to present examples of deltaic sedimentation from a tectonically unstable area. The paper demonstrated that deltaic sedimentary packages are distinctive regardless of the tectonic setting.

Elliott, T., 1989, Deltaic systems and their contribution to an understanding of basin-fill successions: in Whatley, M.K.G., and K.T. Pickering, eds., Deltas: Sites and Traps for Fossil Fuels: Geological Society Special Publication 41, p. 3-10.

A review of progress in deltaic studies to identify current or future topics of interest. Some of the main points made include: Understanding of tide-dominated deltas is limited compared with what is known about fluvial- and wave-dominated deltas. Although the tide/wave/fluvial process classification of deltas remains valid, additional factors influencing deltas such as location within the basin, type of basin, and type and caliber of sediment load are necessary for improved characterization of deltas. Inclusion of more features than fluvial, wave, or tide dominance in the classification of deltas may result in description of ancient deltas without modern analogs, which the author calls non-actualistic models.

Fisher, W. L., and L. F. Brown, Jr., 1972, Clastic depositional systems- A genetic approach to facies analysis: Bureau of Economic Geology, The University of Texas at Austin, 211 p.

Excellent collection of notes for a course emphasizing the genetic approach to stratigraphy and sedimentology through an understanding of depositional processes and their relationships with depositional environments and sedimentary facies. Not illustrated. Useful list of selected references for each of the major deposystems.

Fisher, W. L., L. F. Brown, Jr., A. J. Scott, and J. H. McGowen, 1969, Delta systems in the exploration for oil and gas: A Research Colloquium: Bureau of Economic Geology, The University of Texas at Austin, 78 p.

Notes and illustrations provide a solid basis for understanding the concept of depositional systems, the relative importance of deltas, delta forming pro-

cesses, morphology and component parts of various delta types. An extensive list of selected references is included.

Fisk, H. N., 1955, Sand facies of Recent Mississippi Delta deposits: World Petroleum Cong., 4th, Rome, Proc., sec. 1/c, p. 377-398.

This was the first paper to discuss the origin and distribution of sands in the subaqueous portion of the delta.

Fisk, H. N., 1961, Bar-Finger sands of Mississippi Delta: in Peterson, J. A., and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 29-52.

This excellent summary paper discusses the occurrence and geometry of bar-finger sands and their relationship to other delta facies. Core analysis of the Mississippi bird-foot delta reveals the geometry and facies of bar-finger sands. They are lenticular, elongate sand bodies 15 to 20 miles long with branching distributaries that widen toward the Gulf. The fingers originated as distributary mouth bars. Maximum width is five miles and maximum thickness is 250 feet. Three zones are present in each bar: 1) a central zone of clean sand with only minor silt and clay; 2) a thin upper transitional zone, which grades up to levee and delta plain; 3) a thick lower transitional zone which grades downward and laterally into delta-front. Thin layers of festoon cross- bedding are found in the upper and central zones. Plant fragments and clay laminae are found in the lower zone. Upward deformation of the bars has been caused by diapiric movement of muds, known as mud lumps. An ancient example of bar-finger deposits is the lower Pennsylvanian Booch sand of Oklahoma.

Maps: delta environments, bar finger distribution, 3-D development of bird-foot delta, cross-sections.

Figures: core analysis, faunal chart, grain size plots, sedimentary character charts.

Fisk, H. N., E. McFarlan, Jr., C. R. Kolb, and L. J. Wilbert, 1954, Sedimentary framework of the modern Mississippi Delta: Jour. Sed. Petrology, v. 24, p. 76-99.

The emphasis of this paper was on bar fingers of the modern birdfoot delta. Unlike previous papers, Fisk and others considered all the various depositional environments and related facies of the delta, including subsurface data.

Galloway, W. E., 1975, Process framework for describing the morphologic and stratigraphic evolution of deltaic depositional systems: in Broussard, M.L., ed., Deltas, Models for Exploration: Houston Geological Society, p. 88-98.

One of the most used classifications of delta types based on depositional processes. Marine deltas characterized in terms of three end-member types: 1) fluvial-dominated deltas, 2) wave-dominated deltas, 3) tide-dominated deltas.

Gould, H. R., 1970, The Mississippi Delta complex: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 3-30.

This paper was first presented in 1965. It is a synthesis of the concepts of deltation by H.N. Fisk (and his colleagues) derived from years of work on the Mississippi Delta. All of the older Mississippi deltas prograded onto the shallow inner margin of the continental shelf; only the modern birdfoot delta has advanced into the deeper waters of the continental slope. In general, most of the sands were laid down in the distributary-mouth bars of the delta front.

Kanes, W. H., 1970, Facies and development of the Colorado River Delta in Texas: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 78-106.

This work documented the small birdfoot delta of the Colorado River of Texas, which formed recently in Matagorda Bay behind a barrier sand and divides the bay into eastern and western parts. The deposit was lobe-shaped prior to artificial channeling of the river through the shoreline barrier. An 8-10 ft thick platform of deltaic sediments formed within the bay during the six years after removal of an upstream log jam.

Kolb, C. R., and J. R. Van Lopik, 1966, Depositional environments of the Mississippi River Deltaic plain—southeastern Louisiana: in Shirley, M.L., ed., in Deltas in their Geological Framework: Houston Geol. Soc., p. 17-61.

This is arguably the best summary of the geological history, depositional environments, and sediments of the Mississippi delta-plain complex. Subaqueous portions of the delta were not considered. A large amount of core data were correlated with depositional environments.

Kruit, C., 1955, Sediments of the Rhone delta: Part 1, grain size and microfauna: K. Nederl. Geol. Mijnbouwk. Gen. Verhand., v. 15, p. 357-514.

This paper was the first to be concerned with the relationship between sediments and depositional environments of the Rhone delta. Kruit described the delta sequence based on wells and borings.

Le Blanc, R. J., 1975, Significant studies of modern and ancient deltaic sediments: in Broussard, M.L., ed., Deltas, Models for Exploration: Houston Geological Society, p. 13-85.

This useful paper summarizes, in chronological order, the results of about 60 of the most important papers contributing to our understanding of modern and ancient deltaic deposits.

Morgan, J. P., 1970, Depositional processes and products in the deltaic environment: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 31-47.

Four basic factors control and influence delta formation: 1) river regime, 2) coastal processes including waves, tides, and currents, 3) structural behavior and, 4) climatic factors. The Mississippi, Ganges-Brahmaputra, and Mekong deltas are contrasted based on the relative importance of the dominant processes creating each delta.

Oomkens, E., 1970, Depositional sequences and sand distribution in the postglacial Rhone delta complex: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Spec. Pub. 15, p. 198-212.

Wave-dominated Rhone deltaic sediments can be grouped into one of three depositional sequences: a) transgressive sequences. b) regressive sequences, and c) channel-fill sequences.

Transgressive sequences result in a sediment body where coastal plain deposits are overlain by coarse-grained coastal barrier deposits that are in turn overlain by marine deposits. In the Rhone delta complex these deposits are seldom more than 2 m thick (per cycle).

Regressive processes produce a sediment body that contains fine-grained sediment at its base and dominantly coarse-grained sediment at its top.

Channel-fill sequences fine upward. The basal sand member is seldom more than 5 m thick in the Rhone delta.

Oomkens, E., 1974, Lithofacies relations in the Late Quaternary Niger Delta complex: Sedimentology, v. 21, p. 195-222.

Excellent description of a wave/tidal dominated delta. Tidal channel sand is the dominant lithofacies in the upper 30 meters of the Niger Delta complex. Below 30 meters fluvial sand is dominant. Coastal barrier sand is present in the top 5 meters of the modern coastal belt, but is rarely preserved.

Post-glacial sediments are divided into three units. 1. alluvial valley-fill sands and conglomerates deposited during strong Post-glacial sea level rise. 2. Onlapping complex of lower coastal plain, fine grained lagoonal and mangrove swamp mud at the base and tidal channel and coastal barrier sands in the upper units. This unit is up to 25 meters thick. 3. Offlapping complex of fluviomarine and coastal deposits. The base is marine clay and silt and the upper member is tidal channel and coastal barrier sand. Deltaic progradation resumed as rapid sea level change slowed down in the Holocene. The offlapping sequence is up to 35 meters thick.

Maps: Niger delta, lithofacies distribution, depositional sequences, channel fill sequences, recent tidal channel fill sands of Netherlands, core sample sequence, transgressive-regressive sequences, lithofacies model.

Orife J. M., and A. A. Avbovbo, 1982, Stratigraphic and unconformity traps in the Niger Delta: in Halbouty, M. F., ed., The Deliberate Search for the Subtle Trap, AAPG Memoir 32, p. 251-265.

Hydrocarbons of the Niger delta (a wave-tide dominated delta) are trapped by rollover anticlines and fault closures. Three additional types of stratigraphic trap are also recognized: 1. crestal accumulations below mature erosion surfaces. 2. Canyon-fill accumulations above uncomformity surfaces. 3. Facies change traps. Several important offshore oil discoveries are associated with crestal accumulations below erosional surfaces in southeastern Nigeria. Canyon-fill oil accumulations have been found offshore in southeastern Nigeria in the Qua Idboe Shale. Oil is also found in the Opuana channel fill in the western part of the Niger delta. Facies change traps are found in the central part of the Niger delta. All these stratigraphic traps were observed by the use of seismic data.

Maps: locality, distribution of trap types, structural, seismic sections, cross sections, isopach, trap models.

Fields: Obiafu-Obrikom, Tonjor, Enang.

Wright, L. D., and J. M. Coleman, 1973, Variations in morphology of major river deltas as functions of ocean, wave and river discharge regimes: AAPG Bulletin, v. 57, p. 370-398.

Criteria were established to separate the contribution of fluvial versus marine forces to the building of deltas. Deltas studied include the Mississippi (USA), Danube (Rumania), Ebro (Spain), Niger (Nigeria), Nile (Egypt), Sao Francisco (Brazil) and Senegal (Senegal). These deltas show a range of process regimes from fluvial-dominated, low-wave-energy (Mississippi) to wave-dominated, low-fluvial influence (Senegal).

River-dominated deltas have highly irregular and protruding shorelines, few wave built features and low lateral continuity of sands. Wave dominated deltas have straight shorelines with well developed barriers and beach ridges and high lateral continuity of sands. River dominated deltas are developed only where there is a flat offshore profile. Where the subaqueous slope is steep, wave built shoreline platforms dominate the delta morphology.

Maps: depositional environment map for each delta, discharge map for each delta.

Charts: delta morphology, discharge/wave-power-climate, morphometric properties, vertical sequences through several deltas.

2. GENERAL GEOLOGICAL REFERENCES

Included in the general geological references are selected entrees that supply important information about the sedimentation, distribution of facies and depositional environments, geometry, geological characteristics of reservoirs, and examples from modern deltas.

Allen, J. R. L., 1978, Studies in fluviatile sedimentation: an exploratory quantitative model for the architecture of avulsion-controlled alluvial sites: Sedimentary Geology, v. 21, p. 129-147.

A model of avulsion of rivers studies the construction of new channel sand bodies. This process is also active on deltas and so is included here. Sediment is accumulated during each avulsion. Each sequence is comprised of overbank sediments of a thickness proportional to subsidence rate and avulsion period, and laterally equivalent to a weakly multistory sand body of a thickness proportional to channel depth, avulsion period and subsidence rate. The sandbody width is determined by stream size and dynamics.The model ignores sequence compaction and avoids areas of previous avulsion. Sandbodies are virtually unconnected in alluvial suites containing 50% or more overbank facies. The model results show that coarsening upward alluvial suites may owe much of their character to progressively decreasing subsidence as to a decline in channel sinuosity.

Beerbower, J. R., 1961, Origin of cyclothems of the Dunkard Group (Upper Pennsylvanian-Lower Permian) in Pennsylvania, West Virginia, and Ohio: GSA Bulletin, v. 72, p. 1029-1050.

This paper on the origin of cyclothems is an example of the application of studies of the modern Mississippi delta to the study of ancient sediments (the Dunkard Group of Pennsylvania, West Virginia, and Ohio). Beerbower described the Dunkard cyclothems as having developed in lakes rather than in a marine setting (as in the Illinois cyclothems).

Besly, P., and W. Williams, 1989, Quantification of permeability barrier geometrics within deltaic sandstone reservoir bodies-a study of Carboniferous analogues (abs.): Marine Petroleum Geol. London, v. 6, p. 379-380.

Shales in reservoir sand bodies act as barriers to fluid flow. Well data is used to make 3-D models to predict the discontinuous shale units. Data on thickness, lateral continuity and spatial distribution of shale permeability barriers from Upper Carboniferous channel sandstones in Northern England was used to test the 2 and 3-dimensional models.

In channel mouth bar and channel sand bodies, shale units are identified by minor drapes of the toesets of cross-beds, forming local barriers to vertical flow. More extensive shale "sheets" drape over bedforms and event-deposited sandstone layers forming barriers to both vertical and horizontal flow.

Bloomer, R. R., 1977, Depositional environments of a reservoir sandstone in West-Central Texas: AAPG Bulletin, v. 61, p. 344-359.

Hundreds of stratigraphic traps in fluvial, deltaic, and marine Paleozoic sandstones are present in the eastern shelf and slope of the Midland Basin. The Cook sandstone contains two fluvial and deltaic systems extending about 100 miles from outcrop to shelf edge. Blackwell field is a stratigraphic trap in point bar deposits of the Cook Sandstone. Two high-constructive lobate deltas formed in a shallow sea. Delta plain, delta front-sheet and distributary channel sandstone facies are present. At the shelf edge maximum thickness reaches 1,300 ft and thins basinward. The Jameson "Pennsylvanian Strawn" field produces from the Cook sandstone lower slope and appears to be a submarine fan deposit.

Maps: locality, electric-log, paleodrainage, structure and stratigraphic sections, isopachs.

Brown, L. F., Jr., 1969, Geometry and distribution of fluvial and deltaic sandstones (Pennsylvanian and Permian), North-Central Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 19, p. 23-47.

Brown described sandstones of the delta front, distributary mouth-bar, and distributary channel facies. Also discussed are destructional sands formed during the abandonment phase. The final part of the paper was concerned with factors that control sandstone distribution.

Busch, D. A., 1961, Prospecting for stratigraphic traps: in Peterson, J. A. and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 220-232.

Stratigraphic traps are often related to their environments of deposition. Isopach studies of shales above and below sandstones are of use in reconstruction depositional environments. These isopach maps may serve as indicators for locating certain lenticular sands. Reservoir sands that parallel depositional trends, such as beach sands, strike-valley sands, and offshore bars can be found in this manner. Structure maps with reliable time markers can be of use in locating stratigraphic traps. Electric-logs are essential in this work, and the thinner the preserved sequence, the more important the electric log interpretation becomes.

According to the author, some deltaic reservoirs may be difficult to recognize, but are often well preserved. Understanding of trends of distributary channels and the influence of compaction in producing drape structures is essential.

Example: Booch sandstone, Mississippian of Oklahoma.

Maps: cross-section, structure of Oklahoma, isopachs, block diagram, structure, electric-log correlations.

Busch, D. A., 1971, Genetic units in delta prospecting: AAPG Bulletin, v. 55, p. 1137-1154.

Deltas form at river mouths at the time of sea level stillstands under conditions of cyclic transgression or regression. Reservoir facies consist of continuous or discontinuous bifurcating channel sandstones and delta front sheet sandstones. Lithological components of a deltas are interrelated and collectively referred to as one type of Genetic Increment of Strata (GIS). The GIS is a vertical sequence of strata defined at the top and bottom marker beds by time lithologic units or by an unconformity, or by facies change from marine to non-marine beds. A GIS isopach shows channel trends and delta shapes regardless of variable lithology.

A Genetic Sequence of Strata (GSS) consists of two or more GIS's which together define a shelf, hinge line, or less stable part of a basin.

A hypothetical model serves as the basis for establishing the criteria for: 1. recognizing successive stillstands of a shoreline, 2. predicting paleodrainage courses, 3. predicting positions of a series of deltaic reservoirs, 4. locating isolated channel sandstone reservoirs, and 5. tracing related beach sandstone reservoirs.

Example: Booch sandstone, Mc Alester Fm., Arkoma Basin, Oklahoma.

Maps: Isopach of the McAlester Fm., correlation of Booch Sandstone members, isopachs, cross-sections, structure maps, stratigraphic profile.

Chesnut, D. R., and Cobb, J. C., 1986, Pennsylvanian-age distributary-mouth bar in the Breathitt formation of eastern Kentucky: GSA Centennial Field Guide- Southeastern Section, p. 51-53.

Outcrops of distributary-bars from the Breathitt Formation are found in two locations in Knott County, Kentucky. A coarsening-upward marine bay sequence grades into overlying distributary-mouth bar sandstones, which are truncated by distributary and overlain by distributary-channel sandstones. Peat comprises the top of the cycle. Slumping was penecontemporaneous with formation of the distributary sandstones and bayfill.

Maps: locality, schematic diagrams.

Coleman, J. M., and S. M. Gagliano, 1965, Sedimentary structures, Mississippi River Delta plain: in Middleton, G. V., ed., Primary Sedimentary Structures and Their Hydrodynamic Interpretation: SEPM Spec. Pub. 12, p. 133-148.

Cores of deltaic and marginal deltaic plain facies of the Mississippi River were analyzed. The active environments were studied to determine their sedimentary structures. Twenty-five structure types were identified and illustrated according to the processes of their formation. Suites of structures were found to characterize environments. Twelve depositional environments were studied: shelf, prodelta, delta front (distal bar, distributary mouth bar, distributary channel and subaqueous levee), subaerial levee, marsh, swamp, interdistributary bay, mudflat, and fresh water lake. Maps: locality, sequence of structures, deltaic environments.

Core samples: laminations, textures, inclusions, scour and fill, truncation, organic remains, burrows.

Chart: sedimentary structures in depositional environments.

Coleman, J. M., S. M. Gagliano, and J. E. Webb, 1964, Minor sedimentary structures in a prograding distributary: Marine Geology, v. 1, p. 240-258.

Sedimentary structures were studied from cores taken from the Mississippi River delta at Johnson's Pass. The environments recognized include: subaerial and subaqueous levee, channel, distributary mouth bar, interdistributary bay and marsh. Cores were split and dried and photographed to reveal the minor structures.

The natural levee contained current ripple laminations, unidirectional cross-lamination, parallel and wavy laminations, distorted layers and burrowed, oxidized silty sands.

Channel fill had alternating beds of clay and silt with trough cross-laminations, scour and fill and distorted layers.

The distributary mouth-bar was composed of sand and silt with small multi-directional cross-laminations and air-heave structures. Interdistributary bay deposits consisted of homogeneous clay with a brackish-water fauna or clay with thin parallel and lenticular laminations and ripple marks. Marsh deposits had abundant peat, carbonaceous clays, calcareous nodules and root disturbances.

Maps: Mississippi delta, Garden Island 1872, Garden Island Bay 1891, Johnson Pass.

Cores: textures and structures.

Chart: sedimentary structures and depositional environment.

Collinson, J. D., 1969, The sedimentology of the Grindslow Shales and the Kinderscout Grit: a deltaic complex in the Namurian of northern England: Journal of Sedimentary Petrology, v. 39, p. 194-221.

This paper and another by McCabe (1978) provide a good description of a deltaic system that has no recognized modern genetic equivalent. This Carboniferous delta system, which was fed by a high discharge river system characterized by coarse-grained bedforms, supplied large amounts of sediments to the Central Pennine Basin, a small intracratonic basin in which the basinal waters were substantially diluted by the amount of freshwater discharge entering the basin. As a result most of the coarse-grained sediments bypassed the shoreline and were transported into deeper parts of the basin.

Curtis, B. F., 1961, Characteristics of sandstone reservoirs in United States: in Peterson, J. A. and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 208-219.

7,241 reservoirs in the U.S. were included in this study. 68% of the sandstones are of Tertiary Age. Most sandstones are restricted in size to less than 100 sq miles in extent and have an average thickness of 39 feet.

Petroleum accumulation in sandstones results from structural configuration in 56 % of the reservoirs, from stratigraphic conditions in 10% and from combined structural/stratigraphic causes in 34 %. Thicker sandstones tend to have broader extent and better reservoir characters than thickness alone would indicate.

Of the stratigraphic traps analyzed, 61% were deposited in nearshore or under shoreline conditions. 54% of all reservoir sandstones contain mainly oil, 27 % contain gas and the rest have substantial amounts of both.

Maps: U. S. reservoir localities, trap type, trap relationship to environment.

Charts: age correlations, sand thickness table.

Curtis, D. M., 1970, Miocene deltaic sedimentation, Louisiana Gulf Coast: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 293-308.

Based on a study of Gulf Coast Miocene deltas Curtis proposed the conceptual model where if rate of deposition exceeds rate of subsidence, deltas prograde and normal regressive basin filling occurs; if rate of sedimentation equals rate of subsidence, deltas build vertically and spread out laterally; if rate of sedimentation is less than rate of subsidence, regional transgression occurs and marine processes modify small deltas.

Dott, R. H., Jr., 1966, Eocene deltaic sedimentation at Coos Bay, Oregon: Jour. Geology, v. 74, p. 373-420.

Prior to Dott's (1964, 1966) work it was generally considered that deltaic sedimentation was uncommon in tectonically unstable areas. This paper documents delta building in just such a tectonically active area along the Oregon coast.

Edwards, M. B., 1981, Upper Wilcox Rosita delta system of South Texas: growth faulted shelf-edge deltas: AAPG Bulletin, v. 65, p. 54-73.

The Rosita delta system which is preserved in the deep upper Wilcox of south Texas comprises at least three delta complexes. Growth faults were activated by progradation of the deltas over unstable prodelta-slope muds at the contemporary shelf margin. As the lobes of each complex passed over active growth faults thickness increased by as much as tenfold. Coarsening-upward progradational units were interpreted from electric logs and the following patterns were recognized: prodelta shales, delta-front sandstones, distributary channel and channel-mouth bar sandstones, and interdistributary shales and sandstones. This paper illustrates the importance of synsedimentary growth faulting to reservoir geometry and thickness.

Ekweozor, C. M., and E. M. Daukoru, 1984, Petroleum source-bed evaluation of Tertiary Niger Delta: Reply: AAPG Bulletin, v. 68, p. 390-394.

The authors reply to Lambert-Aikhionbare and Ibe's representation of their original data on the hydrocarbon source for the Niger Delta. Lambert-Aikhionbare and Ibe gave no specific field or well names and no evidence of where their samples came from.

Niger delta source rocks should mature upward, rather than downward within the stratigraphic column, according to the maturity data cited by Lambert-Aikhionbare and Ibe. This is contradictory to evidence from all other sedimentary basins. Maturity depends on relative depth of burial, local geothermal gradient and duration of exposure to thermal stress. The Lambert-Aikhionbare and Ibe claim of immature Akata versus mature Agbada shales isn't supported by evidence from wells.

Most evidence by the authors of this paper and other researchers supports the theory of hydrocarbon generation from relatively deep paralic or paralic-marine shales. Vitrinite reflectance values must be interpreted in conjunction with all geochemical data from the basin.

Elliott, T., 1978, Chapter 6 Deltas: in Reading, H. G., ed., Sedimentary Environments and Facies: Elsevier, New York, p. 97-142.

Elliott's chapter on deltas is part of a comprehensive textbook covering modern and ancient environments.

Fisher, W. L., and J. H. McGowen, 1967, Depositional systems in the Wilcox Group of Texas and their relationship to occurrence of oil and gas: Gulf Coast Assoc. Geol. Soc. Trans., v. 17, p. 105-125.

A regional study based on outcrop and subsurface data of the Rockdale delta System. Maps show the distribution of several large delta lobes similar to those of the Mississippi delta-plain. One of the first papers to interpret depositional environments from a thick subsurface accumulation of clastics in an oil-productive province.

Galloway, W. E., and D. K. Hobday, 1983, Terrigenous clastic depositional systems, applications to petroleum, coal and uranium exploration: Springer-Verlag, New York, 423 p.

Textbook oriented for students interested in sedimentary models for terrigenous systems exploration applications.

Galloway, W. E., C. D. Henry, and G. E. Smith, 1982, Depositional framework, hydrostratigraphy and uranium mineralization of the Oakville Sandstone (Miocene), Texas Coastal Plain: Bureau of Economic Geology, The University of Texas at Austin, Rept. Invest. No. 113, 51 p.

Gregory, J. L., 1966, A Lower Oligocene delta in the subsurface of southeastern Texas: in Shirley, M.L., ed., Deltas in their Geologic Framework: Houston Geological Society, p. 213-227.

The Lower Oligocene (middle Vicksburg) delta in southeastern Texas has an areal extent of 1,100 square miles and is up to 300 ft thick. Gregory concluded that the most favorable location of hydrocarbon traps was in sandstones deposited near the seaward margin of the delta. Structures that formed contemporaneous with sedimentation and remained positive had the greatest effect on hydrocarbon accumulation; subsequent structures had little effect on accumulation of hydrocarbons.

Kruse, C., 1979, A Dictionary of Petroleum Terms: in Kruse, C. ed., Petroleum Extension Service: The Univ. of Texas at Austin, p. 1-129.

An alphabetical listing of terms used in the petroleum industry. Heavily slanted towards the field operator, defining mechanical operations and equipment. Geared toward production data with some engineering statistics, but few geological terms pertaining to depositional facies and diagenesis. Useful to the academic orientated toward interpreting well information and industry jargon.

Lagaaij, R., and F. P. H. W. Kopstein, 1964, Typical features on a fluviomarine offlap sequence: in Developments in Sedimentology, v.1, Deltaic and Shallow Marine Deposits: Elsevier, N.Y., p. 216-226.

This paper presents a summary of the sedimentary sequence of the Rhone delta based on a study of cores.

Lambert-Aikhionbare, and A. C. Ibe, 1984, Petroleum source-bed evaluation of Tertiary Niger Delta: Discussion: AAPG Bulletin, v. 68, p. 387-389.

Earlier work concluded that the Akata shales were the main source of hydrocarbons in the Niger delta based on geochemical analysis. This was based on interpretation of bitumen content that could only occur at greater depths than 2,900 m onshore and 3,375 m in the offshore areas.

The present authors feel this neglects the high extract values of bitumen at shallow depths. Samples were taken from the Agbada shale and the Akata shale. The finding was that the shallower Agbada shales (1,800 m) were thermally mature and could have generated the hydrocarbons. Low extract values in some beds represent areas from which generated hydrocarbons had migrated.

Vitrinite reflectance values were used by both sides to confirm theories, depending on the range of vitrinite reflectance accepted as thermally mature.

Lindsay, J. F., D. B. Prior and J. M. Coleman, 1984, Distributary-mouth bar development and role of submarine landslides in delta growth, South Pass, Mississippi Delta: AAPG Bulletin, v. 68, p. 1732-1743.

Submarine landslides are a major process in building distributary-mouth bars and in transporting sediment into deeper water from the bar front. South Pass of the Mississippi River has advanced more than one mile westward from 1867 to 1953.

Dynamics of bar growth are controlled by the plume of freshwater as it mixes with the saline water of the Gulf. Approximately half of the sediment deposited on the bar bas been moved into the deeper water by submarine landslides. Bar failure occurred following major floods when deposits of thick, unstable water-saturated sediments accumulated on the bar. The triggering mechanisms include major storms and hurricanes, mudlump activity, increased pore pressures resulting from generation of biogenic gas. Failure may occur one to four years following built up. Bar growth and landslides is studied by computer analysis of bathymetric data.

Maps: distributary channel locality, 1888-1953 comparisons, sonar image, cross-sections, contour, 3-D model of bar, shear-strength of soil.

Mathews, W. H., and F. P. Shepard, 1962, Sedimentation of Fraser River Delta, British Columbia: AAPG Bulletin, v. 46, p. 1416-1443.

The Fraser delta was first studied in 1919 by W. A. Johnston. The slope of the delta is 1 1/2 degrees overall and from 1 3/4 to 3 1/2 degrees in the upper parts of the main channel. Landslides on the delta front have caused gullies with hills along the side. The river mouth bar has advanced 840 ft in 30 years. The volume of sediment added in this time is estimated at 700 x 10^9 cu ft., silt predominates. The delta front is sandy to the south and silty north of the river mouth; this distribution may be accounted for by tidal movements. Porosities and liquid and plastic limits of the newly deposited sediments are high, compared to buried sediments. Age of the delta is approximately 8,000 years. Sediments range from an average of 400 feet thick to a maximum of about 700 feet thick. Classical distinctions of foreset and bottomset beds are not really applicable to this delta.

Maps: locality, Fraser delta, Mississippi delta, Rhone delta, profile of Fraser delta, advance of contours, sand-silt-clay ratios, contour of sea slope.

Tables: delta sediments, properties of delta front sediments, ion exchange capacities, depth versus porosity.

McCabe, P. J., 1978, The Kinderscout delta (Carboniferous) of northern England: a slope influenced by turbidity currents: in Stanley, D.J., and G. Kelling, eds., Sedimentation in Submarine Canyons, Fans and Trenches: Dowden, Hutchinson & Ross, Stroudsberg, Pa., p. 116-126.

