GEOLOGICAL CHARACTERIZATION

OF

TEXAS OIL RESERVOIRS

by

William E. Galloway, Project Director

Noel Tyler, Chester M. Garrett, Jr., Don G. Bebout,
Eric S. Cheng, and William L. Fisher

with contributions by

Thomas E. Ewing, Jan S. Posey, and Shirley P. Dutton

Bureau of Economic Geology
The University of Texas at Austin
Austin, Texas 78712-7508

Biennial Report

for studies conducted

September 1, 1981 - August 31, 1983

Prepared for

Texas Energy and Natural Resources Advisory Council
Energy Development Fund
Project Number 82-0-U-1

DISCLAIMER

EXECUTIVE SUMMARY

Approximately 153 billion barrels of in-place oil have been discovered in Texas reservoirs. Assuming recovery efficiency continues to increase modestly, an estimated 61 billion barrels of this oil will be produced, largely by conventional primary and secondary recovery technologies. The remaining 90 plus billion barrels of oil represent a target of immense proportions. For comparison, most recent estimates by the U.S. Geological Survey are that only 6 to 22 billion barrels of additional recoverable oil are likely to be found by continued exploration in the State.

Certainly not all of this unproduced oil can be recovered. Recovery efficiency of oil is limited by several factors. First, a portion of the oil contained within a reservoir, called the residual oil saturation, is not flushed from the rock because it is trapped in dead-end or isolated pores or has "wet" the mineral grains. This oil can only be moved from the reservoir by altering its physical characteristics or by artificially improving the ability of moving fluids to sweep it from the reservoir. Such oil is thus a potential target for the advanced, or so-called tertiary recovery processes. However, residual oil saturation can be measured and commonly ranges between 15 and 35 percent.

Simple arithmetic shows that about one-fourth of the unrecovered 90 to 100 million barrels must remain in portions of the reservoirs that have not been drained in the course of conventional field development. Such oil is trapped in isolated compartments or lenses that were not tapped by wells drilled on conventional, regular spacings. Thus it constitutes a potential target for selective infield exploration and drilling. The objectives of this study were (1) to examine the geology and development history of the entire population of Texas oil reservoirs, (2) to improve our estimate of the amount of oil that remains as a target for strategic infield "exploration" and development, (3) to identify families of oil fields that offer the greatest potential for significantly improving statewide recovery efficiency by application of such infill programs, and (4) develop generic reservoir models that might be applied to improving recovery from the important families of less efficient reservoirs.

The number of oil fields in Texas is enormous. To reduce the potential data base to manageable proportions, only reservoirs (the basic hydrocarbon producing unit) that had a cumulative oil production of more than 10 million barrels were studied. These major reservoirs, which number slightly over 500, account for 71 percent of all Texas oil production.

Geological characterization of 500 of the most productive Texas oil reservoirs on the basis of geologic and engineering parameters facilitates the grouping of reservoirs into plays of similar geology and common engineering and production attributes. Most of the major Texas oil reservoirs are grouped into 47 plays. Twenty-seven oil plays lie to the north and west of the Marathon-Ouachita thrust belt in Paleozoic basins of north and west Texas. Dolomite is the prevalent reservoir lithology. Paleozoic reservoirs in this province contain 73 percent of the in-place oil in Texas, the vast bulk of this resource being trapped in restricted platform and to a lesser extent platform margin, and atoll-reef carbonates as well as in deep water slope and basinal clastic systems of the Permian Basin. Recovery efficiencies of the Paleozoic plays are considerably lower than those of the 20 plays of the coastal plain and East Texas. Major reservoirs in these Cretaceous and Tertiary plays were deposited principally in fluvial-deltaic and barrier-strandplain systems. Fluvial and carbonate reservoirs are less common.

Reservoir genesis clearly influences patterns of hydrocarbon accumulation as well as subsequent trends in production. In-place oil in clastic reservoirs is fairly evenly distributed throughout fluvial-deltaic, deltaic, barrier-strandplain, and deep water sandstones. Ultimate recoveries from all other clastic facies are overshadowed by production from deltaic reservoirs which are estimated to provide almost half (47 percent) of the oil obtained from clastics. On the low end of the spectrum are the slope/basin sandstones, which contain one quarter of the in-place oil in clastics, but will produce only five percent of the total production from Texas' clastic reservoirs. The statewide average recovery from sandstone reservoirs is 41 percent, but ranges from a low of eight percent for slope/basin systems to a high of 68 percent for deltaic reservoirs.

Original in-place oil in carbonate reservoirs is less uniformly distributed throughout the range of reservoir facies than in clastic plays. Restricted platform plays contain 61 percent of the original in-place oil in carbonates; platform margin and deeper water carbonates contain 18 and 17 percent, respectively. Oil recovery from restricted platform carbonates is poor—only 30 percent of the original resource will be produced by primary and/or secondary methods from these plays. Deeper-water atoll and pinnacle reef reservoirs have the best recoveries (50 percent) largely because of successful secondary recovery programs initiated early in field development.

For each play, the total oil in place, the estimated ultimate recovery, and the average residual oil remaining in produced portions of the reservoirs were calculated. Recovery efficiency is simply the ultimate recovery divided by the oil in place. The target oil for strategic infill development is approximated, in turn, by the recovery efficiency less the residual oil percentage (discounted for original water saturation) times the total oil in place in the play. Compilation of results for all of the plays shows that a measured potential target of nearly 20 billion barrels exists in the reservoirs studied. This is a minimum value, reflecting only the large reservoirs incorporated in this study. Abandoned reservoirs largely fit into the same plays; volumes of oil in place represented are much less, however.

Based on the conclusions of this initial characterization of Texas oil fields, and upon well-documented attributes of many of the important producing depositional facies, generic reservoir models have been synthesized. These generic models, which describe key geologic and engineering attributes of major reservoir types, include: (1) fluvial meanderbelt sand, (2) fluvial-dominated delta front, (3) wave-dominated delta margin, (4) barrier-strandplain front sand, (5) barrier core sand, (6) back-barrier bar sand, (7) pinnacle/atoll limestone, and (8) four types of restricted carbonate platform reservoirs.

ACKNOWLEDGMENTS

Personnel of the Central Records section of the Railroad Commission of Texas, under the supervision of Mr. Mark Browning, were extremely helpful in retrieving, sorting, and reproducing voluminous files. Messrs. Tom Garland, Bill Dietzman, and John Wood of the U.S. Department of Energy Energy Information Office, Dallas, provided helpful sources of data and suggestions. Dr. Claude Hocott, Professor Emeritus of Petroleum Engineering, University of Texas, provided counsel throughout the study and aided materially in acquisition of data from industry. Draft copies of this report were reviewed by S. P. Dutton, W. R. Kaiser, S. C. Ruppel, and R. A. Morton.

CONTENTS

ILLUSTRATIONS

Figures

Tables

INTRODUCTION

Texas has long been a major oil province, accounting for nearly 40 percent of the historic production of crude oil in the United States. Texas now holds less than 30 percent of the Nation's proven reserves and less than 15 percent of its estimated as yet undiscovered oil. Discovery and conventional production of oil in Texas have peaked, but more than 100 billion barrels of oil now classed largely as unrecoverable still exist in Texas. This oil, even with the geologic, technical, and economic constraints on its recovery, constitutes a major target for future production.

BACKGROUND AND TRENDS

To date, some 156 billion barrels of oil have been discovered in Texas. About 46 billion barrels have been produced, and 8 billion barrels exist as proven reserves; thus, current estimated ultimate recovery is 54 billion barrels, or a little less than 35 percent recovery of the in-place discovered oil. Estimates of how much oil is left for future discovery vary, although nearly 20 billion barrels in place is a reasonable mean of the estimates. Consequently, Texas oil is thought to total about 176 billion barrels, of which an estimated ultimate conventional recovery is on the order of 60 billion barrels. Approximately 116 billion barrels of the 176 billion barrel total is now classed, at least by most conventional means, as unrecoverable. A portion of this large volume is targeted for different or combined forms of unconventional recovery.

No one knows how much of the now unrecoverable oil in Texas will ultimately be recovered. Recent estimates range from as little as 5 percent to as much as 40 percent. Undoubtedly, however, the long-term future of Texas oil production, including moderation of the decline of conventional production, hinges on our ability to recover oil now classed as unrecoverable. Future progress will depend increasingly on our technical expertise in enhancing recovery of already known oil and less on new field wildcatting. Such is the direction in which we are already headed. Of total Texas oil completions over the past decade, less than 3 percent have been new field wildcats.

Discovery of Texas oil reached its peak in the 1930's, a decade in which nearly 40 percent of all discoveries to date were made. By the end of the 1940's, 84 percent had been found, and by the end of the 1950's, 96 percent of total discoveries to date had been posted. Current production of crude oil in Texas is supported chiefly by old, large fields (Fisher, 1982). More than half of current production comes from fields discovered more than 40 years ago; nearly three-fourths is from fields more than 30 years old. Fields discovered in the past 20 years contribute less than 11 percent to total current production, and those found during the upsurge of drilling in the past decade, less than 5 percent (fig. 1). If estimates of undiscovered resources are correct, only 12 percent of the total universe of Texas oil is yet to be discovered, and that will most likely be in increasingly smaller fields.

Although the significant decline in drilling between the late 1950's and early 1970's contributed to the lower discovery level during the past three decades, the paramount cause has been a steady and serious deterioration in finding rate (or volume of oil discovered per increment of drilling) since the mid-1950's. Even with the upsurge in drilling during the past 8 years, total reserve additions exclusive of revisions have amounted to less than 12 percent of declining production. However, including revisions, total additions have averaged nearly 40 percent of production, indicating that revisions including reserve growth, based in part on further development of older fields, are the primary factor in total reserve additions.

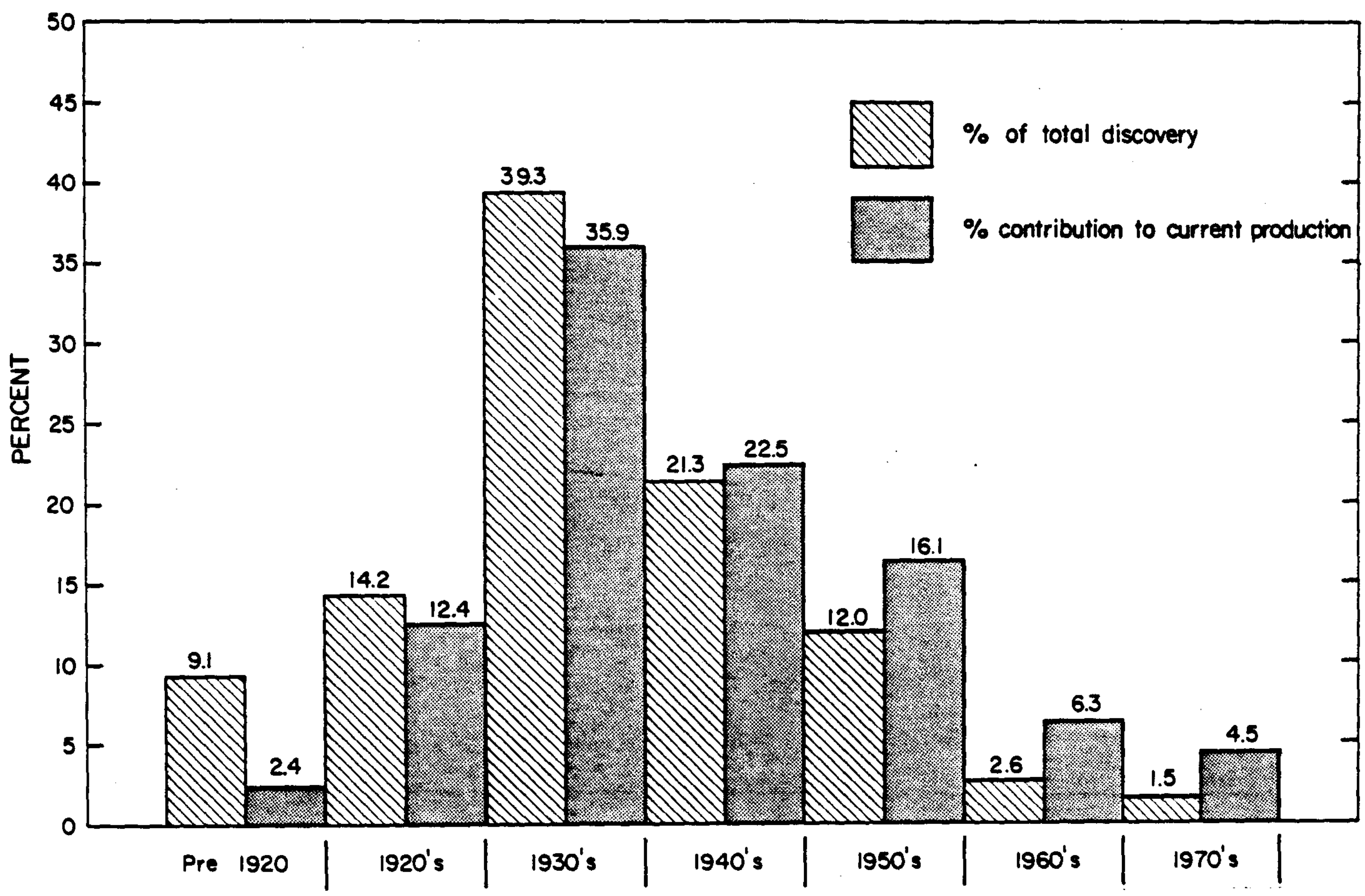

Figure 1. Time distribution of reservoir discovery and contribution to current oil production in Texas.

In contrast to discovery rate, improved recovery is a more positive aspect of Texas additions. Historically, estimated ultimate recoveries in existing reservoirs have increased an average of about 0.3 percent annually. In the 1970's Texas' average annual reserve growth, including all fields was 0.8 percent, nearly triple the historic rate. During the increased drilling of 1980 and 1981, the estimated annual reserve growth rate exceeds 1.5 percent.

For the period from 1974 to 1979 (last data of record) reserve growth has added some 2.2 billion barrels of oil. The API 1979 estimate of ultimate recovery from new fields discovered during the 1974-1979 period amounted to 280 million barrels. The magnitude of the resource base on which reserve growth can occur and the diminished size of the resource base for additional new field discovery are such that reserve growth has been outpacing new field discovery by nearly an order of magnitude. Nehring (1981), calculating future reserve growth from existing fields and the volume of future new field discoveries, estimated reserve growth to be about 9 to 12 times greater than future new field discovery. Nehring's calculation is comparable to the eightfold difference actually recorded since 1973.

At present, tertiary recovery in Texas totals about 30 million barrels annually, about 3 percent of annual production. The bulk of tertiary production (97 percent) is by injection of miscible carbon dioxide in West Texas carbonate reservoirs. Enhanced oil recovery (EOR), although apparently a contributor to reserve growth, thus far appears to be much less significant than intensive development and infill drilling programs.

Character of the Nonconventional Target

The increasing emphasis on development drilling, an apparently increasing rate of reserve growth from existing fields, and the increasing ratio of reserve growth to new field discovery all indicate that the switch from wildcatting to recovery improvement is already taking place in Texas. Increased development drilling also appears to be having a positive result: the crude reserve decline is being modified. From 1974 through 1979, Texas reserves dropped at an average annual rate of 7.9 percent; in the past 2 years that decline rate has slowed to 1.2 percent.

Production decline, which hit a low of 6.0 percent in 1979, last year (1982) stood at 2.9 percent, a decrease of 50 percent. The reserve-to-production ratio, which dropped well below 8.0 in 1977 and which had been slipping at an average annual rate of 3.7 percent from 1973 through 1979, has increased in the past 2 years at an average annual rate of 3.2 percent.

The volume of so-called nonconventional oil in Texas is huge, and the trend toward recovering it, although not yet commonplace, has been established. The larger question is how much additional oil can be recovered, and what are the technical and economic problems attendant on its recovery?

Nonconventional oil exists in a variety of conditions. In some cases, the fluid state must be modified to achieve additional recovery; in others, the rock state must be modified; and in still others, better depletion can be achieved by strategic infill drilling designed around the widespread heterogeneities that exist within reservoirs.

The historical assumption has been that the reservoirs and the distribution of fluids in them are essentially uniform and homogeneous or that the variation is generally uniform. Accordingly, conventional field development has been based on a specified number of uniformly spaced wells (acre-spacing). Considerable evidence indicates that many reservoirs show significant geologic variations and compartmentalization and that uniform spacing, unless very dense, does not efficiently tap and drain a sizeable volume of the reservoir. Such untapped oil is the potential target of strategic infill drilling, provided that controlling heterogeneities can be delineated. In contrast, oil remaining in parts of reservoirs that have been tapped and drained in the course of conventional primary and secondary production, that is, oil in parts of the reservoir effectively swept, is the target of enhanced or tertiary recovery. These targets, and techniques requisite to their recovery, may overlap.

CHARACTERIZATION OF MAJOR OIL RESERVOIRS IN TEXAS

Adequate geologic and engineering characterization of reservoirs is essential to the development of optimum depletion plans, whether such plans entail primary development, secondary recovery, or additional recovery through enhanced recovery programs or strategic infill drilling. Because reservoirs differ widely in physical framework and fluid behavior, different recovery strategies are required to obtain maximum depletion.

As part of a long-term research program using geologic synthesis to increase petroleum recovery, the Bureau of Economic Geology has completed a regional characterization of the major oil reservoirs in the State (Galloway and others, in press). Since the number of Texas oil-producing reservoirs is immense, several screening criteria were applied to reduce the data collection effort to manageable proportions. First, the study focused on the primary element of hydrocarbon production--the individual reservoir. Second, only pools that had produced at least 10 million barrels of oil at the end of 1981 were included in the data base. Where production is commingled or statistics are not maintained for individual producing horizons within a field, production was partitioned among the largest reservoirs. In all, about 500 individual reservoirs met these criteria. Publications, field reports, and hearings files of the Oil and Gas Division of the Railroad Commission of Texas, along with information supplied directly by operators, provided adequate data for a basic geologic and engineering characterization of more than 430 of these reservoirs.

Data collected for each reservoir included (1) general information about the reservoir, (2) matrix and fluid properties, (3) engineering attributes and technology deployed to date, and (4) oil volumetrics. An example of the resultant tabulation is shown in figure 2. These data will be published by the Bureau as an "Atlas of major Texas oil reservoirs".

The second, and equally important, product of this Texas oil reservoir characterization project was the grouping of geologically similar reservoirs into "plays." The concept of play analysis has been used commonly in petroleum exploration strategies and in estimating or

PLAY NAME: HORSESHOE ATOLL (28)

RRC DIST	FIELD AND RESERVOIR	DISC. DATE	LITHOLOGY	TRAP	DRIVE	DEPTH (FT)	OIL COL. (FT)	POR. (%)	PERMEABILITY AVG. (MD)	LOG RANGE		H2O SAT. (%)	API GRAV.	INIT. GOR	INIT. PRES.	TEMP. (F)	PRODUCTION TECHNOLOGY	UNIT. DATE	WELL SPACING (ACRES)	ROS (%)	OIP (MMBBL)	CUM. PROD. (MMBBL)	ULT. RECOV. (MMBBL)	RECOVERY EFFICIENCY (%)
8A	ADAIR WOLFCAMP	50	LS	DTR	SG	8500	215	12	28			24	43	430	3313	133	WF	56	40	35	110	47.4	53.0	48
8A	COGDELL	49	LS	DTR	SG	6800	770	10	18			35	42	664	3125	136	PM	55	40	30	524	240.0	250.1	48
8A	DIAMOND M	48	LS	DTR	SG+PWD	6600	440	9	72	-1	4	28	44	850	3135	130	PM+WF	51-55	40	26	616	221.6	239.5	39
8A	GOOD	49	LS	DTR	WD	8000	489	8	52	-1	3	36	44	1158	3650	140	PM		40	9	124	40.5	50.2	40
8A	HOBO	51	LS	DTR	WD	7100	100	10	32			30	46	1290	2990	150	PM		40		28	11.1	11.7	42
8A	KELLY-SNYDER	48	LS	DTR	SG	6700	700	8	19			22	42	1010	3122	130	WF+CO2+N	53	40	26	2161	1075.6	1229.6	57
8	OCEANIC	53	LS	DTR	WD	8100	215	12	84			18	42	978	3410	160			40-80		59	21.0	21.9	37
8A	REINECKE	50	LS	DTR	SG+PWD	6800	304	10	22	-1	4	21	46	1100	3164	139	PM+WF	71	40	57	166	68.4	90.9	55
8A	SALT CREEK	50	LS	DTR	SG	6300	726	12	10	-1	1	29	40	338	2940	129	PM+N+LPG	52	80		471	194.1	248.0	53
8	VEALMOOR EAST	58	LS	DTR	WD	7400	610	10	38	-1	3	16	48	1290	3362	155	WF+N	74	40	16	125	58.5	67.7	54
8	VEALMOOR	48	LS	DTR	WD	7800	200	10	32	0	2	31	46	1145	3500	164	PM		40		81	34.7	37.9	47
8A	VON ROEDER AND N.V.R	54-59	LS	DTR	SG	6800	155	10	13			20	43	1200	3020	134	PM+WF	54	40	60	62	26.1	27.3	44
8A	WELLMAN	50	DOLO	DTR	SG+PWD	9300	800	8	100	-1	3	23	43	400	4105	151	PM+WF	78	40	35	164	51.4	83.9	51
						6850	632	9	28			25	42	881	3165	133		69 %		28	4671	2082.4	2411.7	51

Figure 2. Format for data tabulation and summary used to characterize the geological and engineering attributes of major Texas oil plays and component larger reservoirs (Galloway and others, in press). The example, the Horseshoe Atoll, includes geographically associated limestone reservoirs deposited as a series of reef pinnacles and knolls that were later buried by basinal marine shale.

assessing potential oil and gas resources (White, 1980). A play, in this application, is defined on the basis of depositional origin of the reservoir, structural or trap style, and nature of available source rocks and seals. In characterizing Texas oil reservoirs, the play concept can be usefully applied to producing or producible reservoirs for two reasons. First, the larger reservoirs themselves constitute a major proportion of the target for improved recovery. Second, the larger reservoirs of each play are typically the geologic and engineering parameters characteristic of the many smaller reservoirs that can be readily included in the plays.

During reservoir development and production, a substantial volume of geologic and engineering data is collected. Several of these data, or combinations thereof, can be used to order and constitute plays, as long as plays having meaningful common attributes can be established. Features such as depth, thickness, lithology, recovery efficiency, gravity, trap mechanism, and drive mechanisms can be used for play definition. However, based on analysis of all the major oil reservoirs in Texas, the most unifying, first-order character in play definition is the genetic origin of the reservoir. When grouped by common depositional or diagenetic systems, reservoirs show great similarity in a variety of attributes. This is true because the physical, chemical, and biologic processes particular to specific depositional environments and resulting depositional facies determine many attributes that are of direct and indirect consequence to hydrocarbon generation, migration, entrapment, and subsequent producibility. These include

1. External geometry and configuration of the reservoir facies;
2. Internal geometry and vertical and lateral variations in both pay and nonpay zones;
3. Reservoir facies relationship to other facies components of the depositional system critical to the source and sealing of hydrocarbons;
4. Direct trapping mechanism, if stratigraphic;
5. Aquifer extent and behavior critical to collecting hydrocarbons and to determining the extent of natural water drive;

6. Control or modification of subsequent diagenetic history, which may determine reservoir properties;

7. Kinds, abundance, and relationships of porosity and permeability.

In some cases, however, first-order definition of plays must be based on factors other than genetic depositional origin. Examples include naturally fractured reservoirs having very low matrix permeability or extensively faulted reservoirs associated with piercement salt domes. In other cases, reservoir plays were defined by relationships to unconformities where weathering diagenesis was an overriding factor in reservoir genesis. However, in most geologic situations, depositional and structural style have at least some genetic coincidence (for example, growth faulting); diagenetic style is commonly influenced strongly by fluid flow paths determined by facies variation attributed to original deposition and intensity of natural fracture systems is commonly related to attributes resulting from facies variation. Although structural configuration and style may be critical to scale and mechanics of trapping as well as to hydrocarbon migration, factors that are the consequences of genetic depositional origin are generally predominant in defining engineering and geologic attributes of reservoirs.

Because both the reservoir and its contained petroleum have a common genesis within plays, fluid attributes tend to be similar. Thus, reservoir engineering problems and applicable technologies are common to most or all of the reservoirs of a defined play.

