Opportunities for Additional Recovery in University Lands Reservoirs

Characterization of University Lands Reservoirs

Final Report

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The University of Texas System

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April 1990

Bureau of Economic Geology
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EXECUTIVE SUMMARY

In 1984 The University of Texas System funded a Bureau of Economic Geology project, "Characterization of University Lands Reservoirs," to assess in detail the potential for incremental recovery of oil from University Lands reservoirs by extended conventional methods. The objectives of the 5-year project were to quantify the volumes of unrecovered mobile oil remaining in reservoirs on University Lands, to determine whether the specific location of the unrecovered mobile oil could be delineated through integrated geoscience characterization of individual reservoirs, and to develop strategies to optimize recovery of this resource. Unrecovered mobile oil is mobile at reservoir conditions but is prevented from migrating to the well bore by geologic complexities or heterogeneities. This final report describes results of the 5 years of research conducted on University Lands reservoirs.

One hundred and one reservoirs, each of which has produced more than 1 million stock tank barrels (MMSTB) of oil, were included in a resource assessment and play analysis undertaken (1) to determine the volumes and distribution of all components of the University Lands resource base and (2) to select reservoirs for detailed analysis. These reservoirs collectively contained 7.25 billion barrels (BSTB) of oil at discovery, have produced 1.5 BSTB, and contain 200 MMSTB of reserves. Ultimate recovery at implemented technology is projected to be 24 percent of the original oil in place; thus, 5.5 BSTB of oil will remain after recovery of existing reserves. Unrecovered mobile oil (exclusive of reserves) amounts to 2.2 BSTB, and immobile, or residual, oil totals 3.3 BSTB.

These 101 University Lands reservoirs are grouped on the basis of geologic similarity into 11 major and minor plays. However, three major plays, the San Andres/Grayburg, Siluro/Devonian, and Ellenburger, dominate the resource base. Together, reservoirs in these formations contained 67 percent of the oil in place and 60 percent of the unrecovered mobile oil. For this reason, these formations and, in particular, the San Andres and Grayburg became the primary focus of the project. Ten reservoirs, Dune (Grayburg), Emma (San Andres), East Penwell (San Andres), Jordan (San Andres), Farmer (Grayburg), Taylor-Link West (San Andres), Three Bar (Devonian), Emma (Ellenburger), McFarland and Magutex (Queen), and Benedum (Spraberry), were selected for detailed analysis. Eight of the ten reservoirs studied lie in the San Andres/Grayburg, Siluro/Devonian, or Ellenburger formations.

The fundamental premise addressed in this project is that geologic complexities in reservoirs prevent some portion of the contained movable oil from migrating to producing wells. Since these complexities are the product of geologic evolution, improved understanding of the processes that cause reservoirs to form allows predictability of the heterogeneities that cause nonuniform drainage in reservoirs. Further, through the integration of geology, petrophysics, and production engineering, sites of poorly drained or uncontacted reservoir segments can be delineated and the volumes of untapped and bypassed oil quantified. Strategic targeting of the resource in this manner allows application of low-cost, low-risk advanced production technology to increase recovery.

In each of the 10 detailed studies implemented in this project the above premise holds true. The overriding control of lateral and/or vertical heterogeneity on the location of unrecovered mobile oil in low-recovery reservoirs is readily demonstrated. In reservoirs characterized by a high degree of lateral heterogeneity, such as Spraberry submarine-fan reservoirs, where unrecovered mobile oil remains stratigraphically trapped in channel sands, the optimal strategy for incremental recovery is targeted infill drilling concentrated in areas of high remaining saturation. In reservoirs where additional recovery targets are defined by vertical heterogeneity, such as in many Ellenburger reservoirs, deepening of existing wells supplemented by drilling of additional wells is appropriate. Most University Lands reservoirs, however, are characterized by the interplay of varying intensities of vertical and lateral heterogeneity. As a result, newly applied recovery strategies must account for uncontacted reservoir compartments as well as bypassing of saturated zones because of permeability stratification. Optimized recovery technology in this class of reservoir will depend on the balance of lateral to vertical heterogeneity that impacts the remaining saturations and will incorporate infill drilling, waterflood optimization to refocus the flood front, and well recompletions. Dune field, which showed a 60-percent increase in daily production as a result of a waterflood refocused on the basis of the Bureau study of the field, provides an excellent example of the benefits of recompletion and waterflood optimization in a laterally and vertically heterogeneous reservoir.

Projected oil recovery from University Lands with implemented technology is 24 percent of the oil in place. An immediate goal should be to increase recovery to 30 percent using strategies outlined in this report. This additional recovery would add more than 400 MMSTB of reserves and triple the existing reserve base, thereby ensuring stable production from University Lands reservoirs at current rates for the next 30 years.

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INTRODUCTION

In 1984, a project titled "Characterization of University Lands Reservoirs" was initiated by the Bureau of Economic Geology. The project, funded by The University of Texas System, had two key objectives: (1) to determine the volume of conventionally recoverable mobile oil that will remain in University Lands reservoirs after production of existing reserves and (2) to develop, through detailed characterization of strategically selected reservoirs, appropriate strategies for improving recovery of that remaining movable oil. This document, the final project report, serves as a review of results of the research effort. In particular, the geologic and geographic distribution of the remaining oil resource base on University Lands is described, and results of 10 detailed reservoir characterization studies are summarized. The final report supplements definitive Bureau of Economic Geology publications on each reservoir and a technology transfer initiative that included a University System-sponsored workshop on the potential for additional recovery from University Lands reservoirs held in April 1987 in Midland; publication of 77 reports, papers, and abstracts; and presentation of 115 oral papers, all of which advocated techniques and strategies for improving recovery from University Lands reservoirs.

The rationale behind the project is that University Lands reservoirs, like most Texas reservoirs, are nearing depletion. It is estimated that when the project began in 1984 cumulative production from University Lands totaled more than 90 percent of the ultimate recovery under the established development infrastructure. However, examination of available volumetric data suggested that more than 70 percent of the oil discovered in University Lands reservoirs would remain unrecovered following depletion.

This large volume of so-called "conventionally unrecoverable" oil in University Lands reservoirs is part of a substantial subset of a much greater volume of unrecovered oil in Texas reservoirs. Results of a state-wide analysis of this Texas resource (Galloway and others, 1983; Tyler and others, 1984; Fisher and Finley, 1986; Fisher, 1987) demonstrated that as much as half of the remaining oil was not "conventionally unrecoverable" but was movable and could be produced by a variety of advanced secondary techniques. These advanced techniques are highly dependent on a detailed knowledge of the geological structure, or architecture, of the reservoir and include geologically targeted infill drilling, improved waterflood design, and profile modification.

Results of the state-wide analysis encouraged a more detailed examination of University Lands reservoirs. The proposed research was approved by The University of Texas System, and the project began in September 1984. This report, in which University Lands oil-producing subplays are geographically and volumetrically defined, type reservoirs in each of the subplays described, and appropriate strategies for additional recovery proposed, describes results of the 5-year project.

RESOURCE ASSESSMENT AND PLAY ANALYSIS

Introduction

University Lands in the Permian Basin extend across 11 major oil-producing plays. A large number of reservoirs are grouped in these plays, 101 of which (plate 1) have each produced more than 1 million stock tank barrels (MMSTB) of oil from University Lands as of December 1987. These highly productive University Lands reservoirs are the subject of a resource evaluation to determine volumes of original oil in place (OOIP) and the volumes and nature of the oil that will remain in University Lands reservoirs after production of existing reserves.

This resource assessment addresses only oil reservoirs. Substantial gas resources also may be contained in University Lands reservoirs either as associated gas within oil reservoirs or as unassociated dry gas in play types of different character and location from the oil plays.

Originally, 7.25 billion barrels (BSTB) of oil was discovered within this group of large to moderate-sized University Lands reservoirs (fig. 1). Cumulative production from these reservoirs amounts to 1.5 BSTB. Under current production practice an additional 200 MMSTB of reserves will be produced. Conventional ultimate recovery at implemented technological levels thus amounts to 24 percent OOIP. Of the original resource of more than 7 BSTB of oil, 5.7 BSTB remains. This remaining resource consists of reserves (0.2 BSTB), mobile oil (2.2 BSTB), and residual oil (3.3 BSTB).

The purpose of the resource assessment was to determine the volume and location of the remaining oil in University Lands reservoirs so that the hydrocarbon-recovery research undertaken in this project could be directed toward those reservoirs with the greatest potential for incremental recovery.

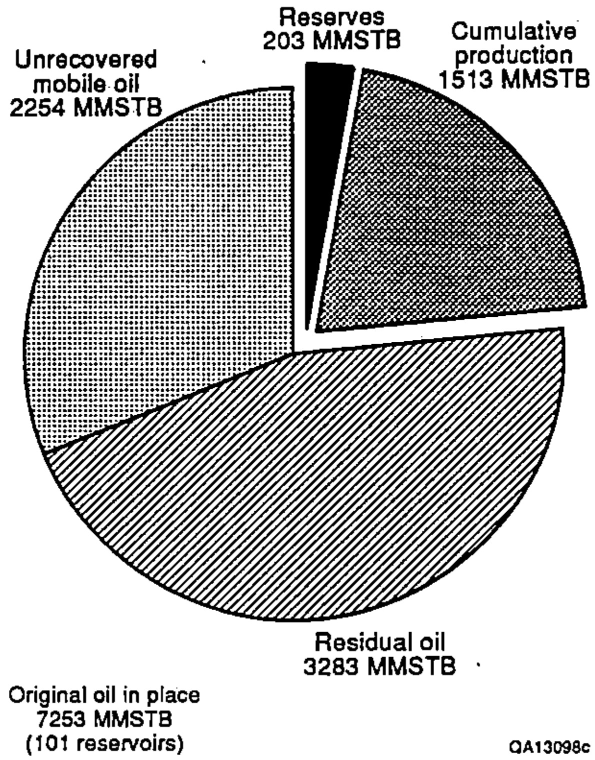

Figure 1. Composition of the oil resource base in the 101 largest University Lands reservoirs. Those reservoirs having cumulative production of more than 1 MMSTB are included. These reservoirs represent 97.4 percent of cumulative production. More than three-quarters of the OOIP will remain in place after recovery of current resources.

Sources of Information and Data Compilation

Pertinent reservoir-specific data were gathered from various sources of public information. The primary source was the Hearing Files at the Railroad Commission of Texas. Other sources included published information, Dwights Energy Information System, and the Bureau of Economic Geology's oil reservoir data base.

Volumetric parameters, applied production practices, and production history were determined for each reservoir (table 1). Volumetric parameters include reservoir acreage, average pay thickness, average reservoir porosity, initial water saturation, residual oil saturation, oil formation volume factors (to account for shrinkage of oil as it is taken from reservoir to storage tank conditions), and drive mechanism. Reservoir acres were measured from field maps. Although many of the candidate reservoirs lie entirely on University Lands, others extend beyond the University's land holdings. In this case only the resource determined to reside on University Lands was included in the assessment. A similar problem exists on unitized property. Where unitized reservoirs included non-University lands, an effective acreage value for the University's holdings was determined so that oil-in-place values could be calculated.

Applied production practices comprise well spacing, total producing wells, and current production technology. Volumetric parameters were used to calculate OOIP. Cumulative production was obtained from the University Lands Midland office. In unitized fields it was assumed that cumulative production reported by the Midland office represented the proportion of production from University Lands alone even though this may have included a contribution from non-University property. Justification for this assumption is that production for each unit participant is apportioned in proportion to original reservoir volumetrics.

Subtracting cumulative production from OOIP provides the total volume of oil remaining in each reservoir. The remaining oil is composed of two components: movable oil and immobile, or residual, oil. To determine the relative volumes of movable and immobile oil, residual oil volumes

Table 1. Reservoir-specific information assembled and compiled for the 101 largest University Lands reservoirs.

General	*Applied production practices*
Railroad Commission District	Well spacing
Field and reservoir name	Number of wells
Date of discovery	Secondary and tertiary recovery
Volumetric information	*Volumetric calculations*
Reservoir acreage	Original oil in place (in stock-tank barrels)
Average pay thickness	Cumulative production
Average reservoir porosity	Percent recovery
Initial water saturation	Remaining reserves
Residual oil saturation	Remaining mobile oil
Oil formation volume factors	
Drive mechanism	

(in stock tank barrels) were calculated (from the residual oil factor, which is the percent of pore space occupied by immobile oil) and subtracted from the remaining resource base. Thus, the product of this resource evaluation was quantification of the composition and volume of oil remaining in all of the University System's large to moderate-sized reservoirs.

Play and Subplay Characterization

The play concept, in which reservoirs of similar age, depositional origin, and structural style are clustered into production plays (fig. 2), is an extremely powerful tool. Because all reservoirs within a play have similar depositional, diagenetic, discovery, and production histories, results of one or two key reservoir characterization projects within a play or subplay can be extrapolated to other reservoirs in that cluster. Similarly, play analysis allows differentiation between plays of different depositional and diagenetic character. For example, as will be shown later in this report, karst-modified San Andres reservoirs on the southern margin of the Central Basin Platform have a very different production response from the non-karst-modified San Andres reservoirs on the east flank of the Central Basin Platform. Because of major differences in postdepositional history, these two subsets of San Andres reservoirs have contrasting production responses. Furthermore, the residency of the remaining mobile oil is controlled by widely divergent reservoir characteristics. Thus, advanced secondary recovery strategies to be applied to these contrasting reservoir types are different.

The 101 University Lands reservoirs included in this analysis were grouped into 11 major and minor plays. Major plays (plate 2) are informally defined as those with a relatively large number of volumetrically important reservoirs; minor plays (plate 3) are those with only a few reservoirs and relatively small amounts of production. Within plays wherein the reservoir population was sufficiently large and there existed substantial differences between subsets, reservoirs were divided into subplays (table 2). The large to moderate-sized University Lands

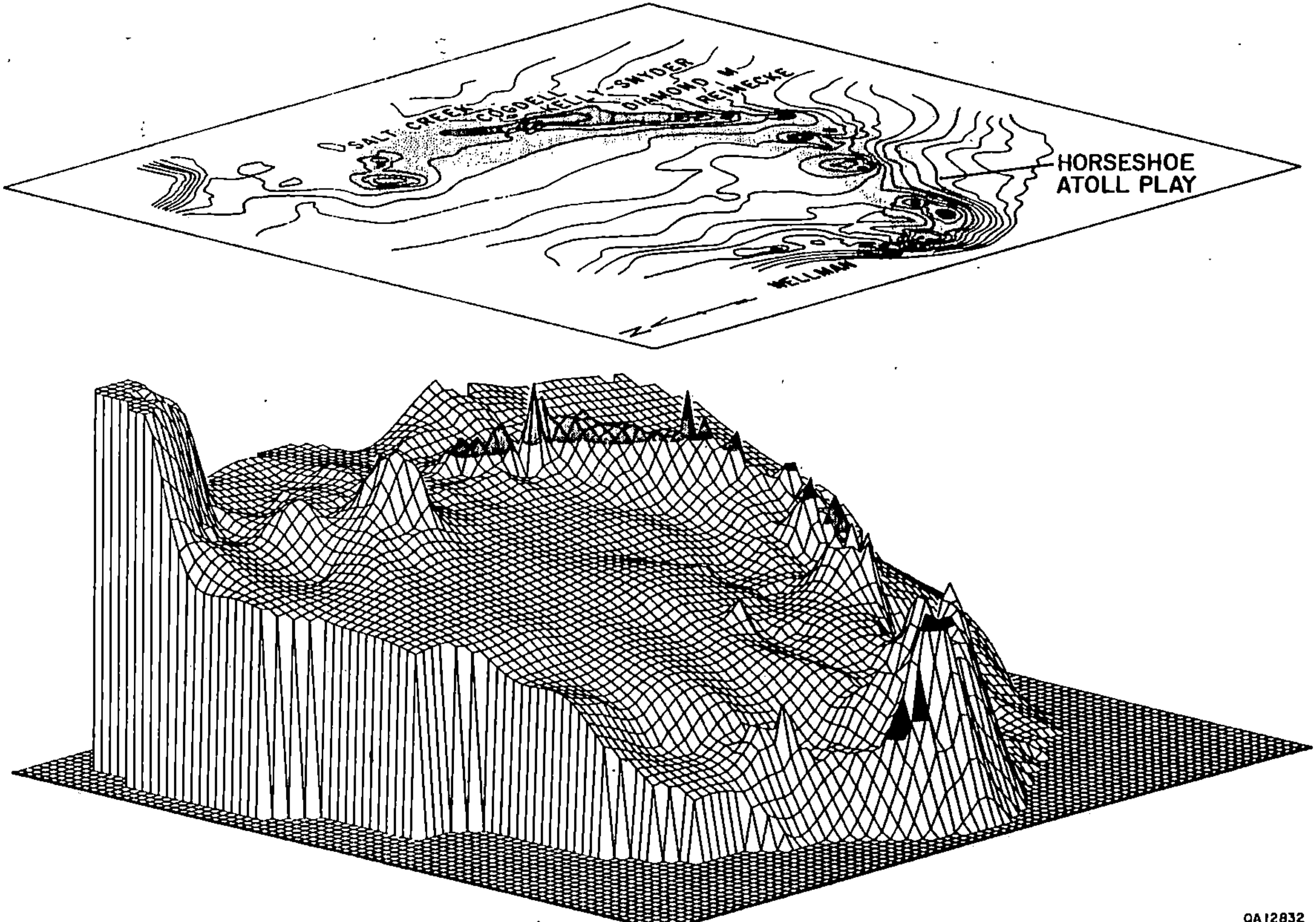

Figure 2. Illustration of the play concept using the Horseshoe Atoll as an example. Coincidence of depositional and structural conditions allows definition of discrete hydrocarbon production plays in which geologically similar reservoirs are grouped into families.

Table 2. University Lands plays and subplays ranked by original oil in place. Ranking is based on total OOIP in the play.

Rank	*Play*	*Subplay*
1	San Andres/Grayburg Platform Carbonate	
		Grayburg Open-Marine Platform—Central Basin Platform
		San Andres Open-Marine Platform—Central Basin Platform
		Grayburg High-Energy Carbonates—Ozona Arch
		Karsted San Andres
2	Siluro-Devonian Carbonates	
		Thirtyone Formation Chert
		Wristen Formation Platform-Margin Buildups and Shallow-Platform Carbonates
		Thirtyone Formation Skeletal Packstone
		Fusselman Formation Shallow-Platform Carbonates
3	Spraberry and Dean Submarine-Fan Sandstone	
4	Ellenburger	
		Ellenburger Karst-Modified Restricted-Ramp Carbonate
		Ellenburger Selectively Dolomitized Ramp Carbonate
5	Clear Fork Platform Carbonate	
6	Wolfcamp Carbonate	
7	Queen Tidal-Flat Sandstone	
8	Pennsylvanian Platform Carbonate	
9	Upper Guadalupian Platform Sandstone	
10	Delaware Basin Submarine-Fan Sandstone	
11	Simpson Group Marine Sandstone—Central Basin Platform	

reservoirs have thus been grouped into 18 subsets (plays or subplays) wherein differences between reservoirs are minimized but differences between subsets are maximized.

Volumetric Ranking of Plays and Subplays

The principal objective of the play and subplay analysis was to determine (1) those plays that have the largest resource recovery potential, and (2) within those plays, those reservoirs that have large volumes of unrecovered mobile oil, and (3) those reservoirs that have strong extrapolation potential to other reservoirs in the play. The entire University Lands project was thus strategically focused to address plays and reservoirs with the greatest potential for improving oil recovery.

Three major plays dominate all aspects of the University Lands resource base (fig. 3). San Andres/Grayburg, Siluro/Devonian, and Ellenburger reservoirs together contained 67 percent of the OOIP in University Lands reservoirs and account for 80 percent of the estimated ultimate recovery (fig. 3a, b). In terms of mobile oil remaining after recovery of proved reserves, these three major plays will contain 60 percent of the resource (fig. 3c). For this reason, reservoirs from these plays became the primary targets for advanced secondary-recovery research in the University Lands project.

Each of the three major plays contains 19 or more reservoirs and is characterized by varying degrees of geologically consistent, intraplay variability. These plays were therefore further divided into subplays (table 2). Even at the subplay level, San Andres/Grayburg, Siluro/Devonian, and Ellenburger reservoirs are the dominant components of the resource (fig. 4), as six of the eight volumetrically most important subplays (in OOIP) produce from these formations (table 3).

The San Andres and Grayburg Formations contain by far the most important reservoirs on University Lands. The four subplays in these juxtaposed, geologically similar reservoirs contained one-third of the OOIP and will account for 38 percent of the ultimate recovery and more than one-quarter of University Lands unrecovered mobile oil. Therefore, the primary effort of the project was in the San Andres and Grayburg Formations.

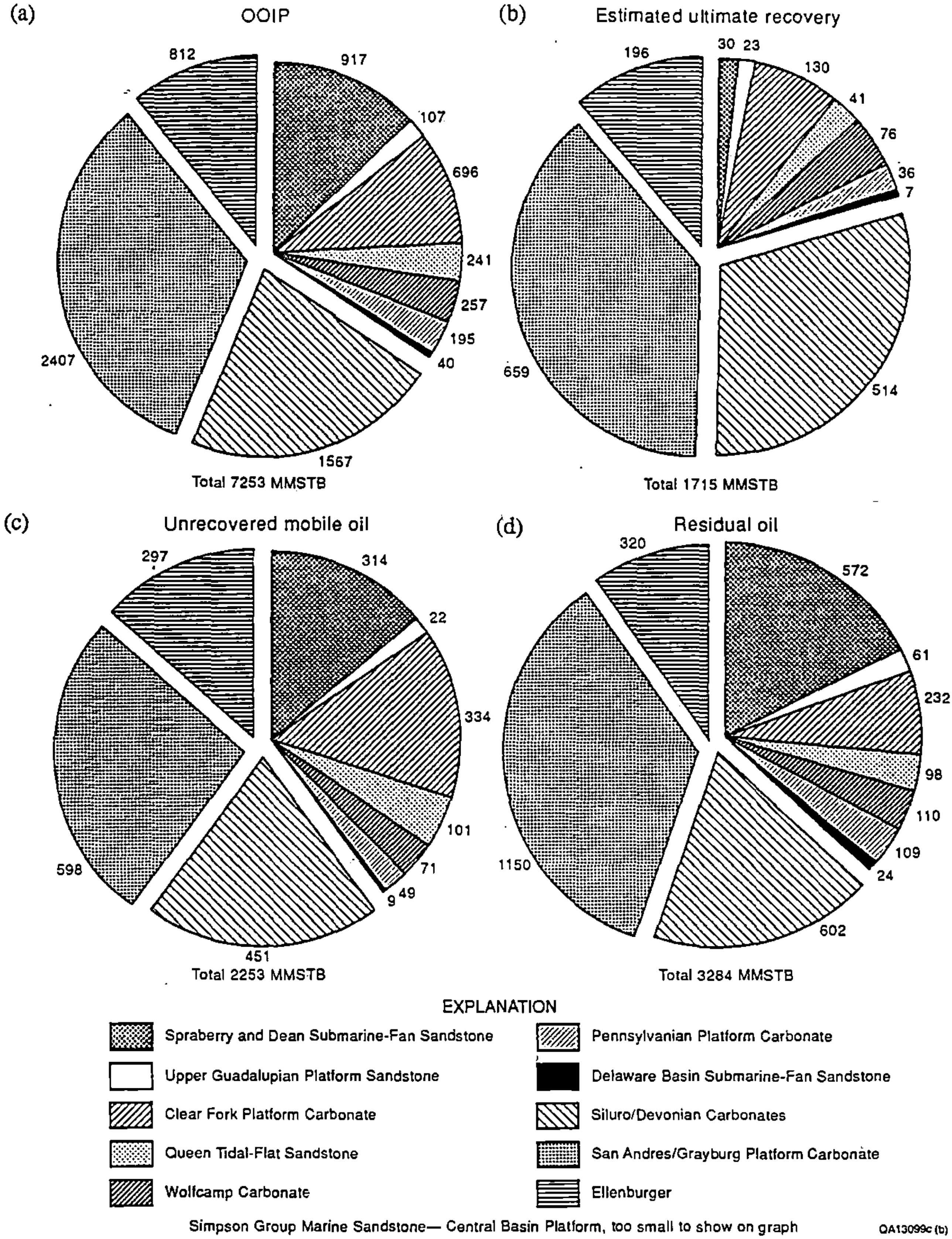

Figure 3. Distribution of (a) OOIP, (b) estimated ultimate recovery, (c) unrecovered mobile oil, and (d) residual oil (in MMSTB) in University Lands plays.