An example of a delta system where gravity transport (turbidity currents and delta-front slumping) were important and removed most of the coarser (sand size) sediments from the shoreline and transported them to the deeper parts of the receiving basin. The resulting delta system is unusual in that it has a fine-grained delta front with incised channels and a sand-rich submarine fan at the foot of the delta.

McEwen, M. C., 1969, Sedimentary facies of the modern Trinity Delta: in Holocene Geology of the Galveston Bay Area: Houston. Geol. Soc., p. 53-77.

This paper was based on a series of cores from the modern Trinity delta, Texas, a small birdfoot delta. The entire delta sequence was illustrated.

Moore, D. G., 1959, Role of deltas in the formation of some British Lower Carboniferous cyclothems: Jour. Geology, v. 67, p. 522-539.

Moore recognized that each cyclothem was formed by a delta that had prograded into a shallow continental sea. The cyclical advance of the delta was related to upstream diversions (crevassing), that resulted in lateral shifts of depocenters.

Moore, D. G., and P. C. Scrutton, 1957, Minor internal structures of some Recent unconsolidated sediments: AAPG Bulletin., v. 41, p. 2723-2751.

This paper established the importance of stratification type and sedimentary structures to depositional environment on the eastern part of the Mississippi delta.

Muller, G., 1966, The New Rhine Delta in Lake Constance: in Shirley, M.L., ed., Deltas in their Geological Framework: Houston Geological Society, p. 107-124.

Not all deltas are at the terminus of their supporting rivers. Muller documented the New Rhine Delta (post 1900) and its effect on Lake Constance, which lies between Bavaria and Switzerland. Over 90 percent of the detritus that enters Lake Constance from the Rhine River is deposited and only a small percentage leaves the lake to be carried to the Rhine's "other" delta and the North Sea.

Murphy, M.A., and S.O. Schlanger, 1962, Sedimentary structures in Ilhas and Sao Sebastiao formations (Cretaceous), Reconcavo Basin, Brazil: Amer. Assoc. Petroleum Geologists Bull., v. 46, p. 457-477.

This study compared Cretaceous deltas of Brazil with the Mississippi Delta.

Nanz R. H., Jr., 1954, Genesis of Oligocene sandstone reservoir, Seeligson field, Jim wells and Kleberg Counties, Texas: AAPG Bulletin, v. 38, p. 96-117.

This paper was the first to consider the distribution of sands in the subaqueous part of the delta. Their work demonstrated to the petroleum industry the importance of studies on sandstone depositional environments.

Nelson, B. W., 1970, Hydrography, sediment dispersal, and Recent historical development of the Po River Delta, Italy: in Morgan, J.P., ed., Deltaic Sedimentation Modern and Ancient: SEPM Special Publication 15, p. 152-184.

The Po River empties into the Adriatic Sea. The character of the delta is determined by: 1 geology, geography, hydrology of the drainage basis, 2. historical development of the delta, 3. hydrology of modern distributaries, and 4. hydrographic conditions in the Adriatic Sea. Freshwater discharge of the Po is 1,500 m^3/sec and the sediment load is dominantly sand and silt. The tidal range at the delta is 60 centimeters. The sea has a high salinity of 38% and is relatively low energy. The delta rests on a slowly subsiding shelf.

The modern delta is artificially confined and changed by man-made construction. Today 60% of the river flow and 75% of the sediment flow is in a single distributary. Delta advance is at a much higher rate than in prehistoric times.

The distributary mouth bar has a crest nearly at mean sea level which acts as a barrier to salt water incursion. Normally the salt water wedge invades the distributaries only at high tide and is flushed out by the river at low tide. The river velocity makes it possible to transport sand over the bar and into the sea. As the river waters enter the marine environment the flow becomes unconfined laterally, and its velocity diminishes causing settling of the suspended sediments. The fresh water plume extends out over the shelf in front of the mouth bar. Fine-grained sediments are transported at least 30 kilometers seaward from the delta before dropping from suspension.

Maps: Po River drainage basin, Adriatic Sea and Po delta bathymetry, Adriatic Sea surface currents, historic growth of Po delta, river mouth profiles, suspended sediment in Adriatic.

Tables and cross-plots: rainfall, river discharge, and sediment flux; particle size distribution and velocity of Po River suspended sediment, current velocities, tidal curve at Venice, hydrologic characteristics, salinity curve. Excellent description of freshwater plume and salinity wedge interaction.

Oomkens, E., 1967, Depositional sequences and sand distribution in a deltaic complex: Geologic en Mijnbouw, v. 46, p. 265-278.

Oomkens described three types of depositional sequences for the Rhone delta: regressive, channel fill, and transgressive.

Pryor, W. A., 1961, Sand trends and paleoslope in Illinois Basin and Mississippi Embayment: in Peterson, J. A. and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 119-133.

Major sand trends in the Illinois Basin and Gulf Coast basin have related paleoslopes, depositional strikes and basin axes. Sand bodies have a southwestern trend. The Gulf Series of deposits in the Mississippi Embayment and the Chester series in the Illinois Basin are similar. Both basins were open-ended to the southwest and parallel to basin axes. Depositional strikes were east-west normal to basin axes. Sediment transport was to the southwest. Deposition was deltaic in the north to marine in the southern parts of the basins. A depositional model for intercratonic basins has been made based on these examples.

Maps: Eastern North America basins, Chesterian series, sand body axes, stratigraphic column, Gulfian Series, sedimentation model.

Psuty, N. P., 1967, The geomorphology of beach ridges in Tabasco, Mexico: Louisiana State Univ. Coast. Stud. Ser., v. 18, p. 51.

Description of a classical cuspate, wave-dominated delta system with very well developed beach ridge facies. Both the Mezcalpa and Usumacinta river systems share a single major outlet to the Gulf of Mexico, the Grijalva River located just west of the Yucatan Peninsula.

Rainwater, E. H., 1966, The geological importance of deltas: in Shirley, M.L., ed., Deltas in their Geological Framework: Houston Geol. Soc., p. 1-15.

The introductory paper for the Houston Geological Society's 1966 volume on deltas is a concise general summary of delta systems, including vertical and lateral sequences of sediments and their geometries.

Ryer, T. A., 1981, Deltaic coals of Ferron Sandstone Member of Mancos Shale: Predictive Model for Cretaceous coal-bearing strata of western interior: AAPG Bulletin, v. 65, p. 2323-2340.

Upper Cretaceous Ferron Sandstone member is a coal bearing unit in the Emery coalfield of central Utah. Accumulation of clastic sediments in a lobate, river-dominated deltaic system along the western shore of the Interior Cretaceous Seaway formed the deposits. Five cycles of deltaic sedimentation, each containing a major coal bed were deposited. The thicker part of each coal bed extends from the vicinity of the landward pinch out of the delta front sandstone landward for a distance of 10 km.

Maps: Emery coalfield, Interior Cretaceous sea, cross-sections, delta models, isopach, predictive model, depositional history.

Photographs: textural features, outcrops.

Saxena, R. S., 1977, Deltaic sandstone reservoirs-exploration models and recognition criteria (abs.): Annual AAPG-SEPM Conv., Prog & abs, p. 51.

The lower deltaic region forms a zone ideal for hydrocarbon generation and entrapment. Two factors make the lower delta plain prolific: its location updip of extensive, organic rich, prodelta and marine shales (source rocks) and the complex lithologic variability and abrupt changes which provide sand-shale juxtapositions to form traps. Five facies were recognized from reservoirs within the lower deltaic plain: 1. point bars, 2. crevasse splays, 3. disributary mouth bars, 4. beach barriers, and 5. reworked deltaic sands. Studies of the modern Mississippi delta and Carboniferous Appalachian Plateau deltas form predictive models.

Grain size characteristics and temporal variations of depositional environment are used to recognize sand bodies in the subsurface using E-logs; SP curves define the shape of the sand bodies.

Scruton, P. C., 1960, Delta building and the deltaic sequence: Recent Sediments, Northwest Gulf of Mexico, Symposium: AAPG, p. 82-102.

Characteristic stratigraphic sequences form during a delta cycle in both constructional and destructional phases. Deltas are seaward-thickening banks of sediment deposited in the constructional phase and modified in the destructional phase. Land-derived clastics are deposited in an orderly sequence to build the delta. The classical delta is composed of top-set, fore-set and bottom-set beds. Similarities between different deltaic sequences are compared.

Environments of sedimentary deposition are defined by: 1. sediment source, 2. processes and their intensities, and 3. rates of deposition. Source areas differ from delta to delta. Rapid deposition is characteristic of deltas. As the river shifts the delta builds in different directions, to be abandoned and modified by wave and current action. During the destructional phase sediment are winnowed into thin veneers, beach ridges and barrier islands. Large delta systems are built by repeated phases of construction and destruction of imbricating deltas.

Maps: modern Mississippi delta, Mississippi delta 1874-1940, 3-D model of Mississippi, sedimentary structures, migration of environments, Frazer Delta-British Columbia, Orinoco River delta- Venezuela, Rhone delta- France.

Smith, A. E., Jr., and M. L. Broussard, eds., 1971, Deltas of the world: modern and ancient—Bibliograpy: Houston Geological Society, 42 p.

This handy publication contains 1,195 references indexed according to modern deltas, by country; ancient deltas, by country; and subject.

Swann, D. H., 1964, Late Mississippian rhythmic sediments of Mississippi Valley: AAPG Bulletin, v. 48, p. 637-658.

Based on the patterns of sandstone thickness maps Swann interpreted these sand bodies to be of deltaic origin. He indicated that the sandstones were not channel fills but, rather bar finger sands, as described by Fisk (1961). Swann was one of the first authors to be concerned with whether so-called "deltaic sands" were channel fills or originated as river-mouth bars, creating bar fingers or delta-front sands.

Maps: tectonic setting, paleogeography, cross section, isopachs, E-log correlations.

Charts: stratigraphy of Mississippi Valley Mississippian age sediments.

Taylor, J. H., 1963, Sedimentary features of an ancient deltaic complex; the Wealden rocks of southeastern England: Sedimentology, v. 2, p. 2-28.

Taylor provided one of the first papers to describe sediments from the entire range of deltaic depositional environments, rather than just portions of the complete deltaic sequence.

Thayer, P. A., 1985, Diagenetic controls on reservoir quality, Matagorda Island 623 field, Offshore, Texas (abs.): AAPG Bulletin, v. 69, p. 311.

This paper documented a gas reservoir in an overpressured lower Miocene deltaic sandstone. Reservoir depth is 10,000 to 14,000 ft. Bottom hole temperature is 275 F. Pay sand porosity ranges from 15% to 35%, permeability ranges from 10 to 3,000 md.

Primary intergranular porosity comprises 60-80% of total porosity. Porosity preservation depends on: 1. early formation of chlorite grain coats, 2. stable mineralogic framework, 3. overpressuring, and 4. entry of gas into reservoir. Chlorite coats form up to

8 % of the rock volume and originate from decomposition of volcanic rock fragments. The chlorite inhibits quartz cementation.

Secondary porosity is derived from feldspar and volcanic rock fragment dissolution. Leaching of calcite did not form significant porosity. Evidence for the absence of large scale carbonate dissolution includes: 1. unaltered carbonate lithoclasts, 2. reworked Cretaceous foraminifera, 3. preservation of chlorite crystal morphology, and 4. absence of pitted or serrated surfaces on quartz overgrowths.

Thompson, R. W., 1968, Tidal flat sedimentation on the Colorado River Delta, northwestern Gulf of California: GSA Memoir 107: 133 p.

This report was concerned with the southwestern portion of the Colorado delta-plain in Baja, California. Extensive mudflats (deposited in an 8-10 m tidal range) and chenier plain were also examined.

Tidwell , E. M., 1974, Bibliography of North American Oil and Gas Fields: AAPG Memoir, 24, p. 300-328.

This reference is an index to geologic papers on U. S. oil and gas fields which appeared in AAPG publications from 1918 to 1974. The index includes: field name, state, country, year of publication, publication volume and pages. Authors names for individual references are not given. There is some cross-referencing of related fields and name changes of fields.

Van Andel, T. H., 1967, The Orinoco Delta: Jour. Sed. Petrology, v. 37, p. 297-310.

A good short summary of the geology of the Orinoco delta which Van Andel compared with the Mississippi, Niger, and Rhone deltas.

Van Straaten, L. M. J. U., 1961, Some recent advances in the study of deltaic sedimentation: Liverpool and Manchester Geol. Jour., v. 2, p. 411-442.

This was the first important summary paper on deltaic sedimentation. It was based largely on studies of the modern Mississippi, Rhine, Rhone, Colorado, and Orinoco deltas which had been studied by various geologists between 1940-1960.

Wadsworth, A. H, Jr., 1966, Historical deltation of the Colorado River, Texas: in Shirley, M.L., ed., Deltas in their Geologic Framework: Houston Geological Society, p. 99-105.

This short paper documents the changes in size of the Colorado delta, Texas, after a 46 mile long log raft was removed in 1929. By 1941 the delta had grown in area 100 times to encompass 7,098 acres. Any barrier beaches that may have existed in front of Matagorda Bay were buried by deltaic sedimentation.

Wanless, H. R., 1965, Environmental interpretation of coal distribution in the Eastern and Central United States: Illinois Mining Inst. Ann. Meeting Proc., Springfield, Ill., p. 19-36.

Unlike most papers on ancient subaerial delta-plain sediments, Wanless discussed the distribution of delta-plain coals rather than channel sandstones. As with his previous papers, the regional picture was emphasized.

Wanless, H. R., J. B. Tubb, Jr., D. E. Gednetz, and J. L. Weiner, 1963, Mapping sedimentary environments of Pennsylvanian cycles: GSA Bulletin, v. 74, p. 437-486.

Using one well per township, the authors illustrated regional scale distribution of several large deltas of Pennsylvanian age from Illinois and the midcontinent.

Whitbread, T., and G. Kelling, 1982, Mrar Formation of western Libya-Evolution of an early Carboniferous delta system: AAPG Bulletin, v. 66, p. 1091-1107.

The Lower Carboniferous age Mrar Formation is located in northwest Libya. The basal part is cap rock and a possible source for hydrocarbons produced from the underlying sandstone reservoirs.

The deltaic environment developed on part of the Saharan platform. The sequences coarsen upward and grade into sandstone. Nineteen subenvironments range from deltaic and delta plain to marine shelf, beach and tidal flat. The prograding deltaic complex was fluvial dominated in the initial stage. The area shallowed progressively and sand was reworked into bars. Subsequently the discharge area migrated 62 miles northwest.

The upper Mrar deposits reflect basinward migration of the diverted discharge regime. Sands pass from bars into beach sands, becoming part of a wave-dominated delta. Further riverine migration reintroduced fluvial deposits. The sandstone is capped by a distinctive algal rich limestone formed in a period of delta lobe abandonment. The basin was slowly subsiding as the delta changed from fluvial to wave dominated. Thin and extensive sheet sandstones are preserved with the thick prodelta shales.

Maps: locality, columnar section, log cross sections, stratigraphic cross-sections, evolution of delta facies.

3. RESERVOIR CHARACTERIZATION: EXAMPLES AND APPLICATIONS

Included here are selected references concerning geological and engineering aspects of reservoir characterization, their application, and information about specific plays that do not fit into section 5 of this bibliography.

Brummert, A. C., R. J. Watts, D. A. Boone, and J. A. Wasson, 1988, Rock Creek Oil Field CO_2 pilot tests, Roane County, West Virginia: Jour Petroleum Tech, v. 40, p. 339-347.

Two CO_2 EOR tests were conducted on the Rock Creek oil field. The history, fluid properties and geology of Rock Creek field is reviewed. Cores and geophysical logs of injection and production were used to study the injection history.

Normal five-spot patterns with 13,000 scf CO_2/stb oil (2315 std m^3/stocktank m^3) were injected. This test recovered 3 % of the original oil in place, but was terminated after 3 years. A second test used increased HCPV's of CO_2 injected for a greater potential oil recovery. Test II was conducted in a 1.55 acre normal four-spot pattern. 11% of the oil was recovered. About 48 % of an HCPV was injected. This suggests that CO_2 miscible flooding may be technically successful in some Appalachian reservoirs.

Maps: locality, columnar section, permeability and porosity profiles, injection history, resistivity log, dual -induction log.

Charts: pilot test data, pilot test injection, stocktank saturations, injection data, oil saturation profiles.

Falkner, A., and C. Fielding, 1990, Sediment body quantification: Examples from a Late Permian mixed influence deltaic system, Bowen Basin, Australia (abs.): AAPG Bulletin, v. 74, p. 651.

An open pit coal mine in Bowen Basen, Australia exposed alluvial and fluviodeltaic sequences. The coal is an upper Permian terrestrial to shallow-marine deposit from 5 to 600 km along strike.

Photo-mosaics of the exposed mine walls were used to obtain a detailed view of the facies. Cores were used to interpret sedimentological data.

The German Creek Formation is interpreted as an extensive lower delta plain of a mixed wave-tide-fluvial influenced delta. Four facies are identified, two of these are possible hydrocarbon reservoirs. First, major channelized sandstone bodies 4 to 11 meters thick and .5 to 5 Km wide, elongate perpendicular to the basin edge; interpreted as distributary channel fills. The second includes tabular sandstone bodies 9 to 20 m thick and tens of km in extent, elongate parallel to the basin margin, internally dominated by hummocky cross-stratification, interpreted as proximal mouth bar deposits.

Finley, R.J., and N. Tyler, 1986, Geological characterization of sandstone reservoirs: in in Lake, L. W. and H. B. Carroll, Jr., ed., Reservoir Characterization, Academic Press, New York, p. 1-38.

This paper summarizes the various aspects of geological reservoir characterization which are today being more heavily relied on during efforts to maximize oil production from mature hydrocarbon provinces. The genetic approach to reservoir facies analysis is defined and explained as the best opportunity for the reservoir geologist and engineer to characterize the interwell area using fundamental rock units that have the greatest likelihood for more than site-specific applications.

Hartman, J. A., and D. D. Paynter, 1979, Drainage anomalies in Gulf Coast Tertiary sandstones: Jour. Petroleum Tech., v. 31, p. 1313-1322.

Unanticipated drainage patterns are termed drainage anomalies. They occur frequently in Gulf Coast sandstone reservoirs. They usually become apparent only after extensive work and production has occurred in a field as they represent unconnected sandstone reservoirs. Pressure data is the best source to indicate anomalies. Detailed engineering reviews of all geological, petrophysical, reservoir and production data is needed to pinpoint the anomalies.

Five examples of drainage anomalies from Louisiana include: 1. South Pass block 27 field "M6" sandstone, 2. South Pass block 27 field "N" sandstone, 3. South Pass block 24 "Q" sandstone, 4. Eugene Island block field, and 5. Two Miocene "K" sandstones (A&B). In reservoirs of this type large volumes of water are produced along with the hydrocarbons.

Maps: locality, structure for each example, E-log correlations, stratigraphic cross sections, 20 year pressure history.

Lowry, P., and A. Raheim, 1989, Characterization of delta front sandstones from a fluvial-dominated delta system: NIPER/DOE Second International Reservoir Characterization Technical Conference (in press): Academic Press, N.Y.

To develop a new oil field one must first define the reservoir architecture; first to establish the geometry of the sandstone bodies and second to define the reservoir heterogeneities or potential permeability barriers within the reservoir. Increasingly accurate description of the reservoir has led to increasing use of the stochastic reservoir simulator which generates a program of probabilistic realizations based on sedimentary sequences observed in well data, and sandstone and shale dimensions.

Two examples were chosen to test the model simulator: 1. The Ferron sandstone member of the Mancos Shale, central Utah, and 2. Pochahontas Basis eastern Kentucky (Carboniferous). Both are fluvial- dominated deltaic sequences.

The Ferron sandstone crops out along a belt 70 km long and 10 km wide. It had five major regressive events with 5 or 6 individual sandbodies, two are mapped as distributary mouth bars 7 to 8 km long and 3 to 4 km wide.

Charts and graphs: ratios of distributary body size, sandstone thickness.

Lowry, P., 1989, SPOR-OPT Establishment of a geologic database for improved reservoir characterization, Part 1: Geometry of Delta Front Sandstones: Institutt for Energiteknikk Report No. IFE/KR/F-89/056: 36 p.

This study, funded by the SPOR program, Norwegian Petroleum Directorate, is part of their program to 1) collect field data from various depositional settings, and 2) establish small prototype database to store quantitative data necessary for efficient reservoir characterization and reservoir modelling.

The majority of the data for this report were taken from the Ferron Sandstone member of the Mancos Shale of central Utah because of the excellent opportunity provided by these outcrops to examine the three-dimensional geometry of the delta front sandstones.

Pryor, W. A., and K. Fulten, 1976, Geometry of reservoir-type sandbodies in the Holocene Rio Grande Delta and comparison with ancient reservoir analogs: Soc. Petroleum Engin., Paper 7045, p. 81-84.

Reservoirs form by the combined processes of deposition, burial, compaction, diagenesis, and structural deformation. Internal geometry is important in understanding the evolution of individual sand bodies and their permeability-porosity variations.

The Rio Grande delta complex has three components: 1. distributary mouth-bar sand bodies, 2. meander point-bar sand bodies, and 3. delta slope sand bodies. The distributary complex sands are bundles of sand in a silt-clay matrix. Permeability and porosity of the Holocene sands are 200 md to 7 darcys and from 5% to 45% respectively..

The Rio Grande delta sand bodies compare well with reservoirs from the Gulf Coast, Western Interior, and Illinois Basin.

Maps: geometry and permeability, locality, log and facies cross-sections.

Richardson, J. G., J. B. Sangree, R. M. Sneider, 1989, Deltas: Jour. Petroleum Tech., v. 41, p. 12-13.

Oil is primarily produced from sandstone reservoirs of ancient delta systems. Deltas form at river mouths as sediments discharge into oceans or bodies of water. Stratigraphic events in delta development include: 1. sediments are carried and deposited in channels, and 2. sediments are reworked by waves and tides. In high energy deltas the clay and silts are eroded leaving sand rich deltas. In low energy situations mud-rich deltas form. High energy deltas have few distributary channels, they are meandering or braided. The Nile delta is cited as the best example of a high energy delta. The Mississippi delta is the best example of a mud-rich delta.

Maps: Nile delta, Mississippi delta, seismic section, sand body model.

Richardson, J. G., J. B. Sangree and R. M. Sneider, 1989, Mud-rich deltas: Jour. Petroleum Tech., v. 41, p. 334-335.

Mud-rich delta systems form where rivers deposit sediment faster than the sediment can be reworked by basin currents. Mud-rich deltas have more silt and clay in the river mouth bars and delta-front sheet sands. They have straight distributary channels that branch frequently. The coarsest, cleanest sand is at the base of the channel. Channel sands become progressively thinner and of poorer reservoir quality toward the channel mouth. Mud-rich deltas can build rapidly. The Mississippi has built hundreds of square miles in the past 5,000 years. Sheet sands are isolated by large areas of silt and clay. Sand beds as little as 1 inch thick may be prolific oil producers.

Maps: Mississippi delta, Geometry model, delta growth.

Richardson, J. G., J. B. Sangree and R. M. Sneider, 1989, Sand-rich Deltas: Jour. Petroleum Tech., v. 41, p. 157-158.

In this short article the authors focused on the characteristic features of high-energy, sand-rich deltas.

Rittenhouse, G., 1961, Problems and principles of sandstone-body classification: in Peterson, J. A. S. and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 3-12.

Original geometry includes size, shape and orientation and can be modified by erosion, faulting, folding, tilting, compaction of underlying sediment or internal compaction. Three problems in geometry of a sandstone body include: 1. to reconstruct the geometry correctly, 2. to know what geometry implies regarding origin, and 3. to know the distribution pattern of sediment .

Isopach maps of sand bodies define size and orientation, but only partly define shape. Modification of original shape by compaction and other processes must be considered. Three dimensional data from ancient sediments is often misinterpreted.

Internal features of cross-bedding, grain orientation, and bed and grain size sequences are important to understanding origin.

Example: Galveston Island, Lavaca Bay, Texas.

Maps: locality, Galveston island, cross-section, sand profiles.

Shelton, J. A., 1973, Models of sand and sandstone deposits: a methodology for determining sand genesis and trend: Oklahoma Geol. Surv. Bull., v. 118, p. 122.

A study of geometry and internal features of sand bodies to determine depositional environments. This article makes use of depositional models to study the genesis of sand deposits. Distributions that must be known include geometry (trend, length, relative location, width, thickness, and boundaries) and internal features (sedimentary structures, texture and constituents).

Twenty-four well documented deposits from twenty different environments were used as models including: Mississippi River; Robinson sandstone, Illinois Basin; Tuscarosa sandstone, Appalachians; Brazos delta, Texas; Rockdale delta, Texas; Bluejacket sandstone, Oklahoma and Kansas; Dakota J3 sandstone, Nebraska; Frio (barrier bar); Texas.

Maps: locality, structure, topography, cross-section, paleocurrents, isopach, delta models.

Tables: depositional environments and models.

Sneider, R. M., C. N. Tinkler, and L. D. Meckel, 1978, Deltaic environment reservoir types and their characteristics: Jour. Petroleum Tech., v. 30, p. 1538-1546.

According to the authors most known oil and gas accumulations are trapped in terrigenous sandstone deltas. The key to understanding their reservoir behavior includes: 1. the type of reservoir potentially available, 2. the distribution and quality of pore space in terms of porosity, permeability and capillary pressure properties, and 3. the location of barriers to flow, both internal and external.

A brief review of delta literature from 1912 is included. There are 32 large deltas forming in the world today. High energy deltas examples; Nile, Rhone, Brazos-Colorado rivers. Low-energy or mud deltas examples, Mississippi, Orinoco, Lena , Volga rivers.

Maps: delta models, dip and strike sections, delta environments, sand distribution, geometry model.

Tillman, R. W., and D. W. Jordan, 1987, Sedimentology and subsurface geology of deltaic facies, Admire 650' sandstone, El Dorado Field, Kansas: in Tillman, R. W., and K. J. Weber, eds., Reservoir Sedimentology: SEPM Spec. Pub., v. 40, p. 221-291.

The Admire 650 ft sandstone reservoir (Permian Wolfcampian) ranges from 11 to 23 ft thick. Discovery was in 1915, secondary waterflood was carried out in the 1950's and a tertiary recovery project began in 1974.

Three types of sandstone reservoirs comprise the Admire 650', distributary channel sandstone with high and low energy subfacies. Initial deposition was from splay channels that prograded into a muddy interdistributary bay. In some areas the channel is thicker than in others or absent in the southeastern corner of interdistributary bay environment. The final phase was a marine transgression that resulted in regional deposition of limestone and shale.

The distributary channel bifurcates with a N to NE paleocurrent flow indicated. Pressure-transient ratios as much as 14 in areas of elongate sandstone body deposition indicate areas of preferred transmissibility which supports the model of a heterogeneous reservoir.

Distributary channel sandstones average 436 md permeability and 28% porosity. Permeability and porosity are reduced by diagenetic processes of clay formation, deformation of rock fragments, mica lamina, quartz growth, secondary leaching of feldspar and cementation.

Maps: locality, cross sections, deltaic models, columnar section, transport direction, delta growth, delta environments, isopach, fence diagrams.

Photographs: textural features.

Tyler, N., and R. J. Finley, 1988, Reservoir architecture- a critical element in extended conventional recovery of mobile oil in heterogeneous reservoirs (abs.): AAPG Bulletin, v. 72, p. 255.

In moderately heterogeneous reservoirs as much as half the mobil oil is not recovered. In low-permeability reservoirs or those with weak drive mechanism primary and secondary yields may be only 15% of the in-place mobil oil.

Internal reservoir seals and resultant compartmentalization controls hydrocarbon recovery. Development of models of internal reservoir architecture; facies composition, extents, geometries, orientations are necessary to maximize hydrocarbon recovery from heterogeneous reservoirs.

Wave-reworked depositional systems with simple architectures have high mobile oil recovery efficiencies. In contrast strong channelized systems with complex architectures including fluvial, fluvial-dominated deltaic and submarine fan reservoirs have low to moderate mobile oil recovery. Carbonate reservoirs display a smaller range of mobile oil recovery efficiencies. Large volumes of unrecovered oil remain in highly stratified laterally discontinuous platform carbonates of the Permian Basin. In Texas reservoirs with complex architectures 35 billion bbl of mobile oil will be unrecovered at abandonment, nationally this resource may be 80 to 100 billion bbl.

Weber, K. J., 1982, Influence of common sedimentary structures on fluid flow in reservoir models: Jour. Petroleum Tech., v.34, p.665-672.

A summary of the use of permeability-distribution models based on cores, sidewall samples and logs. Reservoir heterogeneity studies include: clay drapes and intercalations, cross-bedding, sand laminations, slumping and burrowing.

Figures: shale intercalations as a function of depositional environment, channel fill Rhone delta, permeability distribution in burrowed silt, festoon cross-bedding, vertical permeability in channel fills.