Data on the reservoirs contained in each play were combined to provide a generalized characterization of each play (fig. 2), which summarizes its importance to total State production and provides basic data for determining potential applicability of various additional recovery strategies or technologies. The relatively homogeneous population of reservoirs in each play is also a logical starting point for evaluation and comparison of additional recovery targets and controls on production efficiency.

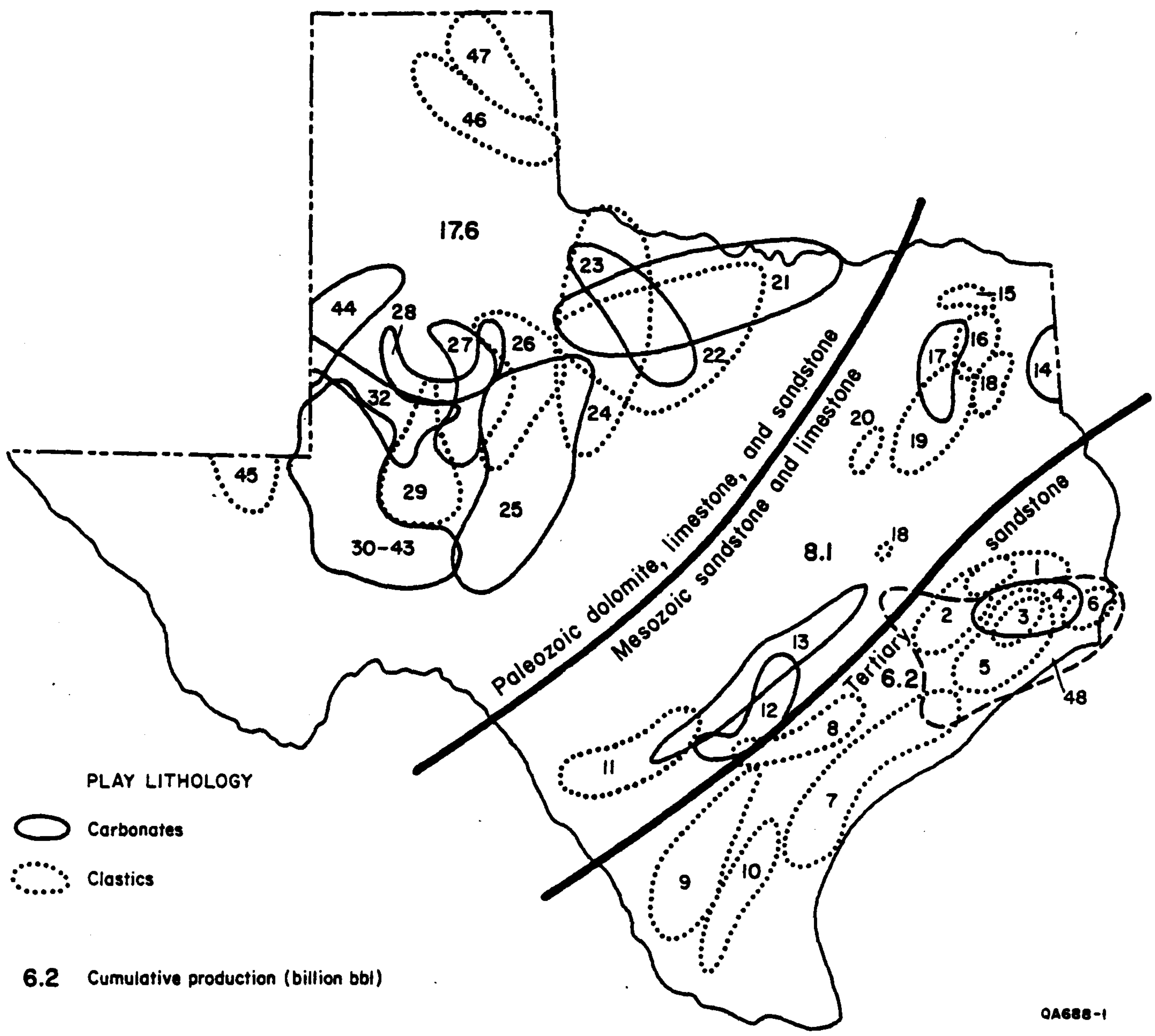

Figure 3. Distribution of the 47 major oil plays in Texas.

EXPLANATION TO FIGURE 3

1. Eocene Deltaic Sandstones
2. Yegua Deep-Seated Domes
3. Yegua Dome Flanks
4. Caprock
5. Frio Deep-Seated Domes
6. Frio (Buna) Barrier/Strandplain
7. Frio Barrier/Strandplain
8. Wilcox Fluvial/Deltaic Sandstone
9. Jackson/Yegua Bar/Strandplain
10. Frio/Vicksburg (Vicksburg Flexure)
11. San Miguel/Olmos Deltaic Sandstone
12. Edwards Restricted Platform
13. Austin Chalk/Buda Stratigraphic Traps
14. Rodessa Stratigraphic/Structural Traps
15. Paluxy Fault Line
16. Cretaceous Clastics/Salt-Related Structures
17. Glen Rose Carbonate/Salt-Related Structures
18. East Texas Woodbine
19. Woodbine Fluvial/Deltaic Sandstone
20. Woodbine Fault Line
21. Strawn Sandstone
22. Bend Conglomerate
23. Strawn Reef
24. Upper Pennsylvanian Shelf Sandstone
25. Pennsylvanian Reef/Bank
26. Upper Pennsylvanian Basinal Sandstone
27. Eastern Shelf Permian Carbonate
28. Horseshoe Atoll
29. Spraberry/Dean Sandstone
30. Central Basin Platform Unconformity
31. Ellenburger Fractured Dolomite
32. Silurian-Devonian Ramp Carbonate
33. Silurian-Devonian Ramp Carbonate (S.C.B.P.)
34. Silurian-Devonian Ramp Carbonate (N.C.B.P.)
35. Yates Area
36. San Andres/Grayburg (Ozona Arch)
37. San Andres/Grayburg (S.C.B.P.)
38. San Andres/Grayburg (N.C.B.P.)
39. Permian Sandstone and Carbonate
40. Clear Fork Platform Carbonate
41. Queen Platform/Strandplain
42. Wolfcamp Platform Carbonate
43. Pennsylvanian Platform Carbonate
44. Northern Shelf Permian Carbonate
45. Delaware Sandstone
46. Panhandle Granite Wash/Dolomite
47. Panhandle Morrow

TEXAS' LARGER OIL PLAYS

The selected Texas reservoirs were grouped into 47 major plays. A summary tabulation and the generalized areal distribution of the plays are shown in figure 3. Complete data for each play will be published by the Bureau in the "Atlas of major Texas oil reservoirs". All but 16 of the 430 characterized reservoirs were incorporated into the identified plays. Each of the 16 represents modest production from geographically or geologically isolated smaller plays that might be of interest in more detailed, regional studies.

It is readily apparent from figure 3 that oil production occupies three broad belts cutting diagonally across the State. Approximately 6.2 billion barrels of oil have been produced from the geologically young, Tertiary sandstone reservoirs constituting plays 1 through 10 along the Coastal Plain. Production of about 8.1 billion barrels has been obtained from large sandstone, limestone, and chalk reservoirs of Mesozoic age that extend as a belt from northeast Texas along the inner Coastal Plain. By far the greatest volume of oil (approximately 17.6 billion barrels) has been derived from Paleozoic dolomite, limestone, sandstone, and conglomerate of North-Central and West Texas. The greatest concentration of vertically stacked plays (numbers 30 through 43) lie along the Central Basin Platform in Andrews, Ector, Crane, Upton, Pecos, and Crockett Counties. Significantly, these same Paleozoic reservoirs exhibit the lowest recovery efficiencies and thus offer the largest aggregate target for additional infill and tertiary recovery programs.

Geographic Distribution of Oil

Texas oil occurs in two broadly-defined petroliferous provinces. To the north and west of the Marathon-Ouachita structural front lie dolomites, limestones, and sandstones of Paleozoic age. Principal petroliferous structural elements include the Amarillo Uplift and Anadarko Basin, as well as the Midland and Delaware subbasins and the Central Basin Platform of the Permian Basin (fig. 4). The Central Basin Platform originated in the later Mississippian as a

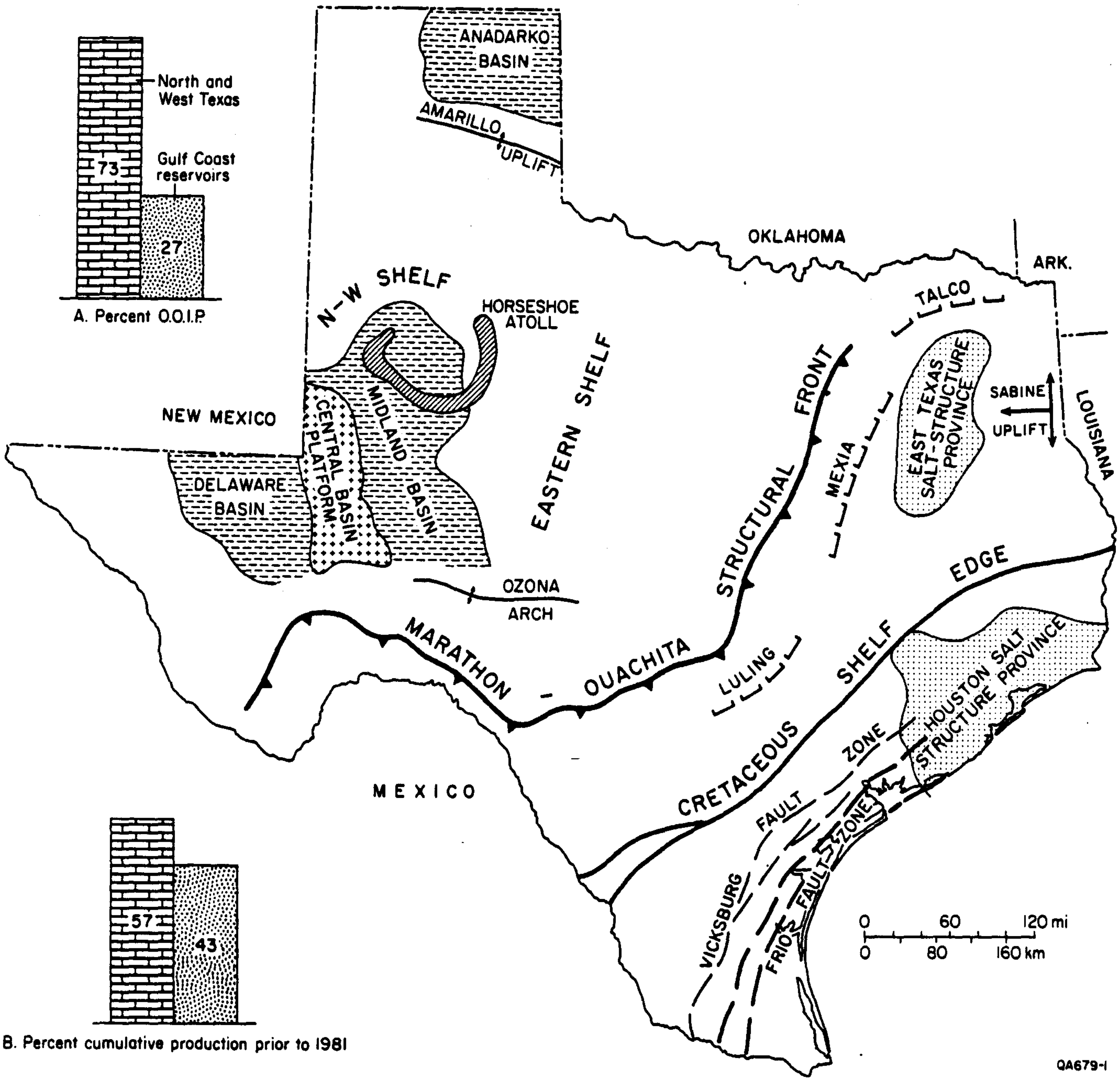

Figure 4. Major petroliferous structural elements in Texas, modified from Galloway and others, 1983 (in press).

horst bounded on either side by slowly subsiding basins (Mills, 1972). This platform, which was the site of shallow water to supratidal carbonate and clastic sedimentation throughout the Pennsylvanian and Permian times, became a remarkably efficient concentrator of oil. Original in-place oil in the 13 plays located on the Central Basin Platform exceeds 31 billion barrels. Paleozoic sediments of north and west Texas contain 73 percent of the in-place oil resource of the 48 major oil plays in Texas (fig. 4, insert A).

The remaining 27 percent of in-place oil is trapped in Mesozoic and Tertiary carbonates and sandstones of the Gulf Coast Basin. Major petroliferous structural elements of this younger oil province that lies to the south and east of the Marathon-Ouachita thrust belt include the East Texas and Houston salt basins, and the Vicksburg and Frio fault zones which lie basinward of the Cretaceous shelf edge (fig. 4). Elevation and truncation of the Cretaceous Woodbine Formation (fig. 5) over the Sabine Uplift ultimately resulted in the prolific East Texas field. Comparatively minor production takes place from carbonates and sandstones of Cretaceous age along the Luling, Mexia, and Talco grabens.

While only 27 percent of the oil resource in Texas is trapped in Cretaceous and Tertiary systems of the Gulf Coast Basin, these prolific sediments account for 43 percent of all Texas oil production (fig. 4, insert B).

Temporal Distribution of Oil

Figure 5A illustrates the temporal distribution of in-place Texas oil. The vast bulk of Texas' oil resource is concentrated in Permian-aged sediments of north and west Texas. Fully 57 percent is contained in the Permian System, mostly in Guadalupian San Andres-Grayburg carbonates (fig. 5). Other major contributions to Paleozoic oil accumulations are the Ordovician Ellenburger, Silurian-Devonian ramp carbonates deposited in the Tobosa Basin (the ancestral Permian Basin, Galley, 1958) and the Pennsylvanian Horseshoe Atoll, as well as the granite wash of the Panhandle field (play 46, fig. 3) in the Anadarko Basin. Cretaceous- and Tertiary-aged reservoirs contain only 27 percent of the total in-place oil in Texas.

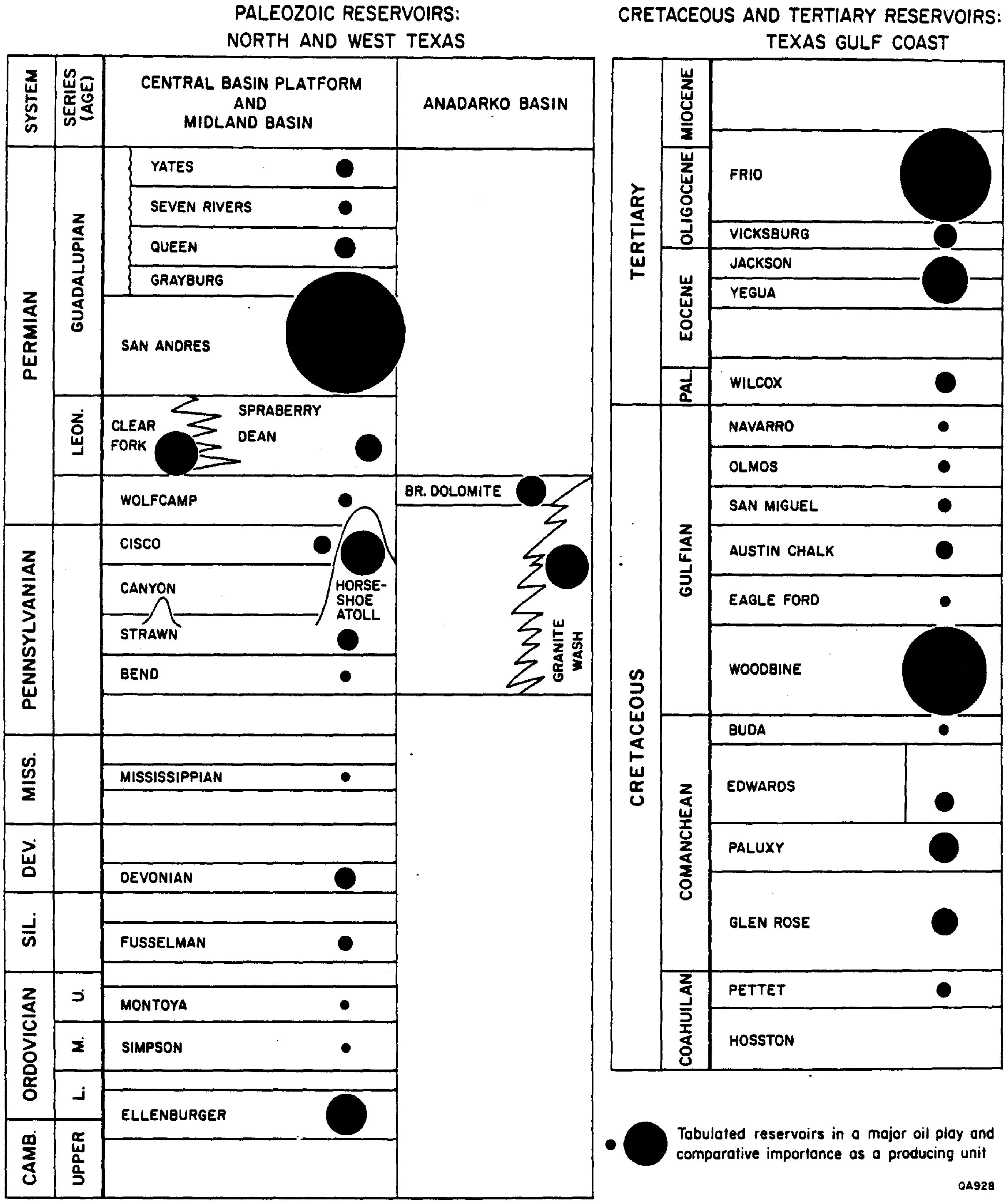

Figure 5. Simplified geologic age relationships of the principal oil producing stratigraphic units of Texas. The circles represent the comparative importance of each unit as an oil producer.

While the in-place oil resource is overwhelmingly concentrated in Permian and older sediments, higher recovery efficiencies in Cretaceous and Tertiary reservoirs of the Gulf Coast Basin afford operators in these younger reservoirs a comparatively larger slice of the production pie (fig. 6B).

Production from Cretaceous and Tertiary reservoirs amounts to 45 percent of the cumulative Texas total, whereas Permian reservoirs contribute only 37 percent. Figure 5 shows that the principal productive units of the Gulf Coast Basin are the Oligocene Frio and Gulfian Woodbine major stratigraphic units (joint cumulative productions of 4.5 and 6.4 billion barrels, respectively) and to a lesser extent the Jackson-Yegua and Glen Rose groups and the Paluxy Formation.

Distribution of Oil by Lithology and Depositional Setting of Reservoir

The most basic characterization of oil accumulation and production patterns is lithologic (fig. 7). Surprisingly, considering the magnitude of oil contained in the Permian System, in-place oil in clastics (47 percent) is only slightly less than that in allochemical deposits (53 percent). The allochemical suite includes dolomite, limestone, chalk, and fractured chert. Production from clastics is slightly more than from the allochemical suite. This reflects higher recovery efficiencies in clastic reservoirs, which on a statewide basis averaged 41 percent as compared to 35 percent for the allochemical reservoirs (fig. 7B).

Terrigenous Clastic Reservoirs

The patterns of hydrocarbon accumulation and subsequent production are strongly facies related. Original in-place oil in clastic reservoirs is fairly evenly distributed throughout fluvial-deltaic, deltaic, barrier-strandplain, and slope-basinal genetic systems (fig. 8A). The fluvial-deltaic category includes both fan-delta deposits such as those of the Panhandle field of north Texas (fig. 9) as well as stacked sandstone sequences where production takes place from superimposed deltaic and fluvial facies tracts, as for example, in the Woodbine play of the East

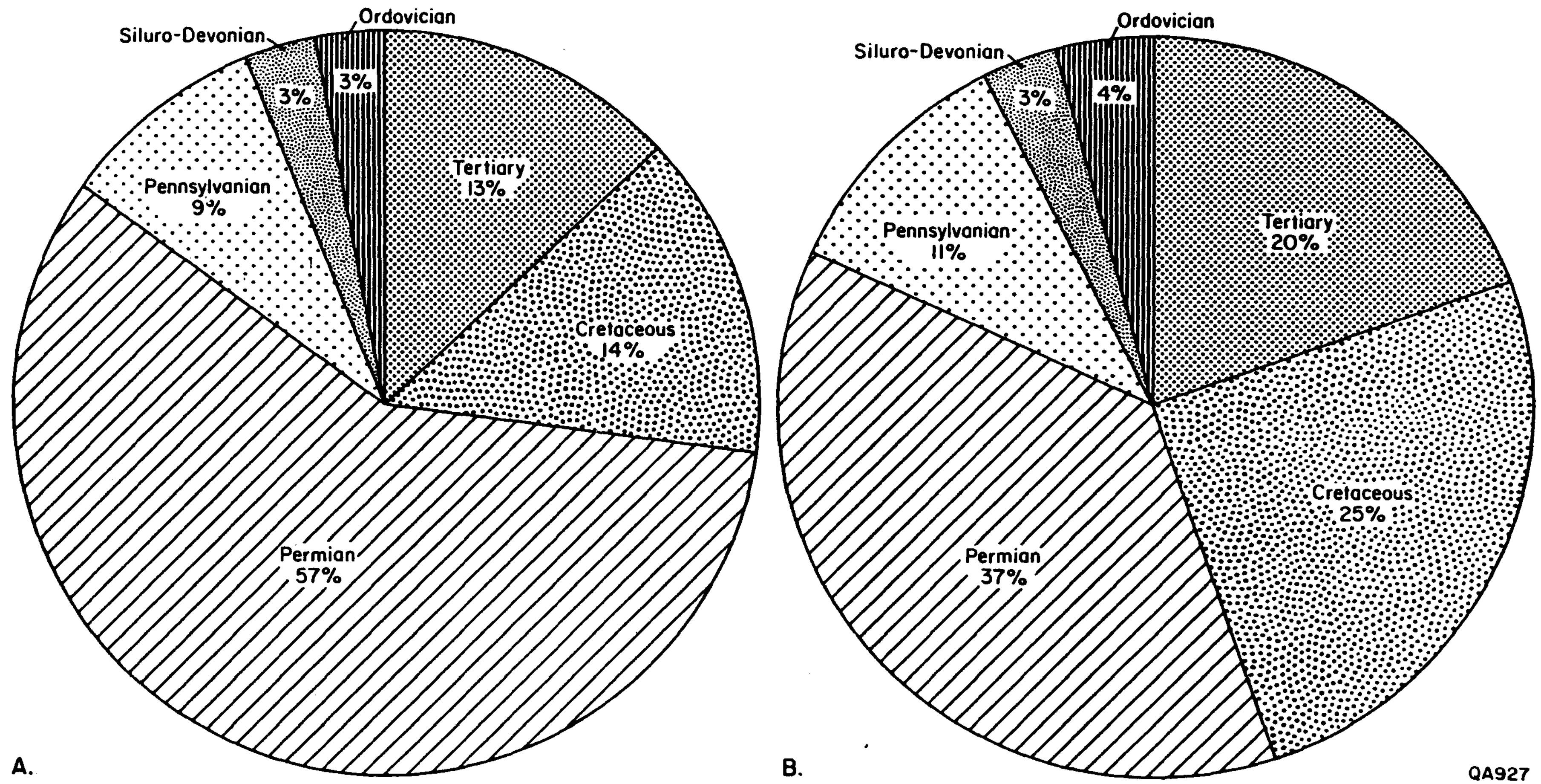

Figure 6. (A). Temporal distribution of in-place Texas oil. (B). Cumulative oil production (as of 1981) by reservoir age.