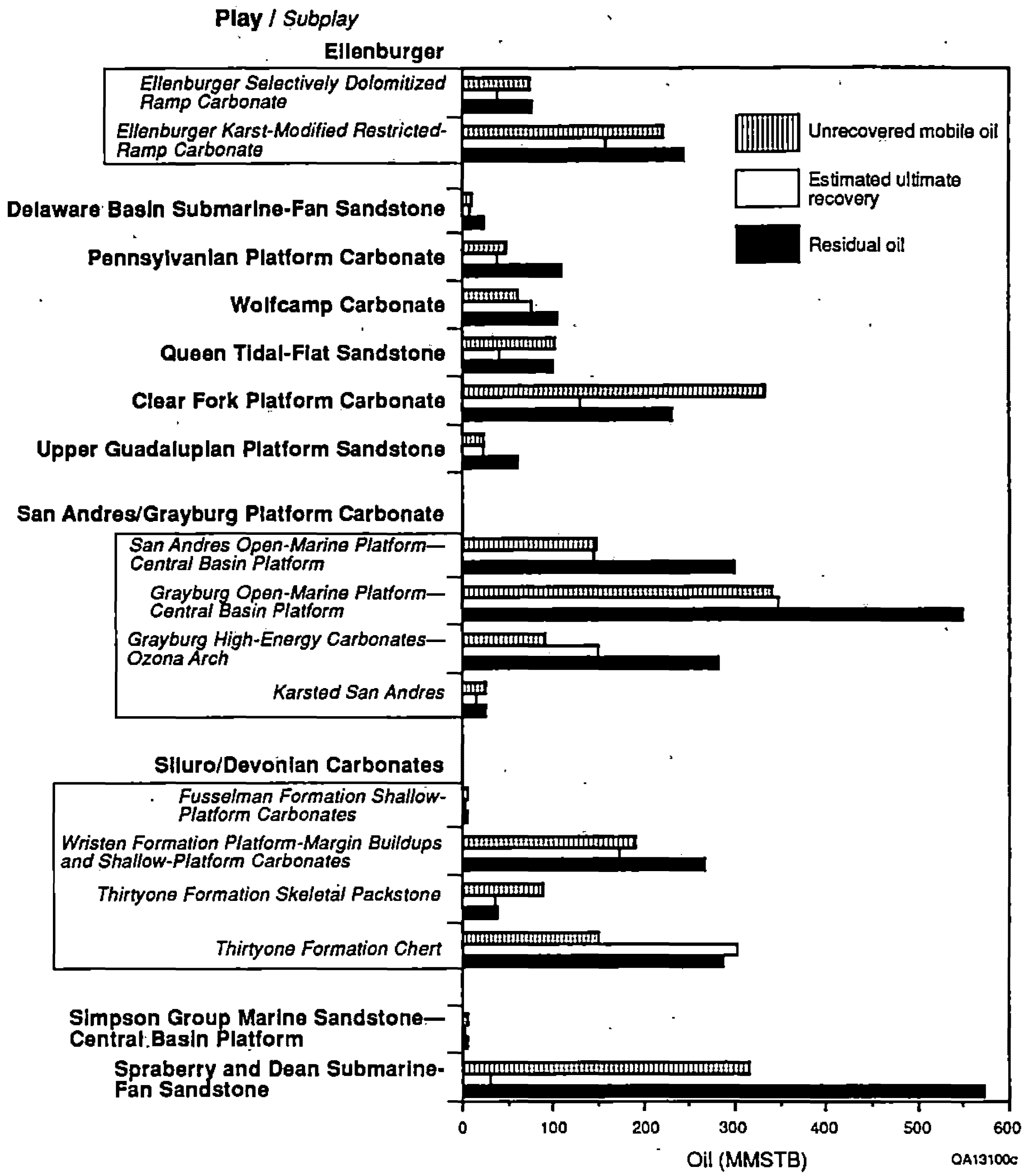

Figure 4. Composition of the University Lands oil resource at the subplay level.

Table 3. Aggregate University Lands play and subplay volumetrics.

Play or subplay	*Number of reservoirs*	*Stock-tank OOIP (MSTB)*	*Cumulative production (MSTB)*	*Remaining reserves (MSTB)*	*Ultimate recovery (MSTB)*	*Conventional ultimate recovery efficiency (%)*	*Residual oil (MSTB)*	*Unrecovered mobile oil (MSTB)*
Spraberry and Dean Submarine-Fan Sandstone	5	917,062	23,015	7,156	30,171	3	572,786	314,105
Simpson Group Marine Sandstone—Central Basin Platform	2	13,833	2,299	3	2,302	17	5,533	5,998
Thirtyone Formation Chert	6	761,019	270,083	32,925	303,008	40	291,342	166,669
Thirtyone Formation Skeletal Packstone	5	163,936	35,890	929	36,819	22	38,811	88,306
Wristen Formation Platform-Margin Buildups and Shallow-Platform Carbonates	8	629,047	158,590	13,509	172,099	27	265,702	191,245
Fusselman Formation Shallow-Platform Carbonates	2	13,126	2,442	9	2,451	19	5,813	4,862
Karsted San Andres	2	64,764	14,626	1,057	15,683	24	24,281	24,800
Grayburg High-Energy Carbonates—Ozona Arch	5	522,627	129,330	19,634	148,964	29	281,422	92,241
Grayburg Open-Marine Platform—Central Basin Platform	6	1,239,330	256,574	91,451	348,025	28	550,081	341,223
San Andres Open-Marine Platform—Central Basin Platform	7	580,707	139,027	7,446	146,473	25	294,207	140,027
Upper Guadalupian Platform Sandstone	3	107,124	23,139	324	23,463	22	61,222	22,439
Clear Fork Platform Carbonate	7	695,872	117,225	12,516	129,741	19	232,367	333,763
Queen Tidal-Flat Sandstone	6	240,620	38,553	2,505	41,058	17	98,361	101,201
Wolfcamp Carbonate	8	256,700	69,146	6,875	76,021	30	109,673	71,006
Pennsylvanian Platform Carbonate	7	194,637	34,102	1,922	36,024	19	109,190	49,423
Delaware Basin Submarine-Fan Sandstone	3	40,373	5,768	1,918	7,686	19	23,529	9,158
Ellenburger Karst-Modified Restricted-Ramp Carbonate	14	623,583	156,090	2,521	158,611	25	242,871	222,101
Ellenburger Selectively Dolomitized Ramp Carbonate	5	188,787	36,896	422	37,318	20	76,691	74,778
Total/Average	101	7,253,147	1,512,795	203,122	1,715,917	24	3,283,882	2,253,345

SUBPLAY DESCRIPTIONS

This section of the report describes the geologic and volumetric characteristics of University Lands plays and subplays. Play descriptions are presented in order of relative volumetric importance. Play and subplay rankings relative to component volumetric categories within the resource base are shown in table 4.

SAN ANDRES/GRAYBURG PLATFORM CARBONATE PLAY

San Andres/Grayburg reservoirs of Permian early Guadalupian age account for approximately 40 percent of the oil produced from the Permian Basin and 15 percent of all oil produced in Texas. On University Lands more than 0.5 BSTB of oil had been produced through 1987 from reservoirs that have produced at least 1 MMSTB. Consequently, San Andres and Grayburg reservoirs are the most important on University Lands, and most of our effort (80 percent of all man-years) was devoted to study of these reservoirs. Furthermore, depositional facies, which control the distribution of porosity, are commonly locally distributed, resulting in highly heterogeneous reservoirs. Reservoirs in which reservoir sections are controlled by complex depositional patterns are most effectively exploited by a carefully designed geologically targeted infield-drilling program based on thorough knowledge of the geological setting.

The carbonates and evaporites of the San Andres/Grayburg Platform Carbonate play were deposited on a shallow-water shelf that surrounded the Midland Basin during the early Guadalupian. Depositional environments varied from bar and bank complexes along the shelf edge to restricted subtidal lagoons and arid tidal flats toward the interior of the platform. Through time the entire facies tract prograded basinward so that the older San Andres shelf edge is located platformward of the younger Grayburg shelf edge. The reservoirs from this play have been grouped into four subplays: (1) Grayburg Open-Marine Platform—Central Basin Platform, (2) San Andres Open-Marine Platform—Central Basin Platform, (3) Grayburg High-Energy

Table 4. Relative ranking of University Lands plays and subplays by resource category. Ranking is at the subplay level. Table 2 shows relative ranking of plays.

Play or subplay	*OOIP*	*Cumulative production*	*Reserves*	*Residual oil*	*Unrecovered mobile oil*
Spraberry and Dean Submarine-Fan Sandstone	2	14	7	1	3
Simpson Group Marine Sandstone—Central Basin Platform	17	18	18	18	17
Thirtyone Formation Chert	3	1	2	4	6
Thirtyone Formation Skeletal Packstone	13	11	14	14	10
Wristen Formation Platform-Margin Buildups and Shallow-Platform Carbonates	5	3	4	6	5
Fusselman Formation Shallow-Platform Carbonates	18	17	17	17	18
Karsted San Andres	15	15	13	15	14
Grayburg High-Energy Carbonates—Ozona Arch	8	6	3	5	9
Grayburg Open-Marine Platform—Central Basin Platform	1	2	1	2	1
San Andres Open-Marine Platform—Central Basin Platform	7	5	6	3	7
Upper Guadalupian Platform Sandstone	14	13	16	13	15
Clear Fork Platform Carbonate	4	7	5	8	2
Queen Tidal-Flat Sandstone	10	9	10	11	8
Wolfcamp Carbonate	9	8	8	9	12
Pennsylvanian Platform Carbonate	11	12	11	10	13
Delaware Basin Submarine-Fan Sandstone	16	16	12	16	16
Ellenburger Karst-Modified Restricted-Ramp Carbonate	6	4	9	7	4
Ellenburger Selectively Dolomitized Ramp Carbonate	12	10	15	12	11

Carbonates—Ozona Arch, and (4) Karsted San Andres (fig. 5). Grayburg subplays dominate the University Lands OOIP resource and production from this play (fig. 6).

GRAYBURG AND SAN ANDRES OPEN-MARINE PLATFORM—CENTRAL BASIN PLATFORM SUBPLAYS

Introduction

The San Andres and Grayburg Open-Marine Platform—Central Basin Platform subplays are located along the east side of the Central Basin Platform (fig. 5). The 13 reservoirs in these subplays comprise 7 in the San Andres Formation (Emma San Andres, Fuhrman-Mascho, Goldsmith North San Andres Consolidated, Jordan, Penwell, Shafter Lake, and Shafter Lake North San Andres) and 6 in the Grayburg Formation (Block 2 Grayburg, Block 31 Grayburg, Cowden North, Dune, McElroy, and Triple-N Grayburg) (fig. 5). Because the depositional style and petrophysical properties of the San Andres and Grayburg reservoirs are very similar, descriptions of the two subplays are combined for most of the following sections. Volumetrics of the two subplays are discussed separately. San Andres and Grayburg reservoirs are developed in thick dolomitized subtidal portions of upward-shoaling cycles; however, siliciclastic siltstone is more abundant in the top part of the Grayburg cycle, where it grades into the overlying interbedded Queen siltstone and anhydrite. Depth to the reservoirs ranges from 2,900 to 4,736 ft. Because of the offlapping configuration of the San Andres/Grayburg section, the trend of the older San Andres reservoirs generally occurs platformward of the trend of the younger Grayburg reservoirs.

Reservoir Description

Upward-shoaling cycles, typical of the San Andres and Grayburg Formations, are each approximately 300 ft thick. The lower two-thirds of each cycle is made up of a thick section of subtidal facies comprising dolomitized skeletal wackestone to pellet grainstone; fusulinids, along

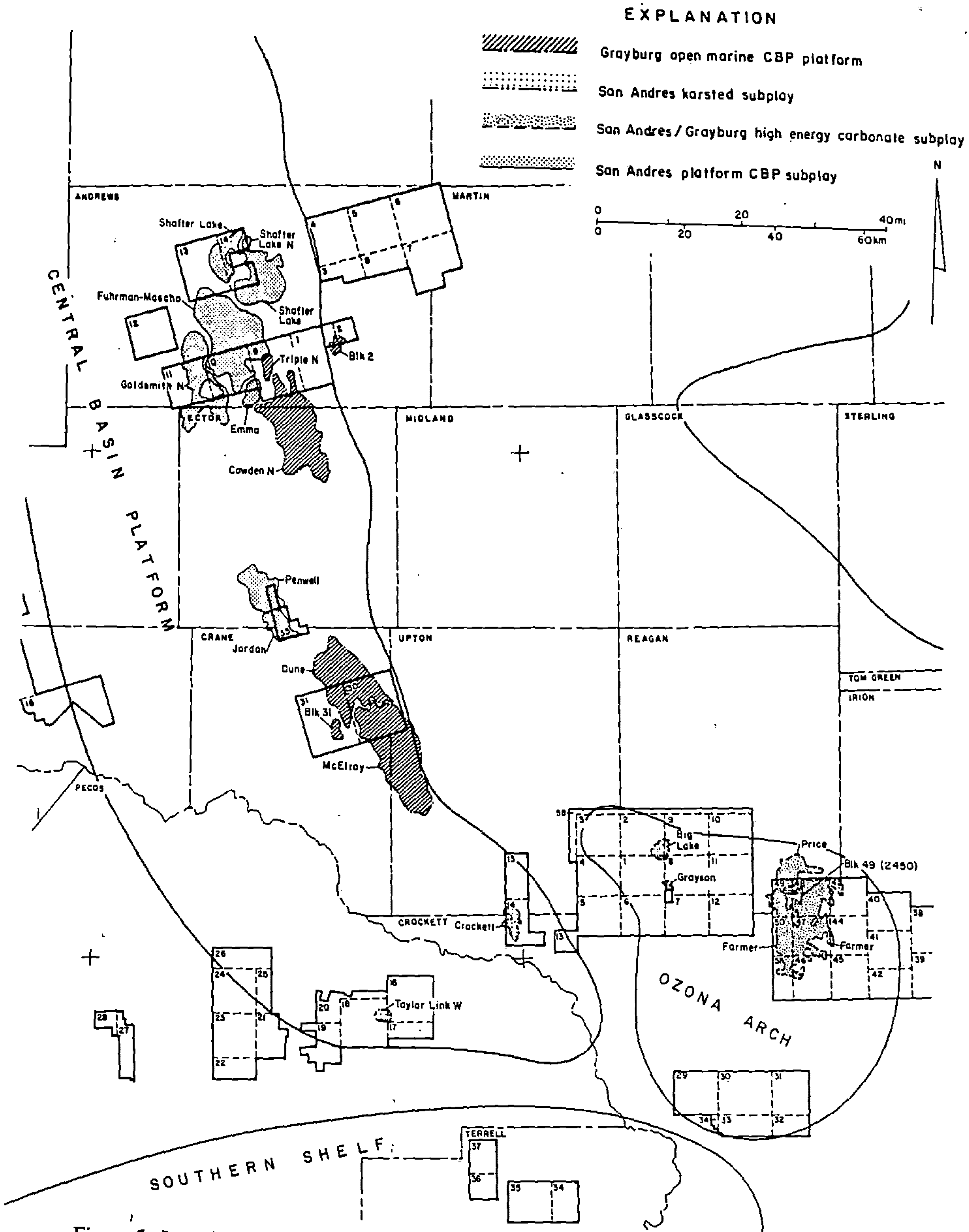

Figure 5. Location map of subplays and reservoirs of the San Andres and Grayburg play.

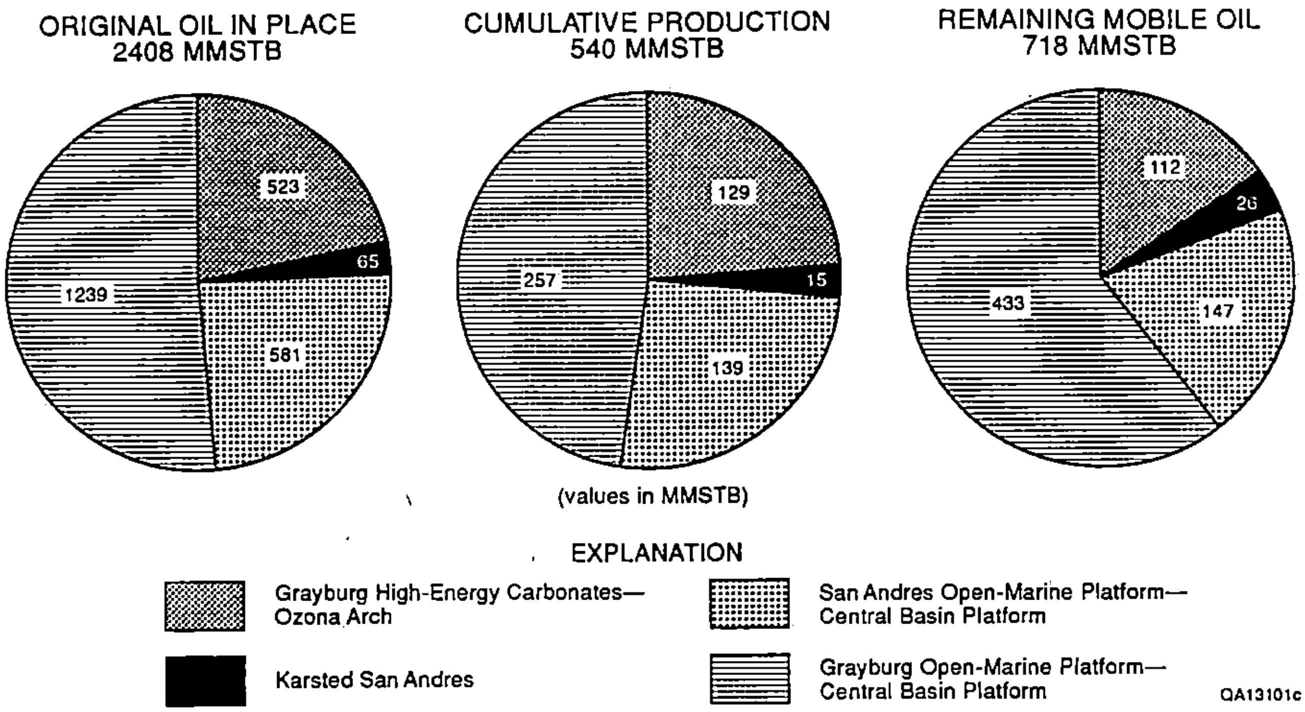

Figure 6. Relative significance of four San Andres/Grayburg subplays in terms of OOIP, cumulative production, and remaining mobile oil.

with other normal-marine fossils, are abundant and characteristic of this portion of the cycle. Sponge-algal-bryozoan bioherms and flanking skeletal grainstone occur locally within this lower part of the cycle. The pellet grainstones are poorly sorted and pervasively burrowed and represent accumulation under low-energy conditions. Overlying the subtidal section is a thin zone of locally distributed shallow-water subtidal to intertidal pellet, skeletal, and ooid grainstones. These grainstones are well sorted and locally laminated and crossbedded, indicating deposition under relatively high energy conditions. Capping the cycle is a supratidal sequence consisting of interbedded mudstone, siliciclastic siltstone, and pisolite facies. The siltstone beds are generally thin but become thicker and more numerous toward the top of the formation. These siltstone beds are easily recognizable on geophysical logs, are widespread, and are thus commonly used as correlation markers.

Intercrystalline and intergranular porosity occur in the subtidal dolostone facies. In most reservoirs the entire subtidal section (approximately 200 ft) was perforated, but production from Emma (Ruppel and Cander, 1988b), Dune (Bebout and others, 1987), Penwell (Major and others, 1988), and the southern part of McElroy (Walker and Harris, 1986) reservoirs is primarily from intergranular porosity in the pellet grainstone facies. Production from North McElroy is reported by Longacre (1986) to be from dolomitized wackestone facies. Part of the production from the Jordan reservoir is from fenestral porosity in the supratidal dolostone facies (Major and Holtz, 1989).