Weber, K. J., 1986, How heterogeneity affects oil recovery: in Lake, L. W. and H. B. Carroll, Jr., Reservoir Characterization: Academic Press, Orlando, Florida, p.487-544.

Reservoir heterogeneity is the major cause of problems with enhanced oil recovery. Reservoir heterogeneities should be quantified to design reservoir models by use of cores and evaluation of reservoir characteristics. The paper summarizes a classification of reservoir heterogeneities.

Figures and Tables: extensive reservoir characterization data, heterogeneity classification.

Weimer, R. J., 1961, Spatial dimensions of Upper Cretaceous sandstones, Rocky Mountain area: in Peterson, J. A. and J. C. Osmond, eds., Geometry of Sandstone Bodies: AAPG, p. 82-97.

Rocky Mountain Cretaceous sandstones were deposited in marine, transitional and non-marine environments. The Fox Hills sandstone of the Rock Spring uplift consists of a series of barrier bar sandstones that change northwestward to lagoonal shales (Lance Fm.) and to the the southeast to marine shale (Lewis Shale). One barrier bar is 30 feet thick and 6-7 miles wide. Each bar extended along the western margin of the Cretaceous seaway.

The upper Judith River Formation of Montana is a transitional and marine sandstone with a width of 140 miles. Thickness ranges up to 100 feet. This unit was deposited between lagoonal shale facies in the west and marine shale facies (Pierre Shale) in the east. Most sand bodies in the Rocky Mountain Cretaceous are similar in pattern and range to the examples given.

Maps: locality SW Wyoming, cross-sections, columnar sections, environments, paleogeographic, locality SE Montana, Judith River outcrop and structure, E-log correlations.

Yinan, Q., 1983, Depositional model, heterogeneous characteristics and waterflood performance of sandstone reservoirs in a lake basin; case study of oilfields, eastern China: Reservoir Geology and Engineering, 11th World Petroleum Congress, London, (PD6) p. 1-13.

Deltas build into lakes during constructional phases and can be divided into birdfoot and fan delta types. Birdfoot deltas are attached to a river system with a distant source. Fan deltas are associated with alluvial fans and relatively nearby sources of sediments.

Waterflood performance of fluvial channel sands is characterized by high productivity, rapid tonguing of injected water, low volumetric sweep efficiency and high in-layer heterogeneity with upward decreasing permeability. River mouth bars have more uniform permeability, but a vertically upward increase in permeability so a larger swept volume is expected.

The studied fan delta composed of conglomerates and coarser sandstones was built by a river with a nearby sediment source and steep slope which directly entered the lake without fluvial plain development. Its pebbly reservoirs present a pore texture of extreme complexity.

Examples: China; Shengtuo field, Daqing field, Dingxing loop of Tumahe River.

Maps: lake basin clastic model, sedimentary facies sections, sweep of injected water, sand thickness and permeability, cross-section.

Engineering data: capillary pressure curves, water flood tables.

4. ENGINEERING TECHNOLOGY

Technologies for discovery, drilling and recovery of oil throughout the World have advanced rapidly in recent years. Reservoir characteristics and the engineering technologies necessary to exploit them go hand and hand in modern research.

Aalund, L. R., 1989, W. Germans plan unit-facility for drilling 45,000 ft borehole: Oil and Gas Jour., v. 87, p. 64-65.

A report on the world's deepest hole located in West Germany. Results are expected to have significance for earthquake and volcanic research as well as data on development of hydrocarbons. The previous deepest hole was 39,000 ft in the Kola Peninsula of the Soviet Union.

Charts: Ultra-deep casing program, locality.

Armessen, P., A. P. Jourdan and C. Maricotti, 1988, Horizontal drilling has negative and positive factors: Oil and Gas Jour., v. 86, p.37-40.

Long -radius horizontal drilling has progressed so that drillholes up to 600 m to 1,250 m are common at depths up to 3,000 meters. Penetration rates have increased dramatically in the past few years.

The high degree of friction in drilling a horizontal well is the biggest problem restricting the length of the borehole. Upward friction is created by the drill pipe rubbing against the walls of the hole. Downward friction is also a problem. The lateral gravity effect of the drillstring creates friction that increases with the length of the horizontal section.

Charts: penetration rate, drilling cost, penetration rate comparison.

Barber, A. H. Jr., C. J. George, L.H. Stiles and B. B. Thompson, 1983, Infill drilling to increase reserves, actual experience in nine fields in Texas, Oklahoma and Illinois: Jour. Petroleum Tech., v. 35, p.1530-1538.

Evaluation of reservoir discontinuity may underestimate the recovery potential by infill drilling. Production in nine fields including carbonate and sandstone reservoirs showed improved reservoir continuity with increased well density. Increased recovery from 870 wells in the nine fields ranged from 56% to 100%. Optimum well density in a given field can only be determined after several years of field performance.

Figures: cross-section, porosity and permeability variations, production data graphs for each field.

Blanco, E. R., 1990, Hydraulic fracturing requires extensive disciplinary interaction: Oil and Gas Jour., v. 88, p.112-117.

Design of horizontal fracturing must be developed on a well to well basis. Design must consider: reservoir properties, rock mechanics, material transport, completion and treatment methodology. Success of a horizontal well is based on permeability anisotropies, reservoir thickness, and proximity to a gas or water contact.

Figures: permeability comparison, equations, nomenclature, reservoir thickness comparison, replacing a horizontal well, longitudinally fractured horizontal well, notched perforations, pressure drop across perforations, stimulated vs. unstimulated horizontal wells.

Bleakley, W. B., 1983, IFP and ELF-Aquitaine solve horizontal well logging problem: Petroleum Engineer International, v. 55, p.22-24.

In traditional well logging tools run on wireline and depend of gravity to reach the bottom of the hole. New techniques needed to be developed for horizontal wells. It is called SIMPHOR and it uses the drill pipe to push the tool to the bottom. Logs are recorded as the tool is retrieved.

Figures: Rig, logging tool with drill pipe, running drill pipe, bottom hole electrical connection, cable arrangement.

Bossio, J. C., 1988, Horizontal wells prove their worth: Petroleum Engineer International, v. 60, p.18-19.

An interview with J. C. Bosio of Elf Aquaitaine Group answers questions of why horizontal drilling is useful. He details the benefits of this technique as to where and in what circumstances it is most effective.

Charts: production data.

Bossio, J., and L. H. Reiss, 1988, Site selection remains key to success in horizontal well operations: Oil and Gas Jour., v. 86, p.71-76.

Horizontal wells fall into two catagories; 1. long or medium radius radius wells which use several hundred meters to curve from vertical to the desired horizontal deviation. These are wide diameter boreholes and use standard equipment. 2. Short radius wells which reach horizontal in only a few meters . These require special equipment. the horizontal position drilled is usually less than 100 meters. A small diameter bore hole is used.

Charts: horizontal well summary, rig time and cost.

Bragg, J. R., and W. W. Gale, 1983, Loudon surfactant float pilot- overview and update: SPE, (11505), p. 525-536.

A successful surfactant (microemulsion) flood in a watered out portion of the Weiler sand, Loudon Field, Illinois was preformed in 1981. The microemulsion system was designed for use in high salinity formation water (104,000 ppm dissolved solids) without use of a preflush. 60% of the oil remaining after waterflood was recovered. Loss of mobility control in the polymer drive bank and premature breakthrough of lower-salinity drive water was observed part way through the test. This loss was caused by bacterial degradation of the xanthan biopolymer used. Formaldehyde was shown to be most effective at killing the bacteria within the formation.

Bragg, J. R., W. W. Gale and W. A. McElhamnnon, Jr., 1982, Loudon surfactant flood pilot test: SPE 10862, Third Enhanced Oil Recovery Sym., Tulsa, Oklahoma, p. 933-952.

A successful microemulsion flood test of the Weiler Sand in the Loudon field, Illinois. The design was to be effective in high-salinity formation water without use of a preflush. Sixty percent of the waterflood residual oil present in the pilot pattern was recovered.

There was bacterial degradation of the biopolymer and a problem with produced oil-water emulsions. However, the high-salinity microemulion formation was considered a success.

Tables: formation brine, fluid and tracers.

Figures: locality, permeability distribution, residual oil distribution, isopach, injection data, concentrations of surfactant, polymer and tracers, C/O ratios, oil saturation, variation of injectivity index.

Brummert, A. C., R. J. Watts, D. A. Boone, and J. A. Wasson, 1988, Rock Creek Oil Field CO_2 pilot tests, Roane County, West Virginia: Jour. Petroleum Tech., p. 339-347.

Two CO_2 EOR tests were conducted on the Rock Creek oil field. The history, fluid properties and geology of Rock Creek field is reviewed. Cores and geophysical logs of injection and production were used to study the injection history.

Normal five-spot patterns with 13,000 scf CO_2/stb oil (2315 std m^3/stocktank m^3) were injected. This test recovered 3 % of the original oil in place, but was terminated after 3 years. A second test used increased HCPV's of CO_2 injected for a greater potential oil recovery. Test II was conducted in a 1.55 acre normal four-spot pattern. 11% of the oil was recovered. About 48 % of an HCPV was injected. This suggests that CO_2 miscible flooding is technically successful in the Appalachian reservoirs.

Maps: locality, columnar section, permeability and porosity profiles, injection history, resistivity log, dual -induction log.

Charts: pilot test data, pilot test injection, stock-tank saturations, injection data, oil saturation profiles.

Dussert, P., G. Santoro and H. Soudet, 1988, A decade of drilling developments pays off in offshore Italian oil field: Oil and Gas Jour., v. 86, p.33-39.

As of 1988 Rospo Mare was the only oil field in the world producing systematically from horizontal wells. Production as of 1-1-1988 was 22,000 bbl of crude oil. The field is in the Adriatic Sea at water depths of 200 to 300 feet. The oil produced has a gravity of 11.9 API. The reservoir is at 4,300 feet.

Maps: structural map Rospo Mare, cross-section of reservoir.

Ferrel, H. H., R. A. Easterly, T. B. Murphy and J. E. Kennedy, 1987, Evaluation of micellar-polymer flood projects in a highly saline environment in the El Dorado Field: DOE/BC 10830-6, U. S. Dept. Energy, Bartlesville, Ok., 127 p.

High oil saturation remained in the El Dorado Field, Kansas even after air, water and steam injection. Two different micellar methods were used, both were sensitive to high salinity and hard water. The project failed to produce measurable additional oil. An interpretation of the geology, oil saturation and reservoir flow properties is used to explain the failure. Specific causes were: 1. gypsum and barium deposits, 2. unusual vertical oil saturation, 3. migration of liquids into the test area, 4. high hardness of waterflood injected water.

Applications to other reservoirs: 1. use of a alkyl arly sulfonate is good for oil displacement only in a narrow salinity range. 2. a preflush is of little benefit particularly if the reservoir contains gypsum. 3. a high average oil saturation is not necessarily a good target for EOR. 4. an unusual pressure gradient and fluid migration within the reservoir can result in excessive salinity. High hardness brine in contact with the micellar slug reduces the slug effectiveness and causes inefficient sweep.

Maps and Tables: extensive production data.

French, M. S., G. W. Keys, G. L. Stegemeier, R. C. Ueber, A. Abrams and H. J. Hill, 1973, Field test of an aqueous surfactant system for oil recovery, Benton Field, Illinois: Jour. Petroleum Tech., v. 25, p.195-204.

In the Benton field of Franklin County, Illinois a tertiary recovery waterflood on a five spot pattern was preformed. Four phases of the test were: 1. preflood of low -salinity water to displace high-salinity formation water. 2. slug of chemical solution with a surfactant 3. a controlled mobility drive solution 4. a waterflood with fresh water.

The solution was capable of displacing oil from a previously waterflooded interval in the Tar Springs Fm. Residual oil saturations were as low as 4%. Oil recovery was somewhat less than predicted.

Figures: chemical flood, chemical and oil production.

Tables: chemical properties by zone, core analysis of chemicals.

Gould, T. L., and A. M. S. Sarem, 1989, Infill drilling for incremental recovery: Jour. Petroleum Tech., v. 41, p. 229-237.

Infill drilling has been a part of good waterflood management for many years. Only in the 1980's was it discovered that infill drilling was a valuable incremental recovery process in itself. Factors to consider before infill drilling: 1. production/injection performance 2.reservoir description 3. infill drilling project design 4. economic evaluation.

"In general the more a reservoir deviates from the ideal behavior, the greater the opportunity for incremental recovery by infill drilling." Infill drilling sweeps unswept zones and improves vertical sweep.

Tables: summary of infill drilling recoveries, summary of infill drilling project characteristics.

Figures: production graphs from several fields, cross-sections, distance between wells, simulation results, selective perforation, effects of heterogeneity, effect of crossflow.

Hamaker, D. E., and G. D. Frazier, 1978, Manvel enhanced recovery pilot-design and implementation: SPE 7088, 5th Improved Methods Oil Recovery Symp., p. 495-504.

A surfactant flooding system for use in high salinity sandstone reservoirs has been developed. Chemicals are mixed directly into the brine and are injected directly without preconditioning the reservoir. The pilot was a Manvel field, Brazoria Co., Texas in the Frio sandstone in a watered out fault segment. A five well pattern of two injectors and three producers was used.

Tables: reservoir data and fluid properties, reservoir transmissibilities, injected pore volumes, chemical distribution, injectivity profiles, surfactant mixing facility, polymer mixing facility.

Maps: structure, location, fence diagram.

Harvey, F., 1990, Fluid program built around hole cleaning, producing formation: Oil and Gas Jour., v. 88, p.37-41.

Potential problems with horizontal drilling can be corrected by careful selection of the drilling fluid. Attention must be given to the cleaning and lubrication properties of the fluid selected.

Tables: comparison of drilling fluids.

Figures: hole angle and particle slip, inclination, inclination and orientation.

Holley, S. M., and J. L. Cayias, 1990, Design, operation and evaluation of a surfactant /polymer field pilot test: SPE/DOE 20232, 7th Enhanced Oil Recovery Sym., Tulsa, Ok., p. 549-556.

Oryx Energy Company evaluated the design and operation of a low tension surfactant polymer test in the McCleskey sandstone of Eastland Co., Texas. Choice of the site was based on: good reservoir permeability, availability of fresh water and high residual oil saturations,

The pilot was success, but did not achieve its design objectives due to reservoir heterogeneity and reduced sweep efficiency. The propagation of chemical fronts and recovery of oil demonstrated that surfactant flooding is capable of recovering tertiary oil.

Tables: polymer injection summary, Ranger tracer recoveries, arrival times-days since injection, Ranger field map, NCRU surfactant pilot production, well production response.

Huh, C., L. H. Landis, N. K. Maer, P. H. McKinney and N. A. Dougherty, 1990, Simulation to support interpretation of the Loudon surfactant pilot tests: SPE 20465, 65th Tech. Conf. and Exit., New Orleans, La., p. 9-24.

A summary of the pilot tests on the Loudon field. Tests included a seven acre five spot, a 40 acre pattern with nine 2.5 acre five spots, and an 80 acre with nine, five acre normal five-spots. An important task was to determine why tests with larger pattern sizes were not as good as smaller pattern tests.

Fluids from neighboring injectors established flow channels within the boundary producers, suggesting poor mobility control by injected fluids. The polymer bank on the 40 acre and 80 acre plots did not propagate as designed.

Tables and Figures: reservoir properties, permeability, oil/surfactant/polymer phase behavior, production data, cross-sections, tracer and polymer drivewater analysis, pattern pore volumes produced.

Iwata, T., Y. Tsuneo and S. Hisao, 1990, Three-dimensional computer simulation system of deltaic sedimentary sequences, abs : AAPG Bulletin, v. 74, p. 651.

Computer simulation to predict deltaic sandstone reservoirs is being developed. Jet-flow, density-flow and bed-load transportation models are used.

Jet-flow of turbulent water into quiescent bays; the parameters needed are location and dimensions of river mouth, flow velocity, sediment concentration and fluid and sediment characteristics.

Density-flow simulates turbidity underflows that occur in fresh water lakes and steep submarine fans.

Wave action, longshore currents, water-level changes are being added to the model's test capabilities.

Joly, E. L., A. M. Dormigny, G. N. Catala and F. P. Pincon,1985, New Production logging technique for a horizontal well: SPE 14463, p. 1-8.

A new technique to run production logs in horizontal wells is presented. Logging tools are carried at the end of a rigid stinger attached to a logging cable. The assembly is pumped down a tubing until the tool reaches the end of the zone and is then retracted. Logs can be recorded when the tool is going in or coming out. Two case histories Lacq 91 (France) and Rospo Mare 6 (offshore Italy) test the new development.

Figures: equations, horizontal logging method, stringer makeup procedure, Lacq 91 well completion, Rospo Mare 6 well completion, flowmeter reading for spinner diameters.

Jones, W., 1990, Unusual stresses require attention to bit selection: Oil and Gas Jour., v. 88, p. 81-85.

Horizontal drilling causes unique stresses on the rock bit during drilling. Analysis of the different stresses and the bits necessary to combat them is given.

Figures: bit design, bend angle of drill stem, redesigned shortened bit.

Jordan, A. P., P. Armessen and P. Rousselet, 1988, Elf has set up rules for horizontal drilling: Oil and Gas Jour., v. 86, p. 33-40.

Drilling techniques without rotation is strictly limited. Rotary or turbodrilling is used for standard deviated wells. Drilling concepts involved include: 1. ultra-short turning radius. The use of jetting action to drill profiles with a radius of curvature less than 30 cm. The diameter of the hole drilled is 2 inches and length is up to 70 meters. 2. short turning radius. The radius is 6 to 22 meters with a 4 1/2 or 6 inch hole. 3. long medium turning radius- standard equipment is used with modifications.

Figures: trajectory profiles, Rospo Mare profile design, typical well profile, bottom hole assemblies.

Lang, W. J., and M. B. Jett, 1990, High expectations for horizontal drilling becoming reality: Oil and Gas Jour., v. 88, p. 70-79.

The progress of horizontal drilling in the 1980's is analyzed.

Charts: Risk analysis, rig count Texas, horizontal well forecast.

Maps: horizontal wells worldwide.

Matson, R., and R. Bennett, 1990, Cementing horizontal holes becoming more common: Oil and Gas Jour., v. 88, p. 4046.

Cementing is used less frequently in horizontal wells. New technology is needed for the tools to be effective in control of free water, to manage cuttings transport and to obtain pipe centralization.

Figures: consistometer strip chart, recirculating mixer, flow rates, real-time monitoring, on site computer cementing analysis, tool-length calculation, off-bottom cementing.

Montigny, O. de, and J. Combe, 1988, Hole benefits, reservoir types key to profit: Oil and Gas Jour., v. 86, p. 50-55.

Advantages of horizontal drilling in low-permeability reservoirs are: 1 increases length up to 2,000 ft horizontal 2. infinite conductivity, resistance to flow is negligible in a horizontal well. 3. control of geometry, the trajectory of a horizontal well can be completely controlled. In contrast hydraulic fracture depends on stresses within the reservoir.

Figures: trajectory design, gas and water coning in layered reservoir, generalization of Merkulov's formula, limitations of Merkulov's formula.

Montigney, O. de, P. Sorriaux, A. J. P. Louis and J. Lessi, 1988, Horizontal well drilling data enhance reservoir appraisal: Oil and Gas Jour., v. 86, p. 40-48.

The lateral evolution of the facies, the fractured zones, and the irregularities at top and bottom of the reservoir are perceived differently in horizontal wells than in vertical wells. To formulate a well design reservoir characteristics must be understood including: entire thickness, heterogeneities, fluid mechanics, interfaces between fluids, and volume of hydrocarbons in place.

Figures: Lacq dolomite zones, Costera Lou structural map, well crossing mini-grabens, open hole logs, Rospo Mare 6 d geology, FWAL in vertical and horizontal wells, FWAL in highly deviated wells, equations, stimulated response curve.

Moritis, G., 1989, Worldwide horizontal drilling surges: Oil and Gas Jour., v. 87, p. 53-63.

Analysis of all aspects of horizontal drilling are discussed. Extensive data from major projects around the world are included. A report on the world's deepest hole is included.

Charts: horizontal wells over 1,000 feet length in 1989, nomenclature, production increase, horizontal well survey.

Moritis, G., 1989, More information from horizontal well survey: Oil and Gas Jour., v. 87, p. 63-65.

Data on measurement tools, stimulation, log running tools, open hole logs and production logs are presented. Many applications in conventional wells can be adapted to horizontal wells.

Charts: terminology, horizontal well survey with equipment data.

Moritis, G., 1990, Horizontal drilling scores more successes: Oil and Gas Jour., v. 88, p. 53-64.

A survey of horizontal drilling around the world based on responses by operators. Up to date practices and objectives of horizontal drilling are analyzed.

Charts: lateral drilling report, nomenclature, horizontal wells over 1,000 ft. length, horizontal well less than 1,000 ft length, horizontal well survey by company, Texas RRC report on independents.

Nazzel, 1990, Planning matches drilling equipment to objectives: Oil and Gas Jour., v. 88, p. 110-118.

Developing a plan for horizontal drilling and selecting the equipment before drilling will save money and be more efficient.

Figures: horizontal well comparison, motors with long range radius, 3-point geometry, Java Sea well data, bottom hole assemblies, trajectory, kotter platform. technical limitations

Ordrusek, P. S., 1988, Micellar/Polymer flooding in the Bradford Field: Jour. Petroleum Tech., v. 40, p. 1061-1067.

A 218 acre micellar/polymer flood project in the Bradford field of Pennsylvania is discussed. Tertiary oil production occurred after injection of 35% PV of micellar slug and polymer. A total of 191,226 bbl or 3.4% PV oil was produced. This was significantly less than predicted. Production response was later and lower than expected. Operations were discontinued before the scheduled polymer injection sequence was completed.

Maps; Locality, wells

Tables and Graphs: reservoir properties, production facilities, injection schedule, injection history, sulfonate and chloride concentration, sulfonate and oil-in-water concentration.

Palmer, F. S., A. J. Nute and R. L. Peterson, 1981, Implementation of a gravity stable, miscible CO_2 flood in the 8000 foot sand, Bay St. Elaine Field: SPE 10160, 56th Tech. Conf. and Exhib., San Antonio, Tx., p. 1-15.

The reservoir is in the costal marshes of south Louisiana. The reservoir overlies a salt dome. Unique equipment was designed to transport and inject the CO_2 solvent slug. Pulse tests indicate that the three project wells were interconnected. The CO_2 solvent effectively recovered the residual oil. A 33% pore volume of the CO_2 solvent slug was sufficient for this field.

Tables: reservoir characteristics, CO_2 solvent mixtures.

Figures: locality, structure, E-log correlations, well bore diagram.

Pursley, S. A., R. N. Healy and E. I. Sandvik, 1973, A field test of surfactant flooding, Loudon Illinois: Jour. Petroleum Tech., v. 25, p. 793-802.

A watered out portion of the Loudon field was used for a surfactant test in 1969-71. The test was designed to determine: 1. extent of surfactant adsorption-fractionation and effect of oil recovery. 2. degree of mobility control and its effect on sweep efficiency. 3. any problems not observed in the laboratory.

Oil recovery was 15.3% of oil-in-place. Excellent sweep efficiency was achieved. Oil recovery was limited by excessive salinities. Low-salinity preflooding was not practical with the type of surfactant used. The tracer made a significant contribution to test evaluation.

Figures: transmissibility, isopach of sand, tracer interpretation, surfactant flood responses, oil recovery.

Reiss, L. H., 1987, Production from horizontal wells after 5 years: Jour. Petroleum Tech., v. 39, p. 1411-1416.

Four horizontal wells were drilled by Elf Aquitaine between 1980-1983. Information from these wells pertains to: drilling, coring, logging devices. reservoir engineering and production behavior. The first three wells were designed primarily to master drilling problems with oil production secondary. The forth well Rospo Mare 6D was drilled for primary production.

Figures: Lacq 90 production profiles, Rospo Mare production profile, Castera Lou production profile, cross-section Castera Lou 110, Lacq 90 structure contours, schematic of Rospo Mare karstic reservoir.

Reppert, T. R., J. R. Bragg, J. R. Wilkinson, T. M. Snow, N. K. Maer, and W. W. Gale, 1990, Second Ripley surfactant flood pilot test: 7th Enhanced Oil Recovery Sym., Tulsa, Ok., p. 463-474.

A second successful test was conducted in the Weiler sand in the Loudon field, Illinois. Changes for the salinity-tolerant micellar polymer process include: 25% smaller microemulsion bank size and addition of formaldehyde to inhibit bacterial degradation of the biopolymer.

68% of the waterflood residual oil present was recovered. Improved mobility and lower surfactant retention enhanced this recovery compared to the first test. A method was developed to separate oil-water surfactant emulsions.

Tables: core analysis, injected fluid anallysis.

Figures: isopach, pore volumes, cross-sections, oil recovery, tracer anallysis, polymer and surfactant transport data, pressure gradient, surfactant retention and remaining oil.

Ruble, D. B., 1982, Case study of a multiple sand waterflood, Hewitt Unit, Oklahoma: Jour. Petroleum Tech., v. 34, p. 621-2-627.

Twenty-two sands in Hewitt field were flooded simultaneously. Injection, production surveillance programs and optimization methods are highlighted in this study. These include injection well bore design, injection distribution, production stimulation, polymer augmented injection, and infill drilling. Successful application of these techniques has increased ultimate recovery.

Sands were of the Hoxbar and Deese formations of Pennsylvanian age. Average depth of sands is from 1,200 to 2,900 feet subsurface. There are five major zones in the 1st pay interval.

Maps: locality, water/oil contact, structure, water flood , polymer project areas.

Charts: reservoir data, injection well, recovery summary, multiple producing patterns, infill drilling.

Seeber, M. D., and D. Steeples, 1986, Seismic data obtained using .50-caliber machine gun as high-resolution seismic source: AAPG Bulletin, v. 70, p. 970-976.

A seismic line across a shoestring sand was used to test a .50 caliber machine gun as a seismic source of high-resolution. The test was to explore its use in discovery potential in shallow sandstone. The test was in the Bronson-Xenia field of the Bartlesville sandstone of the Cherokee Group in Bourbon County, Kansas. The depth was 622 ft. The reservoir has a flat base and irregular top representing a superposition of several fluvial sandstone bodies. The seismic line depicts a lenticular sandstone 56 ft thick and showed both lateral extent and edge of the body.

The frequency of the .50 caliber machine gun is 30 to 170 HZ (dominantly 100 HZ). Two shots per shotpoint are the minimum necessary for acquiring high-quality data, and 12 fold is the minimum acceptable common depth-point coverage. The .50 caliber machine gun has better potential for a high-resolution seismic source than the previously used Betsy seisgun.

Maps: locality, columnar section, stratigraphic section, structural section, seismic lines

Society of Petroleum Engineers, 1989, Regional Low Permeability Reservoirs Symposium and Exhibition: Proceedings, Joint SPE/Rocky Mountain Assoc. Geol., 752 p.

This volume contains a number of papers that analyze Rock Mountain reservoirs. A number of papers deal with horizontal drilling, well stimulation and EOR techniques.

Spreux, A., C., Georges and J. Lessi, 1988, Most problems in horizontal completions are resolved: Oil and Gas Jour., v. 86, p. 48-52.

New techniques necessary for horizontal drilling include:

A. logging - Wire line is restricted to wells with deviations less than 65 to 70 degrees.

B. MWD - Measurement-while-drilling tools used are gamma ray, oriented gamma ray, resistivity, temperature and the density tool.

C. SIMPHOR - Logging tools are mounted on the drill pipe. This does not work well on a floating rig because of wave action.

D. Coiled tubing - This is restricted to shorter length wells of 200 m up to 500 meters using lighter production tools.

E. Pump down stinger - Logging tools are pushed with a pump down stinger through the drill pipe or tubing. This method can only be used with small diameter tools and shorter wells (max. 520 meters).

Figures: logging techniques, liner configuration, acid washing, completion equipment.

Spreux, A. M., A. Louis and M. Rocca, 1988, Logging horizontal wells: field practice for various techniques: Jour. Petroleum Tech., v. 86, p. 1352-1354.

New techniques for running logging tools in horizontal wells include: 1. wireline method 2. the measurement-while-drilling (MWD) method 3. the information and measuring systems in horizontal wells (Simphor) method 4. the pumpdown stinger method and 5. the coiled tubing method.

Logging by wireline is restricted to well inclinations up to 65 degrees. Simphor and MWD methods use drill pipes and can work at any inclination. Only small diameter tools can be used with the telescopic stinger. The coiled-tubing method is fragile and best suited to short horizontal drainholes and use with lighter tools.

The telescopic stinger and coiled-tubing methods have the advantage that they can operate without a drilling rig. They can also be used on wells that are highly deviated, where wireline logging can't be used.

Figures: drillpipe logging, pumpdown stinger, coiled-tubing logging, operating domain of logging techniques.

Table: logging techniques comparison.

Strange, L. K., and A. W. Talash, 1977, Analysis of Salem low-tension waterflood test: Jour. Petroleum Tech., v. 29 ,p. 1380-1384.