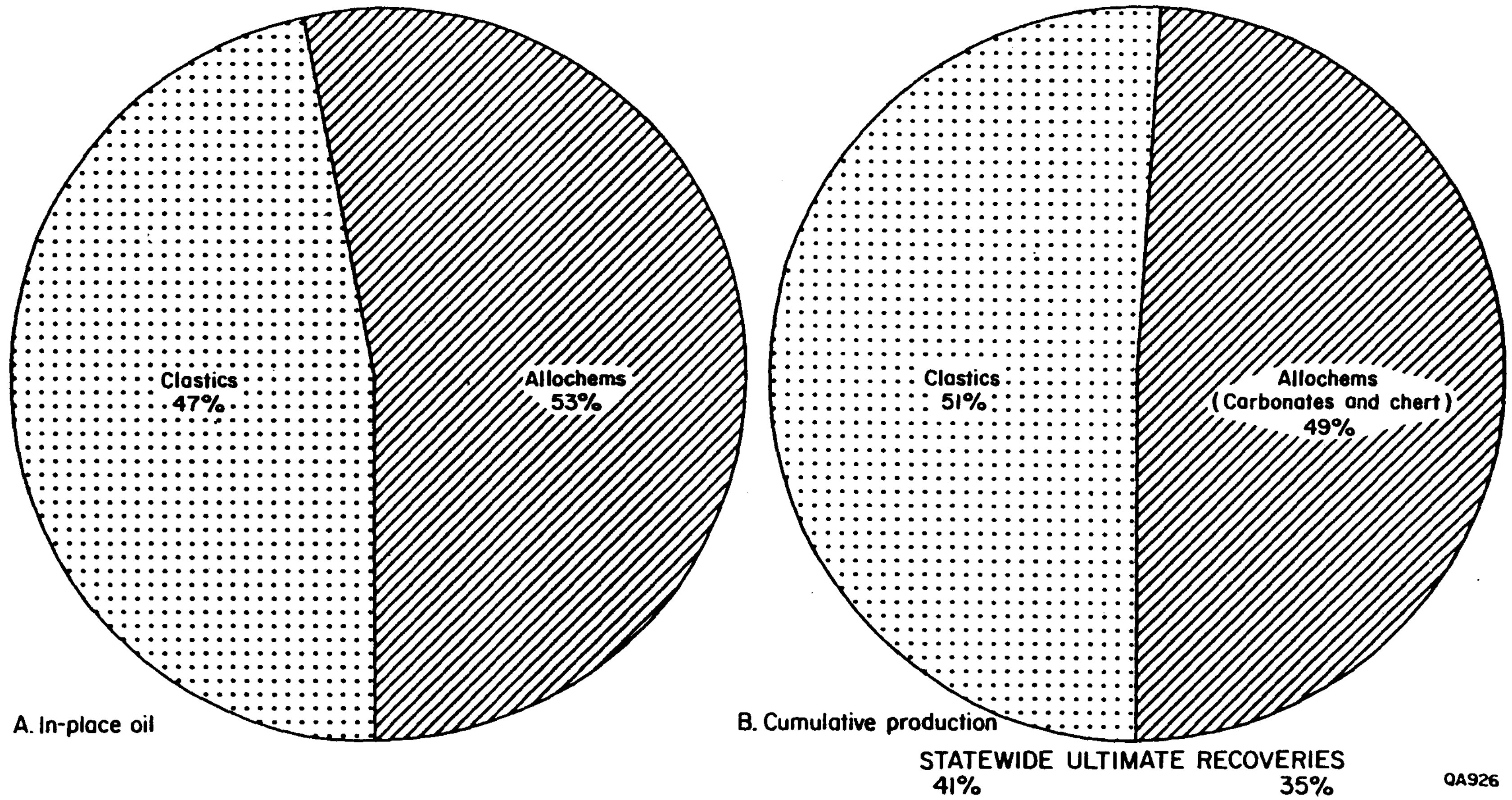

Figure 7. Distribution of major oil in terrigenous clastic and allochemical reservoirs (including limestones, dolomites, chalk and fractured chert). Clastic reservoirs contain a lower in-place oil resource (A) but as a result of better reservoir performance recover slightly more than allochemical reservoirs (B). Percentage figures refer to that proportion of the Texas total contained in, or produced from, terrigenous clastic or allochemical reservoirs, respectively.

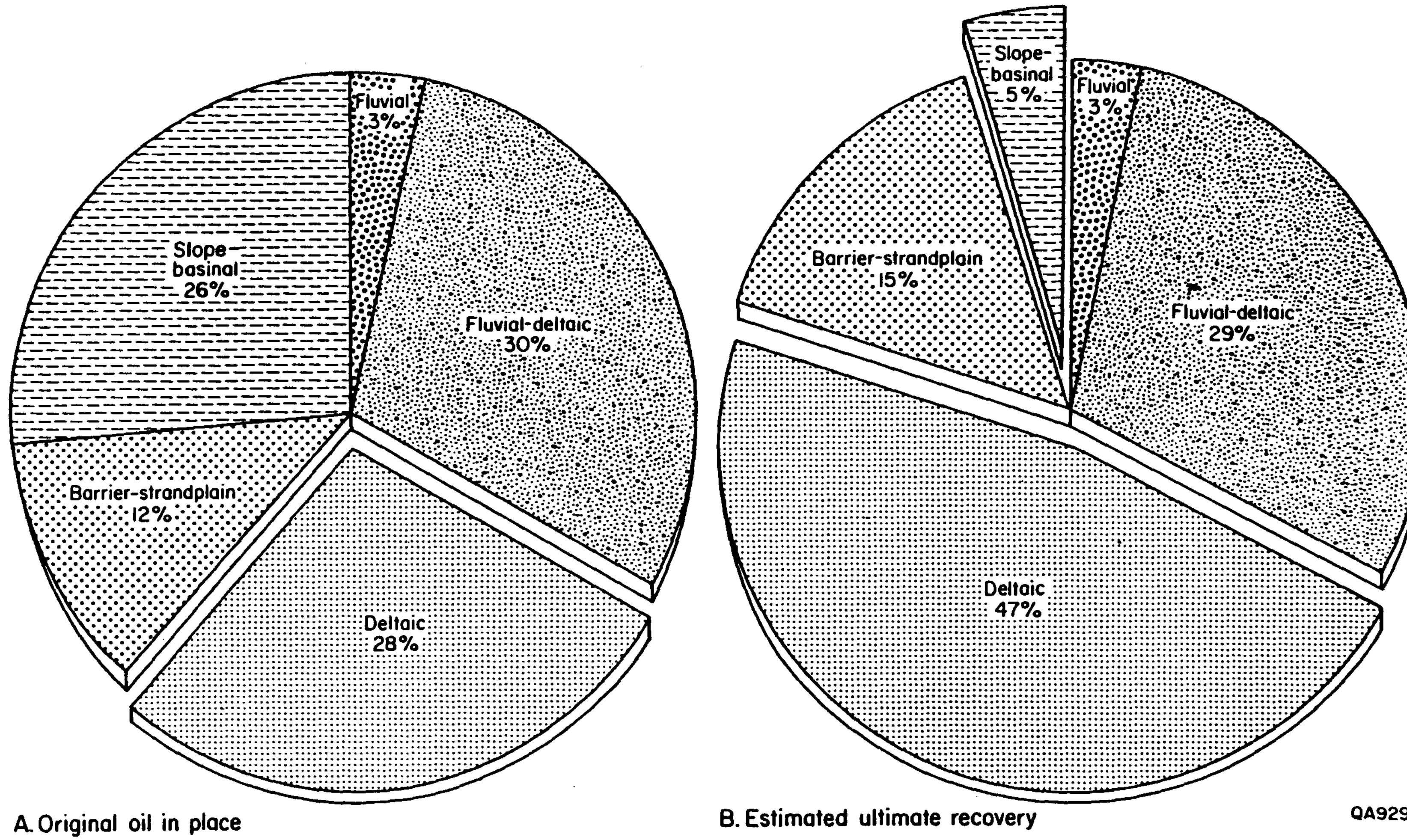

Figure 8. Exploded pie diagrams illustrating the relationship between reservoir genesis and the patterns of (A) oil accumulation in; and (B) subsequent production from clastic reservoirs. Production from deltaic reservoirs accounts for almost half of all production from clastic deposits.

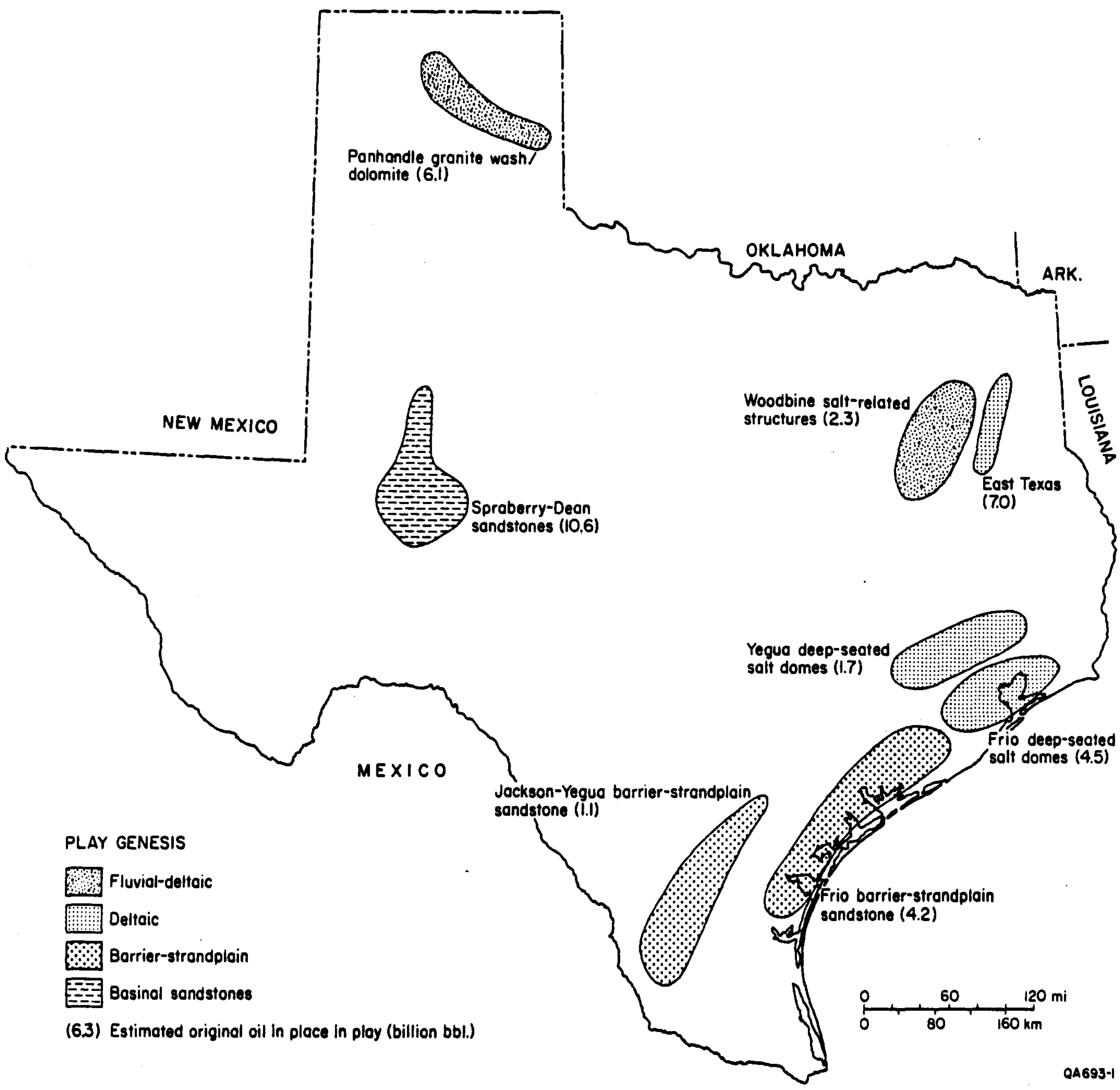

Figure 9. Principal clastic plays of Texas illustrating those plays that contain more than a billion barrels of in-place oil. The eight genetically-related families shown contain 81 percent of the oil in major clastic reservoirs in Texas.

Texas salt basin (fig. 9). Fluvial-deltaic deposits account for 30 percent of the in-place oil in Texas' clastic reservoirs (fig. 8A).

Figure 9 illustrates the geographic distribution and genetic origin of the principal clastic plays in Texas. The eight plays illustrated contain 81 percent of the oil in major clastic reservoirs. None of the true fluvial plays contained one billion barrels of oil and thus are not included on the map. The low concentration of oil in fluvial deposits is depicted in figure 8A; fluvial depositional systems contain only 3 percent of the OOIP in clastic reservoirs in Texas. This low percentage is somewhat biased by the fact that much of the oil in fluvial systems occurs at or near the interface with deltaic genetic units and thus is included in the fluvial-deltaic category.

Deltaic deposits contain 28 percent of the original in-place oil in clastic reservoirs. The most prolific producer in this genetic category is the famous East Texas (Woodbine) field which in terms of current cumulative production (over 4.7 billion barrels) is the most productive oil in the U.S.A. Other large deltaic plays are the Yegua and Frio deltaic sequences which are warped over deep-seated salt domes in the Houston Salt Basin (fig. 9).

Shorezone terrigenous clastics such as the Frio and Jackson-Yegua barrier-strandplain plays (fig. 9) contain 12 percent of the in-place resource in Texas' clastic reservoirs (fig. 8A). The Frio barrier-strandplain play is the largest of the 48 plays in Texas containing 46 reservoirs and two giant fields (Tom O'Connor and West Ranch). Production takes place from stacked barrier deposits folded into broad rollover anticlines on the downthrown side of the Vicksburg and Frio growth-fault zones (fig. 4).

Finally, slope-barrier systems contain over a quarter of the in-place oil resource in Texas' clastic reservoirs (fig. 8A). The largest of the three deep-water basinal sandstone plays is the Permian Spraberry-Dean which held approximately 10.6 billion barrels of in-place oil (fig. 9).

While the original in-place oil was distributed fairly uniformly throughout the spectrum of terrigenous clastic depositional systems, productivity of the contained oil is not. Production from deltaic systems overshadows reservoir yields from all other genetic categories (fig. 8B). It is estimated that deltaic sands will produce almost half of all the oil obtained from clastic reservoirs in Texas. The tremendous volume of oil recovered from the deltaic deposits of the East Texas field biases figure 8B; however, higher than average recoveries from deltaic reservoirs (table 1) clearly result in this large slice of the production pie. On the low end of the spectrum, slope-basin systems are anticipated to yield only 5 percent of the total production from Texas' clastic reservoirs. Considering that these deep-water clastics held more than a quarter of the oil resource in clastic reservoirs (fig. 8A), it is obvious that these submarine fan-turbidite assemblages warrant further study.

Table 1 is a compilation of production statistics of Texas' clastic reservoirs. The table clearly illustrates that reservoir genesis--the geologic origin and nature of the producing zone--emerges as an important factor in determining (and predicting) recovery efficiency in well-managed reservoirs. Fluvial-deltaic, deltaic, and slope-basin systems each contain between 11.5 and 13.2 billion barrels of in-place oil, yet estimated ultimate recoveries range from less than 1.0 billion barrels for basinal sandstones to 9.5 billion barrels for deltaic reservoirs. Recovery efficiencies average 41 percent statewide for clastic reservoirs but range from a low of only 8 percent (slope-basinal) to 68 percent of the original oil in place in deltaic reservoirs.

Fluvial systems.--Conventional recoveries in complex fluvial channel systems are typically low to moderate, averaging 36 percent (table 1). Coarse-grained, sand-rich braided stream deposits such as some of the Bend conglomerate reservoirs (play 22, fig. 3) are exceptions with recoveries exceeding 40 percent. Well-engineered reservoirs coupled with knowledge and application of genetic stratigraphy in positioning infill development wells also result in high recovery efficiencies such as in the Neches (Woodbine) field (play 19).

Fluvio-deltaic and deltaic systems.--Fluvio-deltaic systems are a major producing class in many clastic reservoirs of north, East, and Coastal Plain Texas. This class includes both fan-delta sequences and interstratified fluvial and deltaic facies tracts. Fan-delta deposits contain a multiplicity of small facies elements exhibiting great textural and compositional hetero-

Table 1. Production statistics: clastic reservoirs

PLAY GENESIS	NUMBER OF PLAYS	O.O.I.P. (MMbbl)	ESTIMATED ULTIMATE RECOVERY (MMbbl)	WEIGHTED RECOVERY EFFICIENCY (%)
Fluvial	3	1,541	560	36
Fluvial-deltaic	8	13,242	5,352	40
Deltaic	6	12,616	8,543	68
Barrier-strandplain	4	5,478	2,378	50
Basinal	3	11,578	874	8
		44,455	18,067	41

geneity. Barring extensive diagenetic modification, the coarse grain size and consequent high initial permeability of the reservoir sandstones and conglomerates compensate somewhat for the extensive compartmentalization. Reservoir performance in the Panhandle play (play 46, fig. 3) is poor with a conventional recovery efficiency of only 24 percent.

Facies in the interstratified fluvial-deltaic and deltaic genetic categories have wide ranges of production efficiencies. However, closer examination shows a predictable correlation between reservoir productivity and type of delta system. Fluvial-dominated deltas, which occur in such plays as the Strawn sandstone and shale (play 21, fig. 3), Pennsylvanian shelf sandstone (play 24), and Frio/Vicksburg sandstone (play 10), historically have low to average production efficiencies. In contrast, wave-dominated deltas, such as much of the Woodbine (plays 18, 19; fig. 3), including the East Texas field, have well above average production efficiencies. Large deltas, such as those of the Frio deep-seated dome play of the Upper Coastal Plain (play 5, fig. 3), that exhibit considerable wave modification and produce with the aid of gas cap expansion and gravity drainage, are also highly productive.

Clastic shore zone (barrier bar/strandplain) systems.--Clastic shorezone (barrier bar/strandplain) systems are typified by well-sorted, laterally continuous sand bodies. They exhibit high productivities in plays, such as the Frio barrier/strandplain play, where structural entrapment results in accumulation of oil in the massive, well-developed barrier core sands. Water or combination drive mechanisms also characterize such plays. However, stratigraphic entrapment places the oil in the updip back-barrier sands, which are thin, shaly, and discontinuous. In such plays, solution gas provides most of the reservoir energy, and productivity is only low to moderate. The average recovery from barrier-strandplain plays is 50 percent (table 1).

Clastic slope/basin systems.--Clastic slope/basin systems contain reservoirs deposited as facies in submarine fans and channels. Such reservoirs have inherently low recovery efficiencies averaging only 8 percent (table 1), which are further limited by the dominance of stratigraphic isolation and solution gas drives. Sediments are commonly fine grained, with low permeability and high residual oil saturations. Finally, internal compartmentalization and heterogeneity of submarine fan and channel reservoirs are inherent attributes of the depositional processes.

Intrasystem variability.--There is as much variability in reservoir performance within groups of plays of the same genetic origin as there is between groups of different reservoir genesis. Production characteristics of major deltaic reservoirs are presented as an example (table 2). Deltaic reservoirs have a weighted average recovery efficiency of 68 percent (table 1); however, recoveries range from a high of 80 percent in the East Texas field, to a low of only 21 percent in Cretaceous San Miguel-Olmos reservoirs of South Texas. Recoveries from the four remaining deltaic plays vary between 28 and 58 percent (table 2).

Numerous differences contribute to the wide disparity in recoveries from the East Texas Woodbine and San Miguel-Olmos sandstone plays (plays 18, 11; fig. 3, respectively). These include drive mechanism, production practices, and well spacing, but most importantly, genetic history.

The East Texas field (fig. 10) has a prolific water drive, whereas reservoir energy in the San Miguel and Olmos pools is provided by solution gas, or by combined solution gas - gas cap drives. The close spacing of wells (5-acre patterns) and the protective measures taken by the TRRC to regulate production from the East Texas field are well documented (numerous hearing files at the TRRC). Well spacing in the San Miguel-Olmos play ranges from 10-80 acres. The unifying factor is that the clastic reservoirs in both of these plays were deposited in wave-dominated delta systems (Oliver, 1971; Weise, 1980; Tyler and Ambrose, in prep.). Production takes place from extensive beach-ridge-barrier facies (fig. 11).

The depositional geometry of a wave-dominated delta system, although slightly modified, is still preserved in the San Miguel reservoir of the Big Wells field (fig. 10). This sandstone is a lensoid isolani, sandwiched between marine shale sections (Layden, 1971). Net oil-sand isoliths delineate linear, strike-parallel thicks which are locally truncated by cross cutting sand-poor zones (fig. 12A). According to Layden (1971) porosities and permeabilities are lower in the

Table 2. Production statistics: deltaic reservoirs

PLAY	O.O.I.P. (MMbbl)	U. R. (MMbbl)	RECOVERY EFFICIENCY (%)
East Texas	7,000	5,600	80
Frio Deep Domes	4,491	2,590	58
Yegua Dome Flanks	54	29	53
Eocene Deltas	243	93	38
Panhandle Morrow	188	53	28
San Miguel/Olmos	840	178	21

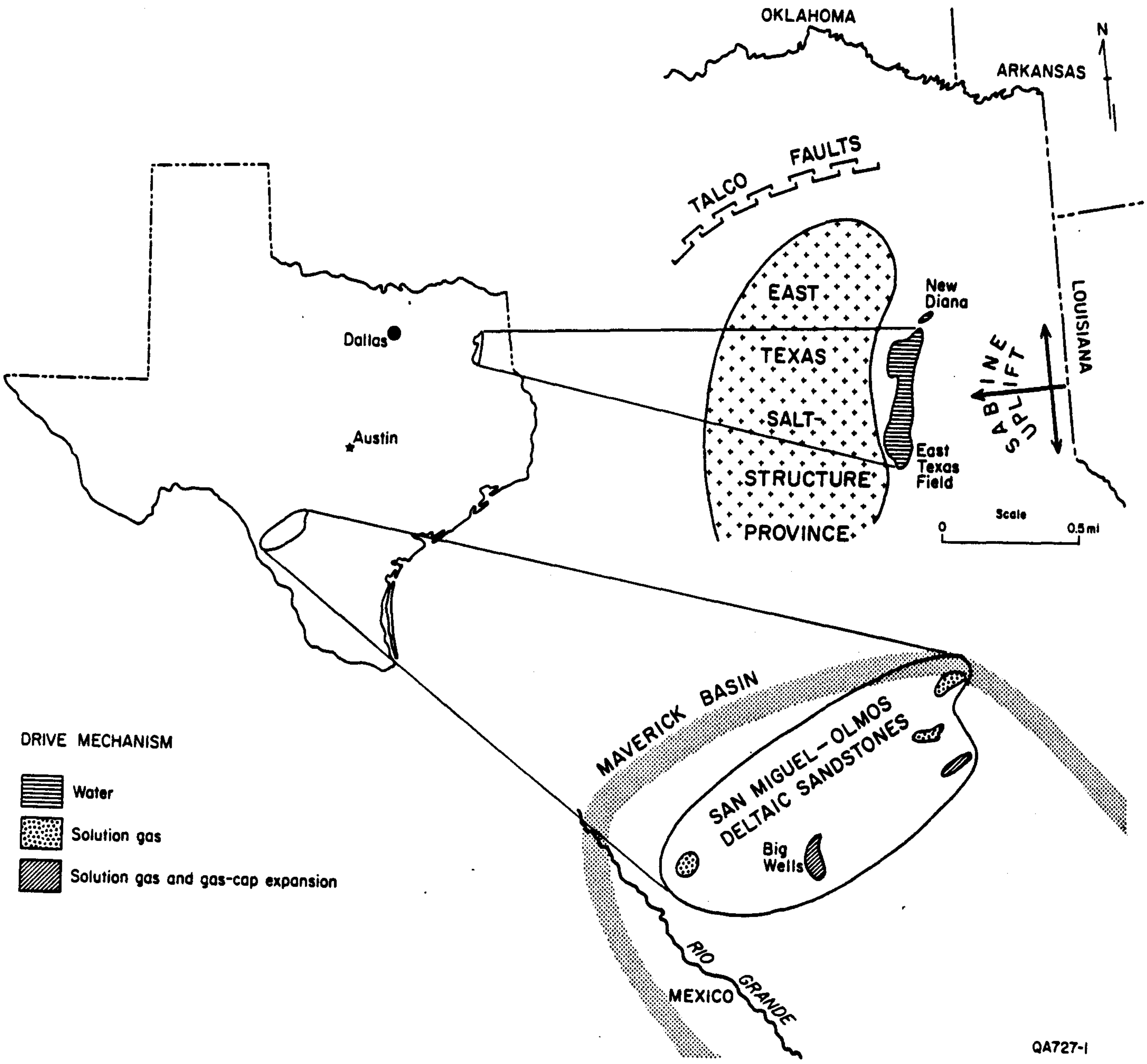

Figure 10. Locations of two Cretaceous sandstone plays that originated in wave-dominated delta systems. The East Texas field produces from the Dexter Formation of the Woodbine Group, the San Miguel-Olmos play from upper Gulfian-aged clastic sequences in the Maverick Basin. Recovery efficiencies are substantially lower in the tight, reworked sands of the Maverick Basin.