Reservoir Characteristics

The reservoirs of these two subplays produce from low-relief anticlinal structures (tables 5 and 6). Trapping mechanism is the result of lateral and vertical facies changes from porous and permeable subtidal dolostones of the reservoir to low-porosity and low-permeability intertidal and supratidal dolostones and anhydrite. Solution gas is the primary drive mechanism; however, all of these reservoirs are now on waterflood. Porosities in the Grayburg subplay (10 to 14 percent) are

Table 5. Reservoir parameters and volumetric characteristics of the Grayburg Open-Marine Platform—Central Basin Platform subplay.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 2	GRAYBURG	1957	442	30	.11	.30	.26	1.20	40	PMW	SG	6451	1823	28.3	2396	2232
8	BLOCK 31	GRAYBURG	1956	2080	20	.11	.30	.30	1.03	80	WF	WD	24127	4428	18.4	10340	9369
8	COWDEN, NORTH		1930	3589	40	.10	.34	.35	1.22	4020	WF	SG+GC	59404	6805	11.5	31312	21287
8	DUNE		1938	12710	80	.10	.37	.32	1.15	2010	WF	SG	432144	55323	12.8	219502	167319
8	MCELROY		1926	14422	86	.13	.37	.25	1.15	2010	PM	SG	685267	181008	26.4	271931	232328
8	TRIPLE-N	GRAYBURG	1964	2640	20	.14	.30	.32	1.23	4020	WF	SG	31937	7187	22.5	14600	10150
													1239330	256574	20.7	550081	432674

ESTIMATED PLAY RESERVES = 91451

UNRECOVERED MOBILE OIL = 341223

REMAINING RESIDUAL OIL = 550081

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 28 %

EXPLANATION

RRC	Railroad Commission of Texas district
FIELD	Name of field
RESERVOIR	Name of reservoir
DISC YR	Year of discovery
RESER. ACRES	Area of University Lands portion of reservoir (acres)
NET PAY	Net pay (ft)
AVG POR	Average porosity (%)
INT WAT SAT	Initial water saturation (%)
RES OIL SAT	Residual oil saturation (%)
OIL FVF	Oil formation volume factor
WELL SPAC	Well spacing (acres per well)
PROD TECH	Production technology
PM(W)	Pressure maintenance (through water injection)
WF	Waterflood
M	Miscible flood
PRIM	Primary recovery
DRIVE TYPE	
W	Water
WD	Water
SG	Solution gas
G	Gas cap
NA	Unknown
STOOIP (MSTB)	Original oil in place in thousand stock-tank barrels
CUM PROD	Cumulative production in thousand stock-tank barrels
PCT REC	Percent original oil in place recovered through 1987
RRO	Remaining residual oil in thousand stock-tank barrels
RMO (MSTB)	Remaining mobile oil inclusive of reserves. Reserves, estimated at the play level and subtracted from remaining mobile oil, indicate potential unrecovered mobile oil volumes

Table 6. Reservoir parameters and volumetric characteristics of the San Andres Open-Marine Platform—Central Basin Platform subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	EMMA	SAN ANDRES	1937	1424	30	.08	.20	.23	1.15	20	WF	SG	18444	7871	42.7	5303	5271
8	FUHRMAN-MASCHO		1930	18338	30	.09	.35	.41	1.23	40	WF	SG+WD	202990	27198	13.4	128040	47752
8	GOLDSMITH, N	SAN ANDRES, CON	1964	1424	35	.08	.38	.30	1.27	40	WF	SG	15028	3738	24.9	7307	3983
8	JORDAN		1937	5149	83	.11	.36	.25	1.28	20	WF	SG	182353	67589	37.1	71232	43532
8	PENWELL		1927	2542	118	.09	.37	.35	1.24	20	WF	SG	108771	27542	25.3	60428	20801
8	SHAFTER LAKE	SAN ANDRES	1953	4760	30	.08	.35	.26	1.25	40	WF	SG	46086	4072	8.8	18434	23580
8	SHAFTER LAKE, N	SAN ANDRES	1952	558	30	.10	.35	.32	1.20	40	PRIM	SG	7036	1017	14.5	3463	2554
													580707	139027	23.9	294207	147473

ESTIMATED PLAY RESERVES = 7446

UNRECOVERED MOBILE OIL = 140027

REMAINING RESIDUAL OIL = 294207

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 25 %

slightly higher than porosities in the San Andres subplay (8 to 11 percent). Initial water saturation in both subplays ranges from 20 to 38 percent and averages 33 percent. Residual oil saturation varies between 23 and 41 percent and averages 30 percent.

GRAYBURG SUBPLAY

Volumetrics

The six Grayburg reservoirs included in this play had produced 257 MMSTB of oil through 1987 from University Lands, 24 percent of the total production from these six reservoirs. The largest of these reservoirs by far is McElroy, which has produced 181 MMSTB from University Lands, followed by Dune, which has produced 55 MMSTB. The remaining four reservoirs have produced between 2 and 7 MMSTB. Recovery efficiency from these reservoirs on University Lands is 21 percent. Reserves compose 91 MMSTB. Of the 433 MMSTB of remaining mobile oil in these six reservoirs on University Lands, more than half (232 MMSTB) is calculated to be in the McElroy reservoir (table 5). After recovery of reserves, approximately 341 MMSTB of unrecovered mobile oil will remain in reservoirs of this Grayburg subplay.

SAN ANDRES SUBPLAY

Volumetrics

The seven San Andres reservoirs in this play had produced 139 MMSTB of oil through 1987 from University Lands, 41 percent of the total production from these seven reservoirs. The Jordan reservoir, the largest of the seven, has produced 68 MMSTB; the next largest reservoirs are Penwell and Fuhrman-Mascho, which have produced 28 and 27 MMSTB, respectively. The remaining four reservoirs are significantly smaller and have produced from 1 to 8 MMSTB from University Lands (table 6). Average current recovery efficiency from the reservoirs on University

Lands is 24 percent. Remaining mobile oil (inclusive of 7.5 MMSTB reserves) on University Lands is calculated to be 147 MMSTB; of this, 43 MMSTB lies in the Jordan reservoir and 48 MMSTB in the Fuhrman-Mascho reservoir. After production of reserves the mobile oil resource base will be 140 MMSTB.

GRAYBURG HIGH-ENERGY CARBONATES— OZONA ARCH SUBPLAY

Introduction

The Grayburg High-Energy Carbonates—Ozona Arch subplay is located on the Ozona Arch in Crockett and Reagan Counties. The five reservoirs of this subplay are Big Lake, Block 49 2450, Farmer San Andres, Grayson, and Price Grayburg (fig. 5). Depth to the reservoirs ranges from 2,200 to 3,000 ft.

Reservoir Description

The reservoir section is more than 300 ft thick and is composed of numerous upward-shoaling cycles, each of which ranges up to 40 ft in thickness. Siltstone and silty mudstone to wackestone in the lower part of each cycle grade upward into packstone to grainstone in the upper part. These cycles represent subtidal, low-energy conditions in the lower part and stable grain flat leeward of a bar complex to high-energy bar environment at the top.

Reservoir Characteristics

Thin zones of intergranular porosity occur in the top few feet of some of the grainstones; these zones are, however, very local in development and generally cannot be correlated from one well to another. Intercrystalline dolomite porosity in the mudstone and wackestone facies of the lower parts of the cycles is correlative from well to well and occurs in thicker sections; however, permeability is low. Low-relief structures are present in all reservoirs of this subplay, but porosity loss because of facies change is a major factor in formation of the trap. Solution gas is the primary drive mechanism, and no waterflood programs have been established. Porosity varies between 8 and 21 percent, and residual oil saturation varies between 30 and 45 percent.

Volumetrics

Through 1987, 129 MMSTB of oil were produced from five reservoirs on University Lands (table 7). This total cumulative production accounts for 98 percent of the total production from these fields on and off University Lands. Big Lake reservoir produced 108 MMSTB, considerably more than the next largest reservoir, Farmer San Andres, which produced 18 MMSTB. The other three reservoirs account for slightly more than 1 MMSTB of production each. Remaining mobile oil (inclusive of almost 20 MMSTB of reserves) on University Lands is calculated to be 112 MMSTB, most of this residing in Big Lake (64 MMSTB) and Farmer San Andres (36 MMSTB). Unrecovered mobile oil will amount to 92 MMSTB after recovery of existing reserves.

KARSTED SAN ANDRES SUBPLAY

Introduction

The Karsted San Andres subplay is located at the south end of the Central Basin Platform. The southern margin of the Central Basin Platform forms the structurally and stratigraphically highest portion of the platform, the crest of the structure coinciding with the position of the giant Yates field. Two major San Andres fields occur in the subplay area (though not on University Lands), the giant Yates field with 4 BSTB of oil in place and the McCamey field with 460 MMSTB of oil in place. Cumulative production from these two fields was 1 BSTB of oil as of January 1, 1982 (Galloway and others, 1983). University Lands has no interest in these two large fields but

Table 7. Reservoir parameters and volumetric characteristics of the Grayburg High-Energy Carbonates—Ozona Arch subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
7C	BIG LAKE		1923	6400	43	.21	.20	.30	1.30	20	PRIM	WD	275908	108391	39.3	103465	64051
7C	BLOCK 49	2450	1955	1195	27	.11	.40	.31	1.20	40,20	PRIM	SG	13765	1095	8.0	7113	5557
7C	FARMER	SAN ANDRES	1953	19920	35	.08	.40	.45	1.20	40,20	PRIM	SG	216355	17656	8.2	162266	36433
7C	GRAYSON		1928	554	20	.10	.40	.31	1.21	40,20	PRIM	SG+WD	4266	1095	25.7	2204	967
7C	PRICE	GRAYBURG	1953	2120	15	.10	.40	.31	1.20	40,20	PRIM	NA	12333	1093	8.9	6373	4867
													522627	129330	24.7	281422	111875

ESTIMATED PLAY RESERVES = 19834

UNRECOVERED MOBILE OIL = 92241

REMAINING RESIDUAL OIL = 281422

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 29 %

does have 100 percent interest in Taylor-Link West and 50 percent interest in Crockett, two similar but smaller fields (fig. 5).

Much of the northward tilt of the Central Basin Platform can be accounted for by post-Guadalupian structural tilting, but thinning by onlap recorded in the Grayburg and Seven Rivers Formations supports the interpretation that this portion of the platform was also a relatively positive feature during the Guadalupian. Localized karst development along the southern margin of the Central Basin Platform in the Yates (Craig, 1988) and Taylor-Link West fields, provides further evidence that this area was a positive feature during the Guadalupian.

Reservoir Description

The reservoirs of Karsted San Andres subplay are characterized by thick accumulations of reservoir-quality grainstones at the top of an upward-shallowing sequence, reflecting the generally higher-energy depositional setting of the shelf margin facing the Sheffield Channel. Primary permeability was greatly increased by solution-enhanced fractures, microbreccias, and large vugs, which developed during a period of prolonged exposure and karstification.

Reservoir Characteristics

Crockett and Taylor-Link West produce from San Andres reservoirs with an average porosity range of 10 to 16 percent and 29 to 40 percent water saturation. The trap is principally structural closure. Both fields have solution-gas drive mechanisms and are currently under waterflood. Well spacing is 10 acres (table 8).

Volumetrics

The two University Land fields have a total of 65 MMSTB of OOIP and an ultimate recovery of 15 MMSTB, for a recovery efficiency of 23 percent. The estimated volume of mobile oil remaining at current producing methods is 21 MMSTB for the Taylor-Link West field, in which

Table 8. Reservoir parameters and volumetric characteristics of the Karsted San Andres subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
7C	CROCKETT		1938	1404	15	.16	.29	.35	1.10	10	WF	SG	16873	4038	23.9	8318	4517
8	TAYLOR LINK W	SAN ANDRES	1929	1805	57	.10	.40	.20	1.05	10	WF	SG	47891	10588	22.1	15964	21339
													64764	14626	22.6	24281	25857

ESTIMATED PLAY RESERVES = 1057

UNRECOVERED MOBILE OIL = 24800

REMAINING RESIDUAL OIL = 24281

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 24 %

the University Lands interest is 100 percent, and 5 MMSTB for the Crockett field, in which the University Lands interest is 50 percent. Only 1 MMSTB of reserves remains; thus the unrecovered mobile oil resource base amounts to 25 MMSTB in the subplay (table 8).

SILURO/DEVONIAN CARBONATES PLAY

The Siluro/Devonian comprises a thick (up to 1,500 ft) sequence of predominantly carbonate rocks that subcrop across most of the Permian Basin of West Texas. Nearly 1.5 BSTB of oil have been produced from the more than 520 reservoirs developed in these rocks. Siluro/Devonian reservoirs also represent a significant component of the oil production on University Lands. As of January 1988, 21 reservoirs on University Lands (fig. 7) had cumulative production totals each exceeding 1 MMSTB. Total University Lands production from these reservoirs is 467 MMSTB, about one-third of the total production from University Lands.

Siluro/Devonian rocks can be subdivided into four distinct lithologic sequences: (1) the basal Fusselman Formation of Upper Ordovician to Middle Silurian age, (2) the Wristen Formation (Middle Silurian), (3) the Lower(?) Devonian Thirtyone Formation, and (4) the Upper Devonian Woodford Formation. Siluro/Devonian reservoirs are restricted to the carbonate section: Fusselman, Wristen, and Thirtyone Formations. The Woodford Formation is composed of shale, which serves as both a top seal for many of the carbonate sequences below and a possible source rock.

Siluro/Devonian carbonates can be subdivided into four subplays (fig. 7), each having characteristic mineralogy, lithology, depositional environment, and porosity development. A total of more than 1.5 BSTB OOIP lies in the 21 University Lands reservoirs included in the Siluro/Devonian play; cumulative production totals 467 MMSTB, and there remains a mobile oil resource inclusive of reserves of almost 500 MMSTB (fig. 8).

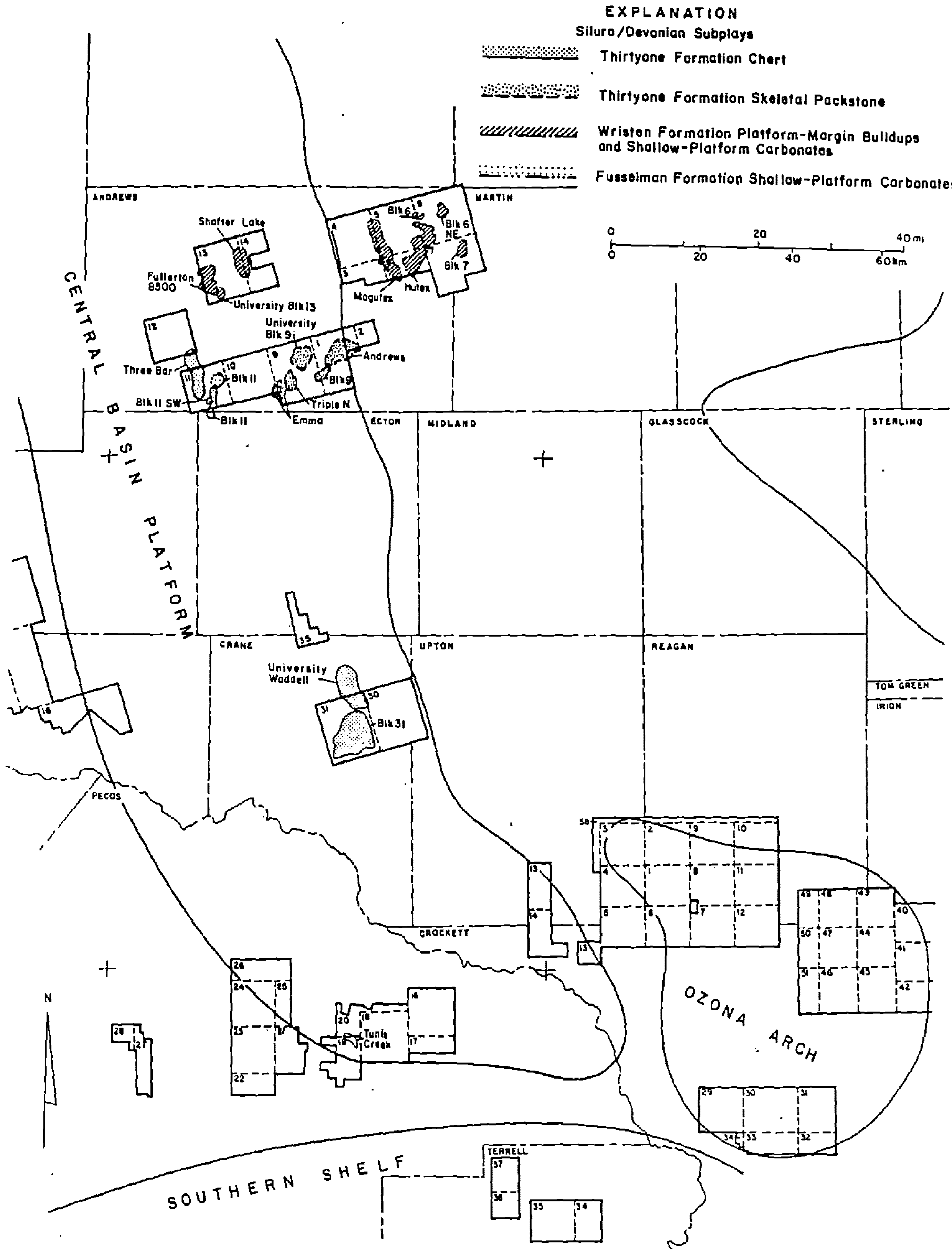

Figure 7. Map showing 21 Siluro/Devonian reservoirs located on University Lands.

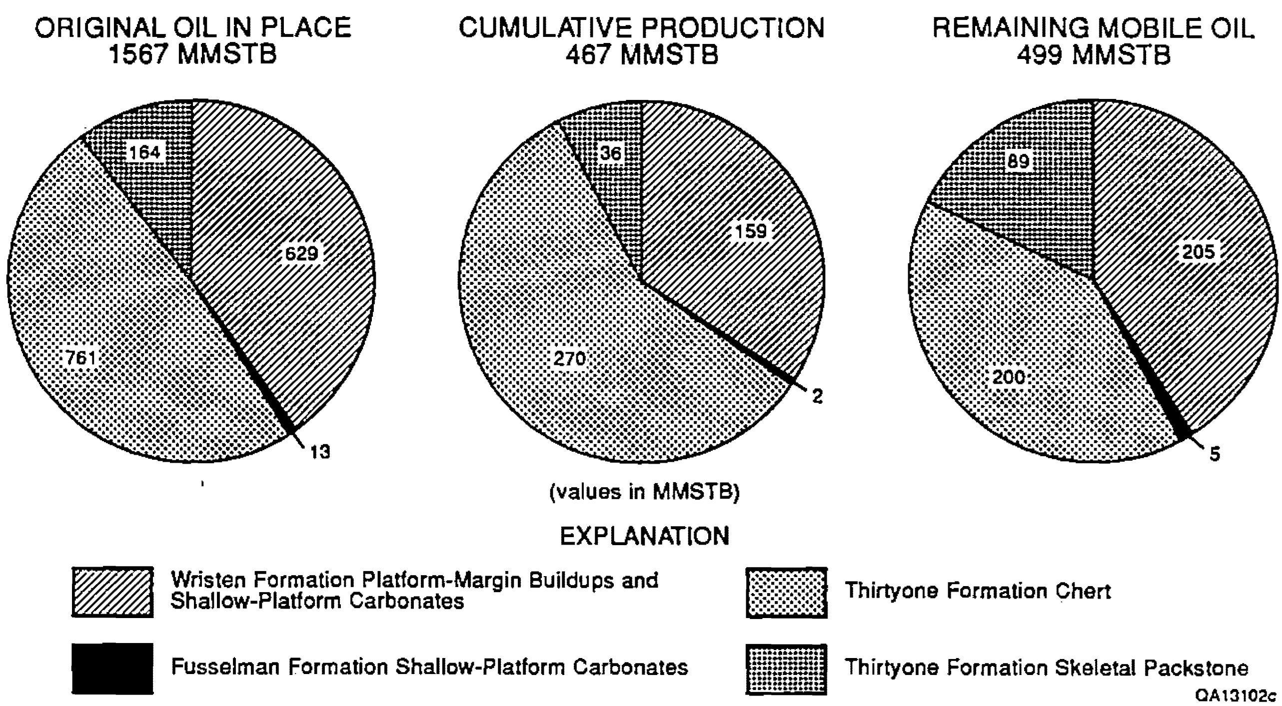

Figure 8. Relative significance of four Siluro/Devonian subplays in terms of OOIP, cumulative production, and remaining mobile oil.

THIRTYONE FORMATION CHERT SUBPLAY

Introduction

Six University Lands reservoirs are assigned to the Thirtyone Formation Chert subplay: Block 11 Devonian, Block 11 Southwest Devonian, Block 31 Devonian, Three Bar Devonian, Tunis Creek Devonian, and University Waddell Devonian (fig. 7).

Reservoir Description

Chert in the Thirtyone Formation accumulated in quiet, probably deep-water conditions removed from the influx of carbonate detritus. Because the source of the carbonate detritus lay to the north, chert sequences are most common at the base of the Thirtyone Formation and thicken to the south. In reservoirs in the northern part of the area (for example, Block 11 Devonian, Block 11 Southwest Devonian, and Three Bar Devonian), the reservoir facies are restricted to one or two areally continuous, highly porous, chert beds (total thickness less than 100 ft) at the base of the Devonian section. To the south (Block 31 Devonian and University Waddell Devonian, for example), porous intervals are developed throughout a much thicker section (several hundred feet) that contains increasing amounts of carbonate upsection.

Most of the porosity in these rocks is moldic and intercrystalline. Moldic pores formed as a result of leaching of spicules and carbonate allochems. Intercrystalline pore space is developed within the chert matrix. Porosity and permeability in these rocks generally decrease with increased carbonate content. Fracturing of the brittle chert matrix is also locally important in some reservoirs such as Three Bar Devonian.

Reservoir Characteristics

Porosity in these reservoirs is highly variable because of variations in chert/carbonate ratio but averages about 16 percent (table 9); permeability is also variable but averages about 23 md. Fracture permeability is of major importance in many of the reservoirs.

Two types of trapping mechanisms are present. The two largest reservoirs in the subplay, Block 31 Devonian and University Waddell Devonian, are anticlinal traps; the rest are formed by erosional truncation. Fracturing and brecciation of the chert reservoir sequences is most apparent in truncated reservoirs. Top seals for the two largest reservoirs are formed by the Woodford Formation, whereas Permian siliciclastics overlie the others.

Average depth for these reservoirs is about 8,100 ft. Solution-gas drive is common to all. Most of the reservoirs are developed to 40-acre spacing.

Volumetrics

Thirtyone Formation Chert reservoirs account for more than 50 percent of the total production from the Siluro/Devonian in West Texas. On University Lands, production from these reservoirs currently totals more than 270 MMSTB and represents 58 percent of the total production from University Lands Siluro/Devonian reservoirs. Total OOIP for the subplay is about 761 MMSTB, 49 percent of the total for the entire Siluro/Devonian play (fig. 8). Remaining mobile oil on University Lands in these reservoirs is estimated to be more than 200 MMSTB, or 40 percent of the total from the Siluro/Devonian, ranking this subplay second only to the Wristen carbonates subplay in terms of resource potential (fig. 8).

Of the six reservoirs included in the subplay, Block 31 Devonian is by far the largest, accounting for 63 percent of the OOIP for the subplay (31 percent of the play total), 75 percent of the cumulative production (43 percent of the play total), and 44 percent of the remaining mobile oil (17 percent of the play total).

Table 9. Reservoir parameters and volumetric characteristics of the Thirtyone Formation Chert subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MTSB)	RMO (MSTB)
8	BLOCK 11	DEVONIAN	1951	1555	45	.15	.25	.40	1.61	40	WF	SG	37958	10032	26.4	20245	7682
8	BLOCK 11, SW	DEVONIAN	1952	176	45	.15	.25	.31	1.61	40	WF	SG	4296	1335	31.1	1778	1185
8	BLOCK 31	DEVONIAN	1945	7840	130	.15	.35	.26	1.60	40,20	M	SG	481830	201627	41.8	192732	87471
8	THREE BAR	DEVONIAN	1945	3640	73	.18	.37	.14	1.67	40	PM	SG	140426	36130	25.7	31107	73189
8	TUNIS CREEK	DEVONIAN	1982	705	53	.22	.30	.37	1.45	40	PMW	NA	30787	1439	4.7	16273	13075
8	UNIVERSITY WADDELL	DEVONIAN	1949	3110	68	.11	.37	.28	1.73	40,20	PM	SG	65721	19620	29.7	29209	16992
													761019	270083	35.5	291342	199594

ESTIMATED PLAY RESERVES = 32925

UNRECOVERED MOBILE OIL = 166669

REMAINING RESIDUAL OIL = 291342

ESTIMATED ULTIMATE RECOVERY EFFICIENCY= 40 %

Recovery efficiencies for this subplay average 35 percent except for two reservoirs: Tunis Creek Devonian and Block 31 Devonian (table 9). Recovery efficiency of the Tunis Creek Devonian reservoir is very low because of its recent discovery (table 9). Block 31 Devonian, which has the highest recovery efficiency for the entire Siluro/Devonian play, owes its success to good reservoir maintenance. Injection of high-pressure gas was begun in Block 31 soon after discovery to maintain reservoir pressure and to create a miscible flood. The Block 31 reservoir also contains thicker sequences of higher porosity, higher permeability chert than found in other reservoirs in this subplay, which contributes to the higher recovery efficiency observed. After recovery of existing reserves, 167 MMSTB mobile oil will remain in Thirtyone Chert Subplay reservoirs (table 9).