A low-tension waterflood test was preformed on the Salem field in a single five-spot pattern. A regional pressure gradient across the pattern was found and is believed to have caused migration of injected chemicals and displaced oil from the pattern area. Less oil was recovered than had been expected.

Surfactant retention was significantly less than the value given by Widmyer et al, 1977. The lower oil production was caused by migration of injected and displaced fluids out of the test pattern.

Figures: fluid concentrations, pressure contour, fluid distribution.

Tables: injection slugs, tracer and surfactant balance.

Taylor, M., and N. Eaton, 1990, Formation evaluation helps cope with lateral heterogeneities: Oil and Gas Jour., v. 86, p. 56-66.

Success in horizontal drilling is dependent upon maintaining the optimum position of the well bore to the productive intervals of the reservoir. Geological tools for this process are mud logging and formation evaluation measurement-while-drilling (FEMWD). The lateral section of a well greatly increases the interval of the reservoir available for analysis.

Figures: Reservoir heterogeneities, bottom hole assembly, time data, mudlog-FE-MWD, well bore paths, mud log sidetrack, example of horizontal coring.

Tillman, R. W., and D. W. Jordan, 1981, Sedimentary facies analysis, El Dorado field, Kansas, micellar-chemical pilot project: AAPG Bulletin, v. 65, p. 1001-1002.

The El Dorado field has yielded 36.5 million bbl of oil by primary and secondary recovery. 71 million bbl remain for tertiary recovery. Micellar polymer tests begain in 1978.

Van de Graff, W. J. E., and P. J. Ealey, 1989, Geological modelling for simulation studies: AAPG Bulletin, v. 73, p. 1436-1444.

Levels of reservoir heterogeneity must be quantified by a reservoir geologist for numerical simulation studies. The most important parameters are field scales, sand-body continuity and interconnectedness. Within a sand body permeability trends, presence and distribution of permeability baffles, vertical profiles of permeability and directional permeability are most critical. At a small scale the influence of cross bedding is important. Examples are given to show the simulated effects of different scales of heterogeneity on fluid flow.

Figures: lateral and vertical reservoir heterogeneity, fluid distribution, conceptual channel patterns, sedimentological model, reservoir quality, reservoir heterogeneity patterns, South Pass (La.) map, fluid distribution example, permeability heterogeneity.

Venuto, P. B., 1989, Tailoring EOR processes to geologic environments: World Oil, November, 1989, p.61-68.

A given reservoir must be thoroughly studied in all geologic characteristics before an EOR design is completed. Natural reservoir pressures are often sufficient for light oil to initiate flow into surface wells. If pressure is low pumps must be used.

EOR production in the U. S. was 6.8% of total U. S. production in 1986. Chemical methods account for 3%, miscible/immiscible gas for 18%, and thermal techniques for 79% of the EOR production.

Reservoir characteristics that must be determined are: 1. what fraction of the rock is reservoir quality 2. what the oil saturation distribution is 3. how much oil can be contracted by EOR methods 4.what flowpaths are for mobilization, displacement and production of oil.

Figures: stratified reservoir, reservoir criteria for slug, physical-chemical factors, waterflood test, phase behavior and flow dynamics.

Tables: reservoir structure, reservoir geologic model, steam injection.

Ware, J. W., 1983, Salem unit micellar/polymer project: SPE 11985, 58th Tech. Conf. and Exhib., San Francisco, Ca., p. 1-19.

Texaco Oil Co. conducted a 60 acre tertiary recovery project in the Benoist Sand of Illinois. A brine tolerant surfactant followed by a biopolymer system was used. Expected tertiary recovery in the Salem unit is 50 m bbl.

The system successfully mobilized the residual oil. It proved that surfactants can be designed for use in high brine reservoirs without lost of time or pretreatment. Problem areas are: contracting the reservoir with injected fluids, handling and mixing viscous injectants, treating produced emulsions, obtaining accurate well tests, and bacteria control in biopolymer solutions.

Tables: rock and fluid properties, core analysis, analysis of injection brine.

Maps and Figures: locality, oil saturation determinations, permeability curves and ratios, polymer taper, radioactive tracer response, chemical tracer response, production curve.

Watts, R. J., W. D. Conner, J. A. Wason and A. B. Yost, 1982, CO_2 injection for tertiary oil recovery, Granny's Creek Field, Clay County, West Virginia: SPE/DOE 10693, 3rd Enhanced Oil Recovery Sym., Tulsa, Ok., p. 285-306.

The objective of the field tests was to determine the feasibility and economics of recovering oil from a flooded out low-oil saturated reservoir. CO_2 was used as the miscible displacement for the residual oil. The original waterflood at this site was very successful. Residual oil saturation was 30-35%. Porosity averaged 16% with 7 md permeability for the reservoir.

CO_2 injection began in 1976. Complex reservoir heterogeneity and field problems suggest that CO_2 miscible displacement is not economical for tertiary oil recovery in reservoirs with such low-oil saturation without better mobility control.

Tables: reservoir fluid properties, core analysis, reservoir properties.

Maps and Figures: location, waterflood pilot, production history, cross-section, log correlations, CO_2 injection, tertiary production plot, bottom hole pressures.

White, C., 1990, Formation characteristics dictate completion design: Oil and Gas Jour., v. 88, p. 58-64.

An optimum completion design for a horizontal well requires preplanning by geologists, production and drilling personnel. Items to analyze: equipment, bell bore location, drive mechanism, further remedial and stimulation requirements, dogleg severity and horizontal length.

Stresses which effect tool selection include: run in wear, gravity, hydrostatic head, hole roundness and caliper, liner tops, and solids on the bottom of the hole.

Figures: stress to bend pipe around a curve, pipe tolerance, tubing workover hookup, slotted-liner completions, hole completion, open hole completions, tools, hydraulic fracturing.

Widmeyer, R. H., A. Satter, G. D. Frazier and R. H. Graves, 1977, Low-tension waterflood pilot at the Salem unit, Mariot County, Illinois-Part 2: performance evaluation: Jour. Petroleum Tech., v. 29, p. 933-939.

A five acre, five-spot pilot test of low-tension waterflood was preformed in the Benoist sand in the Salem field. A model was developed with these features: 1. chemical transport for dispersion, adsorption and partitioning 2. incompressible flow of aqueous and oil phases 3. non-Newtonian flow of polymer solution and permeability reduction.

The pilot performance evaluation included: 1. analysis of tracer data to verify flow patterns, fraction of production contributed by each quadrant and vertical reservoir heterogeneity. 2. the effect of the surrounding Benoist injectors and producers 3. estimation of chemical consumption based on tracer and chemical breakdown. 4. comparison of simulated recovery performance.

Figures: liquid distribution plan, chloride and calcium concentration, iodide tracer concentrations, surfactant responses, surfactant and ammonium thiocyanate tracer configurations, sodium bromide concentration, tertiary oil production.

Table: chemicals in place or injected.

Widmeyer, R. H., D. B. Williams and J. W. Ware, 1985, Performance evaluation of the Salem unit surfactant/polymer pilot: 60th Tech. Conf. and Exhib., Las Vegas, Nevada., p. 1-14.

A brine tolerant surfactant was injected into the Benoist sandstone of Marion County, Illinois. No preconditioning was required. A biopolymer fol-

lowed the surfactant injection. Forty-eight pattern quadrants were studied using different tracers at various injection wells.

Initial production rates were higher than expected. Uneven pressure at the backup injection wells caused flow distortion. Log interpretation indicated that the top 1/3 of the Benoist sandstone had not been completely waterflooded. The chemical flood concentrated in the lower 2/3 of the reservoir. Oil saturation was reduced 2 to 8% in some intervals. There was an early loss of polymer effectiveness due to bacterial degradation. Ultimate tertiary oil recovery is calculated at 47% of the oil-in-place.

Table: fluid data.

Figures: locality, surfactant and polymer injections, oil production, concentrations of tracers, monitor well data, oil recovery efficiency.

Xue, P., 1986, A point bar facies reservoir model, semi-communicated sandbody: SPE 14837, Int. Meet. Petroleum Engineering, Beijing, p.103-115.

Secondary recovery by waterflooding gives poor performance in point bar reservoirs of meandering channels. Low ultimate recovery is estimated at 30%. This type of reservoir has a potential oil reserve of 50% or more based on analysis of swept thickness and water displacement. Simulation analysis combined with geologic studies suggest that a 16% increase in recovery is possible for the point bar facies sand body.

Table: reservoir characteristics.

Figures: photos of textures, locality, point bar model, sand map, water vs. recovery curve, simulation plots.

5. SELECTED PLAYS

Six "unstructured" deltaic plays were chosen from the TORIS database. Selected references about the geology and engineering aspects of these plays are presented in this section. The plays include the Cherokee Group, D & J sands, Frontier Formation, Robinson Formation, Strawn Group sands, and the Wilcox Group sands.

A. Cherokee Group

The Cherokee Group of clastics covers large areas of Oklahoma, Kansas and parts of Missouri. Major producing formations of the Cherokee include the Bartlesville sand, Burbank sand and the Red Fork Formation. Deposition is fluvial-deltaic and stratigraphic entrapment is a major source of oil in the extensive reservoirs.

Bass, N. W., C. Leatherock, W. R. Dilllard and L. E. Kennedy, 1937, Origin and distribution of Bartlesville and Burbank shoestring oil sands in parts of Oklahoma and Kansas: AAPG Bulletin, v. 21, p. 30-66.

The Bartlesville sand is stratigraphically lower than the Burbank sand. The shoestring sands of Greenbank, Butler, and Cowley counties Kansas are equivalent to sands of the Burbank, South Burbank and Naval Reserve oil fields of Oklahoma. Bartlesville and Burbank sands are composed of numerous lenses that occur within narrowly restricted limits in the Cherokee Shale. Burbank sands are set in offset trends similar to offshore bars on the Atlantic and Gulf Coasts. The Bartlesville sand was deposited as offshore bars along the western shore of the Cherokee Sea in an early stage when the seashore migrated across a narrow region from northeastern Oklahoma to southeastern Kansas. Burbank sands were deposited much later after the Cherokee Sea had expanded to the northwest.

Maps: locality, cross-sections, net sand.

Berg, O. R., 1963, The depositional environment of a portion of the Bluejacket Sandstone (unpub thesis): The University of Tulsa.

The Bluejacket sandstone west of Pryor was deposited by a meandering stream. The sands range from less than 4 ft thick to over 55 ft thick. A complete sedimentary description of these sand lenses is given including: grain size analysis and sedimentary features.

Maps: cross sections, sedimentary features.

Berry, C. G., 1963, Stratigraphy of the Cherokee Group Eastern Osage County, Oklahoma (unpub. thesis): The University of Tulsa, 84 p.

The Cherokee sandstone represents the initial transgression of the Pennsylvanian sea in this area. Alternating sandstone and shale with minor limestone (marker beds) comprise the Cherokee Group. The Cherokee Group is divided into 4 time-stratigraphic units based on limestone beds seen on electric logs. Analysis and maps of each interval reveal sandstone bodies that form bars or channels. These channels may be traced laterally up to 70 miles. They were deposited in nearshore settings. Shales and limestones were transgressive units and the sandstones comprise regressive or static phases.

Maps: structure, isopach, stratigraphic sections; E-log correlations.

Boneau, D. F., and R. L. Clampitt, 1977, A surfactant system for the oil-wet sandstone of the North Burbank unit: Jour. Petroleum Tech. v. 29, p. 501-506.

This study compared the performance in water and oil wet sandstones of a surfactant system recommended for a field trial in the North Burbank Unit.

Cornell, F. L., 1991, Engineering improvements for Red Fork fracturing: Jour. Petroleum Tech., v. 43, p. 132-137.

The four main producing zones of the Red Fork in the Anadarko Basin of Oklahoma are the Cherokee, upper, middle and lower Red Fork. Various treatments have been used to improve oil production from these intervals. Five different fluids and four types of proppants were used on 99% of the wells. The Red Fork interval is a very fine to fine grained sandstone of deltaic deposition.

Fracture treatment currently uses controlled fluid volumes and viscosity to control fracture-height growth. The best designs emphasize the relation of net pay to gross fracture height. Intermediate-strength proppants show the best results. Red Fork wells with less than 10% porosity are controlled by secondary porosity.

Figures and Maps: locality, production histograms.

Tables: completion intervals, stimulation averages.

Crawford, C. C., and M. E. Crawford, 1985, Wm. Berryhill micellar polymer project: a case history: SPE 14444, 60th Tech. Conf. and Exhib., Las Vegas, p. 1-8.

A micellar polymer project pilot was began in the Glennpool Field southwest of Tulsa, Oklahoma in 1979. Injection was into the upper member of the Bartlesville sandstone. The polymer flood was scheduled to continue through May 1987. Lithology of the sand played an important part in flood behavior. The micellar polymer flood has moved significant amounts of oil.

Figures: polymer pilot data, polymer and sulfonate injection schematics.

Cruz, J. A., 1963, Geometry and Origin of the Burbank Sandstone and Mississippian "Chat" in T.25 N., R.6.E. and T.26 N., R.6.E. Osage County, Oklahoma (unpub. thesis): The University of Tulsa, 37 p.

E-logs were used to plot isopach maps and stratigraphic cross-sections in this area of Osage County. Depositional settings include chenier, beach ridges, barrier islands, and spits deposited on the western shore of the Cherokee Sea. The Mississippian "Chat" filled topographic lows. Mississippian components were reworked by the Pennsylvanian seas.

Cruz, J.A., 1966, Geometry and origin of the Burbank sandstone and Mississippian "Chat" in T. 25 and 26 N., R. 6 E., Osage County, Oklahoma: Shale Shaker Digest, v. 16, p. 102-116.

Six fields are included in this subsurface study: West Little Chief, North Burbank, Stanley Stringer, South Burbank, Fairfax and East Little Chief. The geometry of sandstone bodies has environmental implications, factors to be considered are: 1. proximity to another sand body; 2. orientation with respect to depositional strike; 3. cross section; 4. relief of the upper and lower surfaces; and 5. stratigraphic relationship to surrounding area. The Mississippian Chat is the thick limestone below the Cherokee strata that filled stratigraphic lows. The Chat was reworked and redistributed by Pennsylvanian seas. The Burbank sand is interpreted as cheniers, beach ridges and barrier islands.

Maps: locality, cross-section, sand isopach.

Ebanks, W. J. Jr., 1979, Correlation of Cherokee (Desmoinesian) sandstones of the Missouri-Kansas-Oklahoma Tri-state area: Tulsa Geol. Soc., Spec. Pub., v. 1, p. 295-312.

Stratigraphic classification across the Cherokee Group in the tri-state area has been difficult due to poor outcrop correlation. New data from logs and cores demonstrates that the "Bluejacket" of Missouri is older than the Bluejacket sandstone member of the Boggy Fm. of Oklahoma and that the "Warner" of Missouri is younger than the Warner sandstone member of the McAlester Fm. of Oklahoma. All four sandstones are present in the subsurface in Kansas. The origin of these sandstones is alluvial-deltaic.

Maps: locality, schematic diagrams, structural cross-sections, stratigraphic cross-sections, sand thickness.

Frank, J., and L. Schoeling, 1985, Injection side applications of polymer and polymer gels in Kansas: 6th Kansas Univ Tertiary Oil Recovery Conf., Wichita, Kansas, p. 92-112.

Forty-one injection side projects have been completed in Kansas in the past 23 years. First use of polyacrylmides in Kansas floods were to correct water-to-oil mobility ratios. In another problem area polymers were used to reduce permeability variations. When permeability variation is severe, polymers are insufficient to correct the problem.

Twenty-seven percent of the projects were classified as economic successes. 21% were classified as failures and 33% were classified as "unknown" due to insufficient data. Four of the successful projects were in the Cherokee sands of southeast Kansas.

Map: locality.

Tables: polymer projects successes, failures, production data, slug size versus incremental oil, permeability variations crosslinked.

French, T. R., and T. E. Burchfield, 1990, Design and Optimization of alkaline flooding formulations: SPE 20238, 7th Enhanced Oil Recovery Sym., Tulsa, Ok., p. 615-626.

Surfactant-enhanced alkaline flooding formulations with low pH alkaline agents have potential for increased recovery. Laboratory results show that surfactant losses by adsorption are reduced under alkaline conditions.

Fronjosa, E., 1965, A study of Oklahoma water flood statistics (unpub Thesis): University of Oklahoma , Geological Engineering, 86 p.

Correlation of geological factors, reservoir, and fluid characteristics to the success of a secondary recovery project. Term effectiveness function, E, is defined as a dimensionless ratio of oil produced by secondary recovery to that produced by primary means. Parameters studied include average permeability, average porosity, geologic age, depth of pay zones, thickness of pay zone, geological structure, texture of reservoir rock, shale partitions, shape and sedimentary patterns, mineralogy, gravity of oil, viscosity of oil, type of water injected.

Charts and graphs: extensive production data and mathematical equations.

Hagen, K. B., 1972, Mapping of surface joints on air photos can help understand waterflood performance problems at North Burbank unit Osage and Kay Counties, Oklahoma (unpub. thesis): The University of Tulsa, 85 p.

Mapping of the surface joints based on air photos was used to interpret waterflood performance problems in the North Burbank field. The joint system of the Permian limestones can be recognized in air photos by lush vegetation. The principal joint set is at N 70 E. Parallel joints at 3,000 ft separation produce oil in the Burbank field. Water flood began in this field in 1950. The pattern of surface joints suggests were to predict waterflood results favorable to oil production.

Maps: locality, drainage patterns, structure.

Harpole, K. J., and C. J. Hill, 1983, An evaluation of the North Stanley polymer demonstration program: DOE/BC/10033-6, 36 p.

Ultimate oil recovery from the project is estimated at 570,000 bbl or 1.4% of the original oil-in-place. This is significantly less than initial predictions. No correlation was observed between polymer production and incremental oil production response in the project area.

Harrison, W. E., and D. L. Routh, 1981, Reservoir and fluid characteristics of selected oil fields in Oklahoma: Oklahoma Geological Survey Spec. Pub., v. 81-1, 317 p.

The results of a questionnaire sent to operators of water flood units in 23 "giant" fields in Oklahoma. (Giant is defined as having an ultimate recovery potential of 100 million barrels.) Information included on each unit: reservoir data; formation, age, lithology, average depth, average thickness, average porosity, average horizontal permeability and range, average vertical permeability, oil saturation at beginning of secondary recovery, type of drive, pressure. Fluid data; API gravity, salinity of formation water, chloride content of formation water, sulfur content of oil. Locality maps for each unit. Note some oil companies refused to release the requested data.

Units containing Cherokee Group; Avant field (Bartlesville Fm.), Burbank field (Burbank ss.), Cushing field (Bartlesville Fm.), Glenn field (Bartlesville Fm.), Hovey-Postle-Hough field (upper Cherokee).

Hatch J. R., J. D. King, and T. A. Daws, 1989, Geochemistry of Cherokee Group oils of Southeastern Kansas and Northeastern Oklahoma: Kansas Geol. Sur., Subsurface Geol. Series., v. 11, p. 1-20.

Seventy-two organic-matter-rich samples (>1.0 % total organic carbon) from the Cherokee Group and Marmaton Group were analyzed for carbon determinations, Rock-Eval pyrolysis, and vitrinite reflectance and compared to 13 samples of the Chattanooga Shale of SW Missouri, SE Kansas, and NE Oklahoma. Offshore shales and coals from all three locations are thermally mature. The organic matter in the Cherokee Group and Marmaton Group shales is hydrogen deficient. Comparisons of saturated hydrocarbons, carbon isotope and other chemical analysis show that oil in sandstone reservoirs of Cherokee and Chatta-

nooga Shale are similar, but are dissimilar to extracts of the Cherokee Group and Marmaton Group offshore shales and coals. It was concluded that the Chattanooga Shale is the source rock for the Cherokee Group oils. The excellent hydrocarbon-generating potential in the middle Pennsylvanian offshore shales and coals suggests that where thermally mature, these rocks are sources for other mid-continent oil and gas reservoirs.

Maps: locality: Charts: geochemical analysis, vitrinite reflectance.

Hemish, L. A., 1989, Bluejacket (Bartlesville) Sandstone Member of the Boggy Formation (Pennsylvanian) in its type area: Ok. Geol. Notes, v. 49, p. 72-89.

Two reference wells were established for the Bluejacket sandstone. Within one mile across the type section the lithology of the Bluejacket changes from medium-grained sandstone with coarse conglomerate at the base to thin fine grained sandstone and silty shale. Interpretations of the depositional environments: 1. the conglomeratic deposits originated as flood deposits in a distributary channel in a deltaic setting, 2. the fine-grained deposits originated as crevasse-splay and overbank deposits on the interchannel deltaic plain. These environments represent different parts of a large delta distributary system.

Maps: locality, columnar sections, cross-sections; core analysis.

Hough, R. M., 1978, Depositional framework of the Lower Red Fork, eastern flank of the Anadarko Basin, Oklahoma (unpub thesis): The University of Tulsa, 60 p.

The Red Fork sandstone has two trends. Sediments were deposited in a complex deltaic environment consisting of distributary channel, distributary mouth-bar, interdistributary bay deposits. The trends were controlled by deepening water to the southwest. Dip oriented distributaries prograded southwestward with a series of distributary mouth-bars at the terminus forming a strike-oriented sandstone trend. The author suggests that the Red Fork sandstone is an extension of deltaic systems to the northeast.

Maps: isopach, cross sections, paleodrainage patterns, sedimentary structures.

Hufford, W. R., and T. T. Tieh, 1984, Diagenesis of Burbank Sandstone, North Burbank Field, Osage County, Oklahoma (abs.): AAPG Bulletin, v. 68, 489 p.

The Burbank sandstone in tract 97 is 2,845- 2,945 feet deep. Five wells were cored to analyze depositional environments and diagenetic alterations and the effects of diagenesis on reservoir rock properties. The Burbank sandstone consists of very fine to fine grain lithic arenite deposited in fluvial-deltaic conditions. Rock fragments and feldspars are 1/3 of the grains, Quartz dominates. Compaction, authigenesis, replacement and dissolution have altered texture and composition of the rock. Compaction is minor due to early cementation. Dissolution of grains and cement has yielded an average porosity of 15%. Carbonate replaced detrital particles iare susceptible to dissolution. For a successful tertiary recovery, the complex effects of cementation, dissolution and authigenesis must be considered.

Jordan, D. W., and R. W. Tillman, 1987, Geologic facies analysis for enhanced oil recovery, Bartlesville sandstone, Greenwood County, Kansas: SEPM Spec.Pub. 40, p. 311-332.

Five depositional facies occur in cores of the Bartlesville sandstone in Greenwood County, Kansas. Orientation of the cores allowed a model to predict the trend of the channel sandstones. Environments of deposition: 1. interdistributary bay siltstone, shale and sandstone facies, 2. crevasse splay sandstone and siltstone facies, 3. overbank shale and siltstone facies, 4. distributary channel sandstone facies, and 5. delta plain shale and siltstone facies. The distributary channel facies is the major reservoir. It overlies brackish to continental delta plain sediments, and is overlain by brackish and marine sediments. The channel has low sinuosity shown by a blocky bell -shape gamma-ray log. An upward decrease in grain size, a decrease in scale of sedimentary structures and increase in clay is typical of fluvial-deltaic sediments.

Permeability differs in the various facies based on packing, the presence of ductile rock fragments, amount and kinds of clays and sorting. Permeability of distributary channel sands decrease from 60 to 100 md in trough cross-bedded sands in the middle channel fill to 20 to 60 md in rippled sandstones, siltstones and shales in the upper channel. Low permeabilities of 0 to 20 md are typical in the siltstone and shale. Distributary channel facies is continuous across the study area, varying in thickness. The overbank, crevasse splay and interdistributary bay facies are not continuous, these filled the topographically lows adjacent to the channel.

Maps: locality, cross-section, lithology, gamma-ray log, isopach, regional cross-section with cores, paleocurrent: Sedimentary facies chart.

Keplinger and Assocs., 1982, An evaluation of the North Burbank Unit tertiary recovery pilot test: contract # DE-AC19-80/BC/10033-2, 29 p.

Although only half of the oil originally predicted was recovered by Phillips Pet. Co., the project was judged technically successful. High sulfonate losses caused the low recovery.

Kumar, R., and J. N. Elbeck, 1984, CO_2 flooding in a waterflooded shallow Pennsylvanian sand in Oklahoma: a case history: SPE 12668, 4th Enhanced Oil Recovery Symp., p. 378-386.

The pilot was to test the tertiary oil potential of the shallow Pennsylvanian Age sands of the Garber field. Ultimate recovery by CO_2 flooding is estimated to reach 14% of original oil-in-place.

Kuykendall, M. D., 1989, Reservoir Heterogeneity within Bartlesville Sandstone, Glenn Pool oil field, Creek county, Oklahoma, abs.: AAPG Bulletin, v. 73, p. 1048.

70 well log suites and 18 cores were used to study reservoir heterogeneity at the 160 acre William Berryhill Unit. The upper delta plain depositional setting of the Bartlesville sand changed facies in short distances with many small scale heterogeneities. There is a tendency to compartmentalize portions of the reservoir because of laterally discontinuous sandstone units. The Bartlesville sandstone is a sublitharenite-litharenite strongly influenced by diagenesis. Porosity is secondary due to dissolution of framework grains. Porosity and permeability, diagenesis, petrophysics, and depositional environmental features aid in reservoir characterization and help to improve enhanced recovery.

Moffitt, P. D., D. R. Zornes, A. Moradi-Zraghi, and J. M. McGovern, 1990, Application of freshwater and brine polymer flooding in the North Burbank unit, Osage County, Oklahoma: SPE 20466, 68th Ann. Tech. and Exhib., New Orleans, La, p. 59-72.

A review of techniques used in polymer flooding in the North Burbank Unit.

O'Reilly, K. L., 1986, Diagenesis and depositional environments of the Red Fork Sandstone (Desmoinesian) in the Wakita Trend, Grant County, Oklahoma (unpub. thesis) The University of Tulsa, 153 p.

The Red Fork represents a low energy transgressive barrier bar system. Sand was deposited over a flat shale surface. A ridge and swale topography characterizes the upper surface of the sand. The shale below the Red Fork is lagoonal or muddy emergent coast. The shale above the Red Fork is a shallow marine facies. Secondary porosity in the shoreface and foreshore deposits was formed by dissolution of carbonate cements and framework grains. Porosity and permeability range from 9 to 18 % and 0.4 to 11.0 md, respectively. Significant oil and gas have been produced from the Wakita Trend.

Maps: locality, structure; Charts and graphs: x-ray diffraction, lithological characters, photomicrographs of pore filling, mineralogy, SEM analysis.

Phares, R. S., 1969, Depositional Framework of the Bartlesville Sandstone in Northeastern Oklahoma (unpub. thesis): The University of Tulsa, 56 p.

The Bartlesville sandstone is part of a large deltaic complex which prograded seaward to the south. Distributary channel system development is the most diagnostic in this area. The Bartlesville sandstone represented a major regression in eastern Kansas and Oklahoma.

Maps: cross-sections, isopach, isolith; core samples.

Rheinholtz, P. N., 1982, Distribution, Petrology and depositional environment of "Bush City shoestring sandstone" and "Centerville Lagonda sandstone" in Cherokee Group (Middle Pennsylvanian), Southeastern Kansas (unpub. thesis): University of Iowa, 180 p.

Sediment patterns in eastern Kansas were influenced by the periodic influx of siliciclastic materials and sea level changes. The deltas prograded in the shallow Cherokee Sea onto the Cherokee platform. Carbonate deposition occurred when sediment supply was reduced. The "Lagonda" interval in Kansas represents a prograding delta . Point bar deposits are recognized by incised channels and fining- upward sequences. The Bush City Channel was incised during a lower sea level, and later filled by a stream system. Detailed sedimentary description of members and units of Cherokee Group are presented with assessment of environment of deposition.

Maps: numerous and detail stratigraphic columns, locality, structure.

Charts, Tables and photographs: core analysis, grain size distribution, mineral content, current classification, textural features.

Riggs, C. H., 1954, Waterflooding in the Burbank field, Osage County, Oklahoma:U.S. Dept. Interior, May, 1954, 19 p.

Analysis of the early phases of waterflooding in the Burbank field.

Saitta, B., and G. S. Visher, 1968, Subsurface study of the southern portion of the Bluejacket Delta: Ok. City Geol. Soc. AAPG-SEPM Joint Mtg. and Field Conf., p. 52-68.

The study area is 7,560 sq miles with an average width of 84 miles and a length of 90 miles. Objectives were: 1. determine the geometry of the Bluejacket Formation and establish a correlation framework, 2. determine paleogeography, and 3. illustrate distribution of SP curve shapes and determine variations of specific shapes. Depositional environments of the Bluejacket include: 1. lower alluvial valley, 2. upper and lower delta plain, 3. delta fringe and prodelta, 4. marine bar, 5. lagoons and bays, and 6. marsh deposits. 4000 E-logs were used to access SP curve shape, 3 trends were studied: 1. nature of upper contact of sand with shale whether it is abrupt, transitional or transitional serrated, 2. central portion of curve, smooth or serrated, 3. base of sand section, abrupt, transitional or transitional serrated.