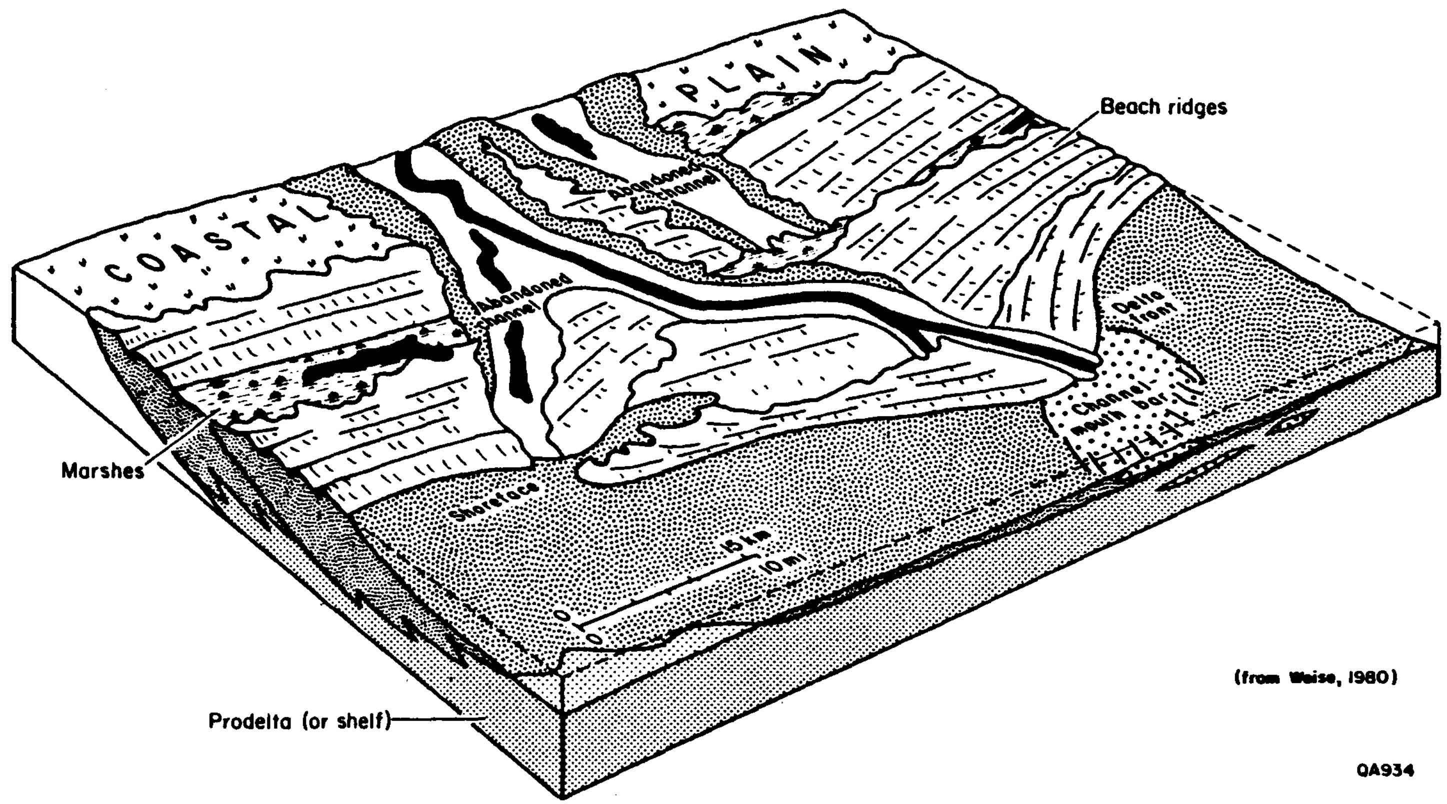

Figure 11. Idealized model of a wave-dominated delta system (from Weise, 1980). Extensive beach ridge-barrier sequences are the principal productive facies in the East Texas field and in the Maverick Basin play.

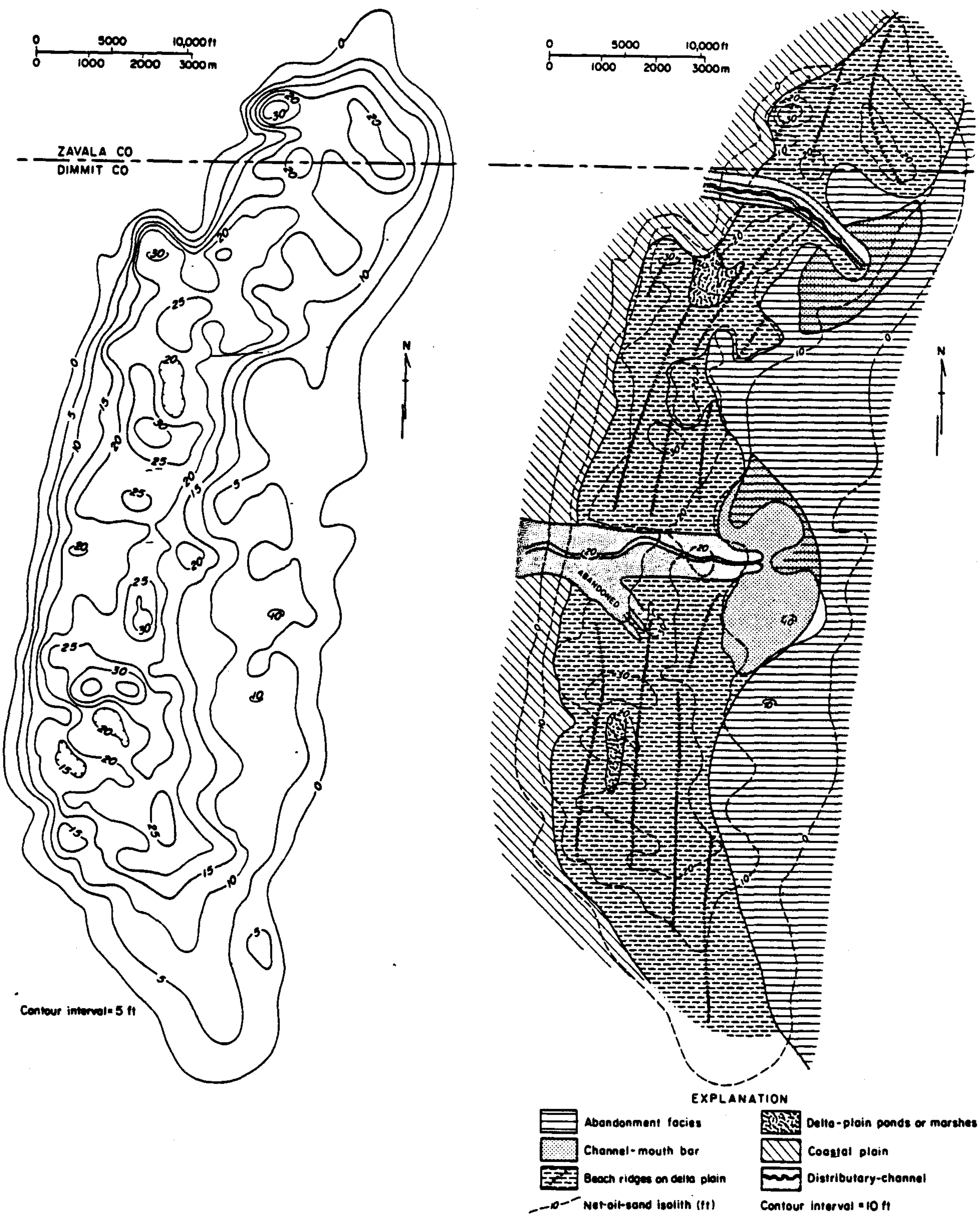

Figure 12. Net-oil-sand isolith map of the Big Wells (San Miguel) reservoir (A). Oil sand isoliths define a lenticular, curvilinear oil zone. Local linear oil-sand-thicks are interpreted as the topographic expression of beach ridges; intervening sand poor zones were probably sites of marsh or swamp sedimentation (B). East-oriented abandoned distributary channel fill deposits are zones of poor reservoir performance, as is the marine reworked northeastern part of the reservoir. Fig. 10A modified from Exhibit 5; Docket No. 1-62914; May 23, 1973, Sun Oil Company; TRRC.

northern half of the field than in the south. Furthermore, pressure data suggest the two halves are separated by a continuous east-west trending zone of poor sand conditions.

Figure 12B illustrates the interpretation of the geometry and thickness trends of the Big Wells (San Miguel) reservoir. The sand thicks were deposited as beach ridges on the foreshore of a wave-dominated delta. Marshes and swamps filled interrridge topographic lows. The east-west trending zone of poor sand conditions probably represents the clay-rich plug of an abandoned distributary channel. Lower porosities and permeabilities in the northern half of the field probably result from postdepositional marine reworking of the beach-ridge sands involving stripping off of the upper well-sorted units of the shoreface, as occured elsewhere in San Miguel deltas (Weise, 1980), and bioturbatory mixing of fine detritus from the overlying marine section into the coarse, well-sorted reservoir sands. Areas of marine reworking are illustrated by horizontal lines on figure 12B. Reworking of the deltaic sandstones and the nature of the bounding shales indicate that this deltaic sequence was deposited during a transgression of the Cretaceous Seaway.

The Woodbine reservoir in the East Texas field, on the other hand, was deposited during a regression. The Dexter wave-dominated delta sequence prograded towards the southwest (Oliver, 1971), and was overlain by an aggrading tributary meanderbelt system (fig. 13). This fluvio-deltaic facies tract then suffered elevation and erosion over the Sabine Uplift. Most of the fluvial deposits were stripped away to be resedimented southwest of the Sabine Uplift as the Harris Delta System (the productive sands in the Kurten ("Woodbine") field). Dense Austin Chalk, deposited on the plane of unconformity, provides the reservoir seal. Production is presently obtained from stacked coastal barrier, and locally from lenticular distal channel-mouth bar sandstones.

In summary, reservoir genesis clearly influences patterns of oil accumulation and subsequent production both on a statewide basis (for example, deltaic versus barrier-strandplain reservoirs) as well as locally within reservoir limits (distributary channel versus beach-ridge facies). As will be shown later in this paper, similar trends also exist in carbonate reservoirs.

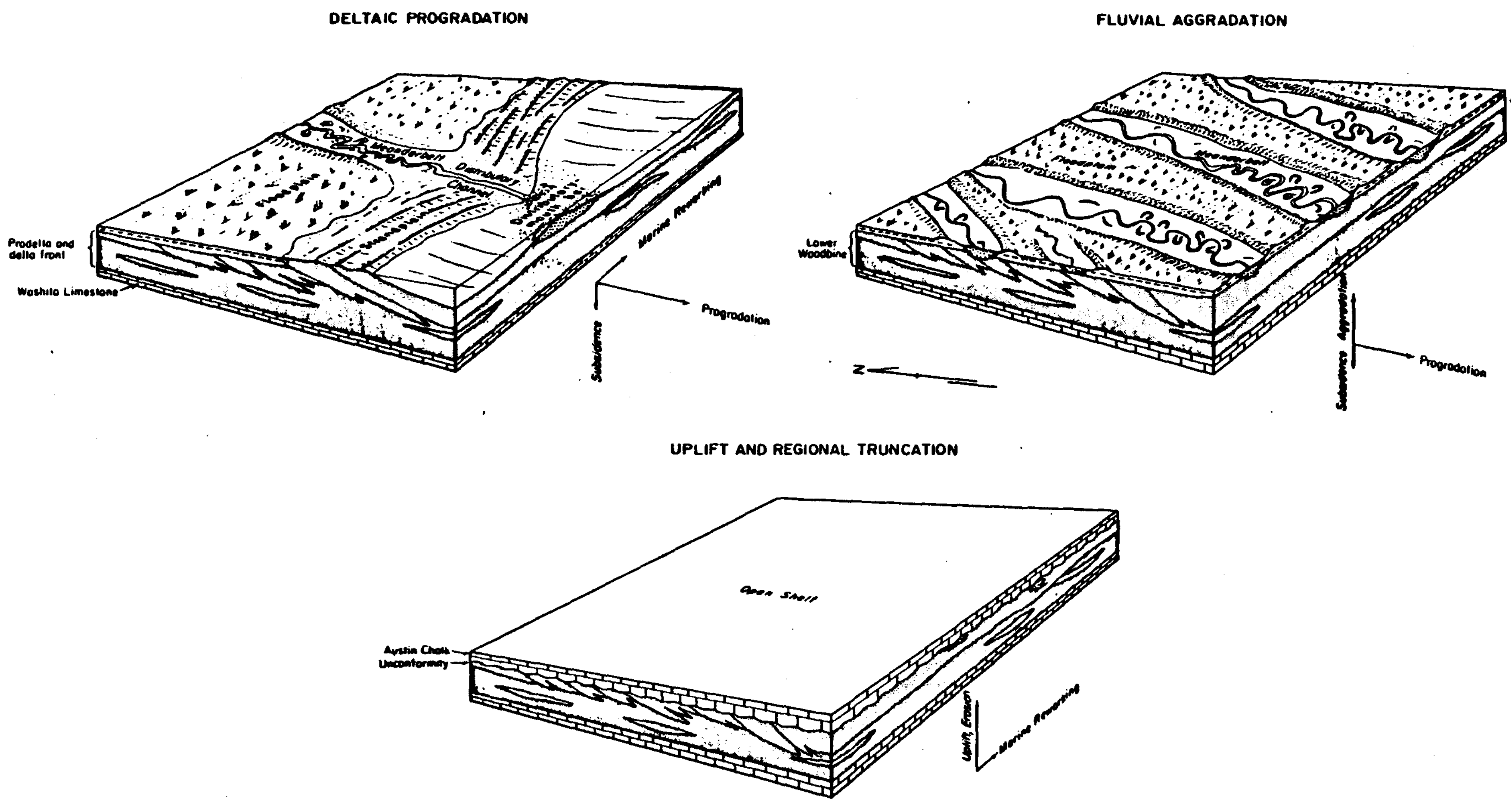

Figure 13. Evolution of the East Texas field area. Southwestward progradation of a wave-dominated delta system was succeeded by meanderbelt aggradation. Elevation of the region over the Sabine Uplift with concomitant erosion resulted in the stripping off of most of the upper Woodbine fluvial deposits. Subsequent subsidence and deposition of dense Austin chalk on the surface of the unconformity provides the reservoir seal. (In collaboration with W. A. Ambrose).

Carbonate Reservoirs

In contrast to the distribution of original in-place oil in clastic reservoirs, where the resource was evenly spread throughout deltaic, barrier-strandplain, and slope-basinal systems, original in-place oil in carbonate sequences is overwhelmingly concentrated in dolomitized restricted platform deposits (fig. 14A). Fully 61 percent of the OOIP in carbonate rocks is contained in this setting, which is composed of a spectrum of interrelated backreef facies including restricted shelf, lagoonal, and tidal flat deposits (fig. 15). Figure 16, a map of the principal carbonate plays in Texas, illustrates that, with the exception of the small cluster of Edwards pools on the San Marcos Arch, the majority of the major restricted platform plays are concentrated on the Central Basin Platform and on the northern and eastern shelves of the Permian Basin. The 12 plays illustrated on this map originally contained more than 51 billion barrels of oil or 86 percent of in-place resource in carbonates. Figure 17, which shows the productive core of the Permian Basin in greater detail, further emphasizes the enormous volumes of oil that are contained in restricted platform deposits. These reservoirs are principally of Guadalupian (San Andres-Grayburg) and Leonardian (Clear Fork) age.

Of the remaining carbonate plays the platform margin deposits, which include both reefal limestones as well as nonreefal limestones and sandstones warped over the shelf margin by differential compaction, account for 16 percent of the OOIP in carbonates (fig. 14A). An example is the Permian sandstone and carbonate play on the west flank of the Central Basin Platform where reservoir facies are porous carbonates and sandstones of Guadalupian age (San Andres through Yates, fig. 5). Original in-place oil in this play was three billion barrels. Deeper water atoll and pinnacle reef plays, such as the Horseshoe atoll (figs. 16, 17), account for 11 percent of the original oil in carbonates.

The three remaining genetic categories collectively contain only 12 percent of the in-place resource. The 31 major, fractured, open-shelf reservoirs (Barnes and others, 1959) in the Ellenburger contained 3.2 billion barrels. The Austin Chalk, which is another example of fractured open-shelf carbonate reservoirs, was not included in this compilation because of the

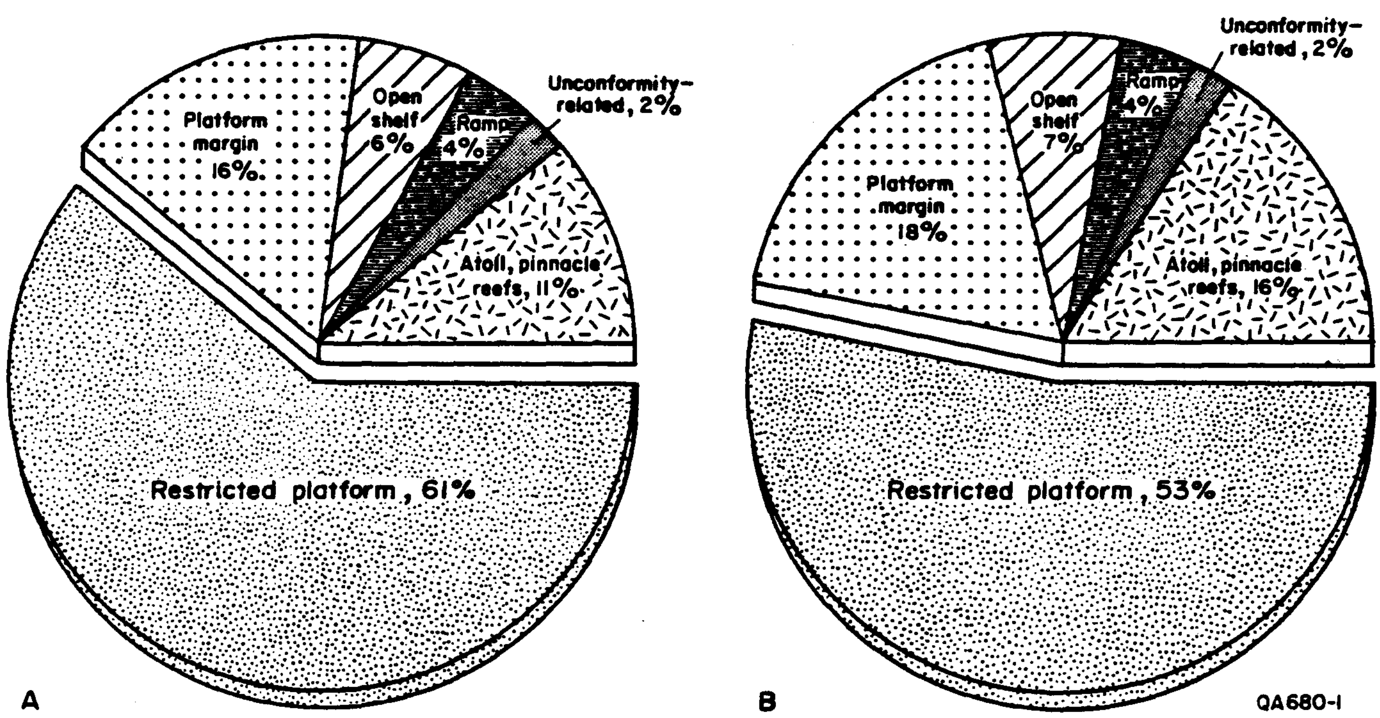

Figure 14. Exploded pie diagrams illustrating the relationship between reservoir genesis and patterns of (A) oil accumulation, and (B) subsequent production from carbonate reservoirs. Restricted platform carbonates contain and produce more than half of the oil resource in carbonate sequences.

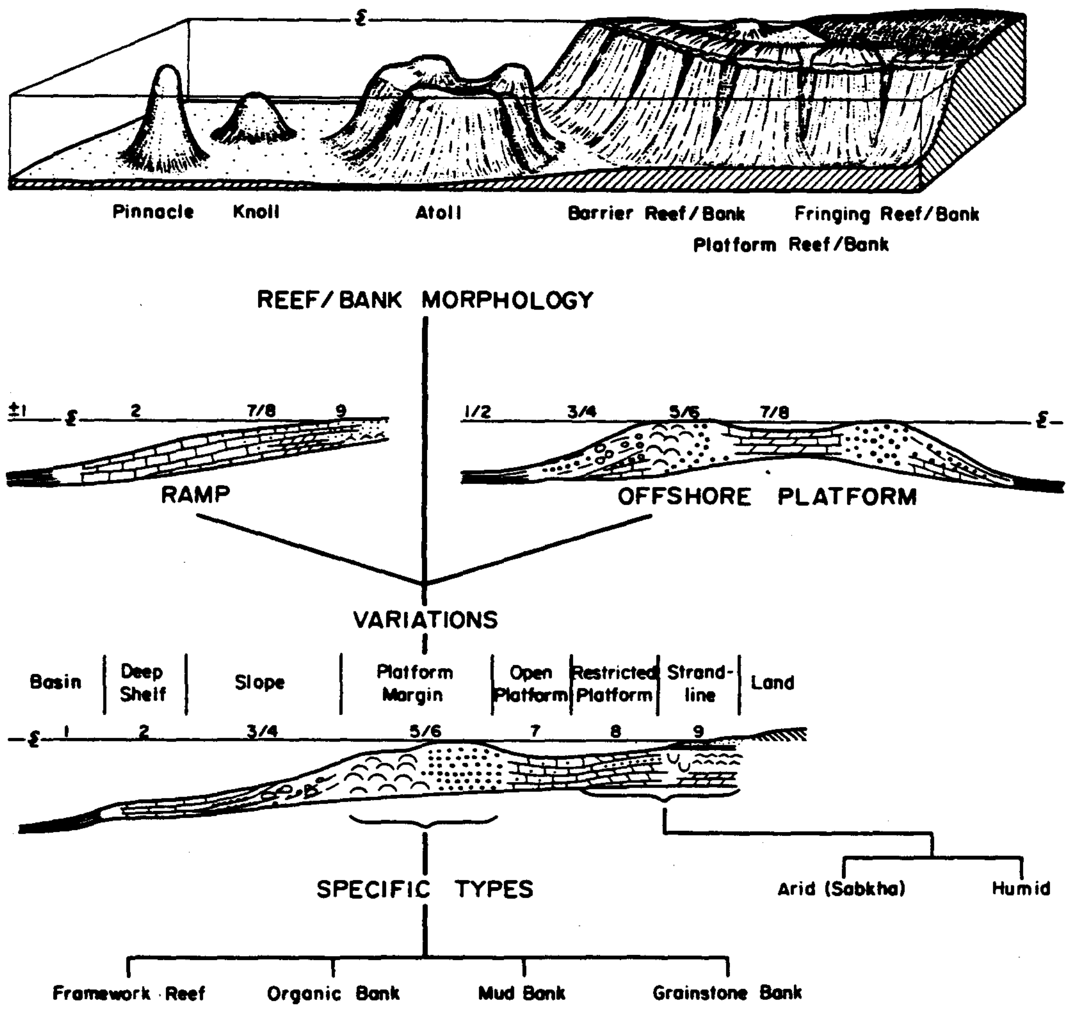

Figure 15. Schematic carbonate depositional systems. Restricted platform deposits which lie on the landward side of fringing or barrier reefs and banks contain the largest resources of oil in carbonate rocks in Texas. Platform margin and atoll pinnacle reef systems also contain large volumes of oil. From Galloway and others, 1983 (in press).