WRISTEN FORMATION PLATFORM-MARGIN BUILDUPS AND SHALLOW-PLATFORM CARBONATES SUBPLAY

Introduction

The Wristen Formation includes all Silurian rocks that overlie the Fusselman. The Wristen has been subdivided into three parts: the basal Wink Member, the Frame Member, and an unnamed carbonate facies (Hills and Hoenig, 1979). These rocks represent the development of considerable bathymetric relief following the differentiation of the region from an extensive, low-relief platform, which characterized the underlying Fusselman deposition, into a platform-to-basin setting during the Middle Silurian.

The Wink Member consists of skeletal packstones and wackestones deposited in a deepening outer ramp setting. The Frame Member and unnamed carbonate facies of the Wristen are overlying lateral equivalents that formed as (1) slope/basin mudstones and wackestones and (2) platform-margin and shallow-water carbonates, respectively.

The Wink and Frame Members are mud-rich carbonates that generally do not contain sufficient porosity to constitute reservoir facies. The unnamed carbonate facies of the Wristen, however, is a complex assemblage of shallow-water carbonates in which porosity is locally very well developed, especially where dolomitized.

Eight University Lands reservoirs lie in the Wristen carbonates subplay, which is limited in distribution to the north part of the Siluro/Devonian subcrop in West Texas (fig. 7). University Lands reservoirs are Block 6 Devonian, Block 6 Northeast Silurian, Block 7 Devonian, Fullerton 8500, Hutex Devonian, Magutex Devonian, Shafter Lake Devonian, and University Block 13 Devonian.

Reservoir Description

Wristen reservoir facies vary from buildup-related, skeletal grainstone and wackestone (both limestone and dolostone) to dolomitized shallow-water wackestones. Buildup facies reservoirs are generally restricted to the Wristen platform margin along the southern margin of the Wristen carbonate facies subcrop. Shallow-water wackestone reservoirs are most common to the north of Andrews County (off University Lands) but also occur locally associated with the platform margin. Distinction of these reservoir types requires analysis of cores, which are not available for all University Lands reservoirs.

Buildup-related reservoirs consist primarily of (1) boundstones and wackestones that contain stromotoporoids, corals, and bryozoans, (2) skeletal grainstones composed of pelmatozoans and bryozoans. Porosity in these reservoirs is developed as primary intergranular porosity in the grainstones and as leached vuggy porosity in the boundstones and wackestones. Examples of buildup-related reservoirs on University Lands are Hutex Devonian and Magutex Devonian.

Wristen shallow-water carbonates reservoirs contain shallow-water mudstones, pelloid grainstones, and skeletal wackestones to evaporite-bearing supratidal mudstones deposited as upward-shallowing sequences in the platform interior. Porosity development in these rocks is associated with the formation of vugs, molds, and intercrystalline pores due to dolomitization and leaching of evaporites and skeletal allochems. Fullerton 8500 contains reservoir deposits of this type as well as buildup deposits.

Reservoir Characteristics

Average porosity in University Lands Wristen carbonate reservoirs is 7 percent (table 10), whereas permeability averages about 54 md. All of these reservoirs are formed along simple anticlinal traps. In the case of the Hutex Devonian and Magutex Devonian reservoirs, at least, these structures are probably largely due to the development of carbonate buildups. Top seals are provided by Woodford Formation shales.

Average reservoir depth is about 11,100 ft. Most of the reservoirs are developed on 80-acre spacing; Shafter Lake Devonian and Fullerton 8500 are on 40-acre spacing. Drive mechanism is by water drive or solution gas (table 10).

Volumetrics

Wristen carbonate reservoirs have accounted for 25 percent of the total Siluro/Devonian production in West Texas and about 34 percent of the cumulative production on University Lands (fig. 8). Remaining mobile oil on University Lands in these reservoirs totals 205 MMSTB, representing the largest proportion of potential resource in the Siluro/Devonian play. Reserves account for 13.5 MMSTB of this volume (tables 3, 10).

THIRTYONE FORMATION SKELETAL PACKSTONE SUBPLAY

Introduction

The Thirtyone Formation of apparent Early Devonian age overlies the Wristen Formation throughout most of the southern Midland Basin and southern Central Basin Platform areas. These rocks are considerably different from underlying Silurian rocks and contain two distinct facies:

Table 10. Reservoir parameters and volumetric characteristics of the Wristen Formation Platform-Margin Buildups and Shallow-Platform Carbonates subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 6	DEVONIAN	1952	1775	40	.05	.30	.31	1.12	80	PRIM	WD	18934	3893	20.6	8385	6656
8	BLOCK 6, NE	SILURIAN	1974	1364	18	.09	.28	.31	1.30	80	PRIM	NA	9494	2253	23.7	4088	3154
8	BLOCK 7	DEVONIAN	1960	1429	30	.06	.30	.31	1.14	80	PRIM	SG+WD	12253	3927	32.0	5426	2900
8	FULLERTON	8500	1944	3744	92	.09	.25	.25	1.18	40	WF	WD	152860	43305	28.3	50953	58602
8	HUTEX	DEVONIAN	1953	7776	90	.06	.35	.30	1.31	80	PRIM	WD	161637	37923	23.5	74602	49113
8	MAGUTEX	DEVONIAN	1953	8327	62	.06	.20	.35	1.50	80	PRIM	WD	128168	42229	32.9	56074	29866
8	SHAFTER LAKE	DEVONIAN	1947	4086	140	.05	.23	.35	1.21	40	PMW	SG	141171	23819	16.9	64169	53183
8	UNIVERSITY BLOCK 13	DEVONIAN	1960	853	15	.10	.30	.31	1.56	80	PRIM	SG	4528	1241	27.4	2006	1282
													629047	158590	25.2	265702	204754

ESTIMATED PLAY RESERVES = 13509

UNRECOVERED MOBILE OIL = 191245

REMAINING RESIDUAL OIL = 265702

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 27 %

(1) skeletal packstones and grainstones and (2) spiculitic chert. The packstones and grainstones were deposited both as largely in-place accumulations on a shallow platform and as resedimented sands on the outer ramp to slope. Cherts accumulated in deeper water beyond the extent of carbonate deposition. Each of these two facies, whose distribution is reciprocal, constitutes a distinct reservoir subplay. Thirtyone Formation carbonates are relatively more abundant in the upper part of the formation and to the north, whereas Thirtyone cherts are most abundant in the lower part of the formation and in the southern part of the Thirtyone Formation subcrop.

The Thirtyone Formation skeletal packstone subplay comprises five reservoirs on University Lands: Andrews South Devonian, Block 9 Devonian, Emma Devonian, Triple-N Devonian, and University Block 9 Devonian, all of which are in Andrews County near the north limit of the Devonian subcrop.

Reservoir Description

Thirtyone Formation carbonate reservoirs are composed almost exclusively of skeletal packstones and grainstones composed primarily of pelmatozoan debris. In all the University Lands reservoirs in this subplay these packstones were deposited in sand shoals and bars in a shallow-water setting. Farther south in non-University Lands reservoirs, very similar packstones appear to have been deposited by downslope gravity flow processes in an outer-ramp to slope setting.

Porosity development is primarily the result of leaching of small amounts of carbonate mud in packstones, which has produced intergranular pore space. Although these rocks are primarily limestones, excellent intercrystalline porosity is developed in local dolomitized areas. Chert is a minor constituent, and some sequences exhibit the development of porosity similar to that seen in the Thirtyone Chert subplay.

Reservoir Characteristics

Porosity in the reservoirs of this subplay averages 6 percent (table 11); permeability averages about 3 md. The top seal for these rocks is formed by shales of the Upper Devonian Woodford Formation. Traps are simple anticlinal flexures, in some instances possibly the result of draping over Wristen buildups (Andrews South field). Drive mechanism for most reservoirs in this subplay, all of which are currently on 80-acre spacing, is solution gas. Average depth is 10,600 ft.

Volumetrics

Thirtyone Formation carbonate reservoirs have produced nearly 36 MMSTB, accounting for about 8 percent of the Siluro/Devonian production on University Lands (fig. 8). Original oil in place totals 164 MMSTB. Remaining mobile oil in this subplay is estimated to be 89 MMSTB, or about 18 percent of the total for all University Lands Siluro/Devonian reservoirs. Less than one million barrels of reserves remain in these reservoirs.

Recovery efficiencies are among the lowest for the entire Siluro/Devonian play. This is largely because most of these reservoirs are still under primary depletion. Andrews South Devonian, which is under waterflood, has the highest current recovery efficiency (table 11).

FUSSELMAN FORMATION SHALLOW-PLATFORM CARBONATES SUBPLAY

Introduction

The Fusselman Formation forms the base of the Siluro/Devonian sequence in West Texas. Most of the Fusselman is apparently Early Silurian in age, although the base of the unit has recently been shown to be of Late Ordovician age (J. Barrick, personal communication, 1989).

Table 11. Reservoir parameters and volumetric characteristics of the Thirtyone Formation Skeletal Packstone subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	ANDREWS, SOUTH	DEVONIAN	1953	5105	55	.05	.21	.15	2.65	80	WF	SG	32468	9013	27.8	6165	17290
8	BLOCK 9	DEVONIAN	1960	960	56	.05	.30	.31	1.61	80	PRIM	SG	9067	1486	16.4	4016	3565
8	EMMA	DEVONIAN	1954	1894	40	.06	.30	.31	1.41	80	PRIM	NA	17537	4593	26.2	7768	5177
8	TRIPLE-N	DEVONIAN	1957	1800	20	.06	.30	.31	1.61	80	PRIM	SG	7298	1070	14.7	3232	2996
8	UNIVERSITY BLOCK 9	DEVONIAN	1954	3750	107	.05	.17	.15	1.43	80	PRIM	WD	97566	19728	20.2	17632	60206
													163936	35890	21.9	38811	89235

ESTIMATED PLAY RESERVES = 929

UNRECOVERED MOBILE OIL = 88306

REMAINING RESIDUAL OIL = 38811

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 22 %

Fusselman rocks are the most widespread of all Siluro/Devonian deposits, extending across most of West Texas.

Two University Lands reservoirs have cumulative production exceeding 1 MMSTB: Block 11 Fusselman and Emma Fusselman (fig. 7).

Reservoir Description

The Fusselman is composed of limestones and dolostones deposited on a shallow-water carbonate platform. The unit contains a vertical sequence of facies that is generally continuous across the area except where locally removed by subsequent erosion. These rocks are variously overlain by the Wristen Formation, the Thirtyone Formation, the Woodford Formation, or younger strata. The Fusselman contains primarily dolostone along the eastern subcrop limit, whereas limestones are more common elsewhere.

The base of the Fusselman is composed of ooid grainstone and packstone. Porosity in these rocks is principally intergranular. Overlying these rocks and perhaps locally equivalent to them are thin deposits of carbonate mudstone and skeletal wackestone. These muddy rocks are porous only where vuggy or intercrystalline porosity is developed associated with dolomitization, that is, principally along the eastern subcrop margin.

The upper part of the Fusselman is composed of a relatively thick interval of pelmatozoan grainstone and packstone. Although interparticle pore space in these deposits is usually filled with cements, vuggy and intercrystalline porosity developed by leaching is locally significant.

Reservoir Characteristics

Regionally, Fusselman reservoirs include stratigraphic pinch-out traps and simple structural (anticlinal) traps. Stratigraphic traps, which are most common along the eastern subcrop margin, are the result of both facies change and local truncation of the Fusselman beneath the overlying Wristen. Both trap types are common along the eastern subcrop margin, whereas simple structural traps predominate elsewhere. University Lands reservoirs included in this subplay, none of which occur along this regional pinch-out, are formed by simple anticlines, although recovery data (see below) suggest that facies-controlled heterogeneities may also be present in these reservoirs.

Average porosity in these two Fusselman reservoirs is 10 percent (table 12). The top seal is provided by impermeable carbonates of the Wink Member of the Wristen Formation in the Emma reservoir. In Block 11 Fusselman, impermeable siliciclastics of the basal Permian ("Permian detrital") constitute the seal. Well spacing is 160 acres, and the reservoirs are still producing by primary drive mechanisms.

Volumetrics

Fusselman reservoirs account for approximately 13 percent of the Siluro/Devonian cumulative production in West Texas. Production from the two Fusselman reservoirs on University Lands, however, is only about 2.4 MMSTB, or about 0.5 percent of the total Siluro/Devonian production on University Lands (fig. 8). Calculations indicate that approximately 5 MMSTB of mobile oil remains in these reservoirs, almost all of this volume being classed as unrecovered mobile oil rather than reserves (table 12). Most of this (3.9 MMSTB) is assigned to the Emma Fusselman reservoir, which has been shut in for several years and has a very low recovery factor of only about 15 percent. The poor performance of this reservoir suggests that facies heterogeneities of the type responsible for trapping and compartmentalization in non-University Lands reservoirs along the eastern margin of the Fusselman subcrop may also be present in this field.

Strategies for Recovery of Remaining Mobile Oil

Although no detailed field study was conducted on reservoirs of this subplay, examination of core indicates that the Emma Fusselman reservoir, by far the larger of the two, is typical of Fusselman reservoirs in having porosity confined to two facies: pelmatozoan grainstone/packstone

Table 12. Reservoir parameters and volumetric characteristics of the Fusselman Formation Shallow Platform Carbonates subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 11	FUSSELMAN	1961	1534	6	.10	.30	.31	1.40	160	PRIM	NA	3574	1025	28.7	1583	966
8	EMMA	FUSSELMAN	1954	600	41	.10	.30	.31	1.40	160	PRIM	SG	9552	1417	14.8	4230	3906
													13126	2442	18.6	5813	4871

ESTIMATED PLAY RESERVES = 9

UNRECOVERED MOBILE OIL = 4862

REMAINING RESIDUAL OIL = 5813

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 19 %

having secondary vuggy and moldic pores, and ooid grainstone having intergranular pores. As is the case for other Fusselman reservoirs, effective exploitation of this reservoir will require careful mapping of facies distribution on the basis of detailed core analysis. Each facies must be considered separately in formulating further production and injection strategies because of their different fabrics and pore characteristics.

SPRABERRY AND DEAN SUBMARINE-FAN SANDSTONE PLAY

Introduction

Spraberry and Dean reservoirs, which at the time of discovery contained more than 11 BSTB of OOIP (Galloway and others, 1983; Tyler and others, 1984), are the richest deep-water, terrigenous-clastic oil reservoirs in Texas. The reservoirs are very fine grained sandstones and siltstones of the Spraberry and Dean Formations (Lower Permian, Leonardian). They form part of submarine fans that were deposited basinward of the southward prograding Northwest Shelf in water depths of approximately 2,000 ft (Handford, 1981; Guevara and Tyler, 1986; Tyler and Gholston, 1988).

Recovery efficiencies of Spraberry and Dean reservoirs generally are less than 10 percent of the OOIP. Therefore, these reservoirs are prime targets for reexploration and extended development programs aimed at infield reserve growth. To ascertain the geological controls for the low recovery efficiencies, the Bureau of Economic Geology initiated in 1985 a program of integrated geological and engineering studies of selected University Lands and adjacent waterflood units that produce from Spraberry reservoirs. Results have been summarized by Guevara and Tyler (1986, 1989), Guevara (1988), and Tyler and Gholston (1988).

Reservoir Description

The Spraberry-Dean play is located in the Midland Basin of the greater Permian Basin of West Texas. The play comprises numerous reservoirs occurring in an area that extends north-south for more than 120 mi, from Borden and Dawson Counties in the north to northern Crockett County in the south. The Spraberry Trend field is the largest accumulation in the play. It contained more than 10 BSTB of OOIP and extends from southern Martin County in the north to central Upton, central Reagan, and western Irion Counties in the south. Major University Lands fields producing from Spraberry and Dean reservoirs are, from north to south, M. A. K. (Martin County), Hutex (Andrews County), Benedum (Upton and Reagan Counties), Flat Rock (Upton County), and Spraberry (Martin, Glasscock, Midland, Upton, Reagan, Irion, and Tom Green Counties) (fig. 9).

The Spraberry Formation is approximately 1,000 ft thick, and the Dean Formation is about 200 ft thick in the central part of the Midland Basin. Spraberry oil reservoirs occur in the upper and lower parts of the Spraberry Formation, and Dean reservoirs form part of the lower and middle parts of the Dean Formation. Research conducted in the University Lands project focused on Spraberry reservoirs, which have produced most of the oil in the play. Geological and production characteristics of Spraberry reservoirs also apply to Dean reservoirs because these reservoirs have similar genesis, lithology, and facies architecture.

The occurrence of intervals containing beds of sandstone and siltstone permits the subdivision of the Spraberry Formation into upper, middle, and lower units. The upper and lower Spraberry, which are respectively about 250 and 100 ft thick in the central part of the basin, comprise submarine-fan facies that form stacked, upward-thickening and upward-coarsening sequences. Two submarine fans, the Floyd and the underlying Driver, compose the upper Spraberry. Deposits of the Jo-Mill submarine fan make up the lower Spraberry. Upper and lower Spraberry fans in the central part of the basin are vertically separated by approximately 650 ft of

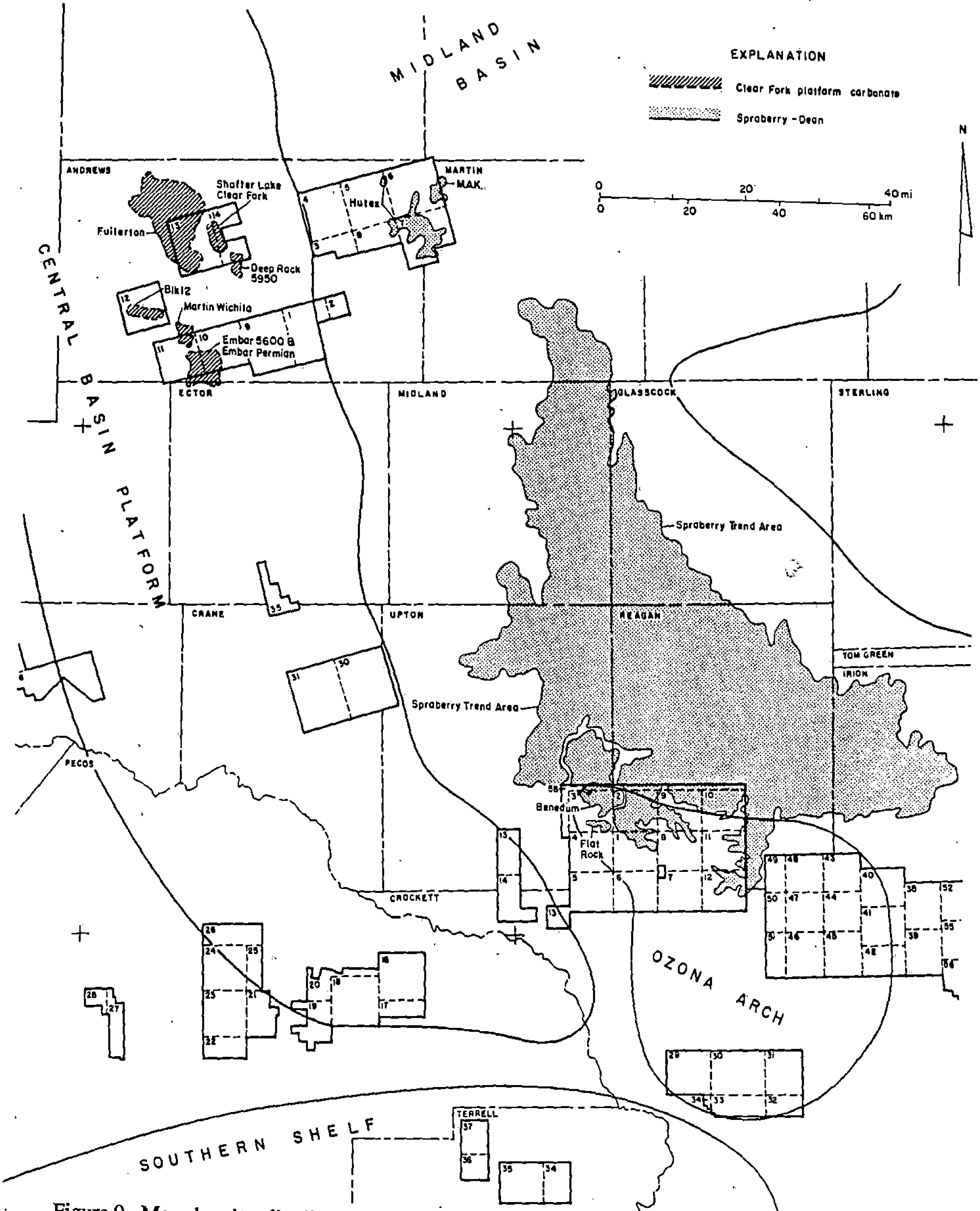

Figure 9. Map showing distribution of reservoirs in the Spraberry/Dean and Clear Fork University Lands plays.

basin-plain and associated facies of the middle Spraberry, which consists of generally calcareous shales and thin carbonates locally bounding upward-fining and upward-thinning intervals of sandstone and siltstone.

Complex facies architecture of Spraberry submarine fans results in highly heterogeneous reservoirs. Because they are vertically separated by shales, oil accumulations are highly layered. Furthermore, they are compartmentalized because the main reservoir rocks are laterally discontinuous channel fills. The fields are stratigraphic and combination stratigraphic and structural traps that produce by solution-gas drive. The main trapping mechanisms are updip pinch-outs and lateral facies variations. Stratigraphic reservoir complexity and low matrix permeability result in numerous intrareservoir traps.

Reservoir Characteristics

Spraberry and Dean are dual-porosity (matrix and fracture), low-permeability oil reservoirs. The best reservoirs are submarine-fan channel sandstones and associated facies that occur in sand-rich belts generally 1 to 3 mi wide and subparallel to the basin axis. Reservoir rocks are massive and laminated, calcareous, very fine grained sandstones and siltstones in beds up to 12 ft thick that occur in the upper parts of upper Spraberry (Floyd and Driver) and lower Spraberry (Jo-Mill) submarine fans. Field-average porosities range from 10 to 15 percent. Secondary porosity due to leaching of feldspars and carbonate cements is locally developed. Matrix permeabilities are mostly less than 1 md, but natural fractures result in preferential flow paths having permeabilities several orders of magnitude greater than the matrix permeabilities. Local areas of high cumulative oil production "sweet spots" generally are in wells drilled in the sandstone depositional axes. Locally, cumulative production in these wells is six times larger than in wells drilled outside the sandstone thicks (Tyler and Gholston, 1988). Well spacing varies from 80 to 160 acres and solution gas provided primary drive mechanism (table 13).