Saitta, S. B., 1969, Environment of deposition of an ancient delta: The Bluejacket Formation in Northeastern Oklahoma: Bol. Inforn. Assoc. Venez. Geol. Miner. Petrol., v. 12, p. 109-150.

The Bluejacket sand was deposited in a large deltaic system. Stratigraphic correlation, mapping and sedimentary-textural analysis were used to interpret the area. Cross-bedding and paleocurrent analysis was used to determine the origin for the sand. Variations of grain size and distribution and sedimentary structures were used to determine current velocity. The Inola and Brown limestones, time parallel units of the Bluejacket were deposited during transgressive phases. The Bluejacket was deposited during a regressive phase of the Cherokee Sea. The base of the sand represents a high energy scour surface; the sands prograded seaward over a flat stable continental platform.

Maps: locality, structural contour, stratigraphic sections, sand isopachs, paleocurrents, environmental model.

Charts: grain size analysis, texture.

Saitta, S. B., 1968, Bluejacket Formation- a subsurface study in Northeastern Oklahoma (unpub. thesis): The University of Tulsa, 140 p.

The Bluejacket represented a complex deltaic environment. The Inola and Brown are time parallel transgressive phases marking the boundaries of the regressive Bluejacket sandstone. Descriptions of structure are based on SP curves. There is a NW-SE paleoslope. The deposits consists of: lower alluvial valley, upper and lower deltaic plain, delta fringe and pro-delta, marine bars, lagoons and bays , marsh .

Maps: cross-sections, isopach, sand/shale ratio, sedimentary structures, grain size distribution.

Scheffe, G. L., and W. E. Full, 1986, Depositional investigation and analysis of porosity development in a Northwestern Oklahoma Cherokee Sandstone, using petrographic image analysis (abs.): AAPG Bulletin, v. 70, p. 645.

PIA (petrographic image analysis) processes digitized scenes of the porosity network. PIA applied to the Bartlesville sandstone of the Cherokee Group was used to define characteristics of the petroleum reservoir. The investigation identified the reservoir as deltaic. Predicted permeability had a correlation coefficient ($R^{2)}$ valve of 0.93. The highest prediction was from the pore type and quantified pore attributes that characterize small pores occurring in high density with small to moderate perimeter roughness. This pore type occurs in quartz sandstone laminations with alternate layers containing small amounts of calcite and fossil fragments. Reservoir production seems related to a system of fractures and microfractures.

Schoeling , L., and D. Green, 1989, Implementation of gelled polymer technology- an example of a joint industry University project: 36th Ann. Petroleum Short Course, Lubbock, Texas, p. 248-260.

Tertiary recovery project at the University of Kansas has investigated gelled polymer technology to improve efficiency in waterflooding. Polymer gels are injection and formed in situ to seal off and reduce permeability of a channel or high permeability zone. Water is then injected to sweep the enclosed area and recover oil. A time-delayed gelation has been developed and tested in Kansas oil fields. The time control is an oxidation-reduction reaction. The polymer solution injected is a polyacrylamide, sodium dichromate, thiourea and brine solution. Testing was done in the Bartlesville sandstone of the Cherokee Group in Allen County, Kansas.

Shulman, C., 1965, Stratigraphic analysis of the Cherokee Group in adjacent portions of Lincoln, Logan and Oklahoma Counties, Oklahoma (unpub thesis): The University of Tulsa, 30 p.

The Cherokee Group consists of a sequence of transgressive and regressive lithologic units. The sea invaded from the east. Pennsylvanian sediments onlap eroded underlying Mississippian topography. The Lower Skinner sandstone is a lenticular, elongate, erratic sand deposited in channels. The Channels were eroded and superimposed over the Mississippian drainage system. The southwest Mount Vernon Pool was deposited as deltaic sands with shales basinward.

Maps: cross-sections, structure, locality.

Thomas, R. D., K. L. Spence, F. W. Burtch and P. B. Lorenz, 1982, Performance of DOE's micellar-polymer project in Northeast Oklahoma: SPE 10724, 3rd Enhanced Oil Recovery Sym., Tulsa Ok., p. 763-769.

Analysis of a micellar-polymer flood in the Delaware-Childers field in the oil-wet Bartlesville Sandstone. The project was not a technical or economic success.

Tight, D. C., 1983, The Bartlesville Sandstone: A detailed subsurface stratigraphic study in the North Avant Field, Eastern Osage County, Oklahoma (unpub. thesis): The University of Tulsa, 115 p.

Production from the Pennsylvanian age Bartlesville sandstone is discussed. The mineralogy is composed of quartz, rock fragments, feldspar, mica, and clays (chlorite, kaolinite and illite). The Bartlesville sandstone has three divisions: 1. clean sands with abrupt basal contact, 2. muddy interval, and 3. upper Bartlesville sands.

Sedimentary structures vary from large scale crossbeds to wavy laminations, decreasing in scale upward. Grain size also fines upward. The clean sandstone intervals are distributary channels. The muddy zone represents channel abandonment. The upper interval represents interdistributary sediments. Oil and gas production are best along paleo-distributary channels. Traps are stratigraphic pinchouts.

Figures: thin sections, e-log correlations, sedimentary structures, grain size curves, models of delta types.

Maps: well locations, isopach.

Trantham, J. C., 1983, Prospects of commercialization, surfactant/polymer flooding, North Burbank unit, Osage County: Jour. Petroleum Tech., v. 35, p. 872-880.

A 90 acre pilot in Osage County produced 221,700 bbl oil in 51 months of operation. Tertiary oil production from this unit is expected to continue for seven years. The reservoir is highly heterogeneous because of a fracture system. It is estimated that 360 MM bbl of sweet 39° API oil will remain when waterflooting reaches its economic limit.

Trantham, J. C., and P. D. Moffitt, 1982, North Burbank unit 1,440-acre polymer flood project design: SPE 10717, 3rd Enhanced Oil Recovery Symp., p. 669-688.

Initial waterflooding in the North Burbank Unit gave a poor response. The size of the test pilot has been increased and polymer slugs have been injected to increase flow.

Trantham, J. C., H.L. Patterson, and D. F. Boneau, 1978, The North Burbank Unit, tract 97 surfactant/polymer pilot-operation and control: Jour. Petroleum Tech., p. 1068-1074.

A fresh water preflush injection in the North Burbank unit in Osage County, Oklahoma was preformed by Phillips Petroleum. A sequence of slug followed the preflush, including salinity preflush, surfactant solution and a graded viscosity-mobility buffer. This paper discusses the mixing and injecting of the fluids to optimize fluid movement within the reservoir.

Charts and Graphs: radioactive tracer response, flow diagram, injection/production balance, production history, surfactant solution analysis, bottom hole pressure, injected polymer solution analysis, total pilot performance, chemical contents, sulfonate in oil.

Vanbuskirk, J. R., 1960, Investigation of reservoir conditions of Lower Deese Sandstones (Pennsylvanian) for a flood project in the North Alma Pool, Stephens County, Oklahoma (unpub. thesis): The University of Oklahoma, 84 p.

A report on the geology of the Pennsylvanian sandstone reservoirs in the North Alma Pool and how geology effects the waterflood process.

Visher, G. S., 1968, A Guidebook to the Geology of the Bluejacket-Bartlesville sandstone, Oklahoma: in Visher, G. S., ed., Ok. City Geol. Soc. AAPG-SEPM joint MTG Field Conf., p. 1-60.

Guidebook includes a general history of the area, photography of outcrops, general sedimentological descriptions and designation of observed deltaic environments. Included are: 1. The Cherokee Group by Carl C. Branson; a map and description of the Cherokee formations; 2. Depositional framework of the Bluejacket-Bartlesville Sandstone by G. S. Visher; a history of research and production of the Bluejacket with outcrop photos and data, paleocurrent data and grain size analysis; and 3. Subsurface study of the southern portion of the Bluejacket Delta by G. Visher and B. S. Saita. Subsurface distribution of the Bluejacket-Bartlesville sandstone is 7,560 sq miles, 84 miles in width and 90 miles in length. It covers 13 Oklahoma counties.

Maps: well locations, deltaic environments, outcrop locality, cross-sections.

Visher, G. S., 1968, Depositional Framework of the Bluejacket-Bartlesville Sandstone: in Visher, G. S., ed., A Guidebook to the Geology of the Bluejacket-Bartlesville Sandstone, Oklahoma, OK. City Geol. Assoc. AAPM-SEPM Joint Mtg. Field conf., p. 1-20.

The Cherokee Group which includes the Bluejacket-Bartlesville sandstones is a major oil producing unit in Oklahoma and Kansas. The stratigraphy of the Cherokee is complicated. Outcrop studies of the Bluejacket show that it extends as a ridge forming unit from southern Kansas to the frontal zone of the Ouachita Mts. over a distance of 160 miles. Many of the facies are of delta origin including offshore marine, upper and lower delta plain, interdeltaic area and pro-delta units that are exposed in outcrop. The subsurface of the Cherokee sand zone covers an area of 20,000 sq miles. It ranges from only a few hundred ft thick in the north to over 2,000 ft in the McAlester basin to the southeast.

Maps: locality, cross-section correlations, depositional environments; core analysis.

Visher, G. S., B. S. Saitta, and R. S. Phares, 1970, Pennsylvanian delta patterns and petroleum occurrences in eastern Oklahoma: AAPG Bulletin, v. 55, p. 1206-1230.

Criteria used to define Pennsylvanian deltas of Oklahoma include: 1. vertical patterns of sedimentary structures, bedding and grain size, 2. clay mineralogy and detrital clasts, 3. trace fossils, and 4. detailed analysis of textures.

A 4 -dimensional delta model is based on 6 environments: 1. lower alluvial plain, 2. upper delta plain, 3. lower delta plain, 4. subaqueous sand sheet, 5. marginal basin, and 6. marginal depositional plain. The lower alluvial plain has meandering stream point bars and confined channel flow. Stream gradients are reduced in the upper delta plain; distributary bifurcation, marsh and levee development occurs. The lower delta plain is characterized by crevasse splays. Sheet sands are produced by shallow water currents. Marginal basin and plain facies are produced by longshore currents and reflect the balance of subsidence, sediment and wave action. Pennsylvanian sediments marked by overall transgression with extensive regressions. The single river sediment system can be traced through the Morrow, Atoka and Desmoinesian strata.

Maps: outcrop, isopach, regional cross- section, delta patterns, and distribution; S-P curves and E-log correlations; oil fields

Walton, A. W., D. J. Bouquet, R. A. Evenson, D. H. Rofheart , and M. D. Woody, 1986, Characterization of sandstone reservoirs in the Cherokee Group (Pennsylvanian, Desmoinesian) of Southeastern Kansas: Department of Geology and Tertiary Oil Recovery Project University of Kansas, Academic Press, p. 39-62.

The Cherokee Group consists primarily of fluvial shoestring sandstones. Five major facies include conglomerate, cross-bedded sandstone, interbedded sandstone, siltstone and clay-shale. Average porosity of the cross-bedded and ripple-bedded sandstones are approximately equal. Initial permeability was reduced three orders of magnitude by compaction. Cementation of clays reduced permeability, rendering some sandstones impermeable. Shoestring sands were laid down in a series of episodes on clean scour surfaces. The cross bedded sandstone has the greatest permeability parallel to the flow of currents. The Cherokee Group in south eastern Kansas has produced over a billion barrels of oil. The Cherokee group is mostly clay-shale and siltstone with some sandstone in Kansas ranging from 100 to 150 meters thick. The thickest part is in Labette County, Kansas. There is little deformation and only minor normal faulting in the Cherokee.

Maps: locality, permeability and porosity charts, cementation charts.

Zornes, D. R., A. J. Cornelius, and H. Q. Long, 1986, Overview and evaluation of the North Burbank unit block, A polymer flood project, Osage County, Oklahoma: SPE 14113, Intern. Meeting Petroleum Engineering, Beijing, China, p. 311-324.

Thirty-six chemical flooding wells in the North Burbank Unit were injected with 4.17 MM pounds of polyacylamide. Fresh water and polymer production were monitored at 84 producing wells in an attempt to correlate oil production response.

B. D & J Sands

The Denver and Julesburg sandstones of the Dakota Group are found throughout the Denver Basin in Colorado, Nebraska and Wyoming. The Denver Basin has thick fluvial-deltaic deposits of Cretaceous Age. The abundant reservoirs in the Denver Basin contain stratigraphic oil traps with enormous potential.

Basan, P.B., J. A. McCaleb, and T. S. Buxton, 1978, Important geological factors affecting the Sloss field micellar pilot project: SPE 7047, 5th Improved Methods of Oil Recovery Symposium, p. 111-118.

A nine acre five spot micellar project in Sloss Field, Kimbal County, Nebraska is in part of the Denver Basin and produces from the Muddy J sandstone. Initial tests showed an inability to match performance data during preflush water injection to mathematical model expectations. A detailed geological study was conducted to obtain a better reservoir description. Two different deposits occur in the field. Type one is a permeable sand deposited in a distributary channel. Permeability is continuous within this channel. Type two deposit (where the first pilot was conducted) represents overbank splay sands and is discontinuous. The flow from type II sands is less uniform and less predictable than flow from type I sands.

Maps: locality, tracer performance, facies distribution, isopach, E-log, permeability distribution, sand thickness.

Coalson, E. B., 1989, Petrogenesis and petrophysics of selected sandstone reservoirs of the Rocky Mountain region: in Coalson, E. B., ed., Rocky Mt. Assoc. Geol., Denver, Colorado, 353 p.

An analysis of the petrology of the sandstone reservoirs of the Denver Basin. A number of papers study different aspects of geology of the region.

Crouch, M.C., 1982, Oil and gas fields of Colorado, Nebraska, and adjacent areas: Rocky Mtn. Assoc. Geologists, p. 354-791.

Sixty-five fields within this area contain D and or J sandstone units. Information given for each field includes: 1. Name, location, formation; 2. Geology; regional setting, surface formations, discovery method, trap type, production formation, thickness and lithology, geometry of reservoir rocks, other shows, and the oldest stratigraphic unit penetrated; 3. Discovery well; name, location, elevation, completion date, total depth, sizing, perforation, treatment, initial potential, pressure; 4. Logging practices; 5. Drilling and completion practices; 6. Reservoir data; productive acres, spacing, net pay-map and average porosity, permeability, water saturation, initial field pressure, type of drive, oil characteristics, gas characteristics, estimated primary recovery; 7. Discussion; and 8. References, tables and maps

Davis, J. C., and T. Chang, 1990, Estimating potential for small fields in mature petroleum province: reply: AAPG Bulletin, v. 74, p. 1764-1765.

D and J sandstones contain an exceptionally homogeneous population of oil pools mostly from stratigraphic traps. Depths are from 4,000 to 8,000 ft in the Denver Basin. The traps are not detectable by seismic work. Statistical manipulation predicts 3000 pools remain undiscovered in the Denver-Julesburg Basin. Simulation experiments extrapolate the trend in the D-J Basin discoveries in the future. The J shaped Pareto distribution is proven not appropriate as a model of the parent pool-size distribution.

Graphs: log models and Pareto model.

Ethridge, F. G., and J. C. Dolson, 1989, Unconformities and valley-fill sequences-key to understanding "J" sandstone (Lower Cretaceous) reservoirs at Lonetree and Poncho Fields, D-J Basin, Colorado: in Coalson, E. B., ed., Petrogenesis and Petrophysics of Selected Sandstone Reservoirs of the Rocky Mountain Region: Rocky Mt. Assoc. Geol., p. 221-233.

A reinterpretation of the 3 genetic units of the "J" sandstone includes: lower unit— delta front- J3; middle unit— J2 is now split into point bar, crevasse splay and floodplain sequences of a meander-belt complex; upper unit— J1 is a destructional marine bar. This reinterpretation is based on thin sections and SEM analyses of cements with quartz overgrowths. J3 delta front deposits underlie an unconformity. Deposits of J3 are tightly cemented by siderite and do not produce oil in either field. J2 sands are productive from meander-belt deposits in both fields. J1 overlying sands include 3 northeast trending marine bars of which only the western one is productive.

Maps (numerous): field and structure, isopach: Engineering data on all three units.

Exum, F. A., and J. C. Harms, 1968, Comparison of marine-bar with valley-fill stratigraphic traps, western Nebraska: AAPG Bulletin, v. 52, p. 1851-1868.

Cretaceous J sandstones of Cheyenne and Banner Counties, Nebraska are composed of marine-bar and valley-fill stratigraphic traps. Marine bars are elliptical lenses 2 to 5 miles long and 0.5 to 1.5 miles wide and less than 25 ft thick. Sandstone grades laterally into marine mudrock. Two generations of marine bars are oriented in different directions. Most of the sandbar deposits are oil filled, and entrapment is independent of structural closure. Reservoirs in the valley fill deposits are 20 miles long and 2,000 ft wide and 50 to 80 ft thick.

Oil is trapped only where valley-fill deposits crosse plunging anticlines. The valley fill interconnects all pools as a single aquifer. The marine bar reservoirs can be predicted by mapping core samples. The valley-fill reservoirs are separated by erosional boundaries and can't be detected by core samples from surrounding areas, however, when found they are large and persistent. Valley-fill reservoirs have water drive, marine-bar reservoirs have only solution gas energy.

Maps: structural, cross-section, isopach, isometric block diagrams. Charts: stratigraphic correlations, core samples, charts on mineralogy and grain size, fossil correlations.

Geyer, A. P., and R. W. Pritchett, 1978, The Davis-Joyce field- a Cretaceous riverine deltaic "D" sand system in western Nebraska: in Pruit, J . D. and P. E. Coffin, eds., Energy Resources of the Denver Basin: Rocky Mtn. Assoc. Geol., p. 63-7.

Deposition of the "D" sand occurred during a minor regression of the Cretaceous Cordilleran seaway. Davis and Joyce fields were separate discoveries, but the fluid systems may be connected. Neither field produces much formation water. The reservoir consists of shoe-string shaped sand bodies of good quality that are part of a riverine-deltaic facies complex. Six general facies can be identified from well log and sample data and can be related to ancient delta systems. The field is a model for further exploration of riverine-delta distributary systems.

Maps: structure, isopach, log correlations, diagrammatic section model; Production data charts.

Griffin, E. G., 1978, The "D" sandstone channel complex of the greater Rogen area: in Pruit, J. D. and P. E. Coffin, ed., Energy Resources of the Denver Basin, Rocky Mtn. Assoc. Geol., p. 61-62.

Two "D" sand oil fields located seven miles apart are thought to be parts of the same delta system because of: 1. channel incisions revealed by isopach mapping, 2. anomalously thick "D" sandstone, and 3. evidence from oriented cores. Subsequent drilling has confirmed that the "D" channel sandstone was emplaced as a series of overlapping point bars separated by impervious channel fill. Production from 30 wells in Dec. 1977 was 29,534 bbl and 112,275,000 cu ft of gas.

Table: production data.

Griffin, E. G., 1963, Prospecting for "D" sand channel production: in Katich, P. J., and D. W. Bolyard, eds., Guidebook to the geology of Northern Denver Basin and Adjacent uplifts: Rocky Mtn. Assoc. Geol., 14th Ann. Field Conf., p. 229-233.

Most of the undiscovered profitable oil and gas to be found in the Denver Basin will be found in channel deposits. High energy channel deposits frequently display coarse grain-size, good sorting and resultant high porosity and permeability. Thickness of channel sands in "D" is 40 ft or greater. The recovery factor is 200 barrel or more per acre foot. The width of "D" channels varies up to 1,000 to 4,000 ft. Lengths may be 15 miles or more. Six criteria for recognizing channel sands are discussed at length.

Maps: structural contour, field maps.

Hamilton, V. J., 1990, Controls of sequence stratigraphy on sandstone body geometry and interconnectedness: example from the Dakota Formation in Kansas (abs.): AAPG Bulletin, v. 74, p. 669.

Three sequence-bounding unconformities on the eastern margin of the Western Interior Basin of western Kansas are recognized by seaward shifts in facies, evidence of subaerial exposure and incomplete facies successions. The unconformities located are at the base of the Cretaceous Plainview Fm., the J sandstone, and the D sandstone.

Gamma ray well logs from recovered cores were used to correlate these sequence boundaries with outcrops sections. In central Kansas the Dakota Group strata become increasingly non-marine, primarily fluvial with some deltaic deposits in the upper part. Channel sandstones are 30 ft thick and 1/4 mile wide. These amalgamate to form sand bodies 100 ft thick and up to 2 miles wide. Channels were controlled by east-west trending faults and interconnections of the sandstone bodies occur at intersections of the trends.

Haun, J. D., 1963, Stratigraphy of Dakota Group and relationship to petroleum occurrence, Northern Denver Basin: in Katich, P. J., and D. W. Bolyard, eds., Guidebook to the Geology of Northern Denver Basin and adjacent uplifts: Rocky Mtn. Assoc. Geol., 14th Ann. Field Conf., p. 119-134.

13,000 wells had been drilled in the Denver Basin by 1963. An analysis of 1,300 E-logs from wells scattered over the drilling areas was made. This paper correlates the relationship within the members of the Dakota Group throughout the Basin.

Maps: stratigraphic diagrams, cross-sections, isopachs of J and D sand intervals and the Mowry Shale.

Higley, D. K., 1989, Comparison of sandstone diagenesis and reservoir development within two lower Cretaceous J sandstone fields, Denver Basin, Colorado (abs.): AAPG Bulletin, v. 73, p. 1160.

Wattenberg field sandstones were buried deeper and subjected to higher heat flows than Kachina field sandstones. Thermal history indicates greater burial temperature and pressure resulted in higher degree of sediment compaction, fracturing of reservoir rocks, and more chert and polycrystalline quartz in the Wattenberg field.

The Kachina field produces from stratigraphic/structural traps in a distributary channel environment. Vitrinite reflectance is .62 %; much of the oil may have migrated from deeper in the basin.

The Wattenberg field produces gas from hydrodynamic stratigraphic traps in the deepest part of the basin. Sandstones of this reservoir are low porosity and low permeability. Hydrocarbon origin is primarily thermogenic gas. Vitrinite reflectance ranges from 1.14 to 1.51 %.

Higley, D. K., and J. W. Schomoker, 1989, Influence of depositional environment and diagenesis on regional porosity trends in lower Cretaceous "J" sandstone, Denver Basin, Colorado: in Coalson, E. B., ed., Petrogenesis and Petrophysics of Selected Sandstone Reservoirs of the Rocky Mountain Region: Rocky Mt. Assoc. Geol., p. 183-196.

An analysis of 135 widely distributed drillholes in the Denver Basin, to study permeability, depth, thermal maturity and porosity. Median core porosity in the "J" decreases from 24% at 4000 ft depth to 7 to 10% at 9,000 ft depth. The decrease in porosity is due to increasing depth of burial and increasing thermal maturity.

Depositional environment is related to porosity: higher average porosities are present in channel sandstones; high porosity is present in the eastern third of the basin in major incised drainage and valley -fill sequences. The Kachina field on the east flank produces oil from highly porous and permeable distributary channel sandstones. Hydrocarbons are trapped by overlying mudstone.

Engineering data in charts, tables and maps

Land, C. B., and R. J. Weimer, 1978, Peoria field, Denver Basin, Colorado- J sandstone distributary channel reservoir: in Pruit, J. D., and P. E. Coffin, eds., Energy Resources of the Denver Basin: Rocky Mtn. Assoc. Geol., p. 81-104.

The Peoria field produces from delta plain sandstones. The reservoirs are stratigraphic traps. The J interval is a complex of distributary channels. Three types of channel-fills reflect stages in development of the distributary channel. Vertical sequence includes a (lower) active channel fill, (middle) partial abandonment, (upper) abandonment fill. Peoria field channels are narrow, 1,500-2,000 ft wide and 30 to 40 ft deep. Fine grained interdistributary deposits include those formed by levees, crevasse splays, marsh or swamp, and marine and fresh water bay deposits are lateral to the channels. Of these, only the crevasse splays are suitable reservoirs. The ability to recognize these facies is important in oil exploration.

Maps: locality, 3-D model, wells, isopachs; E-logs, core samples.

Martin, C. A., 1965, Denver Basin: AAPG Bulletin, v. 49, p. 1908-1925.

The deepest part of the Denver Basin has over 13,000 ft of sediments. The area was a marine shelf during the early Paleozoic. Uplift during the middle Paleozoic exposed older rocks to erosion. Pennsylvanian seas transgressed and eroded Mississippian deposits in the south. Throughout the Permian regression normal marine through evaporitic to terrestrial sediments were deposited. The Ancestral Rockies contributed sediments in the upper Permian and Triassic. In the Middle and Early Jurassic the seas encroached on the northwest followed by the formation of a broad plain.

The present Denver Basin began to form in the early Cretaceous as seas advanced from north to south. Fluvial material from the east and northeast developed into a complex deltaic system. Another delta system fed in from the south and finally merged with the eastern delta. Two Cretaceous sedimentary cycles of transgression contain large reserves of oil and gas. In the Late Cretaceous a major transgression joined the seas forming a large seaway and downwarping continued within the basin. During the Laramide the Front Range was uplifted and the basin acquired its present configuration.

Maps: structure, cross-section, isopach of each major era, lithofacies of each major era.

Mossel. L. G., 1978, Hydrocarbon accumulations in the "D" sandstone, Adams and Arapahoe Counties, Colorado: in Pruit , D. J., and P. E. Coffin, eds., Energy Resources of the Denver Basin: Rocky Mtn. Assoc. Geol., p. 75-80.

The lower Cretaceous "D" sand contains significant hydrocarbon reserves in stratigraphic trap reservoirs. Reservoirs are developed on marine bar sandstones and in deltaic distributary channels. Trapping includes traps formed by up-dip pinchout of sandstone, and traps formed by interchannel point bar porosity-permeability pinchouts. Recognition of environment of deposition of sand bodies from log data will lead to more discoveries in this area.

Maps: isolith, log correlations.

Pruit, J. D., 1978, Statistical and geological evaluation of oil and gas production from the "J" sandstone, Denver Basin, Colorado, Nebraska and Wyoming: in Pruit, J. D. and P. E. Coffin, ed., Energy Resources of the Denver Basin: Rocky Mtn. Assoc. Geol., p. 9-24.

This study of 885 fields in the Denver Basin was based on wells drilled before January 1, 1973. The Denver Basin was subdivided into 15 areas of study. Computer analysis was conducted on field size distribution, mean, median and modal field sizes, density of field sizes, relationship between reserves and aerial extent of field, average reserves per 80 acres, influence of structure on production and the orientation of producing sandstones.

Variations in average 80 acre reserves from 30 M. bbls in the northwest to 406 M. bbls in the south central area reflect variations in reservoir quality. There is twice as good a chance to discovery oil on a structureal nose or on a structure with closure than on a regional dip. As of January 1, 1973 there was an estimated reserve of 134 MM equivalent bbls in the Denver Basin. The Fairway and Kimball areas offer the best promise of future J sandstone production.

Tables: subprovinces of Denver Basin, comparison of area reserves.

Maps: field distribution, equivalent reserves, wild cats drilled.

Ridgley, J. L., 1990, Genetic lithofacies in the Dakota Sandstone, a major oil-and gas-producing formation, Northern San Juan Basin, Colorado and New Mexico (abs.): USGS Cir., v. 1060, p. 67-68.

A geological study of the Dakota Sandstone in the San Juan Basin. The study employed facies analysis and stratigraphy.

Silverman, M. R., 1988, Petroleum Geology, paleotectonics and sedimentation of the Scotts Bluff Trend, Northeastern Denver Basin: Mountain Geol., v. 25, p. 87-101.

Ten J sand oil fields form a long narrow NE-SW trend in western Nebraska, which is related to the Scotts Bluff Trend. The Cretaceous J sands dip gently southwest across the northeast Denver Basin. Several structural-stratigraphic traps are caused by low-relief closures and structural noses. Most traps are controlled by updip facies change from porous, permeable sandstone to siltstone and shale.

Most production from "J" member sands is from porous sandbodies 5 ft thick. Three fields have produced over 1,000,000 bbl oil each.

The J was deposited in elongate, elliptical NW trending marine bars separated laterally by shales. Long distance lateral petroleum migration occurred from thermally mature shales of the Dakota and Benton Groups. Movement along the Precambrian basement faults has enhanced reservoir quality and oil migration, favoring oil accumulation along the trend.

Maps: locality, contour, isolith, structure; log plots.

Specific examples: Cedar Valley, Minatare and High Line fields

Sonnenberg, S. A., 1988, Tectonics and sedimentation—Phanerozoic rocks Golden-Morrison area, Denver Basin, Colorado: Annual GSA-MTG Field Trip, Denver, Colorado.

This paper is a field trip guide to the Colorado Front Range. Stops 1 and 2 viewed synorogenic deposits in the middle and late Paleozoic. Stops 3 and 4 viewed late Jurassic and Cretaceous sequences in the geographic center of the foreland or back arc basin. Stop 5 viewed sedimentation associated with the Laramide Orogeny in the late Cretaceous and Paleocene. Additional stops showed aspects of basin development.