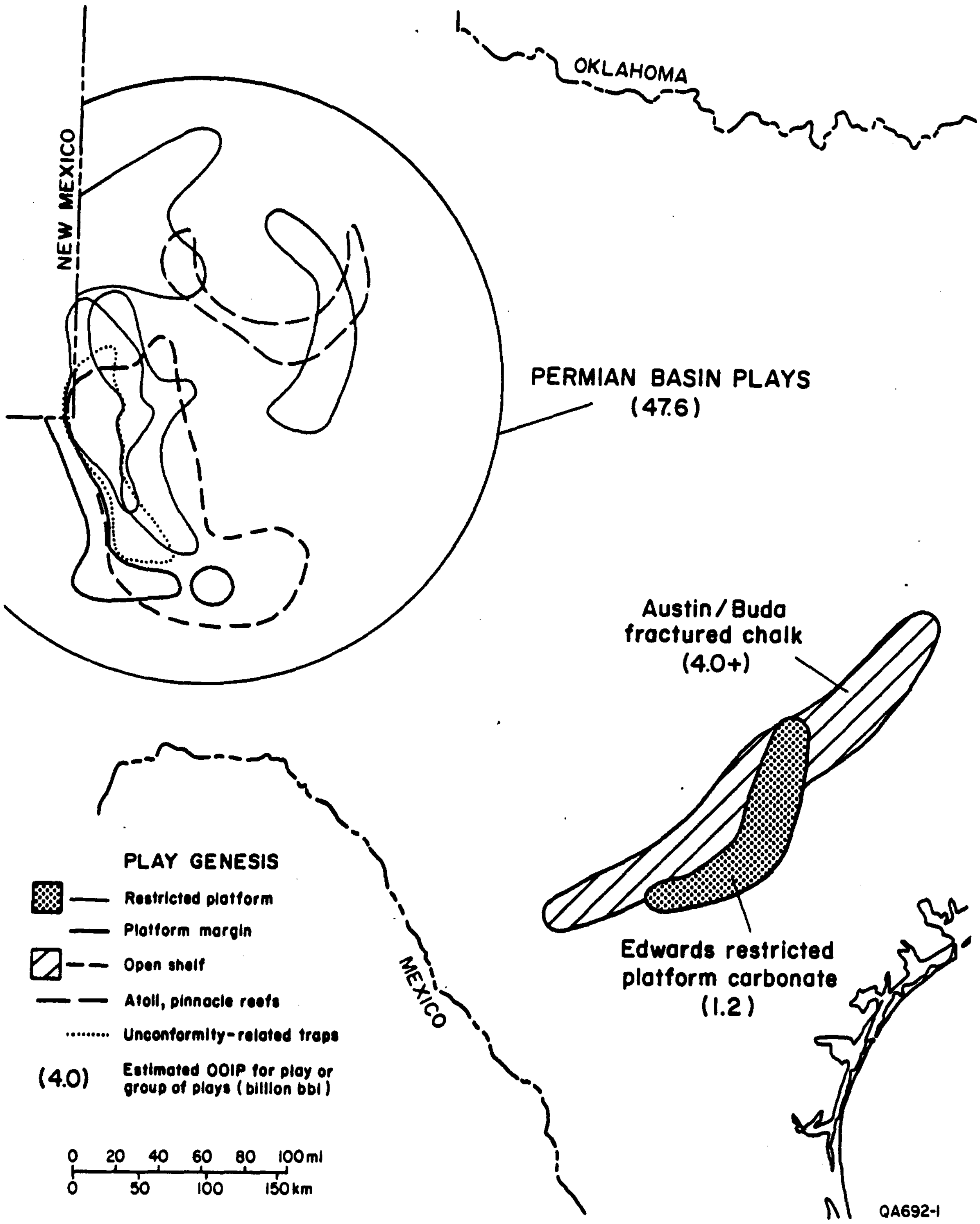

Figure 16. Principal carbonate plays in Texas. Only those plays that contained more than a billion barrels of in-place oil are shown. A more detailed illustration of the Permian Basin plays is shown in Figure 17.

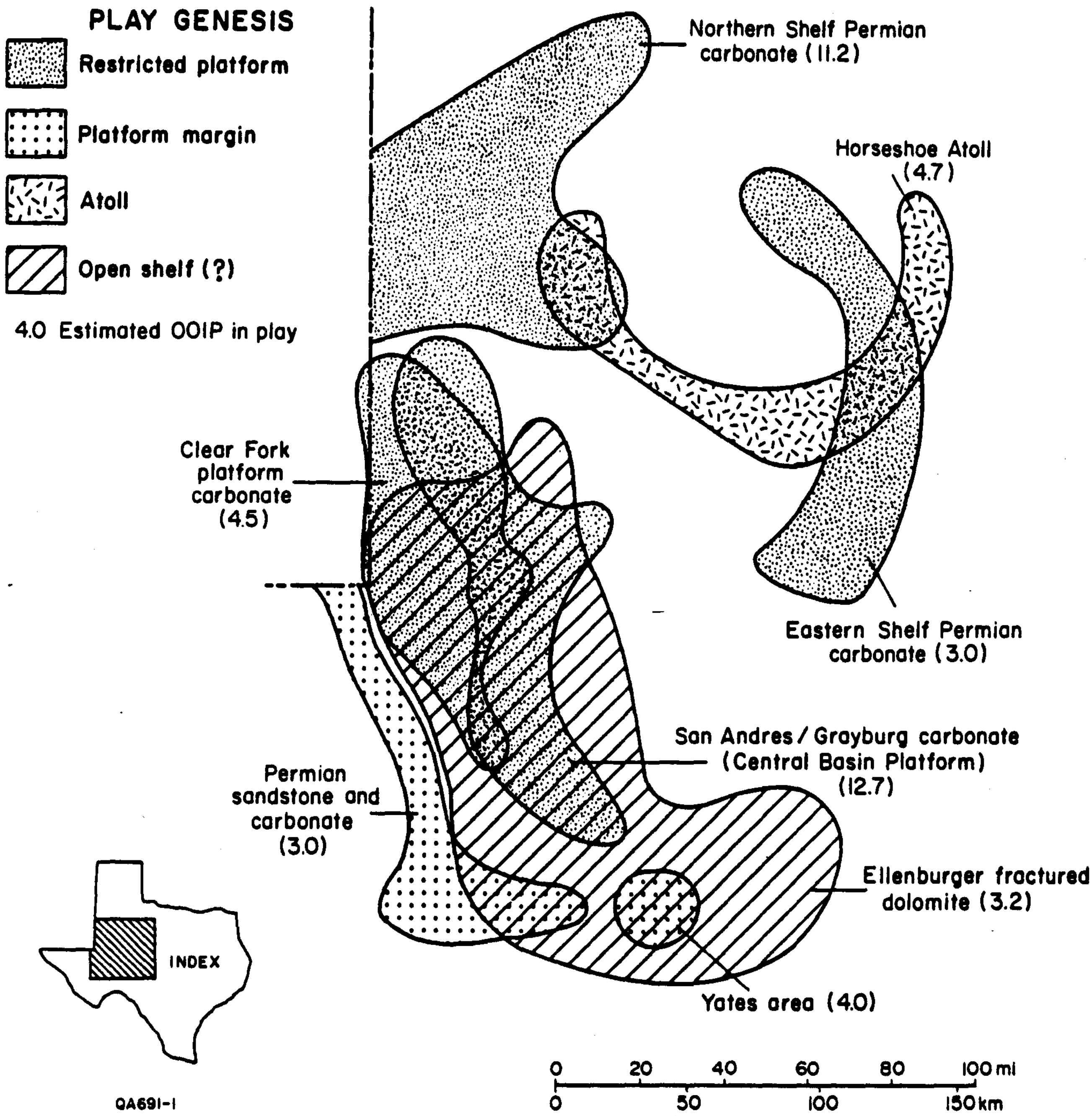

Figure 17. Play genesis and original-oil-in-place statistics for the major carbonate plays of the Permian Basin.

unavailability of a reliable resource estimate. Silurian-Devonian ramp carbonates deposited in the ancestral Permian Basin and unconformity-related reservoirs which produce from a variety of reservoir facies contain 4 and 2 percent of the original in-place oil in carbonates, respectively.

Estimated ultimate recoveries of the carbonate plays are illustrated in figure 14B. While the bulk of Texas' oil resource in carbonates is concentrated in restricted platform deposits, poor recovery from these reservoirs results in a proportionately smaller production. However, these deposits nevertheless will account for 53 percent of all production from carbonates; this is a substantial 10.3 billion barrels. Comparative increases in reservoir yield in atoll/pinnacle reef systems and, to a lesser extent, platform margin and open-shelf carbonates account for the disparity between the in-place and ultimate recovery percentages for restricted platform carbonates (figs. 14A, B) relative to original in-place oil.

Restricted platform systems.--As was indicated in the previous section, restricted platform deposits do not readily release entrapped oil. The nine plays of restricted platform origin contain almost 34 billion barrels of oil, and yet ultimate recovery by primary and secondary methods is estimated to be only 10.3 billion barrels or just 30 percent of the original resource (table 3). Restricted platform deposits originated on shallow water platforms under arid and evaporitic climatic conditions. Consequently, postdepositional diagenesis of original sediments produced extensive beds of dolomite with its characteristically low porosities and permeabilities. Reservoirs are highly stratified and exhibit moderate to high residual oil saturations following flushing. Isolation of permeable zones within lithologically heterogeneous sequences results in dominance of solution gas drives. Together, the comparatively inefficient drive mechanisms, stratification, and combined depositional and diagenetic heterogeneity result in low to moderate recovery efficiencies for plays producing from restricted platform carbonates. Enormous reserves and unrecovered oil are contained within reservoirs belonging to this genetic class, including the San Andres/Grayburg plays of West Texas.

Atoll/pinnacle reef systems.--Recoveries from open shelf atoll, pinnacle reef systems buried by basinal shales and mudstones are uniformly high, averaging 50 percent (table 3). Entrapment results from burial of the porous carbonate mounds within the impermeable sealing shales. Most reservoirs of these reef/bank complexes exhibit solution gas drives, occasionally augmented by water drive where the base of the carbonate mass connects to a widespread limestone unit. The vertical relief, lateral isolation, strongly developed permeability layering, and large reserves typical of open shelf reef and bank reservoirs have resulted in extensive unitization and systematic field development. As a result, recovery efficiencies are unusually high, particularly for solution gas drive-dominated reservoirs.

Platform margin systems.--Accumulations of plant and animal debris along shallow-water, submerged platform edges formed organic reef and bank units characterized by great lithologic and diagenetic heterogeneity. Unlike the reefs that grew upward from deep-water open shelves and were encased in shale, platform margin reefs and banks commonly grade laterally and vertically into a variety of sealing or less permeable strata. Further, facies belts tend to be thin, narrow, highly elongate, and internally complex. Reservoir quality commonly reflects great postdepositional modification of original sediment texture. At one extreme, leaching by fresh water has produced vuggy, cavernous porosity (and an excellent reservoir) as at Yates field (fig. 17). More commonly, permeability is highly stratified and lenticular, and recovery efficiencies are low. Recoveries from platform margin systems, including reefs and banks as well as nonreefal limestones and sandstones warped over the platform edge, average 41 percent (table 3).

Open shelf and ramp systems.--Limestones and dolomites of several plays, including much of the West Texas Ellenburger and Silurian-Devonian production, are tentatively interpreted to have been deposited on broad, shallow to moderately deep, gently sloping carbonate shelves commonly called ramps. Production is controlled largely by postdepositional modifications of the original carbonate strata, including dolomitization, folding and fracturing, erosional truncation and associated diagenesis, leaching, and silicification. Consequently, production efficiency

Table 3. Production statistics: carbonate reservoirs

PLAY GENESIS	NUMBER OF PLAYS	O.O.I.P. (MMbbl)	ESTIMATED RECOVERY (MMbbl)	WEIGHTED RECOVERY EFFICIENCY
Restricted platform	9	33,637	10,246	30
Open shelf	2	3,485	1,397	40
Platform margin	5	8,631	3,526	41
Ramp	3	2,009	799	40
Atoll, pinnacle reefs	3	6,015	3,017	50
Unconformity-related	1	1,342	354	26
	23	55,119	19,339	35

Austin Chalk and Cap Rock plays not included because of insufficient information is variable, generally ranging from poor to average. Younger strata, such as the Glen Rose Limestone in the East Texas Basin, contain a few major reservoirs in similar settings. These diagenetically simpler reservoirs may have better-than-average ultimate recovery. Drive mechanisms may be either solution gas or mixed types including natural water drive. Recovery efficiency varies accordingly, but averages 40 percent.

RECOVERY EFFICIENCY OF TEXAS RESERVOIRS

The overall efficiency of primary oil recovery is largely determined by three groups of variables: (1) drive mechanisms (energy source), (2) basic rock properties (lithology), and (3) fluid properties. If large groups of fields are being considered, the average productivity may be approximated by cross plots of drive mechanism, lithology, and oil gravity. Significant deviations from such average curves indicate important modification of the producibility of oil by other parameters, such as abnormally low permeability or poor reservoir continuity.

More detailed mathematical analysis of oil production (American Petroleum Institute, 1969) shows that, for solution gas and water drive reservoirs, recovery efficiency is controlled by reservoir porosity, permeability, water saturation, formation volume factor, oil viscosity, and the ratio of initial or bubble point pressure and pressure at abandonment. However, even these extensive statistical treatments of reservoir performance are unaccountably variable. Recently, production engineers and geologists have recognized a fourth family of variables relating to the depositional and diagenetic facies makeup of the reservoir (Harris and Hewitt, 1977).

As pointed out by Alpay (1972), variations in ultimate hydrocarbon recovery from a reservoir are result from three levels of heterogeneity. (1) Microscopic heterogeneities are variations that occur at the dimensions of pores within the rocks. Microscopic variables include pore-size distribution, pore geometry, and amounts of isolated or dead-end pore space. These elements primarily affect the irreducible water saturation (S_w) and the residual oil left in swept portions of the reservoir. Consequently, analysis of microscopic heterogeneity is particularly important in design of tertiary recovery programs.

(2) Macroscopic heterogeneity determines well-to-well recovery variability and is a product of primary stratification and internal permeability trends within reservoir units. Complexities include

1. Stratification (bedding) contrasts in grain size, texture, degree of cementation, and so on;
2. Nonuniform distribution of stratification types;
3. Lateral discontinuity of individual strata;
4. Reservoir compartmentalization due to low-permeability zones;
5. Permeability heterogeneity;
6. Vertical or lateral permeability trends;
7. Permeability anisotropy.

All these features are inherent attributes of the reservoir that are products of its depositional history and subsequent diagenetic overprint. It is at the scale of such macroscopic variability that large volumes of reservoir are partially or wholly isolated from the effective swept area. These features usually extend only a few acres areally or a few feet vertically. Consequently, compartments or layers that are not drained by conventional well spacing or completion practices may, if recognized, be tapped by selected infill drilling or by modification of well completion practices.

(3) Megascopic variations, such as lateral facies changes, porosity pinch-outs, and separation of reservoirs by widespread sealing beds, reflect fieldwide or regional variations in reservoirs and are caused by either original depositional setting or subsequent structural deformation and modification. Such large-scale variations are conventionally evaluated during modern reservoir development and management by techniques such as structure and porosity mapping, net pay isopach preparation, and detailed well log cross section correlation. Macroscale heterogeneity, that is, interwell variation or boundaries, is the least studied, least known,

and the most difficult of the three types of variations to define with precision. It is in this area that merging of geologic and engineering perspectives is most needed. Macroscopic heterogeneity offers the greatest potential for increasing ultimate oil recovery.

FACTORS AFFECTING RECOVERY EFFICIENCY

Analysis of characterization of the major Texas oil-producing plays delineates the factors that determine ultimate recovery of hydrocarbons from these reservoirs. The median recovery efficiency of the plays is 38 percent, better than the average efficiency of all Texas reservoirs (table 4). Recovery efficiency data constitute three classes. (1) Poor reservoirs yield less than

Table 4. Comparative Recovery Efficiencies of Various Groups of Reservoirs.

	OOIP (BBO)	Conventional Ultimate Recovery (BBO)	Percent Recovery
Gulf basins			
Giant fields	17	12	70.6
Non-giant fields	32	13	40.6
Subtotal	49	25	51.0
West Texas basins			
Giant fields	43	14	32.6
Non-giant fields	64	15	23.4
Subtotal	107	29	27.1
Total	156	54	34.6
Statewide giant fields	60	26	43.3
Statewide non-giant fields	96	28	29.2
Surveyed reservoirs			
Gulf basins	28	17	60.0
West Texas basins	73	22	30.0
Total	101	39	39.0

32 percent of the in-place hydrocarbons. (2) The better reservoirs yield more than 46 percent of their oil. (3) Average reservoirs are projected to recover between 32 and 46 percent of the oil in place. However, even within a single play, the range of recovery from reservoir to reservoir may vary greatly. Comparison of play averages, as well as evaluation of intraplay variability, suggests several trends affecting and generalizations about ultimate field recovery.

1. The most obvious factor determining recovery efficiency is the reservoir drive mechanism. Either strong natural water drive or a combination of drive mechanisms working in concert characterizes nearly all plays that are projected to produce more than 40 percent of their oil in place. In contrast, nearly all low-recovery plays are characterized by solution gas (depletion) drives. However, well-engineered and carefully managed solution gas reservoirs may approach the recovery efficiency of water drive reservoirs. Because most large plays are composites of many reservoirs, the extent of applied production technology ranges widely, and for the play as a whole, the calculated recovery efficiency tends to reflect the well-known relative efficiency of the natural drive mechanism.

2. Lithology also influences recovery efficiency, but there is great overlap among the various lithic categories. In general, comparison of average play recovery efficiency shows that sandstone reservoirs perform better than limestone reservoirs, which, in turn, outperform dolomite reservoirs. Conglomerates appear to be highly variable. Sand and sandstone reservoirs show great variation in average recovery, which is strongly influenced by the drive mechanism operating within the reservoir. Dolomite reservoirs exhibit, at best, moderate recovery efficiencies. Like sandstones, they are least efficient in solution gas drive reservoirs.

3. Porosity shows little direct correlation with recovery efficiency. However, a weak inverse correlation between porosity and residual oil saturation is apparent. Published reservoir-specific data (Murphy and others, 1977) suggest a decrease in residual oil as porosity increases within the same lithologic type.

4. Permeability varies widely among the reservoirs of the various plays, but shows little obvious correlation with recovery efficiency. Permeability appears to be an overriding

limitation on ultimate production only in a few Texas reservoirs where average values are very low (less than a few millidarcys).

5. Specific gravity of the oil, expressed as API gravity, limits recovery in a few reservoirs. Within most plays, oil gravity varies within a narrow range and thus does not account for production variability within the play. Oil viscosity would likely be a more effective predictor of recovery efficiency, but viscosity is highly dependent on measurement techniques and conditions, which are rarely specified in hearings files of the Railroad Commission of Texas.

6. The impact of well spacing on recovery is difficult to isolate. Within individual plays, spacing typically is reasonably uniform; differences that do exist commonly reflect major changes in overall recovery strategy or technology. To further confuse possible trends that might emerge from comparison of various plays, many shallow, low-recovery reservoirs usually have dense well spacing. Even with unusually close well spacing, they are still poor to average reservoirs. However, the argument that closer well spacing leads to improved ultimate recovery, other factors being equal, is strongly supported by numerous individual field case histories, which document measurably increased projections of ultimate recovery following programs of infield drilling. Many such programs date from the early 1970's and thus require substantial followup to document results.

7. Field development practice emerges as one of the most obvious controls on ultimate recovery efficiency. Table 1 compares the average production efficiency of the large, and consequently more thoroughly engineered, reservoirs included in this survey with the State average and average for non-giant field recovery. Average projected recovery of the larger reservoirs notably exceeds the average of all reservoirs included in the tabulation (table 4).

8. Reservoir genesis--the geologic origin and nature of the producing zone--is an important determinant (and predictor) of recovery efficiency, for two reasons. First, parameters discussed in points 1 through 7 are interrelated variables that are determined by the geologic history of the reservoir. Second, although the relation between interpreted reservoir

genesis and productivity is modified by extremes in permeability or fluid parameters, it otherwise follows predictable trends based on the known scale and internal complexity of depositional or diagenetic "compartments" and heterogeneity within the geologic system.

The Infill Exploration Target

Within the limitations imposed by the data, the infill target was calculated for each play. The total potential target for strategic infill exploration and development (in reservoirs where low permeability or oil gravity do not restrict production) is 19.9 billion barrels, or nearly 20 percent of the total oil in place. Extrapolation to the total universe of Texas oil reservoirs yields nearly 30 billion barrels of target oil. The validity of the calculated percentage is indirectly substantiated by results of a comparison of oil in place calculated by volumetric and mass-balance methods in the Fullerton field, a major San Andres producer (George and Stiles, 1978). Using the same data base, the volumetric calculation was higher, suggesting that only 75 percent of the oil in place has actually been contacted by producing wells, and was thus reflected in the mass-balance calculation. In other words, 25 percent of the oil in place remained as a target for infield development (George and Stiles, 1978). Preliminary examination shows that larger abandoned reservoirs of the State also fit into the same general plays and offer a second, though smaller, target for renewed production.

UTILITY OF GENETIC RESERVOIR MODELS IN IMPROVING RECOVERY EFFICIENCY

Application of genetic reservoir analysis to oil field development is relatively new. A survey of the literature shows that the use of genetic models is most advanced in interpretation of sandstone reservoirs. However, the potential utility of facies or of combined facies/diagenetic analysis in limestone and dolomite reservoirs is presaged by studies such as that of the Zelten field (Bebout and Pendexter, 1975) and the Means San Andres Unit (Barbe, 1971), and in the review by Jardine and others (1977). Genetic facies interpretation and models of sandstones were primarily developed for, and directed toward, improving prediction of reservoir distribution within areas of exploration. Genetic models of sandstone bodies were defined to allow early recognition of reservoir origin so that the direction and probable extent of specific oil-bearing sandstones could be predicted. Facies analysis applied to stratigraphic-trap exploration and discovery-well offset drilling led directly to the development of models that predict external geometry of a sandstone body--its trend, lateral extent, thickness, and potential for recurrence. More than 20 years of effort have been devoted to the generation and application of such exploration-oriented models.

A much smaller body of literature illustrates the potential use of genetic stratigraphic analysis in field development and enhanced recovery programs. In many large fields, external dimensions of the permeable facies (megascopic heterogeneity, figure 18) rather than trap size determine the productive limits of the reservoirs. In a classic study of the Frio Sandstone in Seeligson field (play 10, fig. 3), Nanz (1954) described and interpreted the complex distributary-channel geometry typical of several stacked reservoir sand bodies. In Seeligson field, reservoir dimensions are areally delimited by the sand-body geometries, which, in turn, reflect deposition by upper delta-plain fluvial and distributary channels within a delta system.

Single reservoirs, as defined from apparent correlation and apparent uniform fluid content, may in fact consist of a mosaic of individual genetic units. Pennsylvanian sandstones in the Elk City field of the southern Anadarko Basin exemplify the genetic complexity inherent in a large reservoir analogous to reservoirs of plays 22 and 46. Elk City is a large, asymmetrical anticline covering about 25 mi^2. Detailed stratigraphic analysis (Sneider and others, 1977) of one reservoir, in the L_3 zone, revealed highly variable thickness and distribution patterns that reflect an equally complex facies composition. Core, log pattern, and isolith data were combined to differentiate and map river-channel-fill, distributary-channel-fill, delta-margin, and barrier-bar sandstone facies. Distribution of these facies influences the comparative efficiency of various well completion and recovery practices. Similarly, Hartman and Paynter (1979) described several examples of Gulf Coast reservoir drainage anomalies,

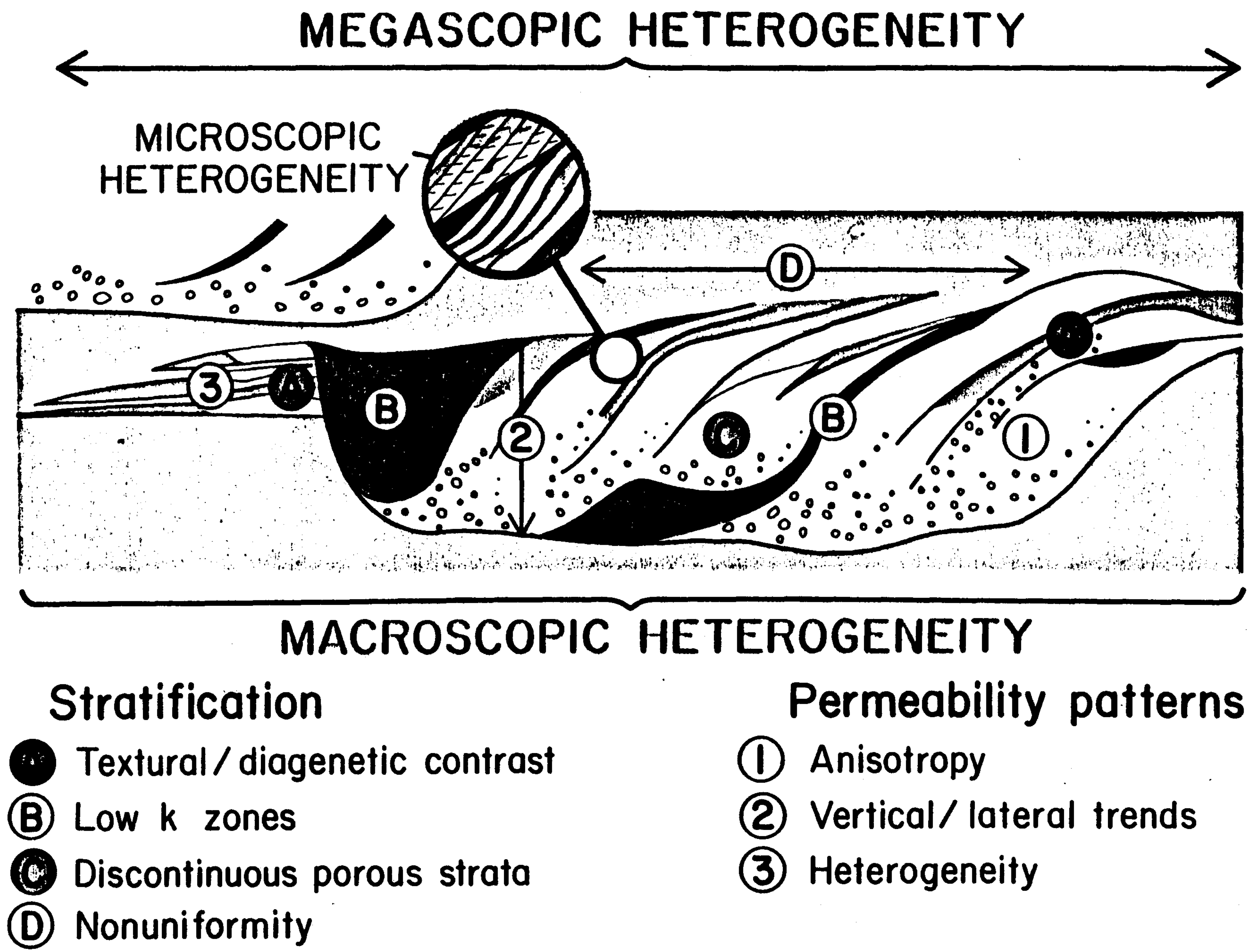

Figure 18. Levels of heterogeneity within a petroleum reservoir.

some of which are clearly related to facies boundaries within single reservoir sand bodies. For example, wells penetrating distributary-channel fills were found to have poorly drained adjacent delta-margin facies. Closely spaced infill wells tapped essentially virgin reservoir pressures and oil-water contacts. Porosity and permeability of these geologically young Gulf Coast reservoirs are high, reflecting the unconsolidated condition of the sands. Similar delta-system reservoirs dominate Coastal Plain plays 1, 2, 3, 5, and 10. Drainage anomalies were noted during infill drilling of Devonian carbonate reservoirs in play 32, where wells as close as 200 ft to abandoned wells have produced water-free oil at near virgin pressures.