Table 13. Reservoir parameters and volumetric characteristics of the Spraberry and Dean Submarine-Fan Sandstone play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
7C	BENEDUM	SPRABERRY	1947	14653	33	.10	.35	.40	1.50	100	WF	SG	162560	5021	3.1	100062	57477
7C	FLAT ROCK	SPRABERRY	1961	2598	29	.10	.30	.40	1.41	160	PRIM	SG	29047	1668	5.7	16602	10777
8	HUTEX	DEAN	1959	11970	5	.15	.30	.47	1.40	160	PRIM	NA	34824	2102	6.0	23382	9340
8	M.A.K	SPRABERRY	1963	2505	39	.15	.38	.47	1.30	160	PRIM	SG	54220	1637	3.0	41102	11481
7C	SPRABERRY	TREND AREA	1949	55530	30	.10	.35	.40	1.32	80	WF	SG	636412	12587	2.0	391638	232187
													917062	23015	2.5	572786	321261

ESTIMATED PLAY RESERVES = 7168

UNRECOVERED MOBILE OIL = 314106

REMAINING RESIDUAL OIL = 572786

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 3 %

Volumetrics

Basinwide, the Spraberry-Dean play contained approximately 11.2 BSTB of OOIP, of which about 917 MMSTB are in University Lands. Cumulative oil production as of December 1988 was 668 MMSTB for the entire play and 23 MMSTB in University Lands. Current recovery efficiency is approximately 6 percent for the entire play and 2.5 percent in University Lands. At current production practice, about 314 MMSTB of mobile oil will remain in University Lands reservoirs after recovery of 7.2 MMSTB of reserves (table 13).

ELLENBURGER PLAY

The Ellenburger play in West Texas represents the deepest significant production in the Permian Basin. Ellenburger reservoirs are structural traps formed in thick, massive dolostones. These dolostones were deposited on a restricted carbonate ramp (*sensu* Read, 1985) that was dominated by low-energy mud-rich facies. Thus, porosity is largely secondary associated with either karst development, late-stage dolomitization/dissolution, or fault-related fracture porosity or both. The Ellenburger play on University Lands consists of two subplays: Karst-Modified Restricted-Ramp Carbonate and Selectively Dolomitized Ramp Carbonate (fig. 10). The 14 reservoirs of the Karst-Modified Restricted-Ramp Carbonate subplay occur in Andrews and Crane Counties; their distribution is approximately coincident with the present-day Central Basin Platform. These reservoirs, which dominate production from the Ellenburger play (81 percent), are characterized by a distinctive karst facies stratigraphy that segments reservoirs into upper and lower zones. The Selectively Dolomitized Ramp Carbonate subplay also consists of structural traps with pay intervals developed in patchy zones of secondary porosity, largely defined by zones of late-stage dolomitization. Selectively Dolomitized Ramp Carbonate reservoirs lie in Reagan,

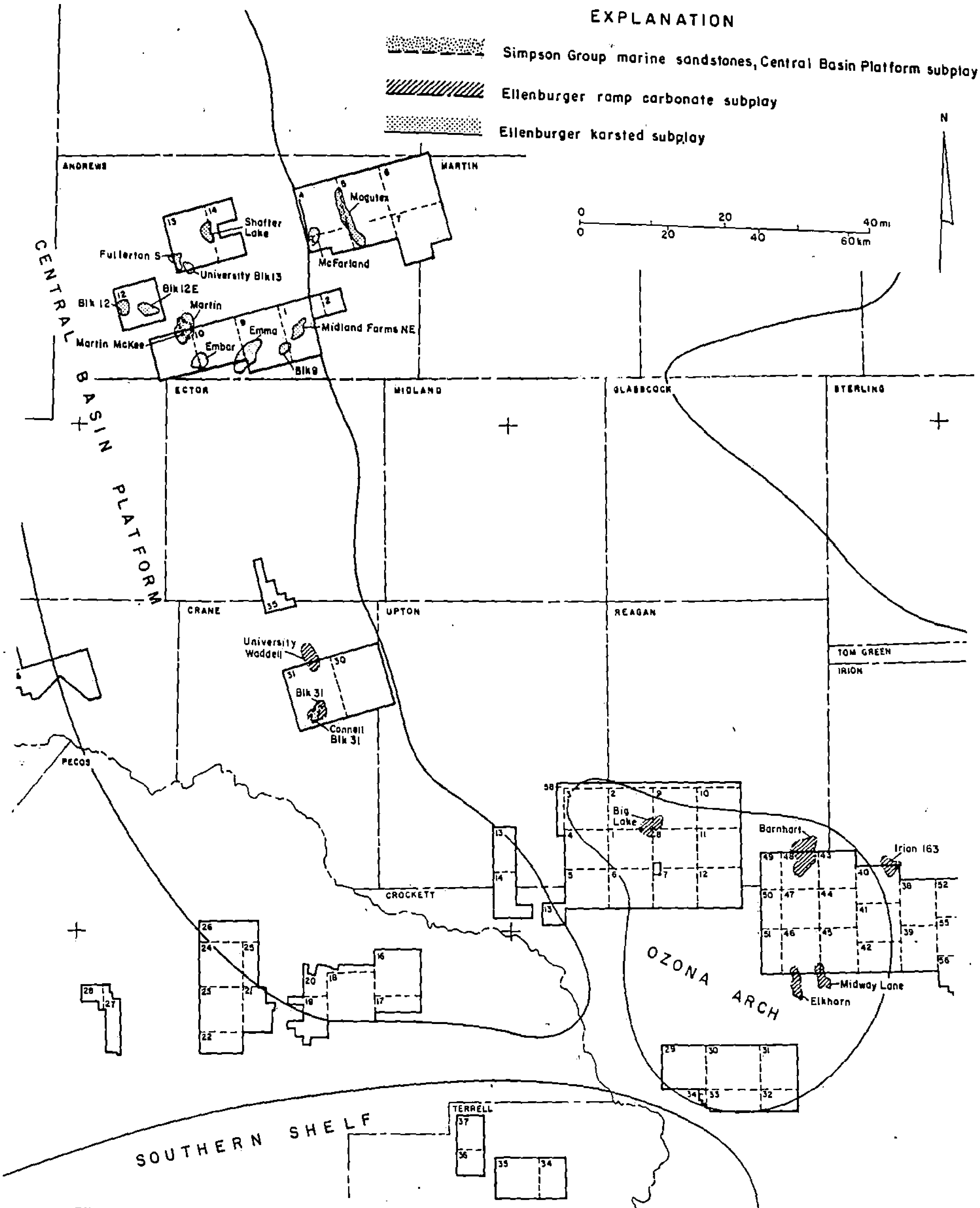

Figure 10. Map showing location of University Lands Ellenburger and Simpson reservoirs.

Crockett, and Irion Counties in the southern part of the Eastern Shelf and are predominantly smaller fields making up 19 percent of University Lands production from the Ellenburger.

ELLENBURGER KARST-MODIFIED RESTRICTED-RAMP CARBONATE SUBPLAY

Introduction

The Karst-Modified Restricted-Ramp Carbonate subplay occurs in the interior of the Ellenburger ramp in Crane and Andrews Counties. The 14 reservoirs in this subplay include 12 in Andrews County on University Blocks 1, 3–5, and 8–14, and 2 in Block 31 in Crane County. The karst-modified reservoirs, all Ellenburger, are Block 12, Block 12 East, Block 31, Block 9, Embar, Emma, Fullerton South, Magutex, Martin, McFarland, Midland Farms Northeast, Shafter Lake, University Block 13, and University Waddell (fig. 10).

Reservoir Description

Geologically these reservoirs form a distinct group wherein the overall carbonate platform succession of the Ellenburger has been substantially modified by pre-Middle Ordovician erosion and karstification. Depositional facies within the Ellenburger Karst-Modified Restricted-Ramp Carbonate subplay consist mainly of mud-dominated lithologies of the mottled mudstone facies assemblage. These facies typically have less than 2 percent matrix porosity. Deeper production in several of the Andrews County reservoirs is from an ooid-peloid grainstone facies assemblage, which consists of variably cemented and extensively dolomitized ooid and peloid grainstones. Intergranular porosity in this facies assemblage is visually estimated to range up to 10 percent locally, thus adding a subsidiary pore type to the dominant fracture/touching-vug, karst-controlled porosity.

Reservoir heterogeneity and internal structure in this subplay are a function of extensive dissolution, cave formation, and subsequent infilling. The resulting karst facies stratigraphy includes, from top to bottom, cave roof (50 to 150 ft thick), cave fill (50 to 150 ft thick), and lower collapse zone (20 to 400 ft thick) facies. This karst stratigraphy has a strong influence on virtually all reservoirs within this subplay that have oil columns greater than 200 ft (for example, Emma Ellenburger, Martin Ellenburger, Midland Farms Northeast Ellenburger). The cave-fill facies acts in these reservoirs as an internal flow barrier separating cave-roof and lower-collapse reservoir zones.

It is important to note that the position of the cave-fill intrareservoir flow barrier is consistently positioned between 50 and 200 ft below the erosional top of the Ellenburger Group, probably reflecting the position of a paleo-water-table. Whereas some erosion and karstification are apparent in the Ellenburger strata of the intercalated limestone/dolomite subplay, the distinct reservoir stratification, such as is found throughout the karst-modified play, is absent, and no consistent position of porous or nonporous zones is observed. Additional details on this style of reservoir compartmentalization are provided in the Emma field description in the following section.

Reservoir Characteristics

Reservoirs in this subplay are characterized by low average porosities (2 to 6 percent) (table 14) and highly variable permeabilities. This aspect, in combination with the low initial water saturations and high initial production rates, suggests that fracture and touching-vug pore systems (rather than the low matrix porosity) control production from these reservoirs, an observation confirmed by inspection of core material. Virtually all Ellenburger reservoirs have a strong water drive, the hydrocarbon seal consisting of tight shaly carbonates of the Simpson Group. Well spacing in these deep reservoirs was originally 40 to 80 acres, but because of declining production in most reservoirs, remaining wells in a field are now spaced at 200 to 1,200 acres.

Table 14. Reservoir parameters and volumetric characteristics of Ellenburger Karst-Modified Restricted-Ramp Carbonate subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 12	ELLENBURGER	1952	600	148	.03	.05	.32	1.28	40	PRIM	WD	12783	4601	36.0	4306	3876
8	BLOCK 12, EAST	ELLENBURGER	1953	800	148	.06	.30	.32	1.23	40	PRIM	WD	31365	9198	29.3	14338	7829
8	BLOCK 31	ELLENBURGER	1945	2000	173	.02	.21	.32	1.42	160	WF	WD	28673	5979	20.9	11614	11079
8	BLOCK 9	ELLENBURGER	1958	960	90	.06	.25	.32	1.20	80	PRIM	WD	23879	3478	14.6	10188	10213
8	EMBAR	ELLENBURGER	1942	2257	195	.05	.25	.30	1.33	40	PRIM	WD	96271	22161	23.0	38508	35612
8	EMMA	ELLENBURGER	1953	4158	290	.03	.20	.29	1.34	40	PRIM	WD	167548	39025	23.3	60736	67787
8	FULLERTON, SOUTH	ELLENBURGER	1948	1382	275	.02	.15	.30	1.27	40	PRIM	WD	39467	10641	27.0	13930	14897
8	MAGUTEX	ELLENBURGER	1962	5821	70	.03	.15	.35	1.20	40	PRIM	WD	67174	15323	22.8	27660	24191
8	MARTIN	ELLENBURGER	1946	655	278	.02	.10	.28	1.11	40	WF	WD	22908	9678	42.2	7127	6103
8	MCFARLAND	ELLENBURGER	1961	1559	46	.06	.20	.32	1.22	80	PRIM	WD	21889	5222	23.9	8756	7912
8	MIDLAND FARMS, NE	ELLENBURGER	1953	914	124	.04	.21	.32	1.31	80	PRIM	WD	21740	7589	34.9	8806	5345
8	SHAFTER LAKE	ELLENBURGER	1948	2131	87	.05	.23	.28	1.18	40	WF	WD	42893	5921	13.8	15419	21553
8	UNIVERSITY BLOCK 13	ELLENBURGER	1960	1040	150	.05	.30	.32	1.27	80	PRIM	WD	33420	13525	40.5	15278	4617
8	UNIVERSITY WADDELL	ELLENBURGER	1947	601	300	.02	.30	.32	1.45	80	PRIM	WD	13573	3769	27.7	6205	3609
													623583	156090	25.0	242871	224622

ESTIMATED PLAY RESERVES = 2521

UNRECOVERED MOBILE OIL = 222101

REMAINING RESIDUAL OIL = 242871

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 25 %

Volumetrics

Cumulative production for the karst-modified subplay dominates University Lands Ellenburger production, with 156 MMSTB, or 81 percent, of University Lands Ellenburger production. Five of the reservoirs in this subplay have produced more than 10 MMSTB, and the remaining nine have produced between 3.5 and 9.5 MMSTB (table 14). Original oil in place for this subplay is also impressive, estimated at 624 MMSTB (table 14), indicating an overall 25-percent recovery efficiency, with individual reservoirs ranging from 14 to 42 percent. Estimates for remaining mobile oil in the Ellenburger are difficult to make accurately because engineering data required for the procedure are typically sparse and of poor quality. Considering these limitations, it is estimated that a substantial quantity of remaining mobile oil, some 225 MMSTB, resides in the 14 reservoirs of this subplay (table 14). Reserves account for 2.5 MMSTB of this volume. Emma field contains an estimated 68 MMSTB remaining mobile oil and represents a major portion of this remaining mobile oil resource.

ELLENBURGER SELECTIVELY DOLOMITIZED RAMP CARBONATE SUBPLAY

Introduction

The Ellenburger Selectively Dolomitized Ramp Carbonate subplay is located in Reagan, Irion, and Crockett Counties in the southern portion of the Ellenburger ramp, immediately east of the Simpson Group erosional limit. The five reservoirs of this subplay, Barnhart, Big Lake Ellenburger 1-11, Elkhorn Ellenburger, Irion 163 Ellenburger, and Midway Lane Ellenburger (fig. 10), have a total cumulative production of 37 MMSTB, making up 19 percent of University Lands Ellenburger production (table 15).

Table 15. Reservoir parameters and volumetric characteristics of Ellenburger Selectively Dolomitized Ramp Carbonate subplay. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT RE	RRO (MSTB)	RMO (MSTB)
7C	BARNHART		1941	4151	75	.04	.24	.25	1.40	80	PMW	SG+WD	52446	8554	16.3	17252	26640
7C	BIG LAKE	ELLENBURGER 1-11	1928	3028	223	.04	.30	.30	1.40	160	PRIM	WD	104771	21165	20.2	44902	38704
7C	ELKHORN	ELLENBURGER	1951	540	121	.03	.35	.39	1.30	40	PMW	WD+SG	7545	2509	33.3	4562	474
7C	IRION 163	ELLENBURGER	1977	774	32	.07	.26	.31	1.25	80	PRIM	SG	7963	1844	23.2	3336	2783
7C	MIDWAY LANE	ELLENBURGER	1947	976	66	.06	.25	.31	1.40	40	PRIM	WD+SG	16063	2824	17.6	6639	6600
													188787	36896	19.5	76691	75200

ESTIMATED PLAY RESERVES = 422

UNRECOVERED MOBILE OIL = 74778

REMAINING RESIDUAL OIL =76691

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 20 %

Reservoir Description

Reservoirs of this play are composed of mixed limestone and dolostone strata of the mottled mudstone and bioclastic/peloid packstone/grainstone facies assemblages. As is the case with the Karst-Modified Restricted-Ramp Carbonate subplay, porosity in these reservoirs is secondary. In contrast to the karst-modified subplay, however, this secondary porosity is not related to karst-related processes but instead appears to be a result of dissolution caused during late-stage burial dolomitization of Ellenburger limestones. The resulting porosity occurs in stringers several tens of feet thick with unknown continuity. Test data from the Elkhorn reservoir shows that multiple-pay zones occur in this reservoir in coarse dolostone, separated by zones of tight limestone and dolostone. Although core material is limited in this subplay, it appears that the distribution of reservoir-quality dolostone zones is controlled by the distribution of primary depositional facies that retained some intergranular porosity. Ooid-peloid grainstone locally occurs in the lower half of reservoirs in this subplay and commonly contains excellent intercrystalline porosity in selectively dolomitized intervals.

Reservoir Characteristics

These reservoirs are predominantly structural traps formed by Pennsylvanian tectonism, although an additional component of erosional topography may also be important. The reservoirs of this subplay were subaerially exposed several times subsequent to the major Middle Ordovician karsting event, and porosity generation in association with these younger events may also play a role. Regardless, the dominant pore type is intercrystalline; some fracture pores also contribute to porosity. Total average porosity is characteristically low, ranging from 3 to 7 percent, with water saturations of 24 to 35 percent. These reservoirs are typically shallower than those of the karst-modified subplay, lying between 7,200 and 9,000 ft. Drive mechanism is also different, being a mixture of solution gas and water drive (table 15).

Well spacings initially were 40 or 80 acres. With many shut-in wells in these reservoirs, acres per producing well currently range from 86 to 519 (table 15).

Volumetrics

Cumulative production for each of the five reservoirs in the selectively dolomitized subplay ranges from 1.8 to 21 MMSTB, and OOIP, from 7.5 to 104.7 MMSTB (table 15). Big Lake Ellenburger 1-11, the largest and most active of these reservoirs, is estimated to contain 38.7 MMSTB of remaining mobile oil. On the basis of the complex patterns of late dolomitization and potential for multiple generations of dissolution associated with both the late-stage dolomitization and the various subaerial exposure events, there is substantial diagenetically controlled heterogeneity within these reservoirs. Remaining mobile oil (inclusive of more than 0.5 MMSTB reserves) amounts to 75 MMSTB (table 15).

CLEAR FORK PLATFORM CARBONATE PLAY

Introduction

The Clear Fork Platform Carbonate play is located in the northeastern part of the Central Basin Platform. Seven reservoirs compose this play. Five of these reservoirs are completely or mostly on University Lands (Shafter Lake Clear Fork, Block 12, Martin Wichita, Embar 5600, and Embar Permian), and two of these reservoirs have a relatively small percentage of their area on University Lands (Fullerton and Deep Rock Glorieta 5950) (fig. 9). The stratigraphic interval for this play is the entire Leonardian (Lower Permian) section, which includes the Wichita (at the base), Clear Fork, and Glorieta (at the top). The Wichita occurs above a Pennsylvanian unconformity. The overlying Clear Fork Formation is informally divided into the lower and upper Clear Fork by a zone of silty carbonate (the Tubb). The top of the Clear Fork is separated from the overlying Guadalupian San Andres Formation by the Glorieta silty carbonate. The entire stratigraphic section is approximately 2,500 ft thick, and the reservoirs occur at depths between 5,600 and 7,200 ft.

Reservoir Description

The Clear Fork carbonates were deposited as numerous upward-shoaling cycles of shallow-marine to supratidal carbonate sediments, now partly to completely dolomitized and containing sulfate minerals as nodules and cements. Lucia (1972) described in detail these cycles in Flanagan and Robertson fields, located about 10 mi north of University Lands. The base of the cycles is bioturbated mudstone or pellet packstone/grainstone; the abundant open-marine organisms indicate deposition in a shallow-water marine environment. The shallow-water marine facies is overlain by mudstone or fine-grained pellet packstone/grainstone characterized by distinct burrows, wispy mottled structures, stromatolites, and rare open-marine fossils. These rocks represent intertidal deposits. The uppermost parts of these cycles are principally mudstone characterized by irregular laminations, lithoclasts, and abundant desiccation features. These rocks contain few marine fossils and are interpreted to have been deposited in the supratidal environment.

Marine and intertidal rocks are the volumetrically dominant reservoir facies, although locally the supratidal rocks are porous and permeable and thus part of the reservoir. Individual upward-shoaling cycles range in thickness from a few feet to a few tens of feet. Rapid lateral movement of the shoreline at the time of deposition has resulted in extreme lateral discontinuity of individual cycles. As a result, reservoir continuity between wells is extremely low (Stiles, 1976; George and Stiles, 1978; Barbe and Schnoebelen, 1987).

Reservoir Characteristics

Fields in the Clear Fork Platform Carbonate play produce from low, broad anticlines, but porous and permeable zones are laterally discontinuous; the trapping mechanism in these fields is a combination of structural and stratigraphic controls (Galloway and others, 1983). Reservoirs in the Clear Fork Platform Carbonate play have porosities that range from 5 to 12 percent and average 9.4 percent, and water saturations that range from 24 to 33 percent and average 29.6 percent (table 16). Net-pay thickness ranges from 10 to 90 ft. The reservoir drive mechanism is solution gas. Well spacing is generally about 40 acres, although spacing in Fullerton field is between 20 and 40 acres, and selected parts of the field have an even greater well density. Fullerton and Block 12 fields are on waterflood; the other fields in this play are under primary production.

Volumetrics

The cumulative production of the Clear Fork Platform Carbonate play on University Lands as of 1987 was 117 MMSTB of 696 MMSTB of OOIP. Nearly 346 MMSTB of mobile oil remains in these University Lands reservoirs, of which 12.5 MMSTB are reserves. The recovery of Clear Fork reservoirs on the Central Basin Platform is generally in the range of 8 to 31 percent, averaging 17 percent. These reservoirs are among the lowest in recovery efficiency on University Lands.

WOLFCAMP CARBONATES PLAY

The Wolfcampian Series (Lower Permian) consists of a thick (more than 2,000 ft locally) sequence of carbonate and siliciclastic rocks that constitute a relatively small but significant hydrocarbon reservoir play in West Texas. Eight reservoirs on University Lands had cumulative oil production greater than 1 MMSTB as of January 1988 (fig. 11). Total University Lands production from these reservoirs amounts to more than 69 MMSTB, or 5 percent of the total University Lands production.