Maps: stratigraphic section, locality, time plots of seaways, cross-section of Red Rocks park, cross-sections of Lyons Fm. and other surface formations, diagrammatic of tectonic movements, isopach of 'J' sandstone.

Sonnenberg, S. A., and R. J. Weimer, 1981, Tectonics, sedimentation and petroleum potential, Northern Denver Basin, Colorado, Wyoming and Nebraska: Colorado School of Mines, Quarterly, v. 76, p. 1-45.

A stratigraphic analysis of Paleozoic and Mesozoic strata in the Denver Basin shows recurrent movement on basement faults especially during major sea level changes. The research area is 30,000 sq miles. Twenty stratigraphic intervals of Paleozoic and Mesozoic age were identified from well data. In general, thin areas on isopach maps correspond to paleo-highs and thick areas correspond to paleo-lows. In the northern Denver Basin four N-E trending paleostructures had recurrent movement in the Permian and Cretaceous. Three N-W trending paleostructures had recurrent movement in Pennsylvanian, Permian, Triassic and Cretaceous. Late Paleozoic sequences are thicker in subsurface then in outcrop.

A tectonic and sedimentation model for fault blocks with recurrent movement aids in exploration for hydrocarbons by predicting the distribution of source and reservoir rocks and identifying early traps. Wells that penetrate only Cretaceous rocks may be used to predict the Paleozoic paleostructure.

Maps: Numerous cross- sections, structure, isopach, seismic .

Charts: Formation correlations.

Taggart, D. L., and S. C. Russell, 1981, Micellar/polymer flood post test evaluation well: SPE/ DOE 9781, Second Enhanced Oil Recovery Symposium, Tulsa Ok., p.139-148.

Sloss field in Kimball County, Nebraska was the site of a successful post-test evaluation well following a micellar-polymer flood. Sufonate loss was 0.4 of a pound per barrel of pore space. Oil was displaced over the entire pay interval, with an average of 30% of the post waterflood residual. The average oil saturation was 8%, rising to 16% in some lower permeability zones. The polymer was severely degraded causing loss of mobility control. Tests indicate that well workover fluids may have caused the degradation along with thermal processes.

Tables: injected and low rate production analyses, well core analysis, workover fluids, core effluent analysis.

Figures: locality, micellar sweep diagram, flow diagram for polymer stability, polymer and IPA concentrations, produced chlorides concentration.

Weimer, R. J., and S. A. Sonnenberg, 1989, Sequence stratigraphy analysis on Muddy (J) sandstone reservoir, Wattenberg Field, Denver Basin, Colorado: in Coalson, E. B., ed., Petrogenesis and Petrophysics of Selected Sandstone Reservoirs of the Rocky Mountain Region: Rocky Mt. Assoc. Geol., p. 197-220.

There are three stratigraphic sequences in the lower Cretaceous of the Denver Basin. Petroleum production is largely from the Muddy (J) sandstone in sequence 2 & 3. The sequence boundary is a regional unconformity. Gas production from the Wattenberg field is from the Fort Collins member of the Muddy (J) sandstone. Fluvial channel sandstones are the stratigraphic traps in the Wattenberg Field. Paleostructure controls distribution of the reservoir. A drop in sea level caused erosion into older sediments of from 20 to 100 ft, Paleosol development in the drainage of these valleys initiated early diagenesis which reduced porosity and permeability. Depths of drilling in the Watttenberg field are from 7,600 to 8,400 ft. 600,000 acres are productive from the Fort Collins Member.

Maps: stratigraphic sections, structure, contour, isopach, E-log correlations: some data on geothermal gradients and thermal maturity.

Weiss, W. W., and J. M. Chain, 1989, J. sand polymer flood performance review: SPE Rocky Mountain Region/Low Permeability Reservoirs Symposium, Denver, Colorado, v. 89.03. 06-08, p. 465-474.

The original polymer flood for the Warner Ranch unit, Nebraska, underestimated the polymer retention and had an adverse affect on performance. Propagation of the polyacrylamide through the rock was much less than anticipated. The injectivity is greatly reduced with polymer injection and approximates that expected when the mobility ratio is less than one. Two wells have produced 18,000 bbl of incremental oil attributed to polymer injection. Production from J sands at 6,150 feet have produced 37° API sweet crude oil. The Warner Ranch field produced 163,729 bbl of primary oil in 16 years prior to waterflooding.

Tables: rock and fluid characteristics; isopach map, graphs of pressure, permeability, viscosity, production profiles, polymer production and injectivity indices.

C. Frontier Formation

The Frontier Formation is a widespread Upper Cretaceous deltaic sandstone found in the Powder River, Bighorn and Wind River Basins of Wyoming. Due to the Laramide folding and thrust faulting many of the Frontier reservoirs in the western parts of the basins belong to structured deltaic reservoir class. The non-structured deltaic reservoirs of the Frontier Formation are primarily in the east and north-central areas of Wyoming.

Terminology in the region is somewhat confusing in that there are Muddy Members in several Cretaceous formations in the Rocky Mountains. The Big Muddy Field is a major new field producing from the Frontier Formation.

Arrow, E., 1969, Waltman Field: Symposium on Tertiary Rocks of Wyoming: Wyoming Geol. Assoc. Field Conf. Guidebook, v. 21, p. 105-110.

The Waltman field is a complex, faulted structural-stratigraphic trap in the Wind River Basin. Production is from the Fort Union (Paleocene) and the Lance Fm. (Cretaceous). The Fort Union is shale and the Lance is composed of fluvial-deltaic deposits of a mixed nature.

Maps: structural base map, stratigraphic cross-section, structure cross-section: some production data.

Berg, R.R., 1976, Trapping mechanisms for oil in Lower Cretaceous Muddy Sandstone at Recluse Field, Wyoming: 28th Ann. Field Conf., Wyoming Geol. Assoc. Guidebook, p. 261-272.

Muddy sandstones form lenticular reservoirs which are stratigraphic traps. Oil is produced from the highest permeability zone located in the center of the reservoir. Two types of reservoirs are present; narrow, sinuous fluvial sandstone bodies of limited extent and a fine-grained sandstone deposited close to the shoreline during a marine transgression, formzing oval sand bodies parallel to strike. In the fine-grained sandstone bodies grain size and quartz content decrease upward while clay matrix and bioturbation increase downward. Permeability drops laterally from 400 md near the center of the field to 17 md or less at the field margin. The oil column is somewhat greater than 130 ft with 120 ft attributed to trapping by down-dip hydrodynamic flow and 20 ft by capillary pressure changes where permeability is reduced. Fluid pressure relationships need to be understood in development of stratigraphic traps.

Maps: structure, cross-sections, core sections, isopachs, potentiometric (hydrogen gradient).

Charts: rock and fluid properties, porosity and permeability, pressure buildup, oil column calculations.

Biggs, P., and R. H. Espach, 1960, Petroleum and natural gas fields in Wyoming: U. S. Bureau of Mines Bull., v. 582, p. 538.

Reports on 271 oil and gas fields in Wyoming as of 1959-60 are summarized with maps. The geology and history of each field is given. 418 crude oil samples are analyzed for sulfur content, nitrogen content, refractive index and other data.

Most of the oil from Wyoming is produced in the BigHorn, Wind River, and Power River basins. Other important basins are the Bridger, Laramie-Hanna and Denver-Julesburg Basins. Natural gas is largely from the Bridger and Wind River Basins.

Maps: contour, structure, locality.

Production data from 1940's and 1950's.

Cardinal, D. J., 1989, Wyoming Oil and Gas Fields Symposium: Bighorn and Wind River Basins: Wyoming Geol. Association, 555 p.

Oil and gas fields are listed in alphabetical order, 65 fields have production from the Frontier Formation. Information given for each field includes: location, formations, discovery well, general field data (well spacing, logging practices, operators). Reservoir data; formation, lithology, porosity, permeability, average pay thickness, oil/gas column, initial pressure, present pressure, drive mechanism, field salinity, bottom hole temperature, character of oil, continuity of reservoir, cumulative production, primary and secondary recovery, perforations, treatment , estimated ultimate recovery.

Maps: each field, references and a short discussion of the history of each field.

Clark, C., 1978, West Poison Spider Field, Natrona County, Wyoming: 30th Ann. Field Conf., Wyoming Geol. Assoc., p. 261-271.

The West Poison Spider Field has oil production from the Frontier Formation. The trap is structural in a deep seated anticline. The folding and faulting in the field are in a NW-SE trend.

Maps: cross-section of structure, top sand map, isopachs, E-log correlations

Tables: production data

Cobban, W. A., 1957, Mowry and Frontier Formation in southern part of Wind River Basin: 12th Ann. Field Conf., Wyoming Geol. Assoc.Guidebook, p. 67-70.

Cretaceous sandstone and noncalcareous shale deposits in this part of the Wind River Basin comprise Mowry Shale (430 to 580 ft thick) and Frontier sandstone Fm. (580 to 1005 ft thick) overlying the Mowry. The Frontier is marine and non-marine sandstone and shale of Late Cretaceous age. The Frontier Fm. outcrops in the southern Wind River Basin.

Maps: isopach, lithologic.

Cole, E. L., 1988, An evaluation of the Big Muddy Field low-tension flood demonstration project: DOE/BC/10830-9, 151 p.

A micellar-polymer demonstration project was carried out on a 90 acre site in the Big Muddy Field of Wyoming. Preflush injection began in early 1980. Low-tension and polymer drive banks were begun in January, 1981 and August, 1982 and the project was discontinued in September, 1985. Production through May 1987 was 290,000 bbl oil. Recovery is estimated at 14 % of the oil-in-place at the beginning of the project. The low-tension process was successfully mobilized waterflood residual oil.

Tables: well completion summary, formation mineralogy, permeability data, brine compositions, surfactant screening, properties of sulfonate, polymer screening, effect of formaldehyde, oil treating results, effect of slug viscosity, composition of slug, injectivity during low-tension slug injection.

Maps: locality, lineament pattern, structure, porosity isopach, net pay isopach, pore volume, permeability, imbibition, drainage, surfactant recovery, salinity effect, oil recovery, schematic of injection plant.

Cury, W. H., 1978, Early Cretaceous Muddy Sandstone delta of western Wind River Basin, Wyoming: Resources of the Wind River Basin, Wyo. Geol. Assoc., v. 30th Field Conf. p. 139-146.

The Muddy Sandstone of the Wind River Basin is a thin well-developed Early Cretaceous delta system. Sixty-five feet of prodelta sediments and delta-front sandstones formed at the northwest seaward edge of the delta. Delta plain sediments prograded over the prodelta sediments. Rapid subsidence preserved most of the Muddy delta sequence. Lower marine rocks were eroded by rivers on the delta plain and most of the delta plain southeast of Lander was eroded away. The delta plain was covered by two successive facies; 1. fluvial channel sandstones, and 2. flood plain deposits. Progressive onlapping by middle marine Muddy sequences buried the older delta system.

The unconformity at the base of beach deposits in the southeast was developed on fluvial sandstones of the delta plain. A second, upper marine sandstone and shale sequence buried the delta in the southeast. Northwest the sandstones grade into marine shales. In the Wind River Basin the Muddy is present in both outcrop and subsurface allowing a more complete analysis than in other areas.

Maps: cross-section, geographic field limits, outcrop and well control.

Davis, J. G., H. H. Ferrell, and W. C. Stewart, 1981, Big Muddy field low tension flood demonstration project: Third Ann. Rept., # DOESF01424-39, U. S. Doe, 85 p.

Analysis of nine 10 acre 5-spot pilot tests to provide data for commercialization of surfactant flooding in the low-permeability freshwater reservoirs of Wyoming and Colorado.

Ferrell, H. H., M. D. Gregory and M. T. Borah, 1984, Progress report, Big Muddy field low tension flood demonstration project with emphasis on injectivity and mobility: SPE 12682, 4rh Enhanced Oil Recovery Symp., p. 41-48.

Low tension flood tests began in the second Wall Creek mbr. of the Frontier Formation in 1980. Optimum slug mobility for maximum oil recovery and injectivity is analyzed for this reservoir.

Ferrell, H. H., D. W. King and C. Q. Sheely, 1984, Analysis of low-tension pilot at Big Muddy Field, Wy.: SPE/DOE 12683, 4th Enhanced Oil Recovery Sym., Tulsa, Ok., p. 49-54.

Conoco preformed a low-tension test on the Big Muddy field east of Casper, Wyoming in 1973. The process mobilized an oil bank ahead of the slug. A peak oil cut of 20% was reached with 36% of the residual oil recovered. Tracers injected in the preflush and postflush showed that over 95% of the flow to the center well came from the two northern injection wells. The successful results of the test supported the development of a 90 acre commercial demonstration in 1980 which still functioned in 1984.

Tables: injection schedule, injected tracers, oil recovery.

Gilliland, H. E., and F. R. Conley, 1976, Pilot flood mobilizes residual oil: Oil and Gas Jour., v. 74, p. 43-48.

Tests in Wyoming indicate early response and a high oil displacement efficiency in a surfactant field test. Production from a one acre 5-spot was 30 bbl per day at an 85% water cut (in 1975). The test is from the second Wall Creek in the Frontier Formation at an average depth of 3,050 feet.

The source of reservoir energy was a solution gas with a possible local water drive. The reservoir began waterflood in 1953 and 6.9 million bbl of oil was produced.

Tables and graphs: injected water analysis, tension vs. salinity, sulfonate retention, oil saturation, production response, surfactant plant flow diagram.

Gries, R., 1983, Oil and gas prospecting beneath Precambrian foreland thrust plates in the Rocky Mountains: AAPG Bulletin, v. 67, p. 1-28.

Sixteen test wells in the area have been drilled through Precambrian rocks to test 3 to 6 million areas of sedimentary rocks below. One recent test (1983) made a major gas discovery, over half the tests showed oil or gas. These wells have helped define the underlying structure and the geometry of the mountain-front thrust using data on seismic velocities of Precambrian rocks. Success of these wells has encouraged further drilling in the Wyoming thrust belt and suggests further areas to test in Wyoming along the Owl Creek Range, Gros Ventre Range, east and west flanks of the Big Horn Range and the north flank of the Hannah Basin.

Maps: locality, well data charts, cross section of thrust belt, thickness charts, cross-section and structural maps.

Tables: Details of drilling results and numbers of days needed to drill to these depths are given.

Hinton, G., 1957, Riverton Dome: 12th Ann. Field Conf. Guidebook, Wyoming Geol. Assoc., p. 132-136.

The Riverton Dome is a surface-seismic discovery in the south-west portion of the Wind River Basin found in 1945. Production of oil and gas is from the Frontier Fm., Muddy, and Lakota sandstones.

Deeper in the field an oil gravity of 46.5 was reported from a 219 ft section of Tensleep Fm. One hundred ft. of closure on a transversely faulted anticline is the trapping mechanism for the Frontier, and 600 ft of closure in the Tensleep. The Riverton Dome was active from Pennsylvanian to Cretaceous time with final movement during Laramide orogeny.

Maps: contour, structure

Tables: production data from 1945 to 1957.

Keefer, W. R., 1969, Geology of Petroleum in Wind River Basin, Central Wyoming: AAPG Bulletin, v. 53, p. 1839-1865.

Over 60 oil fields are located in structural traps that developed during Laramide deformation. Seventeen sedimentary formations produce oil. The principal reservoirs are the Pennsylvanian Tensleep, Permian Park City, Cretaceous Cloverly, Thermopolis (Muddy ss member), Frontier and Lance, Paleocene Fort Union formations.

Cretaceous deposition was in shallow seas. Primary oil accumulation began before folding began. Subsidence during the Laramide induced secondary migrational updip into structural traps that developed along the basin margins. The central deep part of the basin in untested (1969) in the Frontier Fm. where stratigraphic traps may retain oil. Common reservoirs are less than 15,00 ft deep.

Maps: locality, contour, lists of oil field and productive formations and depth. 600 to 1000 ft of Frontier Fm. is productive in the Wind River Basin.

Lawyer, G., J. Newcomer, and C. Eger, editors, 1981, Powder River Basin Oil and Gas Fields : Wyoming Geol. Assoc. v. I, 239 p., and v. II, p. 240-472.

Lists all fields in the Powder River Basin as of 1981. Gives location, formations, reservoir characteristics, maps, engineering and oil recovery data for each of approximately 405 fields. Includes data on five Class I reservoirs cited in the proposed study; Sage Spring Creek and Brooks Ranch producing from the Frontier; and Big Muddy, Burke Ranch and Cole Creek (South) producing from the Dakota Group.

Molenaar, C. M., and B. W. Wilson, 1990, The Frontier Formation and associated rocks of Northeastern Utah and Northwestern Colorado: Geol.Surv. Bull.1787, p. M1-M21.

The Frontier Fm., part of the Mancos Group, received new rank upgrading from Frontier sandstone member of Mancos Shale Fm. in this paper. The Frontier consists of several facies of marine and non-marine Late Cretaceous rocks that become totally marine in easternmost Utah and northeastern Colorado. Six major facies are recognized in the Frontier. 1. a basal transgressive marine sandstone, 2. a marine shale tongue, 3. a prograding coastal sandstone, 4. a sequence of non-marine sandstone, 5. an upper, transgressive coastal sandstone, and 6. an offshore-bar sandstone.

In outcrops along the south and eastern flanks of the Uinta Mts. these rocks range in thickness from 760 ft in the west to 140 ft in the east. The shoreline trend of the deltaic wedge was N 60° E across the Uinta, but swung NW into Wyoming north of the Uinta. South across the Uinta Basin the trend was N

55° E. 100 to 200 ft in sea level rise resulted in deposition of a transgressive shale at the top of the section.

Maps and figures: numerous cross-sections, structure, and correlations.

Saad, V., G. A. Pope, and K. Sepehrnooi, 1989, Simulation of Big Muddy surfactant pilot: SPE Reservoir Engineering, v. 4, p.24-34.

A chemical flood simulator has been used in a low-tension pilot test at the Big Muddy field near Caspar, Wyoming. The tracer injection before the chemical slug injection was analyzed separately. Using composition simulator oil recovery, tracers, polymers, alcohol and chlorides could all be identified.

Results show that for this freshwater reservoir a salinity gradient during preflush with a resulting calcium pickup by the surfactant slug played a major role in success. Analysis of crossflow on the performance of the pilot indicates that for the well spacing of the pilot crossflow is not as important as it would be for a large project.

Maps: well locations, core data streamlines for chemical injection.

Tables: initial reservoir condition, simulation of tracers, injection rates, oil recovery efficiency, injected compositions, simulation parameters, effective CEC on oil recovery efficiency, simulated alcohol concentration, simulated effective salinity and total calcium, simulated chloride concentration, simulated polymer concentration, bottom hole injection pressure.

Saad, N., G. A. Pope, and K. Sepehrnoori, 1990, Big Muddy surfactant pilot project: simulation design studies, abs., #490-704: SPE unsolicited paper, v. SPE 20802, p. 1-32.

An improved chemical flood simulator has been designed. Simulation results indicate that some design changes will substantially increase oil recovery efficiency.

Siemers. C. T., 1975, Paleoenvironmental analysis of the Upper Cretaceous Frontier Formation, Northwestern Bighorn Basin, Wyoming: 27th Ann. Field. Conf. Guidebook, Wyoming Geol. Assoc., p. 85-100.

Seventeen days of field work on outcrops were used to measure sections, collect thin sections and samples for X-ray diffraction. Outcrops studied were near Cody, Wyoming on the Clark's Fork River. The Frontier Formation, originally named for strata far south near Frontier, Wyoming, outcrops in this northern portion of the state. Lithologies and facies chart : 1. marine bar -interbar 2. Prodelta 3. delta plain 4. delta margin 5. nearshore marine; represents one major regressive - transgressive cycle along northwestern margin of the Bighorn Basin.

Tables: thin section analysis, mineral content and cements, paleoenvironment analysis based on grain size and mineral content.

Simmons. S. P., and P. A. Scholle, 1990, Eustatic and tectonic control on localization of porosity and permeability, Mid-Permian, Bighorn Basin, Wyoming: AAPG Bulletin, v. 74, p. 764.

The Goose Egg Formation of the northeastern Bighorn Basin was deposited as arid shoreline (sabka). Low sea levels are represented by terrestrial red beds and high levels resulted in supratidal to shallow subtidal carbonate deposition. During the Pennsylvanian and Permian uplift along the basin margin formed a broken chain of barrier islands and shoals and earlier carbonate members.

The Ervay member on these paleo-highs is fenestral dolomite with tepee structures and pisoids. This is interpreted as highest intertidal to supratidal sabka which formed leeward of the barrier islands. Basinward the deposits grade into bioclastic grainstone beach deposits then open-shelf fossiliferous packstones and wakestones. The eastern area is laminated lagoonal micritic limestones and dolomites.

Fenestral dolomite along the present day basin margin is the most porous facies. Folding here in the Laramide in the Goose Egg carbonates has caused fracturing and high permeabities. The combination of Laramide folding and productive Permian carbonates could be characteristic of other structures along the basin margin yet to be explored.

Stapp, R. W., 1967, Relationship of Lower Cretaceous depositional environment to oil accumulation, Northeastern Power River Basin, Wyoming: AAPG Bulletin, v. 51, p. 2044-2055.

Oil is produced from stratigraphic traps in the NE Powder River Basin. By surface studies it is possible to relate time-equivalent sandstone bodies to depositional patterns. Electric log correlations were used. Depositional trends of the Muddy sandstone were determined by isopach mapping. The Fall River has 3 sandstone bodies, the Muddy has 2 sandstone bodies (Newcastle and Dynneson). The Newscastle has a detrital drainage pattern. Oil production is from the eastern updip edges of maximum sandstone development.

Maps: location, structure, block diagrams, sand distribution, production areas.

Stewart, W. W., 1975, Recent drilling in the Line Creek area of Wyoming and Montana: 27th Ann. Field Conf. Guidebook, Wyoming Geol. Assoc., p. 203-208.

The field is structurally located west of the synclinal axis of the Bighorn Basin. It produces from the Frontier Fm. and Dakota group sandstones. It is believed that the structural feature of the Beartooth uplift obscures more stratigraphic and structural traps in the area. The drilling history of the fields in the immediate area is reviewed.

The paper summarizes difficulties of drilling and prospecting the western Bighorn Basin due to geologic, climatic, and government (National Forest Land) restrictions.

Maps: locality, structure showing formations penetrated by wells in folded area, contour maps.

Stone, D. S., 1967, Theory of Paleozoic oil and gas accumulation in Bighorn Basin, Wyoming: AAPG Bulletin, v. 51, p. 2056-2114.

The concept of a common pool state based on similar chemical compositions of crude oils, associated formation water and vertical density stratification of fluids in multi-zones fields is studied. Paleozoic reservoir rocks include organic-rich phosphatic fine-grained sediments of marine facies. Primary migration of oil was completed by Early Jurassic times. Stratigraphic traps were created by: 1. updip facies change, truncation of the Phosphoria Fm. and 2. uneven Phosphoria-Goose Egg truncation of underlying Teensleep Fm. Locally and further east hydrocarbons were released later by fracturing and faulting.

Maps: cross-sections.

Tables: engineering data (from 1960's production).

Stone, D. S., 1975, Discovery of Silver Tip South Field, Park Co. Wyoming: 27th Ann. Field Conf. Guidebook, p. 189-201.

The Silver Tip field is in the northwestern part of the Bighorn Basin. The structure is a buried anticline with a faulted terrace present at the surface. Production is from the 4th Frontier (Peay sandstone) and lower Dakota (Greybull). The field was discovered by a seismic profile study.

Maps: locality, structural contour, seismic structure, seismic line, structural cross section.

Surdam, R. C., T. L. Dunn, D. B. MacGowan and H. P. Heasler, 1989, Conceptual Models for the prediction of porosity evolution with an example from the Frontier Sandstone, Bighorn Basin, Wyoming: in Coalson, E. B., ed., Petrogenesis and Petrophysics of Selected Sandstone Reservoirs of the Rocky Mountain Region: Rocky Mt. Assoc. Geol., p. 7-28.

Predictions of porosity evolution are based on models to integrate the organic diagenesis with inorganic diagenesis in a source-reservoir system during burial. The processes of progressive burial diagenesis are in three zones. 1. shallow burial from surface to depths equivalent of 176 °F (80 °C). 2. intermediate burial 176° F to 284°F (80° C-140° C) . 3. deep burial 284° F- 410° F (140° C - 210° C). Each zone has specific organic/ inorganic interactions that control mineral stability and porosity evolution.

The key to porosity prediction is spatial distribution of organic/inorganic interaction during progressive burial. Modified Tissot and Espitalc (1975) kinetic maturation model was used. A case history of the Frontier Fm. of the Bighorn Basin was used for the model.

Charts: burial zones, porosity evolution, graphs on cement porosity, oil migration, reaction pathways of organic/inorganic components; specific engineering data for Frontier Fm. from the Bighorn Basin, Wyoming.

Taylor, B. A., 1957, South Sand Draw oil field: 12th Ann. Field Conf. Guidebook, Wyoming Geol. Assoc., p. 143-147.

A summary of the geology and engineering parameters of the South Sand Draw field, Wyoming.

Towse, D., 1952, Frontier Formation, Southwest Powder River Basin, Wyoming: AAPG Bulletin, v.36, p.1962-2010.

A geological description of the Frontier Formation in the Powder River Basin. The Frontier, a major oil producer, is primarily unfaulted in the Powder River Basin.

Waring, J., 1976, Regional Distribution of environments of the Muddy sandstone, southeastern Montana: 28th Ann Field Conf, Wyoming Geol. Assoc. Guidebook, p. 83-96.

The Lower Cretaceous Muddy sandstones occur on the eastern flank of the Powder River Basin. Reservoirs are primarily stratigraphic traps from single beds or a multiple of beds within the Muddy. The Bell Creek field is the only significant field developed in this area.

Beds are thin and lenticular with sand thickness local in extent and variable in character. Previous studies have interpreted the Bell Creek as marine and deltaic facies or barrier bars. During the time of the Lower Muddy the sea transgressed the channeled

Skull Creek surface. By middle Muddy all channels were filled. During the upper Muddy more sheet-like sands were deposited, although still marginal marine.

Maps: structure, locality, isopachs, E-log correlations.

Winn, R. D., Jr., 1991, Storm deposition in marine sand sheets: Wall Creek member, Frontier Formation, Powder River Basin, Wyoming: Jour. Sed. Pet., v. 61, p. 86-101.

The Wall Creek member of the Frontier Formation was deposited in the North American Cretaceous Seaway. The Wall Creek member is as much as 67 m thick and consists of shale, sandstone and minor conglomerate and bentonite. Deposition occurred during a sea level rise. Sandstone and mudstone were deposited as thin shelf sand sheets 6 to 15 m thick. Sand moved offshore and downcurrent from a delta-strandplain system on the west of the Powder River Basin. Delta-strandplain deposits were eroded by a subsequent transgression.

Core and outcrop studies show the Wall Creek to be burrowed to bioturbated medium-scale cross beds, horizontal laminated beds and ripple laminated beds. A dominance of storm current deposits over tidal deposits is indicated by variable bed thickness, structure type, grain size and degree of vertical burrowing.

Maps: locality, Western Interior Seaway, outcrop lithology, cross-section, stratigraphic zones, E-log correlations.

D. Robinson Formation

The Robinson Formation is a Pennsylvanian age sandstone in southern Illinois. Field studies in the early 1960's define the Robinson as fluvial in origin. The more recent TORIS data base defines fields in the Robinson Fm. as non-structured deltaic reservoirs. The Robinson sandstones may be interpreted as fluvial-dominated upper delta plain deposits.

Cole, E. L., 1988, An evaluation of the Robinson M-1 commercial scale demonstration of enhanced oil recovery: DOE10830-10, U. S. Dept. Energy, Bartlesville, Ok., 135 p.

A crude oil sulfonate surfactant system was used to flood the reservoir. At the time the reservoir was in an advanced stage of waterflood depletion. Ultimate oil recovery is estimated at 1,397,000 bbl.

Although the oil/sulfonate system mobilized and produced waterflood residual oil the project was not economic because of lower than expected recovery and higher costs. Low recovery is attributed to: poor volumetric sweep, and salinity/hardness effects. Formation parting due to injection overpressuring and random communication between producer and injectors contributed to the poor sweep efficiency. High salinity and water hardness exceeded the tolerance of the petroleum sulfonate surfactant system.

Tables and Figures: extensive coverage of testing and production data.

Clark, G. A., R. G. Jones, W. L. Kinney, R. E. Schilsm, H. Surkalo and R. S. Wilson, 1965, The Fry in-situ combustion test-performance: Jour. Petroleum Tech., v. 17, p. 343-353.

The test was a five-spot test on a 3.3 acre site in the Robinson sandstone of Illinois. Air injections tests were made at the site. Four cores were drilled in the reservoir.

Earlougher, R. C., Jr., J. R. Galloway, and R. W. Parsons, 1970, Performance of the Fry in-situ combustion project: Jour. Petroleum Tech., v. 22, p. 551-557.