Within a single genetic facies, macroscopic heterogeneities (fig. 18) are introduced by bedding and by spatial variability of textural parameters. Bedding produces a stratified permeability distribution that restricts cross-flow and channel fluids within the more permeable beds (Polasek and Hutchinson, 1967; Alpay, 1972). Preliminary studies (Zeito, 1965, for example) indicated the potential for continuity of internal permeability stratification and showed that the geometry and continuity of bedding correlated with interpreted depositional environment of the sand body. Weber (1982) presented a quantitative summary of the relation between environment and continuity of shale beds. The impact of horizontal stratification is well recognized in reservoir simulation studies; however, more complex bedding styles associated with lateral accretion or progradation are less commonly recognized. Shannon and Dahl (1971) demonstrated compartmentalization of a distributary-mouth-bar reservoir by progradational bedding geometry in a Strawn delta system of play 21. Recognition of the individual reservoir lenses, which reflect the deposition of frontal splays, suggested modifications to well completion practices and improved oil recovery.

Within relatively uniform sand bodies or their component beds, permeability may vary systematically either laterally or vertically and thus influences drainage patterns. For example, distinctive vertical permeability trends that reflect sediment textural trends characterize channel-fill, delta-front, and barrier-shore-face sequences in the Elk City reservoirs (Sneider and others, 1977). Sneider and others (1978) suggested generalized trends of various reservoir properties for framework bar- and channel-type facies of delta systems. The trends are qualitative but can be calibrated with engineering data and used to more accurately simulate reservoir conditions (see Weber and others, 1978, for example) and to improve oil recovery in deltaic reservoirs.

Grain orientation and textural lamination introduce microscopic heterogeneity (fig. 18), which, if systematic, produces permeability anisotropy within the sand bed. Study of modern sand bodies (Pryor, 1973) showed maximum permeability in alluvial sands to be oriented along the channel axis. Thus, flow is greatest along the axis of the resultant genetic unit. In contrast, upper shoreface and beach sands have maximum permeability axes that are oriented parallel to wave swash, producing an axis of maximum permeability perpendicular to the trend of the sand body.

Taken together, studies of both modern sand bodies and their reservoir counterparts suggest that genetic interpretation allows prediction of a hierarchy of parameters, ranging from external dimensions and morphology to internal compartmentalization and permeability stratification, heterogeneity, and anisotropy, that affect reservoir performance. Integrating and calibrating these predictions with reservoir engineering data has been shown to considerably improve recovery efficiency.

Example: Use of Meanderbelt Model for Infill Drilling

As would be expected from their highly variable depositional styles, fluvial (river) systems constitute diverse reservoirs for oil and gas. At one extreme, sand-rich fluvial systems contain abundant reservoir rock but are source- and seal-poor; conversely, mud-rich systems contain only moderate quantities of reservoir lithologies encased in abundant mudstone. However, all fluvial systems share several common reservoir attributes: (1) principal reservoirs are the channel-fill and bar sands; (2) reservoir continuity is excellent to good, at least along channel trend; and (3) internally, fluvial reservoirs are extremely heterogeneous and anisotropic.

Meanderbelt sand bodies are a particularly common reservoir in many productive formations, such as the Wilcox, Yegua, and Frio (plays 2, 3, 5, and 10), Woodbine (play 19), and Strawn (play 21) sandstones. Interbedded floodplain and levee shale results in partial isolation of the commonly stacked meanderbelt sand bodies. Individual meanderbelt sand bodies are, in turn, characterized by well-developed, complex anisotropy and heterogeneity, particularly in their upper section, where hydrocarbons preferentially accumulate. The systematic upward-fining textural trend is reflected by upward-decreasing permeability. Lateral-accretion bedding introduces permeability stratification that cuts across the sand body. The resultant permeability units are arcuate in plan view. The reservoir may be partially compartmentalized by mud plugs. In addition, the top of the permeable reservoir lithology commonly displays buried topography reflecting preservation of muddy ridge-and-swale and channel plugs.

Neches field (Woodbine, play 19) provides an example of the application of this comparatively well-known genetic facies model in targeting an infill well location. Neches field is a simple anticlinal trap producing from a stacked series of laterally discontinuous sandstones deposited as point-bar complexes in a meandering river system. Continuous floodplain shale units separate sandstone bodies vertically, imparting local but strongly expressed vertical heterogeneity to the reservoir (fig. 19). Truncation of the mudstones and local superposition of sandstone units result in vertically interconnected reservoirs, which originally had a common oil-water contact.

Of great importance to management of the reservoir was the recognition of clay plugs within the point-bar sandstone units (fig. 19). As the reservoir drains, these impermeable abandoned channel fills are barriers to oil flow. The field operator recognized that areas downdip of the plugs potentially trapped oil that would not be drained at the conventional 40-acre well spacing. Detailed structural maps of the top of individual sandstone units, combined with interpretive facies information, were used to outline locations of proposed infill wells (fig. 20). Because these wells had to be drilled off regular spacing, locations were submitted to and approved by the Railroad Commission of Texas. Specific results of the in-field exploration

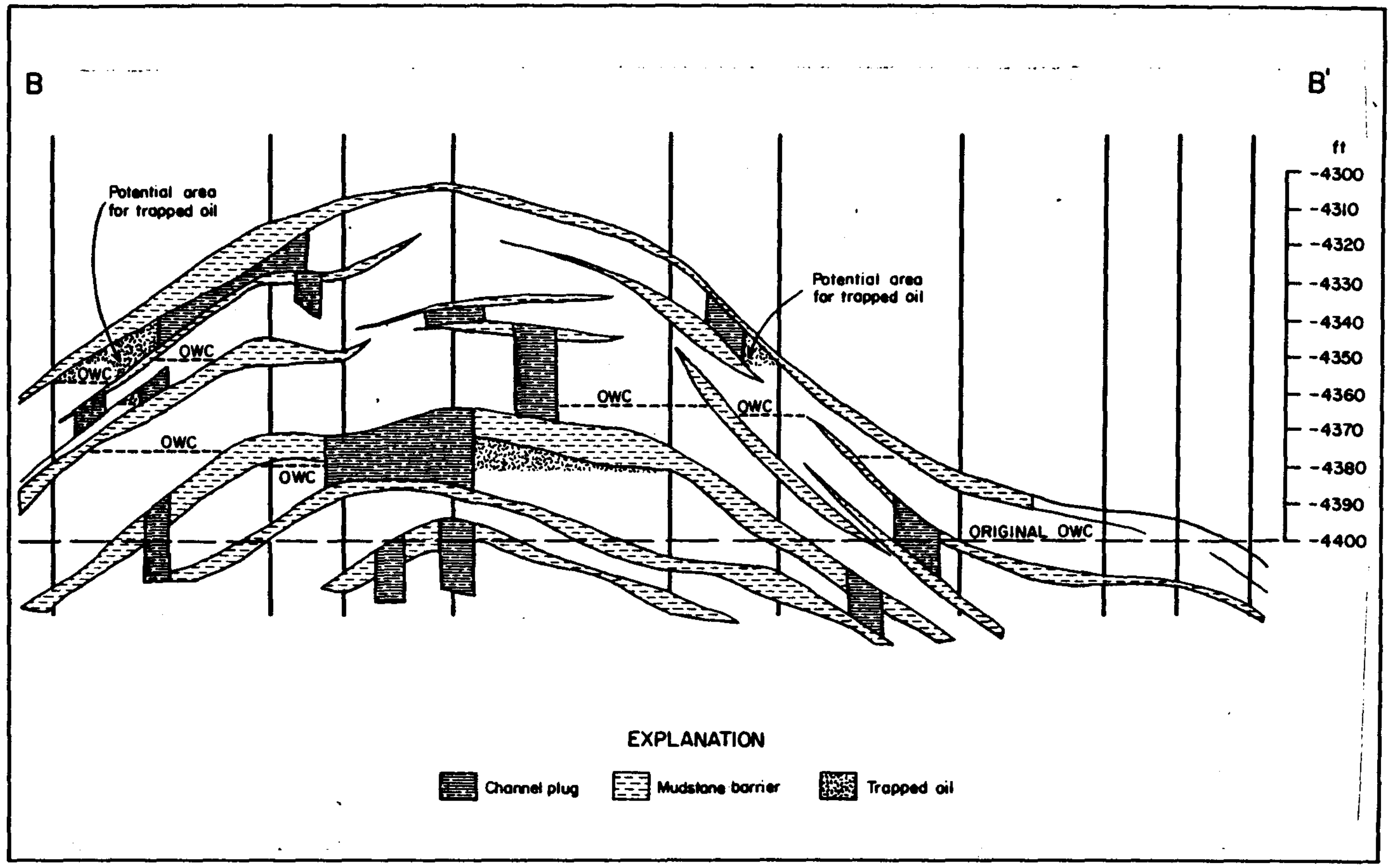

Figure 19. Cross section showing stacked river meanderbelt sandstone bodies forming the Woodbine reservoir in Neches field. Mud plugs form impermeable barriers resulting in divergent oil-water contacts and locally trapping oil within the reservoir. Modified from information in hearing files of the Railroad Commission of Texas.

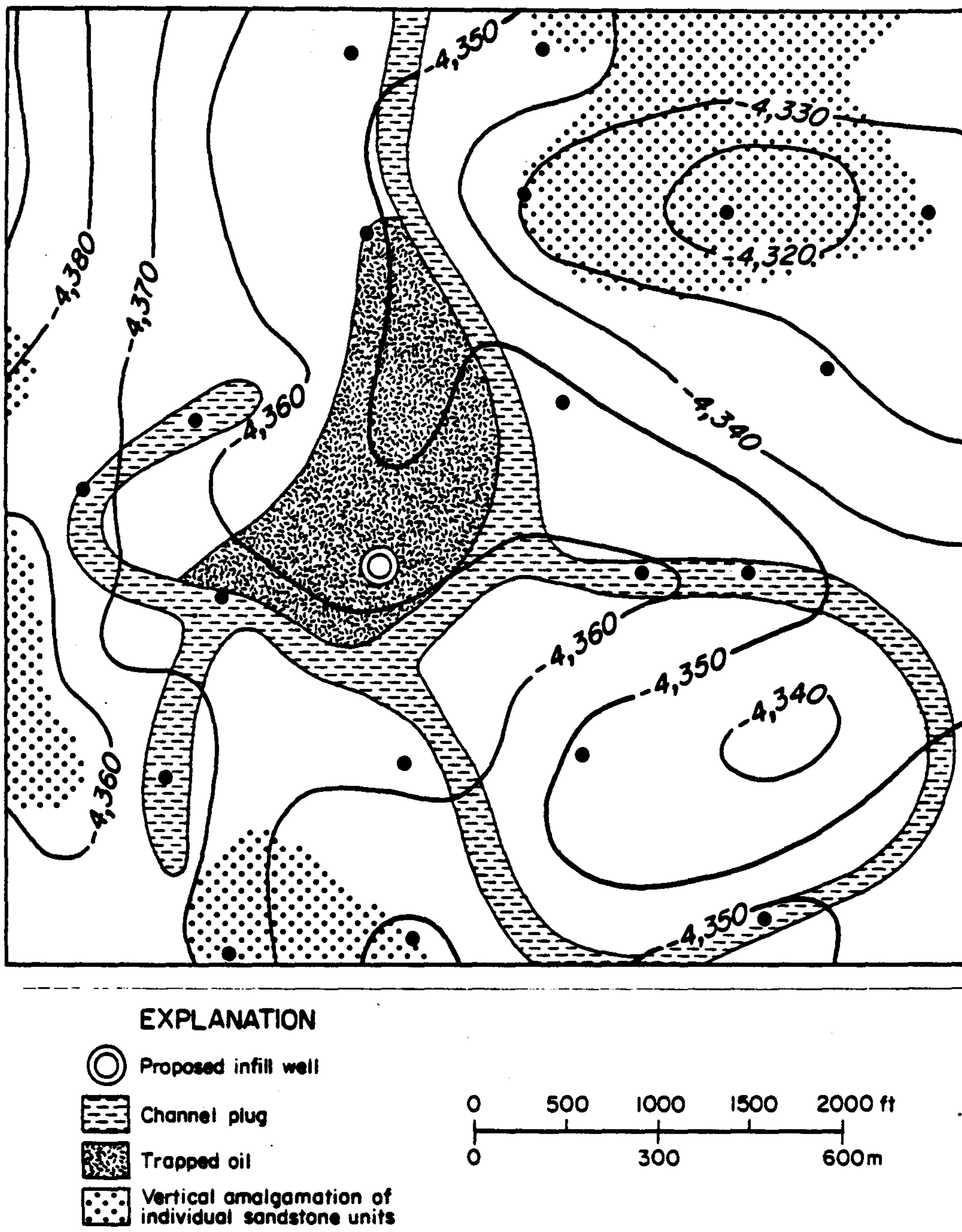

Figure 20. Map of one infill drilling target in Neches field. The contours show the structure on top of an undrained sandstone compartment isolated from the surrounding sandstone by the muddy channel plug. Modified from information in hearing files of the Railroad Commission of Texas.

program are not reported, but an indication of the operators' success is the estimated recovery of 63 percent of the 210 million bbl of oil in place indicated for this reservoir.

Example: Infill Drilling in a Limestone Reef Reservoir

Analogous predictive genetic models of carbonate reservoirs that must reflect both the depositional facies and the pervasive post-depositional diagenetic modification are only now being developed. The Kelly-Snyder limestone reservoir (SACROC unit, play 28) displays the pronounced permeability layering typical of carbonate reef deposits (Jardine and others, 1977). Lateral discontinuity of the lenses, combined with irregular topography on the top of the reservoir, creates isolated lenses of trapped and bypassed oil (fig. 21). According to the field operator, such lenses can be due to several factors, including (1) pinch-out of permeable beds between wells, (2) isolation of lenses within local reservoir topographic closures, and (3) less than optimal sweep efficiencies produced by existing injector-well locations and completion intervals. As shown by figure 21B, typical infill wells located substantial new intrareservoir zones of oil production. Over a 5-year production history following the infill drilling program, additional production of 30 million bbl was attributed by the operator to the infill wells. This amounts to an increase of more than 1 percent in recovery efficiency for this giant field, which is also undergoing miscible flood. Together, the combined infill and tertiary development programs were projected to result in a production efficiency of 57 percent, the best of any of the 13 reservoirs in the Horseshoe Atoll limestone play.

GENERIC RESERVOIR MODELS

Selection of Generic Models for Texas Oil Plays

Selection of generic models is based on several objectives. First, the number of models needs to be fairly small, if they are to be truly generic, and applicable to many different fields. Secondly, models must be sufficiently detailed to indicate the important aspects of each

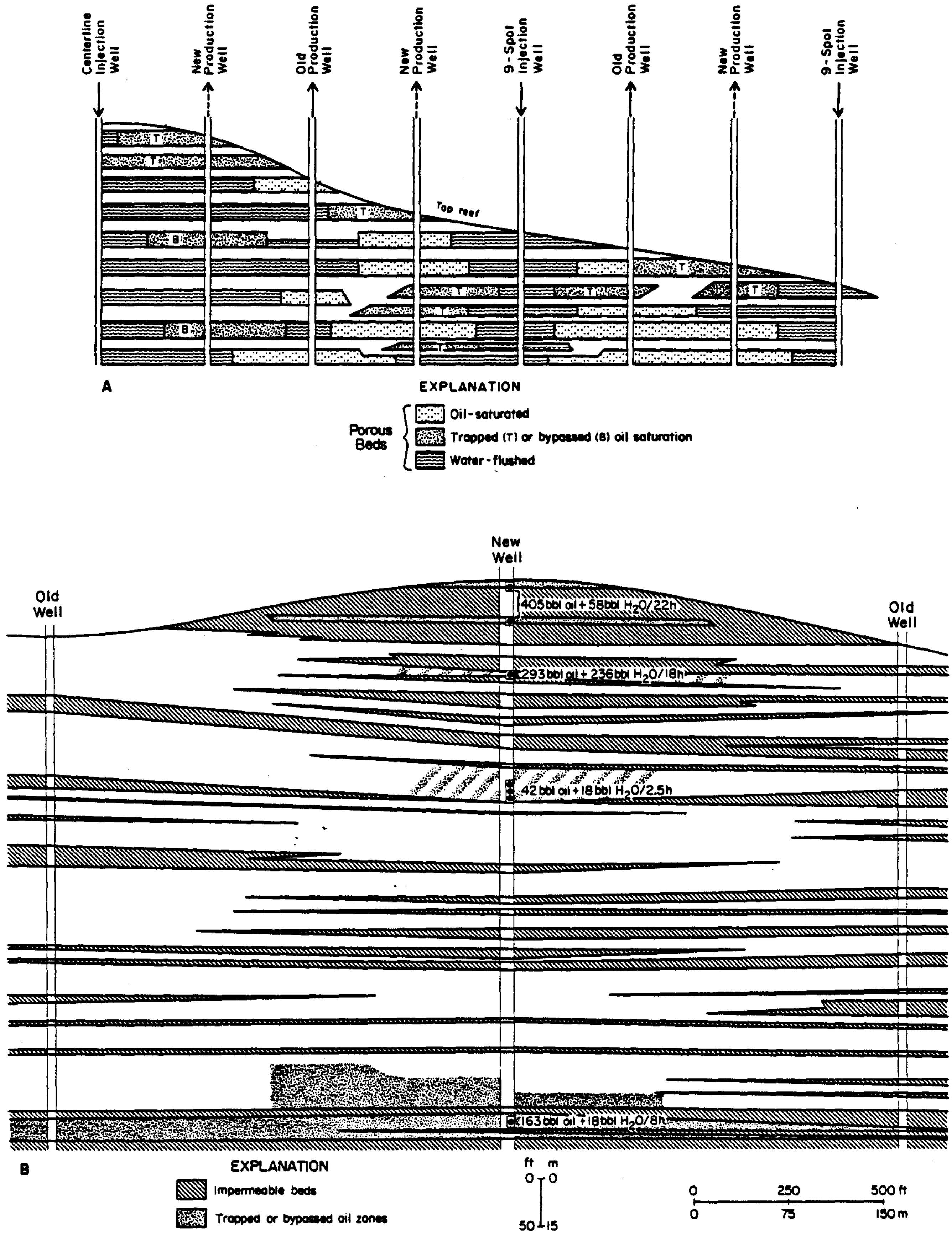

Figure 21. (A). Schematic illustration of anticipated trapped oil lenses in the highly layered reef reservoir at Kelly-Snyder field. (B). Test results of an infill well drilled to recover lenses of trapped oil. Modified from information in hearing files of the Railroad Commission of Texas.

reservoir type that must be understood and examined if the geological description of the reservoir is to be functional. Finally, models developed for this phase of the study were selected because they are applicable to plays containing the major portion of oil in place within Texas reservoirs.

Generic associations for which models were developed include:

1. Fluvial and mixed fluvial/deltaic plays. Seventeen plays produce from sand bodies of these related depositional systems. Together, fluvial and deltaic reservoirs contain more than 27 million barrels of oil in place. Geologic and reservoir data indicated the need for fluvial meanderbelt, fluvial-dominated delta, and wave-dominated delta models.

2. Barrier bar and strandplain plays. Four plays that contain 4.5 billion barrels of oil in place produce exclusively from barrier bar and strandline sand bodies. In addition, such sands are a common secondary productive facies within delta systems. There, they must be identified on an individual basis. Fore-barrier (shoreface), barrier core, and back-barrier models must be differentiated to account for the variability found within reservoirs of this depositional system.

3. Pinnacle reef and atoll plays. Upper Pennsylvanian (Strawn, Canyon) and Lower Permian (Wolfcampian) limestones have produced more than 2 billion barrels of oil from reservoirs developed in carbonate buildups. The Horseshoe Atoll, located in the Midland Basin, is composed of 13 fields which have produced more than 10 million barrels of oil; another 13 fields are located across the broad, low-angle carbonate ramp of the Eastern Shelf.

Subtidal reefs and banks and intertidal bars and beaches comprise a complex carbonate model which resulted in formation of hundreds to thousands of feet of depositional topography. Eventually, individual reefs and banks became dominant and were isolated from one another. Subsequent diagenesis of these carbonates largely controls the type and amount of porosity present.

4. Restricted-platform shelf plays. Upper Permian (Guadalupian) dolomites of the Clear Fork and San Andres/Grayburg Formations were deposited on restricted-platform shelves of the Northern Shelf, Central Basin Platform, and Ozona Arch. The 7 plays included in this

group comprise 76 fields, each of which has produced more than 10 million barrels of oil. These fields have cumulatively produced more than 9 billion barrels of oil.

The plays producing from the San Andres/Grayburg dominate in number of fields and total production and are considered in more detail here. The San Andres/Grayburg Formations have produced more than 6 billion barrels of oil from dolomite reservoirs in the fields along the eastern side of the Central Basin Platform and on the Northern Shelf in an area approximately 200 miles long and 20 miles wide. This prolific trend consists of 34 fields which have each produced more than 10 million barrels of oil. The San Andres/Grayburg Formations range from 1500 feet thick to the north to 1000 feet thick to the south; the top of the Grayburg is deepest to the north (-1500 feet) and shallowest to the south (+1500 feet).

The San Andres/Grayburg platform was typified by very low relief and an irregular edge into the basin. The carbonate model is dominated by platform edge sponge/algal banks which developed on a shallow-water low-energy slope. Zones of higher energy are indicated by oolite and skeletal grainstones, suggesting intertidal conditions. Although the porosity is essentially limited to these facies, the final preservation is dependent upon complex diagenetic processes which resulted in dolomitization, leaching, and cementation by anhydrite and calcite.

Attributes of a Generic Model

Generic reservoir development models, as described here, are defined on the basis of properties and characteristics of the reservoir that are genetic in origin, that is, determined by the depositional or diagenetic processes that originated the porous rock body. The key attributes of each generic model must include expected presence, distributions, and probable scales of both megascopic and macroscopic features that may influence petroleum recovery.