The Wolfcampian comprises a thick sequence of mixed carbonates and siliciclastics that accumulated during the early stages of Late Pennsylvanian/Early Permian structural evolution that led to the development of the Midland Basin and the Central Basin Platform. By early

Table 16. Reservoir parameters and volumetric characteristics of Clear Fork Carbonate Platform play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 12		1946	880	30	.12	.30	.30	1.55	80,40	PRIM	SG	11099	2544	22.9	4757	3799
8	DEEP ROCK	GLORIETA 5950	1954	711	40	.12	.30	.34	1.31	40	PRIM	NA	14160	1082	7.6	6877	6200
8	EMBAR	PERMIAN	1942	3213	57	.05	.32	.34	1.78	40	PRIM	NA	28767	5623	19.5	14384	8761
8	EMBAR	5600	1955	680	75	.07	.28	.34	1.31	40	WF	SG	15744	4894	31.1	7394	3456
8	FULLERTON		1941	17442	90	.10	.24	.23	1.61	40,20	WF	SG	576392	95203	16.5	173976	307212
8	MARTIN	WICHITA	1945	2800	10	.12	.30	.34	1.61	40	NA	NA	11343	1072	9.5	5509	4761
8	SHAFTER LAKE	CLEAR FORK	1948	2948	41	.08	.33	.34	1.31	40	PRIM	SG	38367	6807	17.7	19470	12090
													695872	117225	16.8	232367	346279

ESTIMATED PLAY RESERVES = 12516

UNRECOVERED MOBILE OIL = 333763

REMAINING RESIDUAL OIL = 232367

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 19 %

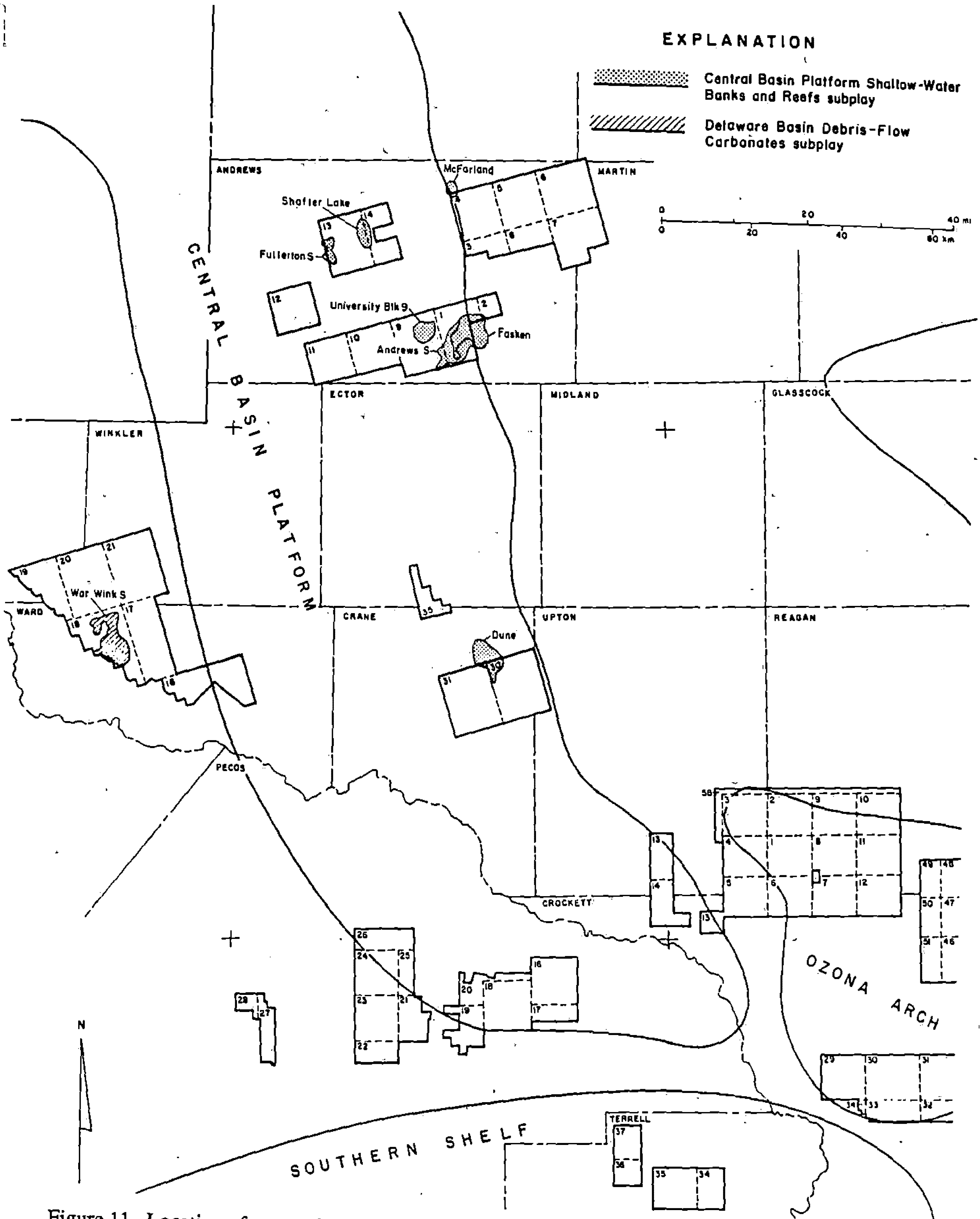

Figure 11. Location of reservoirs in Wolfcamp Central Basin Platform Shallow-Water Banks and Reefs subplay and Wolfcamp Delaware Basin Debris-Flow Carbonates subplay.

Wolfcampian time, the Permian Basin area was differentiated into well-defined basin (Midland Basin, Delaware Basin) and platform (Central Basin Platform, Northern Shelf, Eastern Shelf) areas. Reservoirs producing from Wolfcamp rocks on University Lands can be subdivided into two subplays: (1) Central Basin Platform Shallow-Water Banks and Reefs and (2) Delaware Basin Debris-Flow Carbonates, which contains only one field, War-Wink South (fig. 11).

CENTRAL BASIN PLATFORM SHALLOW-WATER BANKS AND REEFS SUBPLAY

Introduction

Seven University Lands reservoirs are developed in this play: Andrews South Wolfcamp, Dune Wolfcamp, Fasken Wolfcamp, Fullerton South Wolfcamp, McFarland Wolfcamp, Shafter Lake Wolfcamp, and University Block 9 Wolfcamp.

Reservoir Description

On the Central Basin Platform, Northern Shelf, and Eastern Shelf, the Wolfcamp contains a diverse assemblage of high- and low-energy facies deposited in a spectrum of shallow-water platform conditions (Mazzullo, 1982). Most notable among these deposits are carbonate buildup sequences composed of *Tubiphytes* and tubular foraminifers that formed along the platform margin (Wilson, 1975). The lithologies of carbonate-debris beds found in downslope basinal deposits indicate that they were derived principally from these platform-margin buildups. Smaller buildups, or "patch reefs," are also common shoreward from the platform margin. These deposits are surrounded by, and interbedded with, a complex assemblage of (1) muddier rocks that contain platy algae, (2) carbonate sands derived from the platform-margin buildups, and (3) green shales. Although reservoirs developed in Wolfcamp carbonates in platform areas are commonly referred to as reefs because of their geometries, many of these are probably interbedded grainstones and small mud-rich buildups (Mazzullo, 1982).

Reservoir Characteristics

Except in the Dune Wolfcamp reservoir, trapping is the result of anticlinal or domal closure over buildup complexes. Typically these features are less than 2 mi in diameter. In the Dune field, production is localized by facies change on a homocline. Top seals for all reservoirs are provided by interbedded shales and impermeable carbonates.

Although no detailed data are available from University Lands reservoirs regarding porosity, which averages about 9 percent, studies of similar reservoirs indicate that porosity is best developed within buildup boundstones as primary pore space (Malek-Aslani, 1970). Dunham (1969), on the other hand, suggested that porosity is secondary and the result of leaching. Well spacing is variable (40 to 160 acres) and solution gas provided primary drive (table 17).

Volumetrics

Cumulative production for the seven reservoirs in this subplay totals nearly 62 MMSTB, about 27 percent of the estimated OOIP and 90 percent of the play total (table 17). The estimated remaining mobile oil totals 72 MMSTB. Most of this resource, more than 85 percent, is found in the three largest reservoirs: Andrews South Wolfcamp, Shafter Lake Wolfcamp, and University Block 9 Wolfcamp.

DELAWARE BASIN DEBRIS-FLOW CARBONATES SUBPLAY

Introduction

A single University Lands reservoir is assigned to this subplay: War-Wink South Wolfcamp. Although little information is available for this reservoir, well-log data suggest that it is similar to o

Table 17. Reservoir parameters and volumetric characteristics of the Wolfcamp Carbonates play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	ANDREWS, SOUTH	WOLFCAMP	1953	5105	34	.08	.26	.35	1.49	80,40	PRIM	SG	53501	13914	26.0	25304	14282
8	DUNE	WOLFCAMP	1957	1854	14	.08	.30	.40	1.19	160,80	PRIM	SG	9476	2526	26.7	5415	1536
8	FASKEN	WOLFCAMP	1952	1673	25	.06	.29	.35	1.51	80	PRIM	SG	9154	2219	24.2	4513	2423
8	FULLERTON, SOUTH	WOLFCAMP	1955	2455	20	.10	.30	.35	1.50	40	PRIM	NA	17794	3652	20.5	8897	5245
8	MCFARLAND	WOLFCAMP	1955	360	50	.10	.20	.35	1.51	80	PRIM	SG	7398	2332	31.5	3237	1830
8	SHAFTER LAKE	WOLFCAMP	1951	4980	18	.13	.22	.30	1.46	40	WF	SG	48299	12146	25.1	18576	17576
8	UNIVERSITY BLOCK 9	WOLFCAMP	1953	5475	40	.10	.27	.25	1.49	80	PM	SG	83240	25165	30.2	28507	29578
8	WAR-WINK, S	WOLFCAMP	1976	2440	36	.09	.36	.35	1.41	160	PRIM	SG	27838	7202	25.9	15224	5412
													256700	69146	26.9	109873	77881

ESTIMATED PLAY RESERVES = 6875

UNRECOVERED MOBILE OIL = 71006

REMAINING RESIDUAL OIL = 109873

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 30 %

ther Wolfcamp slope/basin sequences described in the Midland and Delaware Basins (Hobson and others, 1985; Loucks and others, 1985).

Reservoir Description

Wolfcamp deposits in the Midland Basin and Delaware Basins comprise primarily dark-colored shales that contain interbeds of detrital carbonate (Wilson, 1975; Mazzullo and others, 1987). Interbedded carbonates consist of a variety of resedimented deposits including breccias, sands, and muds deposited by debris flows, turbidity currents, and bottom currents on the lower slope and basin floor (Hobson and others, 1985; Loucks and others, 1985; Mazzullo and Reid, 1987). These rocks contain clasts of shallow-water facies identical to those observed in platform and platform-margin sequences including skeletal (*Tubiphytes*, foraminifera, corals, and sponges) grainstones and wackestones, and ooid grainstones, indicating that they were derived by downslope transport from the platform margin.

Hobson and others (1985) mapped the distribution of these allochthonous carbonates in the southern Midland Basin and illustrated that they occupy distinct lobes. They also documented considerable vertical and lateral heterogeneity within these sequences due to the irregular stacking of discrete depositional units.

Reservoir Characteristics

Trapping at War-Wink South Wolfcamp is largely the function of closure along a small dome, although variations in porosity and permeability across the structure suggest the same kinds of heterogeneities recorded by Hobson and others (1985) in the Midland Basin. Porosity at War-Wink South Wolfcamp is 9 percent (table 17). According to studies of similar reservoirs by Mazzullo (1982), highest permeabilities in these deposits are developed in carbonate sands. Hobson and others (1985) noted significant intercrystalline, intergranular, moldic, and fracture porosity development in skeletal wackestones and packstones, however.

Volumetrics

Cumulative production at War-Wink South Wolfcamp totals more than 7 MMSTB, or 26 percent of the OOIP (table 17). Remaining mobile oil is estimated at 5.4 MMSTB.

QUEEN TIDAL-FLAT SANDSTONE PLAY

Introduction

The Permian Basin Queen Tidal-Flat Sandstone play (fig. 12) is located along the northern edge of the Delaware Basin, western and eastern edges of the Central Basin Platform, and southeastern edge of the Midland Basin. The Permian (middle Guadalupian) Queen Formation, part of the Artesia Group, contains the widespread sandstone reservoirs of this play (Tait and others, 1962). The first oil discovery in the Queen was in 1910 from the Monahans South Queen reservoir; the first production from this play on University Lands was from Taylor-Link field in 1929. Reservoirs on University Lands in the play are Magutex Queen, McFarland Queen, McFarland East Queen, Midway Lane Permian, Taylor-Link, and Walker. These six reservoirs have a cumulative production of 39 MMSTB of oil.

Reservoir Description

The Queen Formation exists throughout the Permian Basin. Queen Formation thickness variations are coincident with the basic regional structural features, resulting in thickening to the southeast into the Midland Basin and thinning onto the Central Basin Platform and Northern Shelf. The gross thickness varies from tens of feet to more than 300 ft in the Midland Basin.

Queen reservoirs consist of eolian, tidal-flat, and shoreface depositional environments. The vertical sequence of siliciclastic and evaporite sediments is the product of upward-shoaling cycles. Sandstone facies comprise shoreface, tidal-flat, and tidal-channel depositional environments.

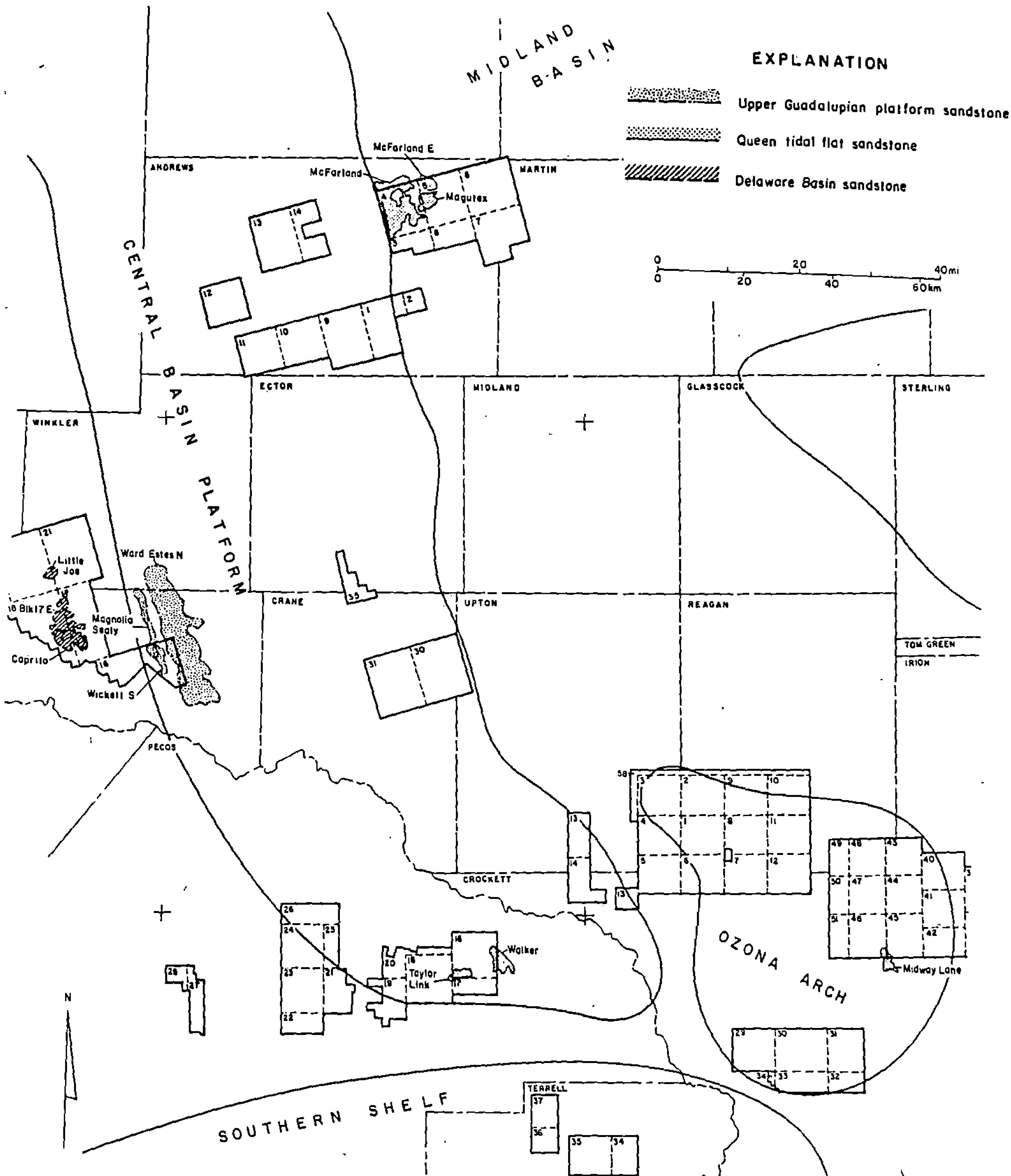

Figure 12. Location of University Lands Queen Tidal-Flat Sandstone, Upper Guadalupian Platform Sandstone and Delaware Basin Sandstone reservoirs.

These sandstones are overlain by sabkha dolomudstones and massive anhydrite. The massive anhydrite is commonly overlain by eolian sheet sands.

Production is from multiple sandstone beds within the reservoir. Each sandstone is sealed by massive anhydrite on both the top and bottom, resulting in barriers to vertical fluid flow. Thus, each sandstone acts as a separate reservoir unit. Within each of these reservoir sandstones flow continuity is further complicated by the mixture of tidal-channel, tidal-flat, shoreface, and eolian facies. The sandstone productivity is controlled by these heterogeneities as well as postdepositional diagenesis. Porosity development is primarily controlled by the amount of cementation from dolomite and anhydrite, but secondary porosity resulting from leaching of feldspar grains is also evident.

Reservoir Characteristics

Small anticlines, anticlinal noses, and irregularly shaped domes and an overlying trapping seal of massive anhydrite compose the trapping mechanisms. The structures appear to have resulted from the draping of the Queen Formation over preexisting paleotopography. Reservoir depths range from 1,124 to 4,800 ft, and the average reservoir depth for all Queen reservoirs is 2,800 ft. The net-pay thickness ranges from 10 to 20 ft.

The primary drive mechanism is solution gas; however, all the reservoirs are now under waterflood and are drilled on 10- to 40-acre spacing. Therefore, solution-gas drive has only a minor effect on present-day production. Average reservoir porosity is 17 percent, but productive sandstone can have values ranging from 11 to 27 percent (table 18). Permeability has an average value of 70 md. Initial water saturations vary between 20 and 40 percent, and the average residual oil saturation is 27 percent (table 18).

Table 18. Reservoir parameters and volumetric characteristics of the Queen Tidal-Flat Sandstone play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	MAGUTEX	QUEEN	1958	2924	20	.13	.36	.32	1.24	40	WF	SG	30441	4203	13.8	15220	11017
8	MCFARLAND	QUEEN	1955	15077	17	.12	.34	.25	1.16	40	WF	SG	135763	23856	17.6	51425	60482
8	MCFARLAND, EAST	QUEEN	1955	1667	10	.11	.25	.27	1.17	40	WF	SG	9119	1678	18.4	3283	4158
7C	MIDWAY LANE	PERMIAN	1956	972	15	.21	.40	.34	1.11	20	WF	SG	12840	1385	10.8	7383	4072
8	TAYLOR-LINK		1929	2800	15	.15	.20	.28	1.20	10	WF	SG+WD	32584	5095	15.6	11404	16084
8	WALKER		1940	1303	10	.27	.25	.36	1.03	10	WF	SG	19874	2336	11.8	9645	7892
													240620	38553	16.0	98361	103706

ESTIMATED PLAY RESERVES = 2505

UNRECOVERED MOBILE OIL = 101201

REMAINING RESIDUAL OIL = 98361

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 17 %

Volumetrics

The six fields in the Queen Tidal-Flat Sandstone play cover 34,500 acres and contain an estimated 390 MMSTB of OOIP. Of this volume, approximately 71 percent, or 241 MMSTB, is on University Lands (table 18). Through 1987, 38.6 MMSTB had been produced, leaving 98.4 MMSTB of residual oil and more than 104 MMSTB of unrecovered mobile oil on University Lands. Thus, the present recovery efficiency for this play on University Lands is only 16 percent. The McFarland Queen reservoir is the largest of the six reservoirs and contains 60.5 MMSTB of mobile oil on University Lands. Reserves account for only 2.5 MMSTB; thus more than 100 MMSTB of mobile oil will remain in these reservoirs if abandonment occurs at current development levels (table 18).

PENNSYLVANIAN PLATFORM CARBONATE PLAY

Introduction

A number of modest-sized oil fields located on the Central Basin Platform produce from Middle and Upper Pennsylvanian carbonates (Strawn, Canyon, and Cisco Groups). The 6 largest fields had produced 91 MMSTB of oil, and another 44 fields had produced an additional 52 MMSTB of oil as of January 1, 1982 (Galloway and others, 1983). Seven of the reservoirs in this play have each produced more than 1 MMSTB of oil from University Lands (fig. 13).

Reservoir Description

Little descriptive material is available for the facies of this play. However, the reservoir facies of the northern five fields (McFarland, Means East, University Block 9, Emma, and Triple-N) are thought to be phylloid-algal packstones and grainstones associated with carbonate mounds.

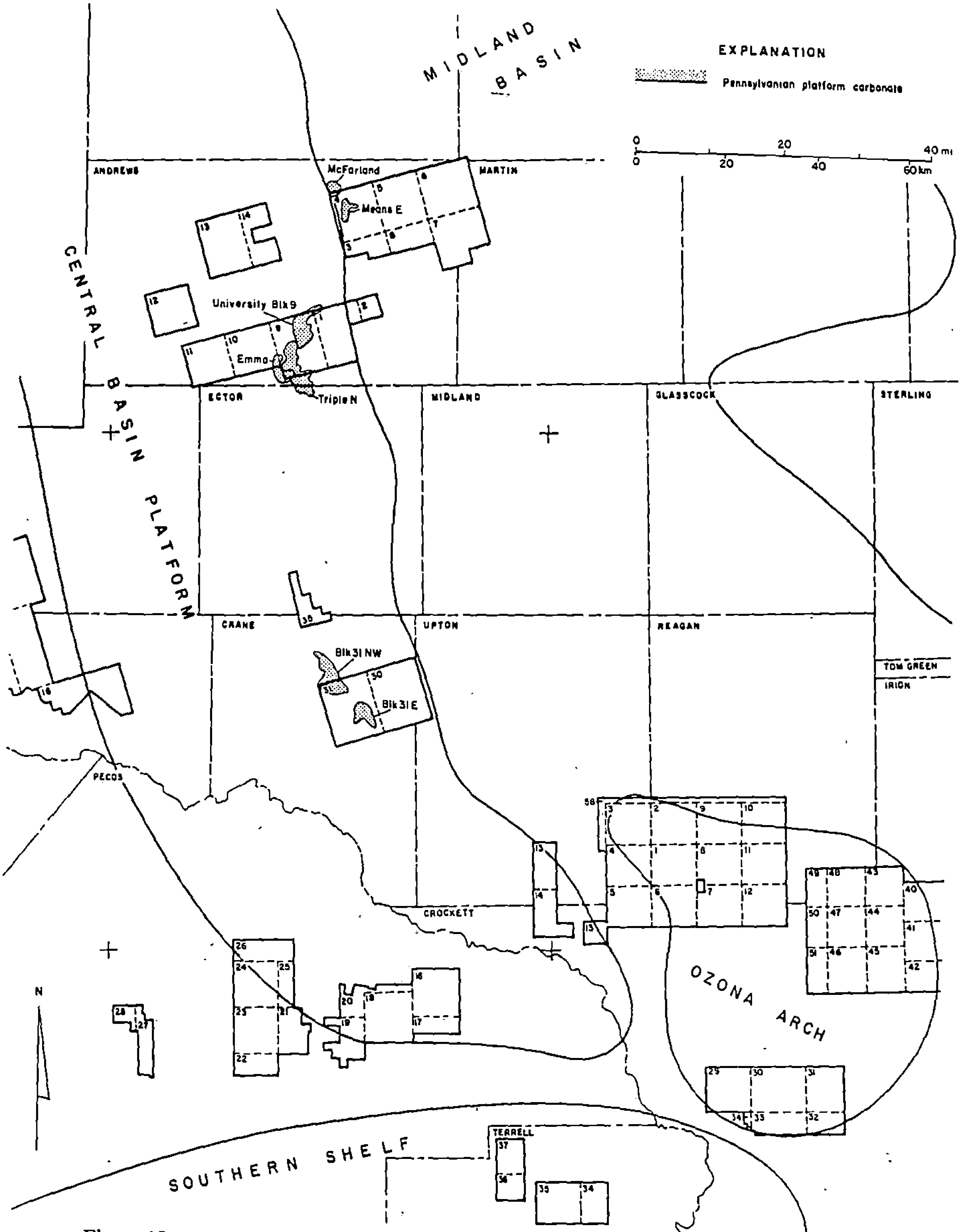

Figure 13. Location of fields included in the Pennsylvanian Platform Carbonate play.