The pilot test was broadened to a field wide test in 1964. The Robinson sandstone is a lenticular sand of Pennsylvanian Age. It is fluvial in origin. Four distinct structural units of the Robinson have been identified varying in thickness from 10 ft to 30 feet.

Earlougher, R. C. Jr., J. E. O'Neal, and H. Surkalo, 1975, Micellar solution flooding, field test results and process improvements: Rocky Mt. Reg. Meeting, Denver, Colorado, p. 1-7.

Small micellar solution field tests were successful for secondary and tertiary recovery. Test fields in two states were used. 1. The Robinson sandstone in Crawford County, Illinois. Estimates are that 59% of the oil within the test pattern might be displaced. 2. Bradford field, McKean County, Pennsylvania. This old field is about 40 to 55 % waterflooded.

The Maraflood oil recovery process is effective for tertiary recovery in sufficient quantities to be economic.

Tables: reservoir characteristics, oil recovery.

Gogarty, W. B., and H. Surkalo, 1971, A field test of micellar solution flooding: SPE 3439, 46th Ann SPE, New Orleans, La., p. 1-12.

Field tests of micellar solutions began in 1962 in Illinois. The first test was in an unflooded reservoir.

Subsequent tests (2 and 3) were conducted in water-flooded reservoirs. Test in waterflooded reservoirs are for tertiary recovery. The Robinson sandstone was the site of the tertiary recovery tests. A large pore volume of polymer was used to ensure complete mobility. 63% of the oil-in-place was recovered in the third test. A 9% volume slug displaced up to 3.8 barrels of oil per barrel of slug injected. Tracer studies indicate a mobility buffer of 50% pore volume is necessary. Tertiary recovery for the the Robinson should be 60%.

Tables: production data.

Maps and Figures: sand isopach, porosity-permeability and lithology, water saturation, slug performance, oil saturation, cumulative oil.

Hewitt, C. H., and J. Morgan, 1965, The Fry in-situ combustion test-reservoir characteristics: Jour. Petroleum Tech. v. 17, p. 337-342.

The test was carried out on a 12,000 foot long, 3,500 foot wide body of the Robinson sandstone of Illinois. The reservoir is at depths of 880 to 936 feet and has three distinct sandstone units, each with different textural and reservoir properties. The Robinson sandstone is of fluvial origin and part of an extensive system.

Howell, J. C., R. W. McAtee, W. O. Snyder, and K. L. Tonso, 1979, Large-scale field application of micellar-polymer flooding: Jour. Petroleum Tech., v.31, p. 266-272.

The Maraflood oil recovery process is a fluid injection with a slug of micellar-polymer injected into a formation by a mobility buffer. The mobility buffer is the polymer-water solution. The test area is the Robinson sandstone of Illinois.

The Robinson sandstone of Pennsylvanian age was deposited by a meandering river as migrating point bars. Production was increased from 40 bopd to 536 bopd during the process. Recovery is estimated to reach 27% to 33% of oil-in-place.

Maps and Figures: location, sand isopach, E-log, injection history, project performance.

Tables: reservoir characteristics, fluid injection sequence.

Shelton, J. W., 1973, Robinson sandstone, Pennsylvanian, southeastern Illinois; in: Models of sand and sandstone deposits: a methodology for determining sand genesis and trend: Oklahoma Geo. Surv. Bull. 118, p. 36-39.

The Robinson sandstone lies in the La Salle anticlinal belt on the eastern flank of the Illinois Basin in Crawford County, Illinois. Pennsylvanian rocks in this area are classic cycles of coals, shales, sandstones and limestone sequences. The Robinson sandstone is an informal member of the Spoon Formation of the Kewanee Group. Robinson sandstone includes a number of irregular sands in a 250 ft interval. The sands are oil bearing on the structural highs of the La Salle anticline. The Robinson is shallow subsurface with a depth from 880 to 940 ft, 21/2 miles long and 1 mile long. The belt of sands of the reservoir averages more than 10 ft thick for a 1/2 mile in length and 3,500 ft in width. Maximum thickness is 50 feet.

The Robinson sandstone has three zones. The upper zone has small scale cross-bedding and climbing ripples. It is 5 to 10 feet thick. The middle zone has medium scale cross-bedding with thin interbeds of small scale cross-bedding. It is 20 to 30 feet thick. The lower zone is mixed sandstone and interbeds of shale. The shale has mud-cracks and mantle ripple marks. This unit averages 20 to 25 feet thick.

Overall the Robinson has an upward decrease in grain size. A conglomerate of pebbles is present at the base. Permeability and to a lesser extent porosity decrease upward. The lower zone has an average porosity of 20% and permeability of 425 md. Average porosity of the middle zone is 19% and permeability 300 md. The upper zone averages 18% porosity and 50 md permeability. In the middle zone vertical permeability is 75% to 95% of horizontal permeability. The three zones are effectively isolated reservoirs.

The depositional environment is though to be bank and channel deposits of a river unto an alluvial plain. A meandering stream is indicated by the sedimentary structures. There are no marine indicators of lower deltaic plain rather than alluvial plain. The narrow width of the deposits suggests limited lateral shift of the stream.

Maps: locality, structure, isopach.

E. Strawn Group

The Pennsylvanian age Strawn Group of North-Central Texas has two major divisions. The deltaic deposits of the lower Strawn fill the deep Fort Worth Basin. Fluvial-deltaic deposits of the upper Strawn spread out over a great distance on the Concho Platform.

Bebout, D. G., and C. M. Garrett, 1983, West Texas (Railroad Commission of Texas Districts 7C, 8 and 8A) Mississippian to Permian plays: in Galloway, W. E., T. E. Ewing, C. M. Garrett, N. Tyler and D. G. Bebout, eds., Atlas of Major Texas Oil Reservoirs: Bureau Eco. Geology, The University of Texas at Austin, p. 106-130.

These several papers summarize and map the major Mississippi, Pennsylvanian and Permian plays in Texas. The Strawn Group appears in several of the regions covered. The majority of these reservoirs are, however, predominantly carbonate deposition. Sections include:

San Andres/ Grayburg carbonate (north and south Central Basin Platform).

Permian sandstone and carbonate

ClearFork Platform Carbonate

Queen Platform / strandplain sandstone

Wolfcamp Platform carbonate

Northern Shelf Permian carbonate

Maps: locality, structure, cross-section, net sand.

Charts: engineering -production data

Boring, T. H., 1990, Upper Strawn (Desmoinesian) carbonate and clastic depositional environments, S.E. King County, Texas (abs): AAPG Bulletin, v. 74, p. 218.

King Co., Texas was the area of interaction between carbonate and clastic deposition during the Desmoinesian. Carbonate facies were deposited along the northern edge of the Knox-Baylor trough. Terrigenous deposits were carried through the trough to the Midland Basin. Distribution and geometry of facies are related to subsidence of the Knox-Baylor trough, Pennsylvanian tectonics, deltaic progradation, avulsion and compaction.

The carbonate cycle on the platform from bottom to top includes the following facies: 1. algal bioclastic wackestones, 2. crinoidal wakestones, 3. algal bioclastic packstones-grainstones/fusulinid crinoidal packstones-grainstones, 4. crinoidal bryozoan wakestone/shale. Clastic sediments from the Wichita and Arbuckle Mts. filled the Knox-Baylor trough in the Desmoinesian. Deposits include: distributary-bar fingers, lobate deltas, offshore bars. Facies from top to bottom: 1. cross-bedded sandstones 2. intercalated sandstones and shales 3. mudstones/shales. Both carbonate and clastics provide excellent reservoirs from a depth of 5,000 to 6,000 ft.

Brown, L. F. Jr., 1973, Pennsylvanian rocks of North-Central Texas: an introduction: in Brown, L. F. Jr., A. W. Cleaves, and A. W. Erxleben, eds., Pennsylvanian Depositional Systems in North-Central Texas. A guide for interpreting terrigenous clastic facies in a Cratonic basin: Bur. Eco. Geo., The Univ Texas at Austin, v. 14, p. 1-9.

Many oil pay zones occur in North-central Texas in the Strawn and Cisco fluvial-deltaic sandstone facies. Maps delineate the stratigraphic position of facies. The commercial development of oil and mineral and rock units in the area is discussed. Maps show the regional structure, cross- sections and oil wells in the area. A map of the evolution of the depositional systems across the Concho Platform, Bend Flexure and Forth Worth Basin is included.

Brown, L. F., 1969, Geometry and distribution of fluvial and deltaic sandstones (Pennsylvanian and Permian), North-Central Texas: Gulf Coast Assoc. Geo. Trans. v. 19, p. 23-47.

Sandstones of the Cisco and Strawn formations and the Virgil and Wolfcamp series are discussed. Facies define a south-west paleoslope of 5 ft /mile across north-central Texas. Sandstone facies include: delta front sheets, distributary mouth bars, distributary and fluvial channels, destructional bars. Multistory sandstone bodies were deposited along narrow, structurally unstable belts maintained during 1,200 ft of Cicso strata. There are 30 stratigraphic levels in 1,200 ft of section of nearshore facies in the Virgil and Wolfcamp series. Very detailed analysis of descriptive stratigraphy of each unit, including outcrop cross-sections, cross-sections from logs and cores.

Maps: facies relationships, sandstone distribution, sand and mud compaction; depositional model for Texas delta basins.

Brown, L. F. Jr., 1973, Cratonic basins: Terrigenous clastic models: in Brown, L. F. Jr., A. W. Cleaves, and A. W. Erxleben, eds., Pennsylvanian Depositional Systems in North-Central Texas. A Guide for Interpreting Terrigenous Clastic Facies in a Cratonic Basin: Bur. Eco. Geol., Univ. Texas at Austin, v. 14, p. 10-30.

Analogs of modern delta models and ancient deltas may display different degrees of basin stability, geometry, scale, and other features. Depositional systems models should be based on processes and environment and not absolute scale and geometry. Depositional systems with a basin's history may include: terrestrial fans, lakes, eolian systems, dip-fed fluvial, deltaic, shelf and slope-basin systems. The rate of subsidence may depend on: 1. dip feeding across a shelf via delta progradation or tidal support. 2. strike feeding along the basin margin to barriers, strandplains and through tidal inlets, or bay-lagoon estuary systems.

Maps: fluvial development, deltaic systems, facies descriptions, schematic diagrams. Examples from the Strawn and other Groups in Texas.

Cate, A. S., 1988, Short-term community transition and "r selection" in shallow marine embayment fauna from Pennsylvanian of North-Central Texas (abs.): AAPG Bulletin, v. 72, p. 170.

Macrofauna from a thin fossiliferous strata of the East Mountain Shale (Strawn Group) was analyzed. Vertical sampling allowed reconstruction of a series of short-term communities and shifts in population structure of 2 gastropods; Glabrocingulum g. grayvillensis and Straparollus a. catilloides. These species shifts are related to environmental shifts brought on by deltaic progradation.

The lowest unit was rapidly colonized by bryozoans and crinoids. These were replaced by more mud-loving species of gastropods. In the upper part characterized by distributary deposits the harsh environment favored infaunal pelecypods. Initially rapid growth rates during early colonization were checked by density dependent limiting factors. Suspension feeders had high mortality rates as increases in suspended inorganics occurred. More stable environments had smaller numbers of larger individuals.

Cleaves, A. W., 1973, Depositional systems in the Upper Strawn Group of North-Central Texas: in Brown, L. F., A. W. Cleaves, and A. W. Erxleben, eds., Pennsylvanian Depositional Systems in North-Central Texas. A Guide for Interpreting Terrigenous Clastic Facies in a Cratonic Basin: Bur. Eco. Geo., The Univ. Texas at Austin, v. 14, p. 31-42.

The Strawn Group is a thick sequence of Middle Pennsylvanian terrigenous clastic and carbonate facies in a narrow band across north-central Texas. In outcrop the Strawn the carbonate facies comprise less than 5% of the total facies. This study used 1,400 E-logs and sample logs from 7,000 sq miles of 8 counties is North-central Texas.

Two general units based on tectonic setting and lithofacies character were defined. Lower Strawn basin fill for the Fort Worth Basin, fan deltas and slope depositional systems (including turbidites) make up the basin fill. It did not extend beyond the western flank of the Fort Worth Basin. Upper Strawn is similar to Canyon and Cisco in terms of deposition, history, and facies. The fluvial and deltaic Buck Creek Sandstone and Dobbs Valley Sandstone prograded over 80 miles beyond the western flank of the Fort Worth Basin.

Because the Midland Basin was not deep, no major slope depositional system developed in the upper Strawn. There was no slope break to localize deltaic sedimentation. Eight separate deltaic progradational cycles are recorded at surface and shallow subsurface in the upper Strawn.

Maps: Stratigraphic sections, cross sections across seven counties based on 80 wells, cross - sections across 5 counties based on 53 wells, three net sandstone maps based on 1,300 wells. Some coals appear in the delta plain facies, locality map for coal. Thick delta plain march deposits were due to high structural stability of the shelf.

Cleaves, A. W., 1990, Controls on cyclic sedimentation patterns with Middle and Upper Pennsylvanian transgressive-regressive sequences in North Central Texas (abs): GSA Bulletin, v. 22, p. 4.

The interval between the top of the Branon Bridge Limestone (middle Strawn) and the base of the Coleman Junction Limestone (top of the Cisco Group) contains 29 carbonate bound transgressive-regressive cycles. Complex influences of the uplift of the Ouachita Mts. and eustatic sea level changes controlled the deposition. Eustatic sea level changes were responsible for transgression of the bounding limestone units. The absence of a distinct shelf edge or vertically accreting carbonate banks adjacent to the Midland Basin was due to tectonic factors not sea levels. One to four geographically distinct fluvial-deltaic depocenters were active in course-grained deposition. Progradation of deltas occurring during a lowstand of sea level gave rise to incised valley-fill of chert pebble conglomerate that cut into earlier limestones and shales.

Cleaves, A. W., and A. W. Erxleben, 1985, Upper Strawn and Canyon cratonic depositional systems of Bend Arch North-Central Texas (abs): AAPG Bulletin, v. 69, p. 142.

Clastic and carbonate depositional systems of the Upper Strawn and the complete Canyon Group were deposited in the Fort Worth Basin and on the Bend Arch of north-central Texas. Twelve major cycles of deltaic progradation and marine transgression were involved. Variations in subsidence in the Fort Worth Basin, Knox-Baylor trough and Bend Arch were responsible for lithofacies geometry of the different cycles. Effects of eustatic sea level changes have not been recognized from the facies evidence in north-central Texas.

Galloway, W. E., 1983, Strawn Sandstone: in Galloway, W. E., T. E. Ewing, C. M. Garrett, N. Tyler, and D. G. Bebout, eds., Atlas of Major Texas Oil Reservoirs: Bur. Eco. Geo., The Univ. Texas at Austin, p. 65-67.

Fluvial and deltaic sandstones of the Strawn Group (Pennsylvanian) produce oil over North-Central Texas. Fields are associated with the Sherman Basin, Muenster Arch, Red River Arch, Fort Worth Basin, Bend Arch, and Eastern Shelf.

On the eastern and northern margins the Strawn clastics are truncated and capped by Cretaceous deposits. The source was the tectonically active Ouachita and Arbuckle Mountains of southern Oklahoma and northeastern TexasThe Strawn had three major elongate fluvial/deltaic lobe complexes. The proximal parts of the Strawn deposits in the Sherman Basin were folded and faulted in the late Pennsylvanian.

Trap type includes the faulted anticlines of the Sherman Basin and widespread -ow relief simple anticlines, combined structural noses or closures, and stratigraphic pinch outs of reservoirs. Multiple stacked reservoirs occur within several hundred feet of stratigraphic section. Many small Strawn fields display stratigraphic entrapment but only the Antelope field has produced over 10 million barrels of oil from a stratigraphic trap.Tables: fields with 10 million barrel production, engineering data

Maps: locality, fluvial-deltaic systems, environment model, structures, cross-sections.

Greimel, T.C., and A.W. Cleaves, 1979, Middle Strawn (Desmoinesian) cratonic delta systems, Concho Platform of North-Central Texas: Gulf Coast. Assoc. Geol. Soc. Trans., v. 29, p. 95-111.

The Strawn Group of the Fort Worth Basin and Concho Platform had four major transgressive-regressive cycles. Information from 4,000 well logs and 35 measured sections was used to correlate and interpret the area. Deltaic facies present within each cycle involve; thin (usually less than 140 ft thick) , multilateral, high-constructive elongate and lobate delta systems. The lowest two cycles extend downdip for more than 200 miles.

There was no true shelf-edge or slope system along the gradually subsiding eastern platform of the basin. The Arbuckle and Wichita Mts. were the source for the more arkosic northern delta systems. The Ouachita fold belt supplied the chert-rich detritus for the fluvial-deltaic facies on the Concho Platform.

Maps: locality, cross-sections, structural contour, facies, models and sand channel distribution.

Hamilton , J. F., and A. W. Cleaves, 1990, Petroleum geology of Missourian Strawn sandstone units, Callahan and Eastland Counties, Texas (abs): GSA Bulletin, v. 22, p. 8.

The uppermost Strawn between the base of the Palo Pinto limestone and the top of the "Morris" limestone can be divided into three units: lower Moran, upper Moran and Cross Cut. Each of these sandstone units represents delta lobes that prograded from SE to NW as part of a high constructive elongate deltaic system. Over 5MM bbl oil have been produced from these three units. Production depth averages 2,300 ft subsurface.

Three coarse-grained reservoir facies are present: 1. discrete distributary channel fills, 2. amalgamated distributary channel and channel -mouth bar sandstones, and 3. growth-faulted and diapirically deformed distal delta front sandstones. Secondary porosity developed where sand-sized fragments were removed through dissolution. Ankerite cement occludes porosity in all three units. These sandstones with open pore work, little authigenic clay (kaolinite) and epitaxial cement are excellent clastic petroleum reservoirs.

Jamieson, W. H. Jr., 1983, Depositional environments of Pennsylvanian Upper Strawn Group in McCulloh and San Saba Counties, Texas (abs): AAPG Bulletin, v. 67, p. 489.

The upper Strawn represents a transition to fluvial from progradational deltaic facies. The lower part of the upper Strawn is composed of horizontally bedded fine-grained sandstones and shales of delta front origin. Foreset beds dip up to 15 degrees. The delta-front facies contain small normal faults. Middle parts of the upper Strawn are massive fine to medium-grained mature sandstones which represent distributary mouth bar deposits and proximal delta front deposits. The upper part of the upper Strawn consists of fluvial trough cross-bedded sandstones and chert pebble conglomerates. The upper Strawn is overlain by the Adams Branch limestone. The upper Strawn of McCulloh and San Saba counties represents continued filling of the Fort Worth Basin.

McInturff, D. L., R. C. Price and R. F. Ward, 1989, Depositional environments and porosity development, Strawn Formation (Middle Pennsylvanian), Wagon Wheel and H S A (Penn) Fields, West Texas (abs): AAPG Bulletin, v. 73, p. 389.

These fields are on the western flank of the Central Basin Platform in the Permian Basin. Siliciclastic and carbonate depositional systems controlled sedimentation in the Strawn in this region. The HSA field is composed of fanglomerate clastics which prograded westward across the basin. The Wagon Wheel is carbonate with five shallowing upward sequences. Rapid transgressions are marked by subtidal phylloid algal wackestone facies. Porosity occurs in interparticle voids within the nearshore fanglomerate lobes and as leached biomolds in the grainstone shoals of the carbonate bank. Late stage ferroan calcite cement reduces porosity.

Shannon, J. P., and A. R. Dahl, 1971, Deltaic stratigraphic traps is West Tuscola Field, Taylor County, Texas: AAPG Bulletin, v. 55, p. 1194-1205.

Hydrocarbons is sandstone bodies of West Tuscola field near Abilene, Texas are in stratigraphic traps composed deltaic sandstone of the Strawn Group. Vertical sequence (bottom to top) is: 1. progradational sequence (prodelta and delta front), 2. aggradational unit (delta plain-marsh and interdistributary bay), and 3. overlying transgressive shallow marine interval.

Reservoir sandstones in the delta-front facies are know locally as the "Gray sandstone". They are stream-mouth-bar deposits, lenticular and irregular in shape. Porosity is variable and, therefore, it makes development of secondary recovery methods and predicting occurrences in other deltaic sandstones difficult.

Sullivan C. E. B., 1990, Planning and interpretation of a VSP in a Strawn mound prospect, Lea County, New Mexico (abs.): AAPG Bulletin, v. 74, p. 773.

A zero offset, single source offset vertical seismic profile was conducted on an 11,500 ft deep Strawn mound. Objectives: 1. an accurate well tie 2. a representation of the mound away from the borehole 3. a comparison with a key surface seismic line. Modeling was used to test whether the VSP could detect changes in mound configuration and porosity content. The difference in phase, the surface line being out of phase with respect to the VSP caused interpretation difficulties. Processing of seismic data with a deconvolution operator designed from the VSP data was recommended in further tests.

Trice, E. L., 1982, Depositional history of Strawn Group (Pennsylvanian) Fort Worth Foreland Basin, Colorado River Valley, Central Texas (abs.): AAPG Bulletin, v. 66, p. 637.

In the Colorado River Valley, Texas, 1,200 ft of terrigenous clastic and carbonate facies were deposited in the Fort Worth Basin. Paleocurrent and petrographic data indicate that the source was the rising Ouachita Mts. in the north and northwest. Outcrop studies divide the Strawn Group into two divisions: 1. lower Strawn-basin and submarine fan sediments deposited as active tectonic subsidence increased water depths in the Fort Worth Basin, and 2. upper Strawn- a progradational sequence of fluvial-deltaic and carbonate platform sediments deposited as regional uplift to the east accompanied progressive shoaling of the sediment surface. The lower Strawn has four facies: 1. massive channel sandstone, 2. massive amalgamated sandstone, 3. turbidite, and 4. shale facies.

The upper Strawn delta platform assemblages include: 1 channel mouth-bar sands, delta-front sands, delta slope sands, interdistributary fine clastics, and 2. carbonate facies including phylloid algal mounds and perideltaic bioclastic limestones. The lower Strawn overlays the Smithwick Shale. Upper Strawn grades from lower Strawn in some areas but rests unconformably over the Marble Falls Fm. in other areas due to orogenic movement of the Ouachitas.

Trice, E. L., and R. C. Grayson, 1982, Depositional systems and stratigraphic relationships of Strawn Group (Pennsylvanian), Colorado River Valley, Central Texas (abs.): AAPG Bulletin, v. 66, p. 637.

Brazos River Valley Strawn deposits are fluvial, deltaic, and shallow marine. The Strawn Group of the Colorado River Valley is divided into lower and upper units. The lower Strawn represents submarine fan and basin fill deposits, at least two cycles of fan progradation are recognized. Upper Strawn represents three regressive-transgressive cycles of deltaic, perideltaic and shallow submarine depositional systems. Lower Strawn is confined to the Fort Worth Basin overlying the Smithwick Shale. The upper Strawn prograded westward up on to the Concho Platform. The sediment source was the Ouachita foldbelt.

Ware, G. D., 1987, Stratigraphic and structural relationships of Strawn Group, Brown, Coleman and Runnels Counties, Texas (abs.): AAPG Bulletin, v. 71, p. 244-245.

Two exposures of the Strawn form triangular areas in north-central Texas; the Brazos River Valley and the Colorado River Valley. The Brazos River Valley outcrops are fluvial-deltaic and represent transgressive shallow marine facies. They grade into carbonate facies in the subsurface. The Colorado River Valley Strawn is divided into two units; the lower Strawn is basin-fill sediments of outer shelf, slope and submarine fan. The upper Strawn is correlated to the Strawn in the Brazos River Valley and west into the subsurface. In the Colorado River Valley and west into the subsurface mapping reveals a system of faults related to horst and graben structures. The Concho Arch area was positive and became a core of persistent algal buildup.

F. Wilcox Group

The Wilcox Group is a sequence of Paleocene-Eocene age clastic formations reaching across the Texas Gulf Coast to include parts of Texas, Louisiana, and Mississippi. Growth faulting in Texas caused the building of thick deltaic sequences in predominantly faulted reservoirs. Further east, in Louisiana and Mississippi, the Wilcox produces from non-structured deltaic reservoirs.

Anderson, M. P., and J. A. Breyer, 1988, Depositional sequences and hydrocarbon exploration in Wilcox Group, South Texas (abs.): AAPG Bulletin, v. 72, p. 155.

Five unconformity-bounded sequences (A to E, from upper to lower) are present in the lower and middle Wilcox of south Texas. In the C, D, and E sequences of the Lower Wilcox of DeWitt County and parts of Gonzales, Karnes and Lavaca Counties there are 33 gas fields, all but two of which are in the Wilcox growth-faulted zone. These 33 fields are located in the downdip Wilcox and contain less than 40% sand. The updip Wilcox sequences above the growth fault zone contain 44 fields, with additional as yet undeveloped areas in the shallow Wilcox trend.

Belvedere, P. G., 1988, South Harmony Church Field, Southwest Louisiana- further insights on Uppermost Wilcox shelf-margin trend (abs.): AAPG Bulletin, v. 72, p. 160.

The Wilcox Group in South Harmony Church Field is a 2,000 ft thick sequence of single and multistory sandstones and shales. Typical lithologies include: bioturbated, muddy sandstone- inner shelf; less bioturbated, arenaceous sandstone- mostly inner shelf; structureless to faintly horizontally laminated sandstone- mostly lower shoreface; horizontal to cross-laminated, commonly deformed sandstone with shales and siltstone interbeds- lower shoreface.

The best reservoir sands are the bioturbated clean sandstones of the shelf-shoreface transition zone where porosity ranges from 5 to 23 % and permeability ranges from 0.01 to 31 md. Porosity is of leached secondary origin. Geologic parameters in Allen Parish are similar to those of Lockhart Crossing Field including: 1. rollover anticline production, 2. shelf to nearshore depositional setting, and 3. lithology. The study area (Allen Parish) is down dip from Lockhart Crossing.

Berg R. R., 1979, Characteristics of Lower Wilcox Reservoirs, Valentine and South Hallettsville Fields, Lavaca County, Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 29, p. 11-23.

The Valentine field produces oil at depths of 9,100 ft in a stratigraphic trap from two sandstones of the Wilcox group. The Technik is a thin-bedded 25 ft thick turbidite, with laminated bedding. Adjacent sandy shales are bioturbated in the lower section but not in the upper section of the Technik sequence. The Kublena zone is similar. The non-reservoir facies are overbank deposits.

South Hallettsville field, lower Wilcox sandstones produce gas at depths of 10,000 to 11,400 ft. Beds are 2-10 ft thick and composed of massive turbidite sandstones. They are stacked channel turbidites isolated by black shale. Some of the sandstone is contorted due to soft-sediment deformation. Regional seismic profiles show lower Wilcox sands deposited on Early Eocene shelf edge and slope.

Maps: locality, E-log correlations, seismic lines, core sections show textural features.

Breyer, J. A., 1985, Coarsening-upward tidal sequences in Wilcox Group in East Texas (abs.): AAPG Bulletin, v. 69, p. 142.

Most concepts of the Wilcox Group are based on paleogeographic reconstructions based on maps of net sand. Coarsening upward tidal sequences found in the walls of lignite mines show the shortcoming of these reconstructions. In the past these sequences were interpreted as prograding floodplain splays in an area of fluvial sedimentation. Recognition of the tidal origin of the coarsening-upward sequences suggests an embayed coast or shoreline at the time of deposition. Smaller intervals can be defined using the principles of sequence stratigraphy and tracing unconformities in the subsurface for predicting the subtle trap.

Breyer, J. A., 1984, Tide-dominated delta model for coal-bearing Wilcox strata in South Texas (abs.): AAPG Bulletin, v. 68, p. 457.

Coal-bearing Wilcox deposits near Uvalde, Texas are from a tide-dominated delta comparable to the Klang-Langat delta of Malaysia. Five facies are identified: 1. lignite 2. underclay 3. interbedded sand and mud with lenticular, wavy, flaser bedding 4. ripple-laminated or cross-bedded sand 5. greenish strongly bioturbated sand.

On the Klang-Langat delta modern equivalents of these facies are: 1. peat formed in freshwater swamps 2. root horizons developed beneath the peat 3. interbedded sand and mud on tidal flats 4. channel sands 5. shallow marine sand and mud.

Tidal flats of modern deltas are crossed by small tidal creeks and larger tidal streams. Tidal channels cut into tidal flat sediments and separate peat forming areas. Channel sands of the Wilcox cut into tidal flat deposits and form washouts in the lignite. Thinner sands in the Wilcox are small tidal creeks with sharp erosive bases, fining upward into mud. The thick sands in the Wilcox have sharp tops and bases and show no grain size trend. They are fills of larger tidal streams.

Chin, E. W., G. A. Cole, M. J. Gibbons, R. Sassen, and R. J. Drozd, 1990, Organic geochemistry of Lower Tertiary shales of Southern Louisiana: regional distribution of source potential (abs): AAPG Bulletin, v. 74, p. 628.