Megascopic attributes include:

1. External dimensions of the reservoir unit.

2. Gross porosity and permeability as determined by depositional or inherent diagenetic processes.

3. Degree of isolation of individual reservoir units by surrounding sealing facies.

Macroscopic attributes include:

1. Presence and degree of reservoir compartmentalization caused by the mosaic of subfacies that constitute the reservoir unit.

2. Depositional topography on the top of the reservoir unit.

3. Degree and geometry of internal stratification.

4. Distribution, geometry, and continuity of both the impermeable beds or zones, which may act as local seals, and of the permeable zones, which may act as channelways for preferential fluid movement.

5. Lateral and vertical trends in porosity and permeability.

6. Lateral and vertical trends in oil saturation.

7. Direction and degree of permeability anisotropy.

Summary Generic Models for Texas Reservoirs

Based on conclusions of this initial characterization of Texas oil fields, and upon well-documented attributes of many of the depositional facies that are important reservoirs in the major plays, several generic models have been synthesized. Models included are: Fluvial meanderbelt sand, fluvial- and wave-dominated delta margin sands, barrier front sand, microtidal barrier core sand, back-barrier sand, shoal-water organic bank limestone, restricted platform margin, high-energy restricted platform, shallow-water restricted platform, and interior restricted platform. Each is outlined in Appendix I.

Model Calibration

Generalized models can only provide probable dimensions, magnitudes, or trends. Similarly, only potentially influential megascopic attributes can be shown so that their effects may be recognized. Each reservoir must be calibrated within the context of the appropriate model by using measurements made with cores, logs, and production data. Within many plays, values found upon calibration will be similar from reservoir to reservoir, and with experience, results from one study can be increasingly transferred with assurance.

Of particular importance is the calibration of the range of permeabilities exhibited by various compartments, beds, or other subunits within the reservoir. In sandstone reservoirs, the degree of isolation between beds may increase dramatically if there is a pervasive diagenetic overprint that has reduced average porosity and permeability. Ranges of porosity and permeability may be even more extreme in carbonate reservoirs.

Spatial variability in recovery efficiency can be determined in a variety of ways. Of particular use is preparation of an oil-in-place map based on geologically interpreted distributions of net effective pay, porosity, and residual water saturation. Resistivity curve analysis is particularly useful for delineation of reservoir compartments within sandstone reservoirs.

COMBINED ENGINEERING-GEOLOGIC APPROACH TO IMPROVING RECOVERY EFFICIENCY

Improved Reservoir Simulation

In modern reservoir engineering, reservoir simulation is considered the best method for predicting reservoir performance, especially for enhanced oil recovery. Reservoir simulation uses numerical methods to solve the mathematical models which describe the physical behavior of the fluids flowing in the reservoir under investigation.

All reservoir simulation models subdivide a reservoir into a two- or three-dimensional network of grid blocks and then apply the volumetric material balance equation for each phase for each grid block. The flow equation (Darcy's law) of each phase is then applied to describe the flow between each grid and its adjacent blocks. Reservoir properties such as permeability and porosity and fluid properties such as pressure, temperature, and oil composition are assumed uniform throughout a given grid block.

Selection of a grid system depends on the objectives of the simulation study. Gross behavior of a reservoir can be studied by selecting a coarse grid system; several wells may be included in one well block. A grid system that provides several empty grid blocks between well blocks would be necessary for study of individual well performance and saturation distribution. Future infill well performance can also be studied with such grid systems. A finer grid system means more equations to be solved in each time step, and the cost and time of a run is heavily dependent upon the number of equations solved per time step. A coarse grid system could lead to numerical dispersion and be unable to match the detail required. A usual approach to this problem is to try several feasibility runs using different grid systems to test if refinement is necessary.

After a grid system is selected, rock and fluid properties are digitized using contour maps of some kind to fit into the grid system. Once all the required input data are ready, the simulation model is tested for a "history match." The actual oil production or injection rate experienced by grid counterparts in the real reservoir is supplied and the response of pressure, gas/oil ratio, and water/oil ratio are calculated to match the measured field production data. Rock and fluid properties are adjusted, if necessary, to obtain a best match. Once a satisfactory history match is produced, this model can then be used to predict the behavior of the reservoir under various types of operations.

In reservoir simulation rock data are input as a matrix of values over the selected two or three dimensional grid. Usually the data are derived by digitizing a contour map prepared from geological studies. Core and well log data combined with knowledge of depositional environment are used to construct the desired contour map of those rock properties. Permeability and porosity trends are smoothed and adjusted, based on the sedimentological model, so that their changes follow the reservoir realistically. In reservoir simulation, it is frequently necessary to modify the rock data to obtain a reasonable historical match. Grid data modification are never made on a single cell basis, but over an area wherein the necessary changes are required. The relative changes of the rock properties are more important in history matching, and knowledge of the depositional environment is very helpful for the simulation engineer in modifying the rock data to obtain the history match while keeping the grid model reasonably realistic.

Knowledge of the presence of fault, pinchout, and intrareservoir barriers are important in modeling. Flow discontinuity must be incorporated into the grid system as realistically as possible. A reservoir with cross-reservoir vertical flow barrier will require using a three dimensional grid system.

Core measurement of permeability can only be applied to small samples of the reservoir rocks. Geometrical mean values of measured permeabilities are usually used. However, these permeability values are actually for rock close to the wellbore, and are not necessarily representative of a reservoir throughout a grid block, which requires an equivalent homogeneous permeability. Shale intercalation also presents difficulties in using averge permeability. A pressure transient test is considered a better tool in obtaining an average permeability for a drainage area of a well. However, interpretation techniques are not well developed for highly heterogeneous reservoirs. Recently there have been a few studies on the influence of common sedimentary structures on fluid flow. Correlations from simulation studies of fluid flow in common sedimentary structures could be used to estimate permeability with minimum core measurement and well logging. By combining flow correlations of common sedimentary structures with depositional generic models, a permeability distribution, in the sense of blocks of the sand body, could be easily transformed to a grid system for reservoir simulation studies. More research work should focus on the influence of depositional generic models and sedimentary structures on selection of a most feasible grid system.

Integrated Reservoir Analysis

The idea of closer integration of the geologic and engineering disciplines in reservoir development is not new (Harris and Hewitt, 1977). The size of the unrecovered oil-in-place target documented by this study merely adds emphasis to the need for and potential rewards that await such synthesis. Stumbling blocks that have prevented integration are both institutional and technical. This study has attempted to address some of the technical problems by developing generic reservoir models that can become the basis for mutual engineering and geological analysis. A general plan of attack for recovery improvement consists of six steps.

1. Complete a conventional geologic interpretation of the reservoir and its host depositional system, and select the appropriate generic reservoir model.

2. Perform a descriptive facies study that includes detailed facies correlation and quantitative isolith mapping, log facies analysis, and synthesis of petrophysical data.

3. Calibrate the generic model using field specific data or data from better-known reservoirs of the same play.

4. Describe areal and vertical oil distribution within the reservoir framework.

5. Evaluate recovery history to determine important attributes of the generic model that have demonstrably affected recovery or success of enhanced recovery practices.

6. Design and implement appropriate recovery enhancement strategies. Field testing and/or realistic simulation of the reservoir response should provide the final evaluation of alternative recovery programs.

ABANDONED OIL FIELDS

One target of nonconventional oil in Texas is the oil that remains in abandoned fields. This target consists both of oil that has not been tapped by conventional field development because of reservoir heterogeneity and of oil that has not been subjected to secondary or tertiary recovery programs. The U.S. Department of Energy compiled a list of abandoned Texas oil fields that had cumulative production of more than 250,000 bbl. Abandoned fields were defined as those fields that had no production in 1977. The Bureau of Economic Geology study focused on the 312 fields with cumulative production greater than 500,000 bbl (Table 5). These fields represent 46 percent of the total number of abandoned fields with greater than 250,000 bbls cumulative production; yet the production from the 312 is more than 75 percent of the total for all 676 fields listed. Some of these 312 fields produced oil in 1982, some were

Table 5. Summary of Texas oil fields listed as abandoned in 1977 by the U.S. Department of Energy (1980)

District	No. fields with .500,000 bbl	Produced oil in 1982	Produced gas in 1982	Produced .10 million bbl	No. produced in 1982
1	2	1	0	0	1
2	25	3	3	2	17
3	56	7	4	1	44
4	99	15	8	3	73
5	2	1	1	1	0
6	14	1	2	0	11
7B	27	11	0	0	16
7C	21	6	3	0	13
8	15	4 fields	0	1	11
8A	14	7 prod	0	1	7
9	36	11 prod	1	0	25
10	1	0	0	0	1
TOTALS	312	66	21	9*	219

*Wasson '72 and production from both upper and lower Clear Fork now reported as Wasson '72.

reclassified and produced gas in 1982, and some had produced more than 10 million bbl of oil and so were included in Phase 1 of the reservoir characterization study. The remaining fields were characterized by the same geologic and engineering parameters that were used in Phase 1. Many of the abandoned fields fall into the same 47 basic plays that characterize the largest Texas oil fields. However, some new plays were established for the abandoned fields, and other fields fall in a Miscellaneous category.

District 1

Railroad Commission District 1 contains only one field that produced more than 500,000 bbl and is currently abandoned. Hindes Field produced from the Upper Cretaceous Olmos sandstone, so it is in Play 11, San Miguel-Olmos deltaic sandstone. Hindes Field produced 543,984 bbl before it was abandoned in 1970.

District 2

The 17 abandoned fields in District 2 produced from the following Tertiary sandstones: Wilcox fluvial-deltaic sandstone (Play 6, 5 fields), Frio barrier/strandplain sandstone (Play 8, 5 fields), Jackson-Yegua barrier/strandplain sandstone (Play 9, 5 fields), and Frio fluvial/deltaic sandstone (Play 10, 2 fields). Fields that produced from Vicksburg sandstones have been included in the Frio sandstone plays because of their similar reservoir characteristics. Total cumulative production from these 17 fields was 24.7 million bbl before abandonment.

District 3

The 44 abandoned fields in District 3, along the northern Texas Gulf Coast, produced from a wide range of Tertiary-sandstone plays. The four plays with the largest number of abandoned fields are Yegua deep-seated salt domes (Play 3, 5 fields), Frio deep-seated salt domes (Play 4, 12 fields), Eocene deltaic sandstones (Play 5, 10 fields), and Frio barrier/strandplain sandstone (Play 8, 8 fields). Other abandoned fields produced from piercement salt domes (Play 0, 4 fields), Yegua salt-dome flanks (Play 2, 2 fields), Wilcox fluvial/deltaic sandstone (Play 6, 1 field), and Frio (Buna) barrier/strandplain sandstone (Play 7, 2 fields). Total cumulative production from the District 3 abandoned fields was 59.4 million bbl.

District 4

District 4 contains 76 abandoned fields that produced more than 500,000 bbl. Three of those fields produced more than 10 million bbl (Table 1), so they were included in the first phase of reservoir characterization. The remaining 73 abandoned fields mainly produced from Frio barrier/strandplain sandstone (Play 8, 18 fields), Jackson-Yegua barrier/strandplain sandstone (Play 9, 16 fields), and Frio fluvial/deltaic sandstone (Play 10, 37 fields). Total production from the 73 fields was 109.5 million bbl of oil before abandonment. In general these smaller abandoned fields have a much reduced data base, however where data allow comparisons to larger fields fairly close relationships appear. Calculations for target oil are limited by the lack of consistent information in connection with original-oil-in-place; however it is apparent that significant volumes of oil have been left behind and represent an important target for new drilling ventures and/or enhanced recovery programs. More than 85 of the abandoned fields of 1977 had been reactivated or reclassified by 1982. Additional activity of this nature is anticipated, as characterization of the reservoirs proceeds.

District 5

Two fields with more than 500,000 barrels of oil are included in the DOE list. Wieland in Hunt County has been reactiviated as an oil producing field. The other, Pickton in Hopkins County was included in Play 20, Woodbine fault line, in the first phase of reservoir characterization. Gas production was reported for 1982, and it should not therefore be included in the abandoned category.

District 6

District 6 in East Texas has recorded reactivation of the 14 abandoned oil fields with greater than 500,000 bbls production. Gas production from two others has also removed them from the list. The remaining fields are divided between Play 17 - Glen Rose carbonate/salt related structure, with 4 of the abandoned fields, Play 19 - Woodbine fluvial/deltaic with 4, and a miscellaneous category with 3 fields. Fairway South, Anderson County, and John C. Robbins, Rusk County, were productive from the Pettet Lime, whereas Waskom (Akin South) and Harrison County, produced oil from the Travis Peak Formation. Pettet and Travis Peak have been productive in more than 220 fields in District 6 with production of more than 85 million bbls. None of the individual reservoirs however have attained the 10 million bbl limit of our Phase 1 play category. The large number of fields with recent dates of discovery suggest that both these formations merit consideration for future play designation.

The total cumulative production for the 11 abandoned fields in District 6 is 13.6 million bbls.

District 7B

Pennsylvanian reservoirs are of primary concern in District 7B and 7C in Central and West Central Texas. The abandoned fields from Pennsylvanian reservoirs are included in the same plays as those determined for the region in the first phase of the Reservoir Characterization project. Play 21 - Strawn Sandstone - accounts for three of the abandoned fields; Play 22 -Bend Conglomerate - for two fields; Play 24 - upper Pennsylvanian Shelf Sandstone - for 3 fields; and Play 25 - Pennsylvanian Reef/Bank - accounts for 4 of the fields.

The other abandoned fields with more than 500,000 bbl cannot be assigned to previously established plays. Mississippian reservoirs, productive in a large number of fields in Districts 7B and 9 without any having attained the 10 million bbl limit for play inclusion, account for two of the abandoned fields in District 7B. The other two produce from Ordovician Ellenburger dolomites. This Ellenburger production is separated from that of play 31 - Ellenburger fractured dolomites - due to geographic and trap differences.

These 16 abandoned fields in District 7B had cumulative production of 16.6 million bbls.

District 7C

The 13 abandoned fields in District 7C account for 17.0 million bbl oil. Both Pennsylvanian and Ordovician reservoirs fall into previously established plays. The 3.2 million bbl Ordovician, Ellenburger production from 4 fields is assigned to Play 31 - Ellenburger fractured dolomite. The remaining abandoned fields produce from Pennsylvanian reservoirs and include 6 in Play 24 - Upper Pennsylvanian Shelf Sandstone - 2 in Play 21 - Strawn Sandstone - and 1 in Play 25 - Pennsylvanian Reef/Bank.

District 8

District 8 contains 11 abandoned fields that have produced, individually, more than 500,000 bbls oil. Total cumulative production for these fields is 9.0 million bbl oil. All but one of these abandoned fields are located on the Central Basin Platform of West Texas. The exception, Coronet (2900'), Howard County, is considered part of Play 27 - Eastern Shelf Permian Carbonate.

The Central Basin Platform abandoned fields include one in Play 31 - Ellenburger fractured Dolomite; three in Play 33 - Silurian - Devonian Ramp Carbonates, South Central Basin Platform (S.C.B.P.); two in Play 34 Silurian-Devonian Ramp Carbonates, North C.B.P. (N.C.B.P.); two in Play 37 - San Andres/Grayburg S.C.B.P.; one in Play 38 San Andres/Grayburg N.C.B.P.; and one in Play 43 Pennsylvanian Platform Carbonate.

One of the fields considered abandoned (1977 DOE) Bakke (Penn) has been reactivated and production of nearly 25,000 bbl oil reported for 1982. Bakke (Penn) with cumulative production of 12.0 million bbl is shown in Play 43 - Pennsylvanian Platform Carbonate - in the Phase 1 - Characterization Report.

District 8A

Included in the 14 abandoned fields that had produced more than 500,000 bbl each are 3 that were not actually abandoned but rather combined with other production and not separately reported after a particular date. Wasson 66 (upper Clear Fork) was combined with Wasson '72 (lower Clear Fork) by decision of the Railroad Commission of Texas in hearing number 8A-63195, October 1, 1973. Since that date production from both upper and lower Clearfork are reproted as Wasson 72. Similarly, Justiceburg (Glorieta) and Dorward (San Andres) were combined with Dorward on January 1, 1975, and production from that date is reported only as Dorward.

The seven abandoned fields in District 8A had cumulative production of 6.4 million bbl. Two of the fields that produced from the Ordovician Ellenburger on the northern and eastern flank of the Midland Basin could be included in the previously mentioned miscellaneous play (District 7B) one field in Play 42 - Wolfcamp Platform Carbonate - and another in Play 43 - Pennsylvanian platform carbonate - are located on the northern part of the Central Basin Platform. One field each is assigned to Play 44 - Northern Shelf Permian Carbonate - Play 28 - Horseshoe Atoll; and Play 26 - Upper Pennsylvanian Basinal Sandstone.

District 9

The 36 abandoned fields that had produced more than 500,000 bbl in District 9 in 1977 had been reduced to 25 at the end of 1982 by reactivations of previously abandoned fields. The 25 remaining had produced a total of 27.0 million barrels prior to abandonment.

Eleven (11) fields with cumulative production of 14.7 million bbls. are included in the previously established Pennsylvanian-Strawn Sandstone play #21. Data do not allow for precise comparisons, however, in general recoveries efficiencies for the smaller abandoned fields would be lower than for the larger fields in the play.

Two (2) fields are included in the upper Pennsylvanian Shelf Sandstone play 24 and two (2) are in the Pennsylvanina Reef/Bank play 25. Another two are considered part of play 22 Bend Conglomerate. The Pennsylvanian thus accounts for 17 of the 25 abandoned fields in District 9.

The other eight in the miscellaneous category include two in the previously mentioned (District 7B) Mississippian play; one in the Ellenburger (District 7B, 8A); two fields in the Silurian Viola limestone; one from the Ordovician Simpson, one from Ordovician Oil Creek Sandstone; and one with no data is included here.

District 10

Only one abandoned oil field in District 10 produced more than 500,000 bbl. Rehm (Granite Wash) Field produced 727,248 bbl from Pennsylvanian granite wash (Play 47) before it was abandoned in 1971.

REFERENCES

Alpay, O. A., 1972, A practical approach to defining reservoir heterogeneity: Journal of Petroleum Technology, v. 24, p. 841-848.

American Petroleum Institute, 1969, A statistical study of recovery efficiency: Dallas, American Petroleum Institute, 33 p.

Barbe, J. A., 1971, Evaluation and modification of the Means San Andres unit waterflood: Journal of Petroleum Technology, v. 23, p. 1421-1427.

Barnes, V. E., Cloud, P. E., Jr., Dixon, L. P., Fold, R. L., Jonas, E. C., Palmer, A. R., and Tynan, E. J., 1959, Stratigraphy of the pre-Simpson Paleozoic subsurface rocks of Texas and southeast New Mexico: University of Texas, Austin, Bureau of Economic Geology Publication 5924, 836 p.

Bebout, D. G., and Pendexter, C., 1975, Secondary carbonate porosity as related to early Tertiary depositional facies, Zelten field, Libya: American Association of Petroleum Geologists Bulletin, v. 59, p. 665-693.

Fisher, W. L., 1982, Texas energy: recent trends and outlook to the year 2000, _in_ Texas, past and future: a survey: Austin, Office of the Governor, Texas 2000 Commission, p. 77-97.

Galloway, W. E., Ewing, T. E., Garrett, C. M., Jr., Tyler, N., and Bebout, D. G., in press, Atlas of major Texas oil reservoirs: The University of Texas at Austin, Bureau of Economic Geology.

Harris, D. G., and Hewitt, C. H., 1977, Synergism in reservoir management--the geologic perspective: Journal of Petroleum Technology, v. 29, p. 761-770.

Hartman, J. A., and Paynter, D. D., 1979, Drainage anomalies in Gulf Coast Tertiary sandstones: Journal of Petroleum Technology, v. 31, p. 1313-1322.

Jardine, D., Andrews, D. P., Wishart, J. W., and Young, J. W., 1977, Distribution and continuity of carbonate reservoirs: Journal of Petroleum Technology, v. 29, p. 873-885.

Layden, R. L., 1971, The story of Big Wells: Gulf Coast Association of Geological Societies Transactions, v. 21, p. 245-256.

Mills, J. M., 1972, Late Paleozoic sedimentation in West Texas Permian Basin: American Association of Petroleum Geologists Bulletin, v. 56, no. 12, p. 2303-2322.

Murphy, R. P., Foster, G. T., and Owens, W. W., 1977, Evaluation of waterflood residual oil saturations using log-inject-log procedures: Journal of Petroleum Technology, v. 29, p. 96-118.

Nanz, R. H., Jr., 1954, Genesis of Oligocene sandstone reservoir, Seeligson field, Jim Wells and Kleberg Counties, Texas: American Association of Petroleum Geologists Bulletin, v. 38, p. 96-118.

Nehring, Richard, 1981, The discovery of significant oil and gas fields in the U.S.: Santa Monica, California, The Rand Corporation, 236 p.

Oliver, W. B., 1971, Depositional systems in the Woodbine Formation (Upper Cretaceous), Northeast Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 73, 28 p.

Polasek, T. L., and Hutchinson, C. A., Jr., 1967, Characterization of non-uniformities within a sandstone reservoir from a fluid mechanics standpoint: Proceedings, Seventh World Petroleum Congress, v. 2, p. 397-407.

Pryor, W. A., 1973, Permeability-porosity patterns and variations in some Holocene sand bodies: American Association of Petroleum Geologists Bulletin, v. 57, p. 162-189.

Shannon, J. P., and Dahl, A. R., 1971, Deltaic stratigraphic traps in West Tuscola field, Taylor County, Texas: American Association of Petroleum Geologists Bulletin, v. 55, p. 1194-1205.

Sneider, R. M., Richardson, F. H., Paynter, D. D., Eddy, R. E., and Wyant, I. A., 1977, Predicting reservoir rock geometry and continuity in Pennsylvanian reservoirs, Elk City field, Oklahoma: Journal of Petroleum Technology, v. 29, p. 851-866.

Sneider, R. M., Tinker, C. N., and Meckel, L. D., 1978, Deltaic environment reservoir types and their characteristics: Journal of Petroleum Technology, v. 30, p. 1538-1546.

Tyler, N., and Ambrose, W. A., (in prep.), Deltaic and strandplain systems in the Cretaceous Olmos Formation of South Texas: The University of Texas at Austin, Bureau of Economic Geology.

Weber, K. J., 1982, Influence of common sedimentary structures on fluid flow in reservoir models: Journal of Petroleum Technology, v. 34, p. 665-672.

Weber, K. J., Klootwijk, P. H., Konieczek, J., and van der Vlugt, W. R., 1978, Simulation of water-injection in a barrier-bar-type, oil rim reservoir in Nigeria: Journal of Petroleum Technology, v. 30, p. 1555-1565.

Weise, B. R., 1980, Wave-dominated delta systems of the Upper Cretaceous San Miguel Formation, Maverick Basin, South Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 107, 39 p.

White, D. A., 1980, Assessing oil and gas plays in facies-cycle wedges: American Association of Petroleum Geologists Bulletin, v. 64, no. 8, p. 1158-1178.

Zeito, G. A., 1965, Interbedding of shale breaks and reservoir heterogeneities: Journal of Petroleum Technology, v. 17, p. 1223-1228.

APPENDIX I

Model 1

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Fluvial meanderbelt sand

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Point bar	Elongate, lenticular	3,000-26,000 ft x 300-21,000 ft	10-75 ft	Complex; medium to thin, thickness decreases with height. Muddrapes common in upper P.B. Channelward dipping and sub-parallel lateral accretion surfaces common	Complex; curvilinear lateral-accretion ridges initially parallel to flow. Orientations change through time	Excellent
Abandoned channel plug	Elongate, lenticular	Orders of magnitude less than the point bar	,10-75	Massive mud to thinly stratified mud and sand	Absent	Very poor to nil

III. DESCRIPTIVE GEOLOGIC MODEL:

Meanderbelt deposits composed of fining- and thinning-upward sandstone bodies that have dip-elongate lenticular geometries: Lateral accretion may impart a tabular geometry. Decreasing grainsize in the system corresponds with increasing tortuosity of the channel sand. Abandonment of channel results in deposition of channel plug of variable but commonly argillaceous composition.

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Point bar	Uniform to upward decrease, decrease bankward and down stream	Decreases upward	Increases upward	Increase upward	Greatest perpendicular to isopach trend. Accretion surfaces form boundaries of local compartments
Channel plug	Approaches zero	---	---	---	---

B. General Reservoir Model:

Commonly multistoried, lenticular sands separated by impermeable floodplain mudstones. Because sands have an elongate, lenticular geometry, field structures are only partly productive. However, multipay reservoirs are the norm. Porosity and permeability decrease upward; directional permeability is oriented parallel to isopach trend. Clay plugs deposited during the channel abandonment phase compose impermeable barriers which compartmentalize the reservoir. Lateral accretion surfaces may act in the same manner.