Limited information from the southern two fields (Block 31 Northwest and Block 31 East) suggests that they produce from detrital limestones.

Reservoir Characteristics

The seven reservoirs of this play produce from an average depth of 9,150 ft. Production is from an average of 38 ft of net pay in the Upper Pennsylvanian (Canyon and Cisco), Strawn, and Atoka. Porosity is variable (3 to 16 percent), and initial water saturation and residual oil saturations average 27 and 39 percent, respectively. The principal drive mechanism is solution gas, and well spacing varies from 160 to 80 acres. The dominant geologic characteristic of these fields is the very discontinuous nature of the porous facies, with structural closure playing a minor role (table 19).

Volumetrics

The OOIP on University Lands for these seven fields is estimated at 195 MMSTB, of which 34 MMSTB had been produced as of 1987, for a current recovery efficiency of 17 percent (table 19). Proved reserves are estimated to be 2 MMSTB, for an ultimate recovery of 36 MMSTB of oil. The volume of mobile oil that will remain on University Lands after the proved reserves are recovered is estimated at 49 MMSTB. University Block 9 Pennsylvanian and Triple-N Pennsylvanian. Upper reservoirs, located in Andrews County, are the largest reservoirs, having produced a total of 21 MMSTB of oil.

UPPER GUADALUPIAN PLATFORM SANDSTONE PLAY

Introduction

The reservoirs that make up the Upper Guadalupian Platform Sandstone play (fig. 12) are located along the western edge of the Central Basin Platform. The stratigraphic interval for this

Table 19. Reservoir parameters and volumetric characteristics of the Pennsylvanian Platform Carbonate play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 31, EAST	ATOKA	1965	1400	10	.16	.25	.40	1.55	160	PRIM	SG	8409	1116	13.3	4485	2808
8	BLOCK 31, NW	PENN UPPER	1969	3054	24	.03	.30	.39	1.41	160	PRIM	SG	7057	2379	33.7	3932	746
8	EMMA	STRAWN	1958	2154	20	.11	.30	.39	1.51	80	PRIM	SG	17058	3131	18.4	9504	4423
8	MCFARLAND	PENNSYLVANIAN	1956	414	96	.06	.25	.39	1.65	160	PRIM	WD	9054	2122	23.4	4708	2224
8	MEANS, EAST	STRAWN	1954	1876	27	.10	.25	.39	1.70	80	PRIM	SG	17510	3852	22.0	9105	4553
8	TRIPLE-N	PENN., UPPER	1958	5189	20	.11	.30	.40	1.35	80	PRIM	SG	45922	9384	20.4	26241	10297
8	UNIVERSITY BLOCK 9	PENNSYLVANIAN	1954	5855	35	.12	.30	.40	1.49	80	PM	SG	89627	12118	13.5	51215	26293
													194637	34102	17.5	109190	51346

ESTIMATED PLAY RESERVES = 1922

UNRECOVERED MOBILE OIL = 49423

REMAINING RESIDUAL OIL = 109190

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 19 %

play includes both the Yates and Seven Rivers Formations. These reservoirs produce mainly from multiple sandstones within both formations and also have minor production from dolomite packstones. University Lands reservoirs in this play are Magnolia Sealy South, Ward-Estes North and Wickett South Yates. The first reservoir discovered with University Lands production was Ward-Estes North (Ward and Winkler Counties) in 1929.

Reservoir Description

The upper Guadalupian Yates and Seven Rivers Formations are the restricted-platform equivalents of the middle and lower Capitan Reef platform-margin carbonates. On the west side of the Central Basin Platform the Yates Formation is an overall upward-shallowing sequence of various siliciclastics associated with sabkha carbonates and evaporites (Casavant, 1988). These sediments were interpreted as having been deposited in a prograding tidal-flat/lagoonal setting inside the shelf-margin reef (Casavant, 1988). In outcrop on the Eastern Shelf the Yates Formation is represented by approximately 90 ft of red and gray, thin-bedded very fine grained sandstone and thin limestone beds. (Mear and Yarbrough, 1961). The Yates reservoir rock ranges from siltstone to fine-grained sandstone; cement and clay-matrix content vary significantly within reservoirs, contributing to heterogeneity. The sediment sources of the Yates are from the Northwestern, Eastern, and Southern Shelves (Mear and Yarbrough, 1961).

Lithology of the Seven Rivers is very similar to that of the Yates. In the type section outcrop the Seven Rivers displays a lower evaporitic member and a upper dolomitic member. The reservoirs, however, consist of an upward-shallowing siliciclastic to carbonate and evaporite sequence similar to that of the Yates Formation.

Reservoir Characteristics

The trapping mechanism is a combination of facies change and northwest- to southeast-trending, elongate anticlinal structures formed by compaction draping over buried structures.

These reservoirs range in depth from 1,010 to 5,140 ft; the play average depth is 2,620 ft. The net pay is developed in multiple sandstone beds, which range from 10 to 100 ft thick (average thickness 40 ft).

The primary drive mechanism in the Upper Guadalupian Platform Sandstone play is solution gas; water drive has a minor influence in some reservoirs. The reservoirs are drilled on 10- to 20-acre spacing, and all are under secondary water injection recovery (table 20). Reservoir porosities range from 13 to 20 percent, giving the play an average of 17 percent.

Volumetrics

The three reservoirs in the upper Guadalupian play contain an estimated 107 MMSTB of OOIP on University Lands. Through 1987, 23 MMSTB had been produced from University Lands, leaving 61 MMSTB of residual oil and 23 MMSTB of unrecovered mobile oil. Ward-Estes North, the largest of the three reservoirs, contains 16 MMSTB of target oil on University Lands. The remaining reserve base is small, however, and unrecovered mobile oil (exclusive of reserves) amounts to 22 MMSTB (table 20).

The Upper Guadalupian Platform Sandstone play has a current 21-percent recovery efficiency, and approximately 75 percent of the OOIP will remain in the reservoir at abandonment. Current recovery efficiencies for the three University Lands reservoirs range from 8 to 26 percent. Ultimate recovery projections, assuming current production practices, put these reservoirs near the end of their productive life with an ultimate recovery efficiency of 22 percent.

DELAWARE BASIN SUBMARINE-FAN SANDSTONE PLAY

Introduction

This small University Lands play produces from submarine-fan sandstones in the Delaware Basin west of the Central Basin Platform. The three reservoirs, Block 17 Southeast Delaware,

Table 20. Reservoir parameters and volumetric characteristics of the Upper Guadalupian Platform Sandstone play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	MAGNOLIA SEALY, SOUTH		1940	1072	30	.13	.45	.38	1.10	40	WF	WD	16217	1328	8.2	11205	3685
8	WARD-ESTES, NORTH		1929	2844	30	.20	.35	.35	1.10	20,10	WF	NA	78226	20047	25.6	42122	16057
8	WICKETT, SOUTH	YATES	1952	1700	10	.20	.47	.33	1.13	40,20	WF	SG	12681	1764	13.9	7896	3021
													107124	23139	21.6	61222	22763

ESTIMATED PLAY RESERVES = 324

UNRECOVERED MOBILE OIL = 22439

REMAINING RESIDUAL OIL = 61222

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 22 %

Caprito Middle Delaware, and Little Joe Delaware, lie entirely on University Lands (fig. 12). Production is from the upper part of the Delaware Mountain Group and ranges in depth from 5,000 to 6,200 ft.

Reservoir Description

Reservoirs are well-sorted, very fine grained sandstone interbedded with laminated and burrowed siltstone, organic-rich shale, and some limestone. The reservoir sandstone bodies were deposited by broad, anastomosing, and internally braided channels along the lower slope and floor of the deep Delaware Basin (Bozanich, 1979; Williamson, 1979). Sandstones show abundant evidence of transport by saline density currents derived from the northern marginal shelf, which was a restricted evaporite platform. Because the deposits of this slope/basin system were not deposited by turbidity currents, they are quite different from facies of conventional submarine fans (Galloway and others, 1983). Sandstone beds that compose the reservoirs rest on the flat floors of long, straight to slightly sinuous, steep-walled channels that were cut into laminated siltstone. Interbedded siltstones form blankets of uniform thickness draping channel floors and sides and interchannel areas. The reservoirs are limited to the major sandstone-filled channels.

Reservoir Characteristics

The productive channel facies occur as southwest-trending, broadly lenticular belts. The Block 17 Southeast Delaware area illustrates the limited lateral distribution and bifurcation of productive sands typical of submarine-fan channels. Traps are anticlinal but are stratigraphically modified by areally limited sand distribution. Permeabilities are moderate, averaging 33 md for the play. Porosities range from 18 to 22 percent; however, available information suggests bound-water saturations may be high, at least in Caprito field (table 21).

Table 21. Reservoir parameters and volumetric characteristics of the Delaware Submarine-Fan Sandstone play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 17 SOUTHEAST	DELAWARE	1956	1040	10	.20	.30	.31	1.31	40	WF	SG	8627	1294	15.0	3821	3512
8	CAPRITO	DELAWARE MIDDLE	1974	4352	11	.18	.55	.31	1.31	40	PRIM	NA	22964	2967	12.9	15820	4177
8	LITTLE JOE	DELAWARE	1965	1123	9	.22	.30	.31	1.40	80	PRIM	NA	8782	1507	17.2	3889	3386
													40373	5768	14.3	23529	11076

ESTIMATED PLAY RESERVES = 1918

UNRECOVERED MOBILE OIL = 9158

REMAINING RESIDUAL OIL = 23529

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 19 %

Drive mechanism in the play is solution gas, and well spacing is 40 or 80 acres. Apart from disposal of produced waters for pressure maintenance in Block 17 Southeast Delaware, the reservoirs all produce through primary reservoir energy.

Volumetrics

Although the Delaware Basin Submarine-Fan Sandstone play is a relatively small University Lands play, component reservoirs contained 40 MMSTB of oil at discovery. Recovery to date amounts to almost 5.8 MMSTB. Caprito accounts for more than half of the play's in-place oil and production (table 21). Decline-curve analysis suggests a recoverable reserve base of 1.9 MMSTB.

Analysis of the remaining mobile and residual oil resource base (exclusive of proved reserves) of 32.6 MMSTB shows that mobile oil amounts to 11 MMSTB, or 28 percent of the total. This resource is divided fairly evenly among the three fields in the play.

SIMPSON GROUP MARINE SANDSTONE—CENTRAL BASIN PLATFORM PLAY

Introduction

Oil reservoirs of the Simpson Group Marine Sandstones—Central Basin Platform play are distributed along the Central Basin Platform in fields on University Lands that also produce from larger reservoirs in the underlying Ellenburger Group and overlying Permian System (fig. 10). Oil accumulations occur in the Connell, McKee, and Waddell sandstones of the Simpson Group on structural closures; however, the distribution of porosity in the sandstones limits the oil accumulation.

Simpson Group reservoirs are limited in areal extent. Only two reservoirs are included here in the Simpson Group Marine Sandstone play: Block 31 Connell and Martin McKee. Total cumulative production is 2.3 MMSTB (table 22). Seven additional Simpson Group Marine Sandstone reservoirs have produced oil; however, none has produced as much as 1 MMSTB (total

Table 22. Reservoir parameters and volumetric characteristics of the Simpson Group Marine Sandstone—Central Basin Platform play. Abbreviations explained in table 5.

RRC	FIELD	RESERVOIR	DISC YR	RESER ACRES	NET PAY	AVG POR	INT WAT SAT	RES OIL SAT	OIL FVF	WELL SPAC	PROD TECH	DRIVE TYPE	STOOIP (MSTB)	CUM PROD (MSTB)	PCT REC	RRO (MSTB)	RMO (MSTB)
8	BLOCK 31	CONNELL	1948	1163	25	.07	.30	.28	1.33	160	PRIM	SG	8310	1083	13.0	3324	3903
8	MARTIN	MCKEE	1945	410	20	.16	.30	.28	1.29	40	WF	SG	5523	1216	22.0	2209	2098
													13833	2299	16.6	5533	6001

ESTIMATED PLAY RESERVES = 3

UNRECOVERED MOBILE OIL = 5998

REMAINING RESIDUAL OIL = 5633

ESTIMATED ULTIMATE RECOVERY EFFICIENCY = 17 %

for the seven is 1.3 MMSTB), and reservoir data are lacking for these smaller reservoirs. Sixty-three percent of the total oil production from Simpson Group Marine Sandstone reservoirs on University Lands is from these two largest fields.

Reservoir Description

Little has been published regarding the origin of these sandstones. The McKee, Waddell, and Connell sandstones are considered to be marine in origin because of the occurrence of trilobites and graptolites in associated sediments (Galley, 1958). Porous sandstones that are well sorted and rather poorly cemented by carbonate cement in some areas change within a few miles to being very shaly and containing streaks of green shale.

Reservoir Characteristics

Porosity ranges from a low of 7 percent at Block 31 Connell to 16 percent at Martin McKee. Both are solution-gas-drive reservoirs, although Martin McKee is benefitting from a secondary recovery water-injection program.

Volumetrics

As of 1987, 22 percent of the OOIP at Martin McKee had been recovered, compared with the 13 percent at Block 31 Connell. It should be noted that Block 31 Connell is no longer producing and that Martin McKee is very near the economic limit.

CHARACTERIZATION OF SELECTED UNIVERSITY LANDS RESERVOIRS

Ten reservoirs were selected for detailed analysis (fig. 14). Six of these reservoirs produce from the volumetrically dominant San Andres/Grayburg Platform Carbonate play, and one each was selected from the Spraberry, Ellenburger, and Siluro/Devonian plays. Only one field study was undertaken in a minor play—a study of the McFarland-Magutex field complex, which produces from the Queen sandstone.

Reservoir analyses followed the methodology developed in the study of Dune field, the first University Lands field selected. Geologic analysis, which was initiated first, was incorporated into supporting petrophysical, well-log, and production engineering analyses (fig. 15). The fundamental objective of all reservoir studies was the quantification and geographic delineation of original and current oil saturations and the development of strategies for optimal recovery of the remaining oil.

DUNE GRAYBURG RESERVOIR

INTRODUCTION

The Dune reservoir, Crane County (fig. 14), was discovered in January 1938, and since that time more than 1,200 wells have been drilled in the 28,764-acre field area. University Lands account for 50 percent of this area. The field is developed on an average well spacing of 24 acres, and the University portion is developed on an average spacing of 40 acres. The lower Guadalupian Grayburg pay zone is approximately 80 ft thick. Original oil in place across the entire field area inclusive of non-University Lands is estimated to be 978 MMSTB. Through 1987, 171 MMSTB of oil had been produced from the entire field; 55 MMSTB of that amount is from University Lands.

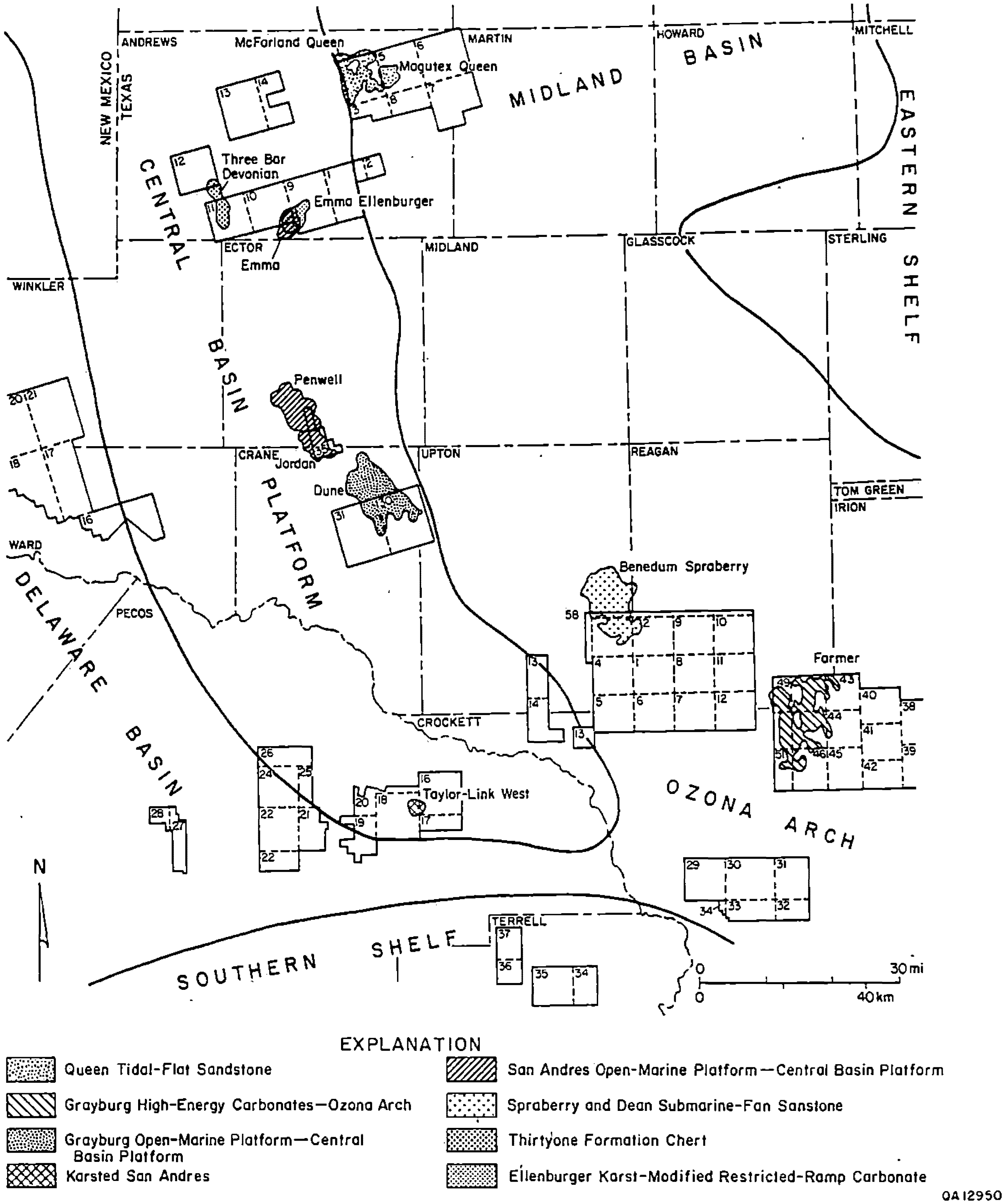

Figure 14. Geographic distribution of reservoirs studied and their play affiliation.

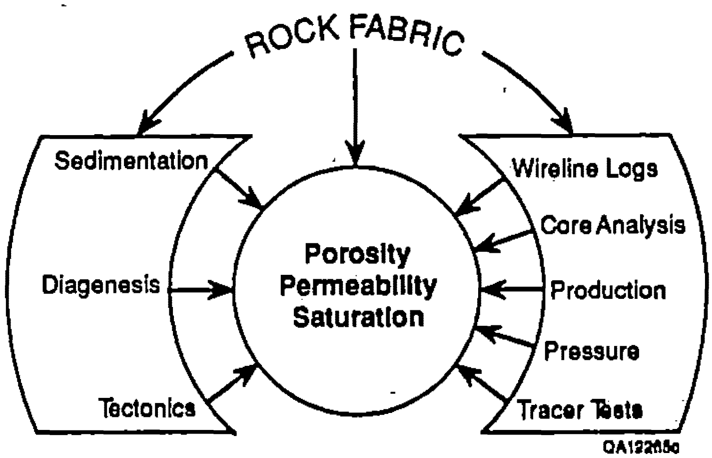

Figure 15. Flow chart illustrating integrated geological, petrophysical, and production engineering approach followed in the characterization of University Lands reservoirs, with emphasis on definition of remaining hydrocarbon saturations (after Lucia and others, in press).

The Dune Grayburg reservoir study (Bebout and others, 1987) focused on the Mobil University Unit 15/16, University Block 30 (fig. 16). Production in this unit was established in 1938. However, major drilling programs were not conducted until 1954 to 1957, when 20-acre well spacing was completed in Section 15; between 1971 and 1974 the 20-acre program was completed in Section 16. Between 1978 and 1986 Section 15 was converted to 10-acre well spacing. Water injection began in 1976 in Section 16 and in 1980 in Section 15; there are now 39 injection wells in these two sections (fig. 16).

The availability of cores from several closely spaced wells and modern wireline logs and the production history for each well in the Mobil University Unit 15/16 (fig. 16) made possible a detailed geologic and engineering study of this area. In addition, heterogeneity was well displayed in the unit by significant production inequalities between Sections 15 and 16 (fig. 17). The cumulative production from Section 15 is about 10 MMSTB, whereas that from Section 16 is only 2 MMSTB. Furthermore, wells from the same reservoir within Section 15 have yielded widely varying amounts of total production.

GEOLOGICAL SETTING

Introduction

The Dune field is located on the east side of the Central Basin Platform, on the edge of the Midland Basin. The topography on which this field and the neighboring McElroy field to the south are situated appears to be partly controlled by drape over fault blocks of a buried Late Pennsylvanian fault system. Restricted-platform subtidal and tidal-flat carbonates and siltstone accumulated to the west of the field, and slope and basinal carbonates are equivalent to the east. The single thick, dominantly marine cycle at Dune is equivalent to multiple cycles of subtidal to tidal-flat sediments farther shelfward.