Outer continental shelf shales of Paleocene/Eocene Wilcox Group and Middle Eocene Sparta Fm. are potential source rocks for oil in southern Louisiana. 837 shale samples from 24 wells were analyzed using Rock-Eval pyrolysis and pryolysis-gas chromatography and gas chromatography-mass spectrometry. Regional trends in organic geochemistry are related to sedimentary facies transition from proximal deltaic to shelf/slope environments and thermal maturity. Thermal effects increase from east to west and from north to south as depths of 30,000 ft are reached in the Wilcox. There is more oil from west to east in southern Louisiana with maximum in the shelf/slope flexure zone of south-central Louisiana. Sparta Fm. shales show excellent potential in shales overlain by shelf-edge barrier sands. Wilcox source rock potential is high in shales deposited in submarine fan environments.

Chuber, S., 1979, Exploration methods of discovery and development of Lower Wilcox reservoirs in Valentine and Menking Fields, Lavaca County, Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 29, p. 42-51.

The Valentine field was discovered by correlations of 48 wells in a 185 sq mile area. The Wilcox Group in the Valentine field is 4000 ft thick. Six deltas in this field were correlated. A northeast-striking barrier bar model was used to pick offset-development locations. Subsurface data exposed two shale-filled channels which are responsible for the oil accumulation.

The Menking field was an accidental discovery in the Kubena sandstone, 100 ft above the shale-filled channel.

Maps: locality, deltas, isopach, sand trends, structural contours, E-logs.

DePaul, G. J., 1989, Environment of deposition of Upper Wilcox Sandstone, Katy Gas Field, Waller County, Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 30, p. 61-70.

Sandstones of the Wilcox Group produce gas at depths of 10,021 to 11,000 ft. Reservoirs are controlled by stratigraphic and structural features. Producing zones are from 6 to 42 ft thick. Production is localized on the top on an anticline. The upper Wilcox was defined as delta front grading upward to bay-marsh deposits (Williams 1974). and turbidite deposits by (Berg and Findley, 1973). The field is downdip from the Wilcox fault zone. Cores from the upper Wilcox show the sandstones are submarine, channel turbidites. The sandstones are sparsely bioturbated. Forams indicate bathyal water depths at the time of Wilcox deposition.

The upper Wilcox group is associated with late Sabinian transgression, deposition in a submarine fan.

Maps: locality, structure, isopach; E-log correlations, core sections for textural analysis.

Dingus, W. F., and W. E. Galloway, 1990, Morphology, paleogeographic setting, and origin of the Middle Wilcox Yoakum Canyon, Texas Coastal Plain: AAPG Bulletin, v. 74, p. 1055-1076.

The Yoakum is the largest Gulf Coast Eocene erosional gorge. It is interpreted as a buried submarine channel. The canyon can be traced 67 miles from the Wilcox fault zone. The canyon was formed adjacent to the Rockdale Delta and depths exceed 3,500 ft of shale-fill. The sequence of formation was: 1. distal deltaic facies of the lower middle Wilcox were deposited during regression, 2. upper middle Wilcox progradation atop the unconsolidated muds initiated slump of the continental margin, 3. erosion of the canyon across the shelf contemporaneously with subsidence and disruption of sediment supply, and 4. Yoakum Canyon filled by hemipelagic and prodelta muds of upper Wilcox.

Maps: isopachs, paleogeographic, logs; 3 -dimensional model of canyon

Dow, W. G., and P. K. Mukhopadhyay, and T. Jackson, 1988, Source rock potential and maturation of deep Wilcox from South-central Texas (abs): AAPG Bulletin, v. 72, p. 179.

Organic rich shales from depths of 5,000 to 24,000 ft were analyzed. Lowest and highest vitrinite reflectance and bottom hole temperatures are .4% R and 122° F at 5,000 ft and 4.5% R and 460° F at 24,000 ft. Four types of organic facies were found. Three phases of types IIA and IIB oil prone kerogens are related to environment. Deltaic coal and deep sea-fan or prodelta shales in thelower Wilcox are source rocks for the liquid hydrocarbons in south-central Texas. Generation and expulsion of crude oil occurred during deposition of overlying middle Miocene reservoir facies.

Edwards, M., 1981, Upper Wilcox, Rosita Delta system of South Texas: Growth-faulted shelf-edge deltas: AAPG Bulletin, v. 65, p. 54-73.

A study based on 500 well logs. A complex of three deltas each up to 10's of miles along strike can be traced 15 miles downdip. Basinward across the growth fault zone each delta has 600 to over 3,000 ft of deposits. The growth faults were activated by progradation of deltas over unstable prodelta-slope muds at the contemporary shelf margin.

The Wilcox deltas are Duval, Zapata and Live Oaks, from oldest to youngest. Each has several lobes, with thickness increased by tenfold due to progradation over active growth faults. Characteristic coarsening upward sequences include: prodelta shales, delta front sandstones, distributary channel and channel-mouth bar sandstones and interdistributary shales and sandstones. For the Wilcox the Paleocene-Eocene was the first extensive period of progradation of terrigenous sediment in the Tertiary Gulf Coast basin. It thicken from 100 ft near outcrop to over 6,000 ft subsurface across 60 to 100 miles.

Conclusions: 1. The sandstones in deep upper Wilcox were deposited in shallow water deltaic environments. 2. Upper Wilcox deltas of Rosita complex prograded rapidly toward the shelf edge in association with growth faults accumulating great thickness.

Maps: delta location and shelf edges, stratigraphic sections, log sections, strike sections, structural dip sections showing faults; correlations.

Edwards, M. B., 1980, The Live Oak Delta Complex: an unstable, shelf/ edge delta in the deep Wilcox trend of South Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 30, p. 71-79.

Correlation of 500 well logs shows three major delta complexes in the Rosita delta system. They were previously defined as lower Wilcox shelf-edge facies. Now reinterpreted as upper Wilcox deltas that prograded across a stable shelf to an unstable margin.

The Live Oak Delta complex is the youngest and has the most numerous lobes. The Luling and Slick lobes are extensively growth faulted, changing downdip from delta plain to prodelta facies. Thickness increases downdip where rapid subsidence occurred. The deltas prograded out to the shelf margin and the associated growth faults reflect gravity instability related to the adjacent prodelta slope.

Maps: locality, isopach; E-log correlations.

Edwards, M. B., 1985, Effect of differential subsidence in growth-faulted regions on E-log patterns and preservation potential (abs.): AAPG Bulletin, v. 69, p. 251-252.

Electric log correlation in the Eocene Wilcox Group and Oligocene Frio Fm. of the Texas Gulf contradict the idea that changes in log character across growth faults only reflect changes in environment. Growth ratios on the downthrown blocks vary from 1:1 to as much as 10:1. The basic unit of both deposition and correlation is the regressive coarsening upward sequence. Growth faults had no significant surface expression and did not separate contrasting environments.

In the Wilcox, prodeltas pass up into delta front sandstones. In the Frio barrier-bar or strandplains, shelf and lower shoreface deposits pass up into upper shoreface sandstones. A change in log character across a growth fault appears to indicate that the subsidence rate on the downthrown block exceeds a threshold valve, enabling preservation of low energy muddy layers and episodic storm deposits that were largely destroyed by weather-wave reworking on the upthrown block. Sandstones in the downthrown block may contain shale barriers to vertical fluid flow if the threshold rate was exceeded.

Fisher, W. L., 1969, Facies characterization of Gulf Coast basin delta systems, with some Holocene analogues: Gulf Coast Assoc. Geo. Soc. Trans., v. 19, p. 239-261.

There are two basic delta types on the Mesozoic-Cenozoic Gulf Coast: high-constructive— largely fluvial and fluvial influenced facies, and high-destructive—predominately marine facies. High constructive lobate and elongate systems are recognized as well as high-destructive wave dominated and tide dominated deltas.

Examples of high-constructive deltas are: Lower Wilcox of Texas, Louisiana, and western Mississippi, Yegua and Jackson of Texas, and Woodbine of Texas, and Cotton Valley of Mississippi and Louisiana. The Holocene analogue is the modern Mississippi delta.

High-destructive deltas include the upper Wilcox, Vicksburg, and Frio of Texas. Holocene analogues include the Rhone, Po, Apalachicola, and Tabasco delta systems. The paper discusses stratigraphy, facies, and depositional processes.

Maps: delta schematics, depositional systems, delta locality map, facies distribution examples, net sand, maps of delta types and logs.

Fisher, W. L., and J. H. McGowen, 1967, Depositional Systems in Wilcox Group (Eocene) of Texas and their relation to occurrence of oil and gas: Gulf Coast Assoc. Geol. Soc. Trans., v. 17, p. 105-125.

See annotation in next entry.

Fisher, W. L., and J. H. McGowen, 1987, Depositional Systems in Wilcox Group (Eocene) of Texas and their relation to occurrence of oil and gas: in Beaumont, E. A., and N. H. Foster, ed., Reservoirs II Sandstones; Treatise of Petroleum Geology, Reprint Series, v. 4, p. 242-266.

A regional investigation of the Wilcox group in outcrop and subsurface indicates seven principal depositional systems. 1. Mt. Pleasant fluvial system updip and in outcrop north of the Colorado River. 2. Rockdale delta system, primarily subsurface between the Guadalupe and Sabine Rivers. 3. Pendleton lagoon-bay system, outcrop and subsurface on the southern flank of the Sabine uplift. 4. San Marcos strandplain-bay system, outcrop and subsurface on the San Marcos Arch. 5. Catahoola barrier bar system, subsurface, South Texas. 6. Indio bay-lagoon system, updip and outcrop in South Texas. 7. South Texas shelf system, extensive in the subsurface.

The Rockdale delta system of large lobate wedges of mudstone, sandstone, and carbonates is the thickest and most extensive on the lower Wilcox depositional systems. It grades updip into the Mt. Pleasant fluvial system. Deposits of the Rockdale were the source for redistribution by marine processes. Delineation of the component facies of the several systems permits establishment of regional oil and gas trends which show relation of producing fields to potentially productive trends.

Maps: depositional systems, outcrop and subsurface distribution of sand, stratigraphic sections, delta system locality, mud-sand ratios, production map.

Galloway, W. E., 1989, Genetic stratigraphic sequences in Basin Analysis II: application to Northwest Gulf of Mexico Cenozoic Basin: AAPG Bulletin, v. 73, p. 143-154.

The Gulf of Mexico Cenozoic sedimentary wedge illustrates the use of genetic stratigraphy. The principal genetic units of the basin fill are sequences defined by regional marine flooding. Periods of basin margin offlap punctuated by period of transgression and marine deposition. Continental margin outbuilding is concentrated in one or more shelf edge-delta systems. The depocenters relocate during transgression and flooding. Syndepositional structural style results in sporadic uplift of basin-fringing deposits and facies along zones of normal faulting and enhanced subsidence are preserved. Genetic statigraphic sequences reflect interplay of variables such as tectonic events in the source rock area in the early Cenozoic. Late Cenozoic sequences are more related to sea level fluctuations.

Maps: Stratigraphic section of Gulf Coast, movement of depocenters in Gulf Coast, 3-D model, E-log correlations across Gulf Coast, source areas for Gulf, position of major delta systems in Cenozoic.

Galloway, W. E., 1968, Depositional systems of the Lower Wilcox Group, North-central Gulf Coast Basin: Gulf Coast Assoc. Geol.Soc. Trans., v. 18, p. 275-289.

Lower Wilcox of Louisiana, Mississippi and Alabama consists of 4 depositional systems. 1. Holly Springs Delta system is the largest, 2. Pendleton Bay-lagoon system which extends into east Texas, 3. a restricted shelf system east of the delta system, and 4. an unnamed fluvial system along the flanks of the Mississippi trough. Three lobes of the delta mass are separated by mud-rich interdeltaic-subembayments.

Facies mapping from E-logs recognizes seven components of the delta system: 1. bar-finger sand facies, 2. interdistributary bay mud-silt facies, 3. distributary channel sand facies, 4. prodelta mud facies, 5. distributary mouth bar-delta front sand facies, 6. interdistributary deltaic plain sand-mud-lignite facies, and 7. destructional phase sand-mud-lignite facies.

There are two principal types of deltas in the Holly Springs system. The bird-foot lobes were constructed where distributaries prograded over thick prodelta muds; thinner more lobate shoal-water delta lobes formed on shallow sandy shelves or old delta plains. There is a correlation in depositional environment and oil production between Holly Springs and Rockdale system of Texas. Sand units associated with distal margins of lobes or destructional units are the most prolific reservoirs.

Maps: locality, sand isolith , cross-sections, sand-shale ratios, E-logs.

Galloway, W. E., W. F. Dingus and R. E. Paige, 1988, Depositional framework and genesis of Wilcox submarine canyons systems, Northwest Gulf Coast: AAPG Bulletin, v. 72, p. 187-188.

Wilcox slope systems have two families of paleo-submarine canyons. The Yoakum is in the regressive middle Wilcox. Four canyons exhibit high length to width ratios and the fill is primarily mud. The fill is genetically related to the upper Wilcox fluvial-deltaic sequences.

Lavaca type canyons form a system of erosional features created along the rapidly prograding, unstable lower Wilcox continental shelf. Five canyons are characterized by low length to width ratios, and broad, flat floors. They cut out large volumes of prodelta and slope facies, fill is both mudstone and sandstone. Cores reveal slump and debris-flow sedimentary packages. Lavaca type canyons are associated with large slumps.

General process model for submarine canyons includes: 1. depositional loading of the continental margin creating instability, 2. initiation of large-scale slump or listric bedding-plane faults, and 3. headward and lateral expansion of the depression by slumping and density under-flow erosion.

Short broad canyons form on narrow shelves of active prograding margins. Elongate mature canyons form in regressive or transgressive settings.

Garbis, S. J., B. J. Brown and S. J. Mauritz, 1985, Review of the completion practices in the Wilcox Formation in South and South Central Texas: SPE/DOE Low Permeability Gas Reservoir, Denver, Colorado, v. 13900, p. 497-508.

This paper gives specific engineering data with averages and ranges from a number of Wilcox units in south Texas. There is a discussion of rock characteristics, drilling and completion data, fracturing considerations, and design.

Tables: X-ray diffraction analysis, mineral content of formation water, reservoir and frac fluid characteristics; examples of casing program for well, proppant profiles, and calculated productivity.

Gibson, T. G., 1982, New stratigraphic unit in the Wilcox Group (Upper Paleocene- Lower Eocene) in Alabama and Georgia: U. S. Geol. Surv. Bulletin, v. 1529-H, p. H23-H32.

A new lithostratigraphic unit is named in this paper. The Baker Hill Formation of the Wilcox Group outcrops in eastern Alabama and western Georgia. Baker Hill is largely kaolinitic clay and cross-bedded sand and was previously part of the Nanafalia Formation. Outcrops are in the Chattahoochee River Valley. The name change relied heavily on invertebrate fossil identification and stratification.

Maps: locality, cross-sections, age relationships.

Gulmon, G. W., H. E. Hansen, and A. T. Ricci Jr., 1972, Hazlit Creek Field, Wilkinson County, Mississippi: AAPG Memoir 16, p. 318-328.

Oil in the Hazlit Creek field is found in stratigraphic traps of the Lower Wilcox at depths between 6,875 and 7,250 ft. Eight sandstone units comprise 375 ft of pay sands.

Maps: locality, contour: facies description, description of production zones, sample logs and some engineering characteristics.

Herrmann, L. A., 1986, Computer-aided exploration-a case history, (Caldwell Parish, Louisiana): Gulf Coast Assoc. Geol. Soc. Trans., v. 36, p. 151-159.

Gas exploration is the Wilcox Group of Louisiana used data from 223 wells in 1975 and 469 wells in 1986. Computer use of this data predicted wells based on structure, isopach, trend surface, and residual maps. 34% of the wells produced gas.

Hutchinson, P. J., 1987, Morphology and evolution of a shale-filled Paleo-channel in the Wilcox Group (Paleocene- Eocene), Southeast Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 37, p. 347-356.

Seven paleo-channels in the Wilcox Group of the Gulf Coast have been described. An eighth suggests passive submarine erosional forces shaped the channels prior to active erosional forces such as turbidity currents. The Tyler (Hardin) channel is 24 miles long and 12 miles wide with over 1,000 feet of shale fill. It bifurcates updip.

The deep marine shale infill of these channels acts as a source of oil and gas and a seal for adjacent reservoir rock. Upward migration of oil through fractures and faults fills the reservoirs in overlying Wilcox deposits. Most oil fields in the Wilcox Group of Tyler and Hardin counties are associated with the underlying channel fill.

Maps: locality, stratigraphic sections, isopach of channel fill, correlation of channel fill and oil fields, hydrocarbon migration.

Hutchinson, P. J., 1987, Morphology and evolution of shale-filled paleochannel in Wilcox Group (Paleocene-Eocene), Southeast Texas (abs.): AAPG Bulletin, v. 71, p. 1117.

Paleochannels in the lower Wilcox include: Bejuco—Lalaja, Chicontepec, DeSoto, Nautla, Ovejas, St.Landry and Yoakum and Tyler (Hardin). The Tyler (Hardin) is 24 miles long, 12 miles wide and displays over 1,000 ft of shale fill in a N-S trending channel. It bifurcates updip into two channels with many gullies. The channel grew from youthful to mature stages through passive erosive mechanisms. In the mature stage it was enlarged by turbidity currents. In old age infilling occurred with a deep marine shale. The deep marine shale of the channel fill acts as a source of oil and gas and a seal for adjacent reservoir rock. Upward migration of oil through faults and fractures in the fill are the source of oil for the reservoirs of the Upper Wilcox in Tyler and Hardin Counties, Texas.

Lawless, P. N., 1990, Genetic stratigraphy of the Lower Paleogene of Central Louisiana (abs.): AAPG Bulletin, v. 74, p. 700-701.

The Wilcox Group and related Porters Creek Formation were divided into three sequences using 476 wells and 6 seismic lines. Genetic sequences include: 1. Midway, 2. Eolly Springs, and 3. Carrizo. They are locally dominated by highstand systems tract deposits. The Midway was deposited in a very rapid sea level fall. It is characterized by shingled prograding clinoforms. The Eolly Springs was deposited during a sea level rise and is fluvially dominated. The Carrizo was deposited during sea level fall and has poorly developed deltaic facies. The three sequences represent separate hydrocarbon migration routes. Oil has been produced from the Carrizo and Eolly Springs, but not from the Midway.

May, J. A., and S. A. Stonecipher, 1988, Diagenetic/stratigraphic modeling: Wilcox Group, Texas Gulf Coast (abs.): AAPG Bulletin, v. 72, p. 218.

Diagenetic/stratigraphic modeling of Wilcox facies interpretations are based on depositional process and lateral variation and vertical sequence of processes. Diagenetic models require knowledge of chemical processes. Chemistry of bottom waters affects formation of specific authigenic clay and carbonate cements. The Wilcox Group is the 1st major regional clastic wedge built over and beyond the Cretaceous carbonate shelf edges. Cores analyzed attribute sediments to subenvironments of the delta plain, delta front and continental shelf. Turbidites are present along delta fronts, however no submarine fan sequences have been found (16 wells).

McCulloh, R. P., and L. G. Eversull, 1986, Shale-filled channel system in the Wilcox Group (Paleocene-Eocene), North-central, South Louisiana: Gulf Coast Assoc. Geol. Soc. Trans., v. 36, p. 213-218.

The shale channel is a N-S trend that bifurcates to form two branches downdip. The channel cuts across adjacent sandstone-shale Wilcox strata. The channel shale is nearly featureless with uniform lithology and in interpreted as a submarine canyon fill. The length of the channel is 30-35 miles and the width is 6 miles. The thickest fill is 985 ft at the point of bifurcation. The channel indicated potential for stratigraphic hydrocarbon traps along its flank in adjacent sandstone units of the Wilcox.

Maps: stratigraphic dip sections, E-log correlations.

Rolf, E. G., 1987, Structural framework and sand genesis of the Wilcox Group, Travis Ward Field, Jim Hogg County, Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 37, p. 207-215.

Since 1983, eight deep wells have been drilled in the Wilcox, 4 produce from deep sands and one produces from the top of the Wilcox. Reserves are estimated at 60 to 200 BCF gas. Wilcox and Queen City production is related to normal faulting associated with deep salt and or a shale ridge within the Rio Grande interior salt basin. Growth of the ridge has resulted in the Wilcox being as much as 2,000 ft structurally high to areas adjacent to Travis Ward field. Ridge associated sea floor topography, shelf currents, sediment source proximity and rate of sedimentation have combined for development of high quality clean reservoir sands.

Maps: locality, structure, cross-section, seismic section, block diagram of sand genesis, production data.

Sassen, R., 1990, Lower Tertiary and Upper Cretaceous source rocks in Louisiana and Mississippi: Implications to Gulf of Mexico crude oil: AAPG Bulletin, v. 74, p. 857-878.

The Wilcox crude oil from Louisiana and Mississippi has two kerogen variations. In downdip areas of southern Louisiana the oil migrated short distances, in updip areas Wilcox production results from long range material migration (150 km) from mature source rocks. Crude oil in Upper Tertiary and Pleistocene reservoirs is explained by vertical migration from deep lower Teritary source rocks.

Tables of 695 core samples discuss total organic carbon, temperature and hydrogen index and oxygen index (on graphs). Tables cover chromatographic studies of 78 oil samples.

Maps: migration pathways.

Sassen, R., R. S. Tye, E. W. Chinn, and R. C. Lemoine, 1988, Origin of crude oil in the Wilcox trend of Louisiana and Mississippi: Evidence of long-range migration: Gulf Coast Assoc. Geol. Soc. Trans., v. 38, p. 27-34.

Long range updip migration (sometimes greater than 100 km) from deeply buried Wilcox source facies provides the best explanation for emplacement of crude oil in the shallow Wilcox trend of central Louisiana and SW Mississippi. Geochemically distinct oils with lower wax contents are found in this trend. Research on the thermal maturity of the Wilcox in Louisiana and Mississippi show the source is in marine shales of the deep Wilcox Group in south central Louisiana.

Tables and graphs: geochemical data of crude oil from Louisiana and Mississippi comparing Wilcox, Tuscaloosa and Smackover reservoirs; Kerogen assessment and mean vitrinite reflectance, pyrolysis and TOC determination, engineering data plots on parameters of thermal maturity.

Self, G. A., S. Q. Bread, H. P. Raef, J. A. Stein, M. O. Traugett, and W. D. Eason, 1985, Lockheart Crossing Field: New Wilcox Trend in Southeastern Louisiana (abs.): AAPG Bulletin, v. 69, p. 306.

In 1982 Wilcox oil was discovered in the Lockhart Crossing field known previously for its gas production from Cretaceous Tuscaloosa sandstones at depths of 17,000 to 18,000 ft . Oil from the Wilcox was produced from 10,000 ft depths. The main field is a marine sandstone with 2 facies present. The dominant facies is a coarsening-upward sequence deposited as nearshore bar. The other facies is tidal channel deposits fining up to very fine grain sand. The relationship of the facies is one of progradation of tidal channels and erosion into existing nearshore bars. The primary trapping mechanism is a structural rollover anticline.

Suter, J. R., and H. L. Berryhill, 1985, Late Quaternary shelf-margin deltas, Northwest Gulf of Mexico: AAPG Bulletin, v. 69, p. 77-91.

Seismic interpretation of 21,000 sq miles of single-channel high resolution profiles across the continental shelf indicate 5 late Wisconsin shelf margin deltas. Isopach patterns show size range up to 1,900 sq miles and thicknesses of over 590 ft. Deposits are elongate parallel to strike indicating subsidence of the shelf margins as a whole. Deltas are fluvially dominated and effected by eustatic sea level fluctuations. Models for the ancient record include the Rio Grande, and Mississippi deltas.

Maps: 3-D models, seismic profiles, bathymetric contours.

Swann, C., and J. M. Poort, 1979, Early Tertiary lithostratigraphic interpretation of Southwest Georgia. (Midway and Wilcox Group equivalents): Gulf Coast Assoc. Geol. Soc. Trans., v. 29, p. 386-395.

Wilcox and Midway Group equivalents in four counties in SW Georgia and one county in Alabama were studied. New mapping and drilling projects from 1975-78 allowed reinterpretation of the lithology and correlation of units. Description of surface and subsurface units, locality maps are included. Part of the region is a mining district of low grade iron ores and only minimal oil production.

Tye, R. S., C. W. Wheeler, W. C. Kimbrell, and T. F. Moslow, 1988, Lithostratigraphic framework and production history of Wilcox in central Louisiana (abs.): AAPG Bulletin, v. 72, p. 255.

The Wilcox Group in Louisiana is a complex of fluvial, deltaic and marine deposited multiple, discontinuous sandstones. Hydrocarbon reservoirs are found in positive structural features or in areas of favorable stratigraphy. Numerous Wilcox depocenters in Louisiana necessitate division. A five fold lithostratigraphic framework is proposed. The five zones cover 21 parishes. These zones vary from 115 to 1,000 ft thick with sand content from 25 to 60 %. Production in updip Wilcox is highest from zone III. Zones I and II are most productive downdip in "deep" Wilcox wells. All zones have a strong north-south isopach trend.

Tyler, N., 1983, Wilcox fluvial /deltaic sandstone: in Galloway, W. E. , T. E. Ewing, C. M. Garrett, N. Tyler, and D. G. Bebout, eds., Atlas of Major Texas oil reservoirs: Bur. Eco. Geol., The University of Texas at Austin, p. 19-21.

Five Wilcox reservoirs have produced over 10 million barrels of oil each. They are all located on the west flank of the San Marcos Arch. Four produce from the upper Wilcox, Carrizo Sand and one from the Falls City Sand of the lower Wilcox. All fields in this play are fault bounded. The Slick and Cottonwood Creek South fields are simple fault-bounded anticlines. Sand pinch out gives partial stratigraphic control to the Slick field . The Helen Gohlke field is intensely faulted. Closure in the Falls City field is a rollover anticline.

Hydrocarbon accumulation in the lower Wilcox is controlled by the distribution of specific deltas. Reservoirs are delta front sands and reworked marine sands. Hydrocarbon production from the upper Wilcox is related to the overlying marine Reklaw Shale.

Maps: locality, net sandstone, sandstone and hydrocarbon relationship, structure maps, cross-sections (strike and dip).

Walters, C. C., and D. D. Dusang, 1988, Source and thermal history of oils from Lockhart Crossing, Livingston Parish, Louisiana: Gulf Coast Assoc. Geol. Soc. Trans., v. 38, p. 37-44.

Chemical analysis reveals that oils from the Lower Tuscoloosa reservoir and the newly discovered Wilcox reservoir in Louisiana constitute two separate oil families. Within each reservoir the oils become progressively more mature with depth due to thermal cracking. Wilcox oils were generated from clay-rich shales with significant bacterial organic matter. Wilcox shales are the oil source rock. Tuscaloosa oils

are more thermally mature and are associated with late stage oil/gas condensate generation from lower marine Tuscaloosa shales and other variable source rocks.

Wilcoxon, B. R., and R. E. Ferrel, Jr., 1990, Depth and lithofacies-related diagenesis in the Wilcox Group of Southwest Louisiana: Implications for porosity evaluation: AAPG Bulletin, v. 74, p. 791.

Core from a well in Allen Parish, Louisiana was analyzed to relate depth and lithofacies parameters to diagenetic history of the Wilcox Group in Southwest Louisiana. Optical and scanning electron microscope petrography, x-ray diffraction, backscattered electron image analysis and pyrolysis techniques were used to describe five facies. Pyrite, early chlorite, mixed illite/smectite were precipitated during early diagenesis. Intermediate diagenesis stage showed increased water/rock interaction at higher temperatures and pressures leading to potassium feldspar dissolution, quartz overgrowths, kaolinite and calcite precipitation and beginning of smectite to illite transition. Late stages observed include destruction of kaolinite, precipitation of chlorite, iron carbonates and fibrous illite, and increased rate of organic matter decarboxylation.

Compaction in early phases was detrimental to the porosity of lithofacies containing detrital clay. Quartz overgrowths arrested compaction of clean sands. Calcite locally destroys porosity. No evidence of carbonate leaching to form secondary porosity was found. Late authigenic minerals did not affect porosity but reduced permeability. Clean quartz rich sandstones have greatest reservoir potential.

Winker, C. D., 1982, Cenozoic shelf margins, Northwestern Gulf of Mexico: Gulf Coast Assoc. Geol. Soc. Trans., v. 32, p. 427-448.

Late Pleistocene shelf margin deltas are used as a guide to interpret earlier Tertiary deltas on the Gulf Coast. Late Pleistocene deltas are characterized by rapid subsidence and growth faulting and thick progradational deposits. Many Tertiary formations have similar growth faulting with geopressured gas reservoirs. Pre-Pleistocene shelf margin deltas are not synchronous across the basin and reflect sediment supply rather than sea level changes. The three largest Tertiary deltas associated with major tectonic episodes are: 1. Paleocene (lower Wilcox) Rockdale Delta of East Texas coincides with Laramide uplift of the Rocky Mts., 2. Oligocene Frio of South Texas coincides with volcanism of the Sierra Madre Oriental, and 3. Neogene ancestral Mississippi delta coincides with reactivation of the southern Rockies and regional uplift.

Maps: paleogeography, cross-sections, seismic sections.

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