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Recoveries commonly low in poorly understood (or unrecognized) meanderbelt reservoirs; high in well-managed reservoirs (e.g. Neches (Woodbine) field).
2. Channel plugs act as barriers against complete drainage of oil.
3. Multiple completions in multistoried sand bodies.

VI. PRODUCTION STRATEGIES:

1. Locate channel plugs to facilitate efficient drainage.
2. Accommodate the concept of directional permeability (parallel to long axis of sandbody) in secondary and tertiary recovery programs.

VII. EXAMPLES:

Neches (Woodbine) field
Seeligson (Frio) field

Model 2

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Delta margin sand of a fluvial-dominated elongate to lobate delta lobe.

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Distributary channel	Elongate, lenticular	100-10,000 ft x 10,000+ ft	10-80 ft	Massive to thick--incr. at top; lent. to lat. accretionary	Irregular--arcuate depressions and mounds	Excellent (5-100+ D).
Channel mouth bar	Elongate, lenticular to irreg. sheet	3,000-25,000 ft x 10,000+ ft	10-100 ft	Thk. to thin--incr. toward all boundaries; subhoriz. to lenticular	Convex upward	Good (1-10 D)
Mouth bar slope	Lenticular	100-5,000 x 100-5,000 ft	1-10 ft	Massive to thin, planar	Minor	Fair-poor (.1-1 D)

III. DESCRIPTIVE GEOLOGIC MODEL:

Distributary mouth bar sands form an elongate, laterally thinning lobe symmetrically to asymetrically placed around and beneath the distributary channel fill; sandy channel fill commonly lies above crestal mouth bar deposits, may be partially filled with a narrow, impermeable mud plug. Mouth bar sediments coarsen upward, thin and fine toward distal margins, and may show gradational top as well; channel fill shows faint to marked upward fining.

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Distributary channel	Irreg. upward decrease	Upward decrease	Upward increase	Upward increase	Highly discontinuous--no pattern
Channel mouth bar	Upward or central increase; decrease with thinning	Upward or central increase; decrease with thinning	Upward or central increase; decrease with thinning	Upward decrease; may decrease with thinning	Greatest perpendicular to isopach trend.
Mouth bar slope	Typically low--no pattern	no pattern	Typically high	Common, no pattern	No pattern

B. General Reservoir Model:

Elongate, lenticular sand body consisting of bi-convex belt incised along the crestal thick by a partially to wholly isolated channel fill; underlain with variable degree of isolation by thin, imbricate lenses of sand. Principal reservoir attributes improve within core of sand body, but change abruptly within the channel fill. Significant depositional topography associated with channel fill, which may be further segmented by mud plug. Permeability may range by 2 orders of magnitude.

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Isolation of channel/mouth bar compartments.
2. Presence of multiple, variably isolated and discontinuous subzones.
3. Irregular water incursion, fingering, or coning.

VI. PRODUCTION STRATEGIES:

1. Detailed subzone delineation.
2. Selective zone completion/injection.
3. Infill drilling.

VII. EXAMPLES:

1. Fargo 3900, Big Mineral Creek Barnes, Walnut Bend Winger reservoirs in Strawn sandstone play
2. Conroe (Yegua) reservoirs
3. Rincon field

Model 3

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Delta margin sand of a wave-dominated cuspate delta

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Distributary channel	Paleo-dip elongate; lenticular	600-7,000 ft x 10,000 ft	15-100 ft	Massive to thick, decreases at top. Local lateral accretion	Irregular; arcuate depressions and mounds	Poor-to-good
Coastal barrier	Strike-elongate; lenlenticular	(w)600 ft - 7.5 mi x (l)3-20 mi	30-100 ft	Thin-to-thick; thickness increases upward, inclined seaward	Sigmoidal; irregular convex upper surface	Good
Mouth bar slope-barrier face	Stike-elongate to -lenticular		5-20 ft	Thinly-bedded (internally thinly-laminated)	Minor	Poor to moderate

III. DESCRIPTIVE GEOLOGIC MODEL:

Coastal barrier sands form two elongate, curvilinear belts symmetrically arranged about the distributary channel. Distributary channel sands cross-cut barrier sands, when abandoned they may be partly filled by a mud plug. Barrier sands coarsen upward, and thin perpendicular to isopach trend. Mouth bar slope - barrier face sands feather-edge into prodelta and shelf deposits, and may or may not be gradational with coastal barrier sands.

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Distributary channel	Uniform to upward decrease	Uniform to upward decrease	Upward increase	Upward increase	Greatest perpendicular to isopach trend
Coastal barrier	Uniform to upward increase	Upward increase	Low; upward decrease	Upward decrease	Greatest parallel to isopach trend
Mouth bar slope-barrier face	Upward increase	Upward increase	High; upward decrease	Upward decrease	Greatest parallel to iospach trend

B. General Reservoir Model:

Strike elongate, lenticular sand body, sheetlike to sigmoidal in cross section, locally incised by partially-mudfilled distributary channel deposits. Coastal barrier sands compose the principal reservoir, mouth bar slope - barrier face sands have higher water saturation and lower porosities and permeabilities and therefore lower OOIP. These finer-grained deposits may or may not be in communication with the principal reservoir. Paleodip-oriented accretionary surfaces in the coastal barrier sands may compose intra-reservoir stratigraphic traps.

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Coastal barrier sands contain largest proportion of inplace oil; recoveries highest from these sands. Persistent oil saturation along strike.
2. Barrier face - mouth bar slope sands have less efficient drives and lower recoveries; may be isolated from main (coastal barrier) reservoir by mudstone.
3. Cross-cutting distributary channel sands have poor recoveries, create isolated compartments in coastal barrier reservoirs.

VI. PRODUCTION STRATEGIES:

1. Reservoir energy in lower mouth bar slope - barrier face sands is commonly different from that in the principal reservoir, production methods need to be adjusted accordingly.
2. Coastal barrier sands transected by distributaries creating local compartments. Distinguish channel sands (paleodip elongate) from barrier sands (paleo-strike elongate).

VII. EXAMPLES:

East Texas field
Big Wells (San Miguel) field
Obigbo North field, Niger delta, Africa

Model 4

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Barrier and Strandplain Front Sand

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Barrier-strand plain front	Elongate, lenticular	4 mi - 30 mi x 4,000 ft-5 mi	20-40 ft	Med. to thick; accretionary	Sigmoidal; ridges on top	Good to excellent
Interbarrier delta	Elongate-digitate to lobate	8,000 x 10,000 ft	10-30 ft	Thin to medium; lenticular	Irregular mounds	Poor to good

III. DESCRIPTIVE GEOLOGIC MODEL:

Accretionary barrier composed of lenticular, strike-elongate sandstones; thickness and grain size decrease seaward, transected by tidal or storm surge channels of variable dimensions. Local inter-barrier deltas (fluvial and ebb-tidal) contain mixed upward coarsening and upward fining textural sequences, lenticular bedding.

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Accretionary barrier	Uniform to upward increase	Uniform to upward increase	Upward decrease	Upward decrease	Greatest parallel to isopach trend
Inter-barrier delta	Irregular upward increase; local upward decrease	Overall upward increase	Irregular upward decrease	Upward decrease	Upward increase, locally lenticular

B. General Reservoir Model:

Elongate belt, lenticular to sheetlike (in progradational barriers) in geometry, crosscut by tidal lenticular inlets and channels of varying dimensions. These frequently act as low permeability barriers or isolated lenses, which compartmentalize the reservoir. Porosity and permeability increase upwards with concomitant decrease in stratification. Directional permeability oriented perpendicular to isopach trend in barrier face sands and parallel to trend in barrier crest deposits. Thin mud layers separate seaward dipping and superimposed barrier sequences creating intrareservoir stratigraphic traps. Intrabarrier deltas contain heterogeneous upward increasing and decreasing porosity and permeability trends, significant channelization, and low continuity of sandstones.

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Oil saturated zone laterally persistent in strike direction.
2. Crosscutting channels cause flow restriction or channeling and separate areas of low water from high water cut zones.
3. Water incursion irregular in early stages of reservoir development, later becomes uniform.
4. Superimposition of barriers results in paleo-seaward dipping multiply layered trap.
5. Deltaic reservoirs are compartmentalized, have variable oil saturations and recovery.

VI. PRODUCTION STRATEGIES:

1. Locate cross-cutting channels (permeability barriers) particularly for secondary recovery.
2. Geometric well spacing acceptable because of areally uniform oil distribution.
3. Positioning of perforations critical, as lower accretionary barriers separated from upper reservoirs by low k interval reducing vertical communication.

VII. EXAMPLES:

1. North Markham - North Bay City, Aransas Pass and Flour Bluff fields of the Frio barrier/strandplain trend
2. Jackson-Yegua barrier/strandplain trend

Model 5

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Barrier core of microtidal barrier, bar sand.

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Barrier core	Strike-elongate gate	1 to 5 mi x 5 to 30 mi	20 - 50 ft	Large scale-seaward dipping zones.	Convex upward	Good to excellent
Inlet fill	Dip-elongate, lenticular	1000-10,000 ft x 1 to 6 mi	30 to 80 ft	Massive	Capped by barrier or beach/spit accretion topography	Good to excellent

III. DESCRIPTIVE GEOLOGIC MODEL:

Main barrier or strandplain axis. Characterized by large scale, low angle accretionary foreset bedding or zonation in progradational settings. In aggradational settings, the barrier core is laced with crosscutting inlet fills, capped by accretionary spits and forming basinward and landward thinning lenses. Both grade basinward into coarsening upward shoreface sands and landward into back barrier and tidal delta sands (barrier/lagoon) or into coastal plain deposits (strandplain).

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Barrier core	Uniform to upward increase	Uniform to upward increase	Uniform or upward decrease	Few, no pattern	no pattern
Inlet fill	Upward decrease to irreg.; good perm. likely at top	Upward decrease	Upward increase; pods of lowest S_w at base	Few, no pattern	Greatest perpendicular to regional isopach trend

B. General Reservoir Model:

Massive, tabular sand body consisting of uncorrelatable crosscutting dip-elongate lenses; unstratified, but zones of best reservoir quality occur as generally dip-oriented pods within massive sand body. Crosscutting depositional topography of 10 ft± (but only a small proportion of total sand volume affected).

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Irregular initial S_w and drainage pattern.
2. Irregular water encroachment and fingering; oil bypassing.
3. Difficult intrareservoir zone control.
4. Good pressure continuity.
5. Water coning.
6. High GOR rarely a problem.

VI. PRODUCTION STRATEGIES:

1. Arbitrary zone definition (slicing) and perforation control.
2. Edge injection for pressure maintenance.
3. Controlled production rate (to minimize water cut).

VII. EXAMPLES:

1. West Ranch and other Greta reservoir fields of the Frio barrier/strandplain play

Model 6

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT:

Back-barrier of microtidal barrier bar sand

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE:

Element	Geometry	Areal Dimensions	Thickness	Stratification (Deg., Geom.)	Deposit. Topog.	Init. Res. Quality
Tidal inlet fill	Elongate, lenticular	100-5,000 ft x 1-8 mi	10-60 ft	Lenticular, tabular, internal bedding	Convex downward irregular	Good to excellent
Flood tidal delta	Tabular to lobate, landward convex apron	2-10 mi x 2-5 mi (segmented)	10-50 ft	Med. to thick horizontal to sub-horizontal	Irregular mounds	Good to poor
Washover fan	Lobate, landward convex apron	1 x 1 mi to 4 x 5 mi	5-20 ft	Thin to thick horiz. bedding; lenticular bedding	Irregular mounds	Excellent to poor

III. DESCRIPTIVE GEOLOGIC MODEL:

Flood-tidal lobe transected by numerous lenticular channel fills; thickness, grain size, and channel dimensions decrease landward; mixed upward coarsening and upward-fining textural sequences. Washover fan sand body is thinner and channeling is most prominent in the upper part. Both merge basinward into barrier core facies.

IV. RESERVOIR PROPERTIES:

A. Depositional Elements:

Element	k	Pore Size	S_w	Number of Imperm. Beds	Bed/Lens Continuity
Tidal inlet fill	Irreg. upward decrease; decrease with thinning	Upward decrease; decrease with thinning	Irreg. upward increase; increase with thinning	No pattern	Greatest parallel isopach trend
Flood tidal delta	Irreg. upward increase; decrease with thinning	Increase up in base of sand body; decrease with thinning	Upward decrease; decrease with thinning	Upward increase; increase with thinning	Upward decrease; increase with thinning
Washover fan	Upward increase; decrease with thinning	Upward increase?	Upward decrease; increase with thinning	No pattern	Upward decrease; increase with thinning

B. General Reservoir Model:

Tabular sand body consisting of relatively uniform, poorly to moderately vertically zoned, variably stratified segments sharply bounded by lenticular, crosscutting, variably oriented fills. Contrasting vertical trends in reservoir parameters characterize juxtaposed segments. Reservoir quality trends parallel isopach trends. Moderate depositional topography. Permeability range = 1-2 orders of magnitude; S_w ranges by factor of 3.

V. DOCUMENTED PRODUCTION ATTRIBUTES:

1. Highly variable S_w = highly variable oil distribution.
2. Potential for irregular water influx.
3. Local compartmentalization as expressed by comparative well water-cut and GOR histories.
4. Highly variable recovery in individual reservoirs.

VI. PRODUCTION STRATEGIES:

1. Selective zone completion—vertically isolated zones within reservoir.
2. Infill drilling—partial isolation of reservoir elements; reservoir topography.

VII. EXAMPLES:

1. West Ranch and Old Ocean fields
2. Most fields of the Jackson/Yegua bar/strandplain play

Model 7

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT

Shoal-water organic banks and associated grainstone bars. (Pinnacle reef/atoll)

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE

Element	Geometry	Areal Dimensions	Thickness	Stratigraphy	Deposit. Topog.	Diagenesis
Subtidal to intertidal banks and bars	Elongate	5-10 mi long 2-5 mi wide	200 to 3,000 ft	Horizontal stratification is dominant and most obvious from log correlations. However, core studies indicate important but subtle changes laterally within these correlation units.	Prominent ridges and peaks	Primary porosity cemented by calcite. Leached grains (moldic porosity) developed later during aerial exposure
Subtidal shallow-water wackestones	Blanket	--		Laterally equivalent to bank facies	None	Compaction--porosity destruction
Terrigenous shale and thin sandstones	Blanket		500' to 2 - 3000'	Covers reservoir facies	None--fills pre-existing topography	Compaction--porosity destruction

III. DESCRIPTIVE GEOLOGIC MODEL

Massive carbonate buildups which developed prominent depositional topography largely because of the dominance of framework-building organisms. Reefs and associated shoal-water deposits characterize the buildups; low-energy mud-dominated facies characterize the off-buildup areas.

The entire carbonate system commonly buried by prograding terrigenous marine shale and thin sandstones.

IV. RESERVOIR PROPERTIES

A. Depositional Elements

Element	k	S_w	Nature of Impermeable Beds	Bed Continuity
Subtidal to intertidal banks and bars	28 md	25%	Most reservoirs are vertically segmented by a number of continuous tight limestone beds or shale breaks.	Continuity good across field but subtle lateral changes affect porosity and permeability within single beds.
Subtidal shallow-water wackestones	--	--	Impermeable	Extensive, off bank
Terrigenous shale and thin sandstones	--	--	Impermeable	Extensive--covers structure.

B. General Reservoir Model

Reservoirs developed in great variety of horizontally continuous carbonate facies types separated by thin shales or carbonates. Character of reservoirs changes laterally as a result of subtle changes in the carbonate fabric and resulting carbonate diagenesis. Constructional topography developed.

V. DOCUMENTED PRODUCTION ATTRIBUTES

High degree of horizontal stratification.
20-80 acre spacing.
40 acres in Horseshoe Atoll.
Variable in Pennsylvanian reefs and banks.

VI. PRODUCTION STRATEGIES

Secondary - recovery methods employed early in history of the fields because of low projected recovery efficiency.
Water and gas injection.
Infill drilling successful due to common lensing of porous beds. Delineation and drilling of isolated lenses.
Large scale CO_2 injection at SACROC increased expected recovery to 60%.

VII. EXAMPLES:

1. Jameson (Reef)
2. Round Top (Canyon)
3. Kelly-Snyder

Model 8

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT

Restricted platform margin
Well-defined shelf margin with dominant sponge-algal framestone

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE

Element	Geometry	Areal Dimensions	Thickness	Stratigraphy	Deposit. Topog.	Diagenesis
Lagoonal and supratidal siltstones, grainstones, and pisolites	Blanket			All units are prograding toward the Midland Basin	None	Early cementation--anhydrite and dolomite
Sponge-algal framestone	Broad-elongate belt	Fields 5 to 10 mi long and 2 to 4 mi wide	125' 400' at Yates		Very low-relief mounds	Dolomitization and leaching of grains to form moldic and vug porosity. Loose packing because of framework results in higher permeability
Subtidal fusulinid wackestone	Blanket				None	Dolomitization and leaching of grains

III. DESCRIPTIVE GEOLOGIC MODEL

Progradation of a thick shelf-edge facies (sponge-algal framestone) basinward over the offshore subtidal facies (fusulinid wackestone).

IV. RESERVOIR PROPERTIES

A. Depositional Elements

Element	k	S_w	Nature of Impermeable Beds	Bed Continuity
Lagoonal and supratidal siltstones, grainstones, and pisolites			Anhydrite-cemented grainstones, siltones and pisolites.	Overall section continuous over large area. Extreme variability expected locally.
Sponge-algal framestone	7 md average thin zones of up to 100 md.	25-35%	Minor changes in rock fabric within overall permeable section	Entire facies is continuous over large area. However, permeability varies widely within the facies. Extent of variability unknown.
Subtidal fusulinid wackestone				

B. General Reservoir Model

Reservoir section consists of a single thick progradational unit. Thickens to the south where is 400' thick at Yates. Variability of permeability is the result of minor changes in fabric within the sponge-algal facies.

V. DOCUMENTED PRODUCTION ATTRIBUTES

Original well spacing - 40 acre.
Recovery efficiency 20 to 30%.
50% at Yates - Karst porosity.

VI. PRODUCTION STRATEGIES

Pressure maintenance with water and/or gas at Dune, Yates, Goldsmith.
Waterflood at McElroy, Cowden N., Cowden S., Goldsmith, Foster.
CO_2 injection planned at Cowden N., McElroy (some underway), and possibly others.

VII. EXAMPLES:

1. Cowden N.
2. Foster
3. Cowden S.
4. Dune
5. McElroy
6. McCamey
7. Waddell
8. Yates

Model 9

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT

High-energy restricted platform
Mobile bar belt intertidal grainstone.

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE

Element	Geometry	Areal Dimensions	Thickness	Stratigraphy	Deposit. Topog.	Diagenesis
Lagoonal and supratidal dolomite and anhydrite	Blanket			This large progradational cycle is several hundred feet thick with the lower subtidal part thickest.	None	
Intertidal oolite bar	elongate lens	1.5x6 mi	up to 150'		10-20 feet	Dolomitization Leaching of oolites
Subtidal dolomitized wackestone	Blanket				None	

III. DESCRIPTIVE GEOLOGIC MODEL
A single progradational cycle consisting of, from bottom to top, subtidal wackestones, intertidal oolite grainstones, supratidal carbonates and evaporites.

IV. RESERVOIR PROPERTIES
A. Depositional Elements

Element	k	S_w	Nature of Impermeable Beds	Bed Continuity
Lagoonal and supratidal dolomite and anhydrite	---	---	Extensive distribution over reservoir facies	Great
Intertidal oolite bar	32 md	25-35%		Narrow in dip direction Elongate in strike direction Field divided in middle indicating possibly separate bars oriented perpendicular to strike.
Subtidal dolomitized wackestone	---	---		Great

B. General Reservoir Model

Reservoir section consists of single thick progradational cycle with porosity best developed in the intertidal oolite-bar facies.

V. DOCUMENTED PRODUCTION ATTRIBUTES

Original well spacing - 40 acre; infill-drilling programs are reducing spacing.
Recovery efficiency - 41%.

VI. PRODUCTION STRATEGIES

Waterflood underway in all fields.
Seminole - gas injection into gas cap, discontinued. Water injection for pressure maintenance.
West Seminole - gas and water injection for pressure maintenance.

VII. EXAMPLES:

1. Means
2. Seminole
3. Seminole W.
4. Midland Farms
5. Mabee

Model 10

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT

Shallow-water restricted platform: NORTHERN SHELF

Shallow-water restricted platform with thin subtidal to supratidal cycles.

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE

Element	Geometry	Areal Dimensions	Thickness	Stratigraphy	Deposit. Topog.	Diagenesis
Supratidal dolomite and anhydrite	Blanket	3 x 10 mi	10 - 20'	Highly stratified as a result of the repetition of cycles comprising these	None	Early leaching of fossils, plugging by anhydrite cement
Intertidal pellet grainstone	Narrow, elongate, parallel to strike.	..5 x 1 mi	.10'	these elements	Few feet	Early cement of anhydrite and dolomite
Subtidal dolomitized wackestone	Blanket	3 x 10 mi	30 - 50'		None	Leaching of fossils to form molds; dolomitization and formation of vug porosity.

III. DESCRIPTIVE GEOLOGIC MODEL

Repetition of a number of shoaling-upward cycles resulting in interbedded nature of the major facies types.

IV. RESERVOIR PROPERTIES

A. Depositional Elements

Element	k	S_w	Nature of Impermeable Beds	Bed Continuity
Supratidal dolomite and anhydrite	---		Thin, interbedded, continuous	Great
Intertidal pellet grainstone	---		Thin, interbedded, discontinuous	Little in dip direction better in strike direction
Subtidal dolomitized wackestone	2-10 md	15 to 30%		Great

B. General Reservoir Model

A number of subtidal to supratidal cycles 50 - 100 feet thick. Porosity/permeability best developed in subtidal facies. Interbedded impermeable beds-intertidal and supratidal facies extensive-cause vertical stratification. Lateral variation more gradual.

V. DOCUMENTED PRODUCTION ATTRIBUTES

Original well spacing - 40 acre; infill-drilling programs are reducing spacing.
Recovery Efficiency - 35 to 40%.

VI. PRODUCTION STRATEGIES

Selective perforations
Water flood in all fields
Pilot CO_2 projects planned for Levelland, Slaughter, and Wasson.

VII. EXAMPLES:

1. Brahaney
2. Wasson
3. Levelland
4. Slaughter
5. Reeves

Model 11

I. DESCRIPTIVE GEOLOGIC ENVIRONMENT

Interior restricted platform:

Mixed restricted subtidal environments.

II. PRINCIPAL DEPOSITIONAL ELEMENTS AND THEIR FACIES ARCHITECTURE

Element	Geometry	Areal Dimensions	Thickness	Stratigraphy	Deposit. Topog.	Diagenesis
grainstones-skeletal, pellet, pisolite	Elongate?	Local	1-3'		Slight	Cemented early with anhydrite, dolomite Later leaching of grains in some to form moldic porosity
Algal laminated bird's eye dolomite	Probably broad areas	Local	1-2'		None	Early cementation with anhydrite
Coal		Local	.5-2'		None	Compaction
Mudstones	Blanket	?	40-50'		None	Dolomitization--leaching to form vugs
Fusulinid wackestone	Blanket	?	50-80'		None	Dolomitization--leaching to form vugs

III. DESCRIPTIVE GEOLOGIC MODEL

Vertical aggradation of restricted-platform carbonates resulting in vertical variability but lateral continuity.

IV. RESERVOIR PROPERTIES

A. Depositional Elements

Element	k	S_w	Nature of Impermeable Beds	Bed Continuity
Grainstones			Locally developed, thickness variable	Discontinuous
Algal-laminated bird's eye dolomite			Thinly bedded, highly variable in composition, thick section	
Coal			Thin	Probably locally extensive, little control.
Mudstone	2-4 md	35%		Extensive
Fusulinid wackestones	2-4 md	35%		Extensive

B. General Reservoir Model

Reservoir units relatively thin but extend over wide areas.
Permeability variable due to anhydrite cementation.
Moldic porosity best developed -- low permeability.

V. DOCUMENTED PRODUCTION ATTRIBUTES

Recovery efficiency 23%
10 acre spacing on some leases

VI. PRODUCTION STRATEGIES

Waterflood and infill drilling in all fields.

VII. EXAMPLES:

1. Lea
2. Sand Hills