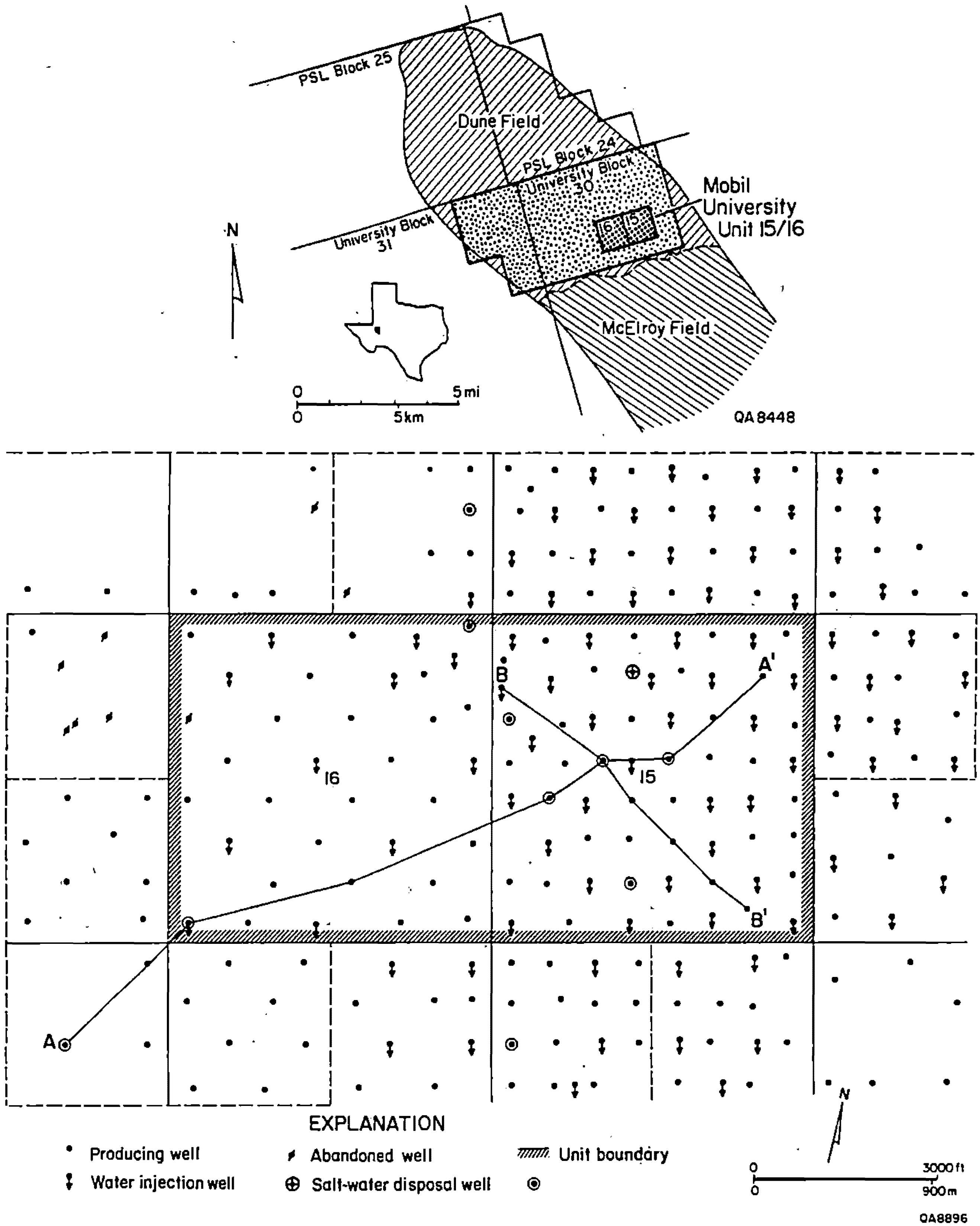

Figure 16. Location of the Dune reservoir study area in University Blocks 30 and 31. The geological study area is shown with the stippled pattern; the engineering study concentrated on Section 15 of the Mobil University Unit 15/16. Cross section A-A′ is shown in figure 18. Cross section B-B′ is shown in figure 19.

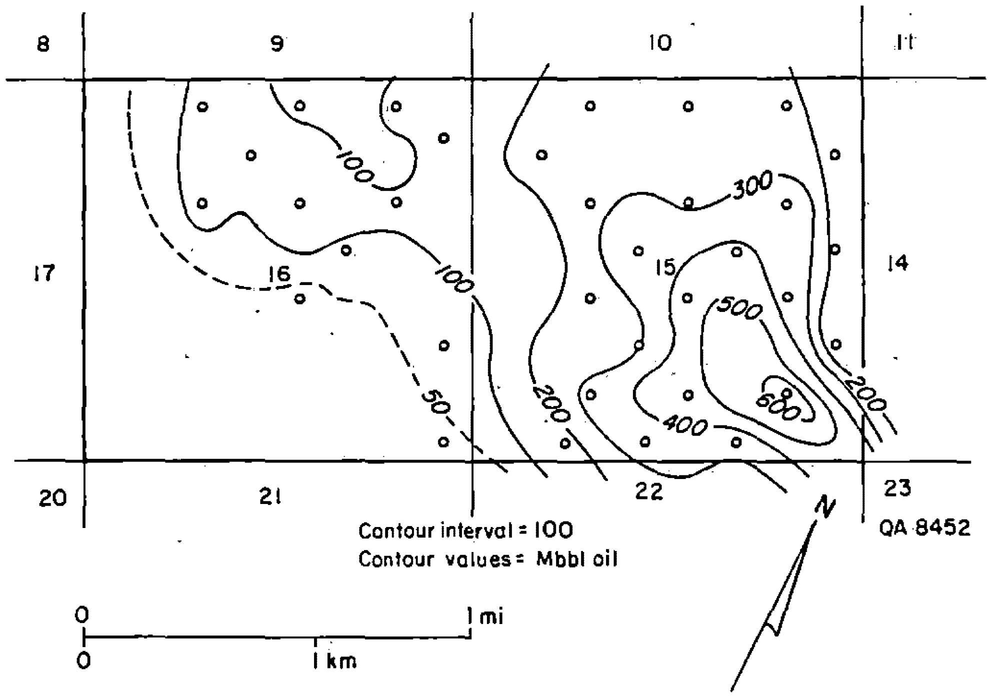

Figure 17. Isoproduction map of the Mobil University Unit 15/16, Dune field, prior to waterflooding.

Facies Distribution

In general, the San Andres and Grayburg Formations comprise several upward-shallowing cycles with more open-marine facies at the base of the cycles and more restricted supratidal (pisolite) facies at the top (fig. 18). The Grayburg represents the topmost cycle and overlies several similar cycles of the older San Andres Formation.

The Grayburg Formation in the Mobil University Unit 15/16 and surrounding study area of the Dune field has been subdivided into three units on the basis of the study of all available cores: (1) the lower unit extending from the top of the San Andres to the M gamma-ray marker, (2) the middle unit extending between the M marker and A siltstone marker, and (3) the upper unit extending from the A siltstone marker to the top of the formation.

The lower unit comprises fusulinid wackestone in all wells studied. This fusulinid wackestone of the lower unit rests with sharp contact on the underlying San Andres Formation, which at the top is composed of siltstone and pisolite beds in the western part of the area and marine brachiopod-dominated facies to the east. The fusulinid wackestone in the lower unit typically has very low matrix porosity, and the fusulinids are preserved as open molds or molds filled with anhydrite and gypsum. The contact of the lower unit with the overlying middle unit is also sharp, suggesting a significant geological break. The gamma-ray curve shows a pronounced low-gamma shoulder at this contact, designated here as the M marker, and provides ready correlation throughout the local study area.

The middle unit includes the section from the M marker up to the base of the A siltstone marker. Fusulinid wackestone composes the upper 20 to 25 ft of the section and in all wells is in sharp contact with the underlying facies. Beneath the fusulinid wackestone, the crinoid packstone/grainstone facies extends northwestward across the eastern two-thirds of the area, and the vertical-structured facies is distributed across the western one-third. The carbonate fabric ranges from wackestone to grainstone within a single core of the crinoid packstone/grainstone

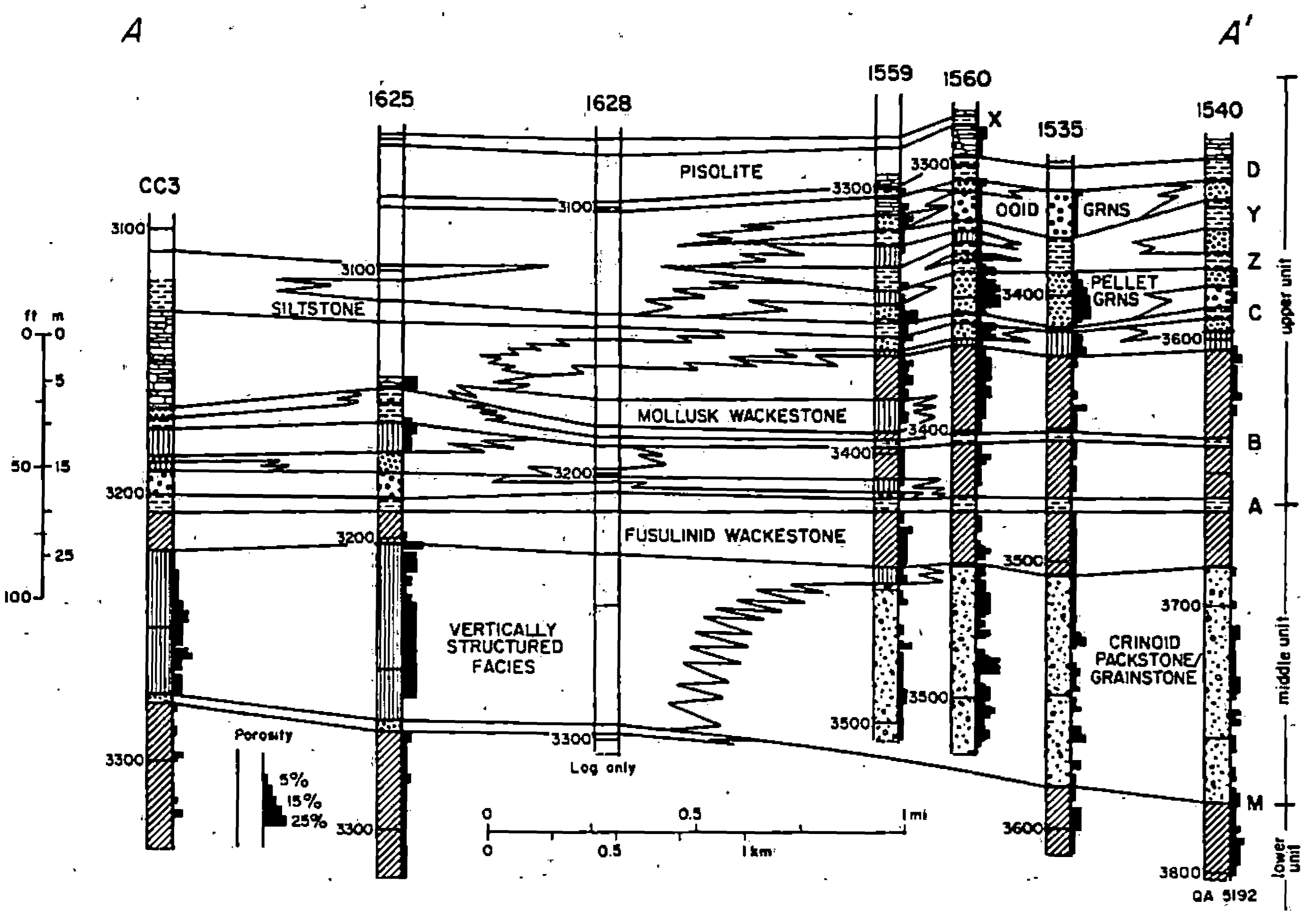

Figure 18. Facies dip section A-A′ across the Dune field. Location of the section is shown in figure 16.

facies; the wells in which this facies is dominantly grainstone are located along northwest-trending bands. Porosity is best developed along these grainstone trends.

The upper unit extends from the top of the A siltstone up to the top of the formation. This upper unit comprises fusulinid wackestone at the base, pellet and ooid grainstone near the top, and pisolite grainstone and anhydrite at the top. Siltstone beds are thicker and more closely spaced toward the top of the unit. Isopach/facies maps of the dolostone units show at least part of a facies tract that composes pisolite facies in the west and ooid and pellet grainstone and fusulinid wackestone in the east. Vertically, this general facies tract shifts from west to east upward in the section. This shift represents the eastward progradation of the pisolite facies with low porosity and permeability over the more porous and permeable pellet grainstone, fusulinid wackestone, and crinoid packstone/grainstone facies.

Depositional Environments

Abundant fusulinids, burrows, and carbonate mud indicate that the lower unit was deposited in normal-marine water below wave base in low-energy conditions. However, extensive high-energy shoals and tidal flats equivalent to most of this subtidal section are expected to occur to the west toward the interior of the platform.

The vertical-structured facies of the middle unit is interpreted to represent a low-energy shallow-water bank composed largely of carbonate mud. However, some vertical structures suggest oriented heads of calcareous sponges and blue-green algae. These structures are characterized by abrupt horizontal changes in carbonate textures across the core surfaces. The banks were probably oriented approximately perpendicular to the tidal energy, and they focused higher energy tidal currents between them. Crinoid packstone/grainstone accumulated in channels between the banks and as tidal deltas adjacent to the bank. Development of lower energy conditions basinward of the bank and tidal-delta trend is indicated by the muddier crinoid packstone, which may represent low-gradient slope deposits. Local low-energy grainstone bars developed on the slope parallel to the bank.

The upper unit contains an upward-shoaling succession that is interpreted to represent a progradational sequence from shallow-water subtidal to arid tidal-flat environments. Pisolites, sheet and shrinkage cracks, and tepee structures at the top of the sequence indicate an arid subaerial environment subjected to severe desiccation. Associated with the pisolite facies are laminated mudstones and algal-laminated mudstones that were probably deposited in restricted ponds on the tidal flat and islands. Highest energy occurred along the edges of these islands where crossbedded and laminated ooids accumulated as fringing bars and beaches. Basinward of the ooid facies, pellet grainstones represent a broad area of low-energy, burrowed stable grain flat that formed generally below normal wave base. Farther offshore, the fusulinid wackestone facies represents the extensive shallow-water subtidal shelf.

PETROPHYSICS, ENGINEERING, AND PRODUCTION ATTRIBUTES

Introduction

The following sections on porosity, permeability, and water saturation use a number of concepts and methods developed in industry over the past several decades. However, the integration of these procedures into a single effective routine for evaluation of the Grayburg reservoir in the Dune field is new and, thus, deserves description here. This reservoir description and evaluation routine was also applied to the Taylor-Link West San Andres and Farmer San Andres reservoirs.

Porosity

The Dune field produces from intergranular and intercrystalline pore space and very little vuggy pore space. Intergranular pores in dolograinstones are located between peloids that average

180 μm in diameter. Intercrystalline pores are located between dolomite crystals that have pervasively replaced wackestones and mud-dominated packstone. Mud-dominated packstones are grain-supported carbonate rocks in which intergranular areas are filled with carbonate mud. The dolomite crystals range from 30 to 80 μm in diameter and average about 50 μm. Most samples contain either intercrystalline or intergranular porosity, but some samples contain both types coexisting on a scale of inches. Samples with both types of porosity are referred to as grain-dominated packstones, which are grain-supported carbonate rocks in which the intergranular areas are partly filled with carbonate mud. Therefore, three "pore families" are recognized: dolomitized grainstones with intergranular pore space, dolomitized wackestones with intercrystalline pore space between 30 and 80 μm dolomite crystals, and a dolomitized grain-dominated packstone with both intergranular and intercrystalline pores.

The presence of as much as 55 percent gypsum in the Dune reservoir complicates porosity calculations. Routine core analysis uses temperatures higher than 60° C, and bound water from gypsum is released, resulting in erroneously high porosity and permeability. Only cores analyzed using a special low-temperature technique were used in this study.

Gypsum has a large effect on neutron- and density-log responses and little effect on acoustic-log response. The neutron log measures the hydrogen ion content of the rock, and porosity can then be calculated from these measurements under the assumption that all the hydrogen ions are in the fluids. Hydrogen ions in pore water and in bound water of gypsum are recorded as porosity on the neutron log, producing a large error in porosity calculations and, hence, OOIP calculations if large volumes of gypsum are present.

The acoustic log is the porosity log least affected by the presence of gypsum and was therefore used as the porosity tool in this study. The acoustic log does a poor job of measuring vuggy porosity, but detailed studies of cores from this field have shown that very little vuggy porosity exists.

Permeability

Lucia (1983) showed that the permeability of nonvuggy carbonates is related to particle size and interparticle porosity. A similar relationship between particle size, interparticle porosity, and permeability has been established in the Dune field. Dune reservoir samples having intergranular pore space between 180-µm particles plot close to or within the >100-µm field of Lucia (1983). Dune field samples having intercrystalline pore space between 50-µm-diameter dolomite crystals plot close to or within the 20- to 100-µm field. Dune reservoir samples having a mixture of intergranular and intercrystalline pore space generally plot on the boundary between the two fields of Lucia.

Water Saturation

The three pore families have unique water saturations. The intergranular pore family has the lowest water saturation, the intercrystalline pore family has the highest water saturation, and the mixed intergranular-intercrystalline pore family has intermediate water-saturation values. The following saturation fields define the three pore families (table 23).

The relationship between water saturation and pore family is interpreted to be due to different pore-size distributions characteristic of each family. Thin-section examination shows that the intergranular pore family has the largest pore sizes; the intercrystalline pore family, the smallest pore sizes; and the mixed family, intermediate pore sizes. Therefore, connate-water saturation is highest in the intercrystalline pore family and lowest in the intergranular pore family.

Permeability Calculations

Permeability profiles were calculated for all wells in Section 15 having acoustic logs and laterologs. Permeability cross sections were constructed using permeability profiles from selected wells (fig. 19). The permeability values from one well were correlated to offsetting wells under

Table 23. Water saturation by pore family (from Bebout and others, 1987).

Saturation field (% S_w)	*Pore family*
< 20	Intergranular
20–25	Mixed intergranular-intercrystalline
> 25	Intercrystalline

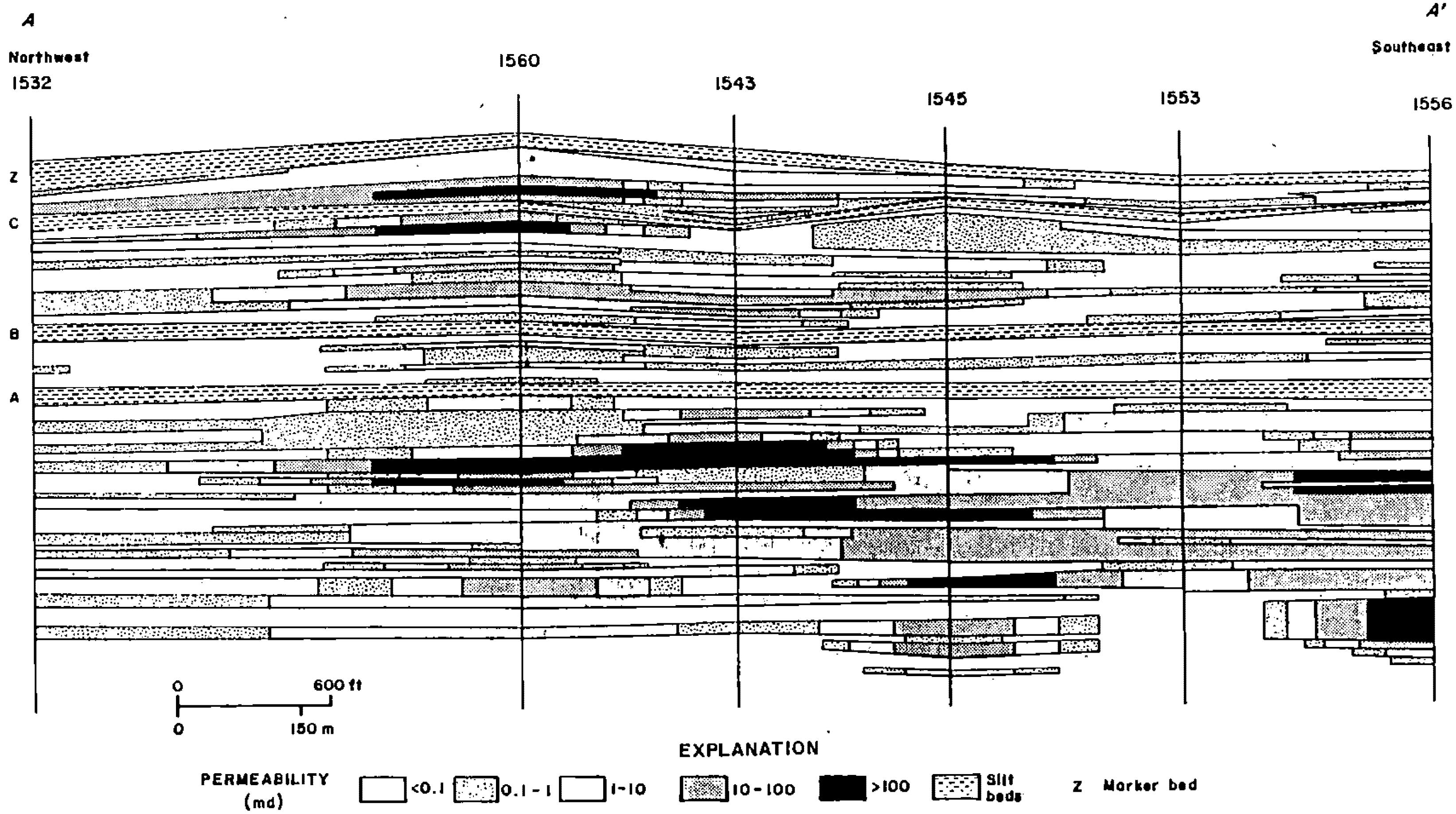

Figure 19. Permeability cross section B-B′ of Section 15. Location of the section is shown in figure 16.

the assumptions that the analyzed beds are parallel to the closest marker bed and that the change in permeability values is gradational between wells. These cross sections illustrate considerable lateral and vertical variation in permeability. Permeability changes of up to four orders of magnitude occur over a distance of 500 ft, and vertical changes in permeability are as large. Where high-permeability beds are continuous between wells, they are suspected of acting as thief zones, causing cycling of injected flood water. The large permeability changes over short distances occur within units that otherwise would be considered continuous pay if only porosity were considered, and the permeability distribution is probably much more complicated than depicted on the cross section.

VOLUMETRICS

Original Oil in Place

Stock-tank original oil in place was calculated as the product of porosity, oil saturation, and thickness (SoPhiH). Data were derived only from wells drilled in Section 15 after 1978. Porosity values have not changed since initial development 40 years before, and water saturation does not change significantly because Dune field produces by pressure depletion. Water encroachment has occurred, probably from offset waterflooding operations, but has been accounted for in the calculation of the water-saturation values. The decrease in pressure has liberated dissolved gas, calculated at 9 percent gas saturation in 1978 (Bebout and others, 1987).

The OOIP for each well in Section 15 was calculated as the product of porosity times oil saturation times thickness (SoPhiH). Intervals having <6 percent porosity or >1,000 ohmm resistivity were considered to be 100 percent water saturated and were omitted from the calculations. The SoPhiH values were posted on maps and contoured using depositional models as guides (fig. 20). The total OOIP for Section 15 is calculated to have been 30.90 MMSTB;

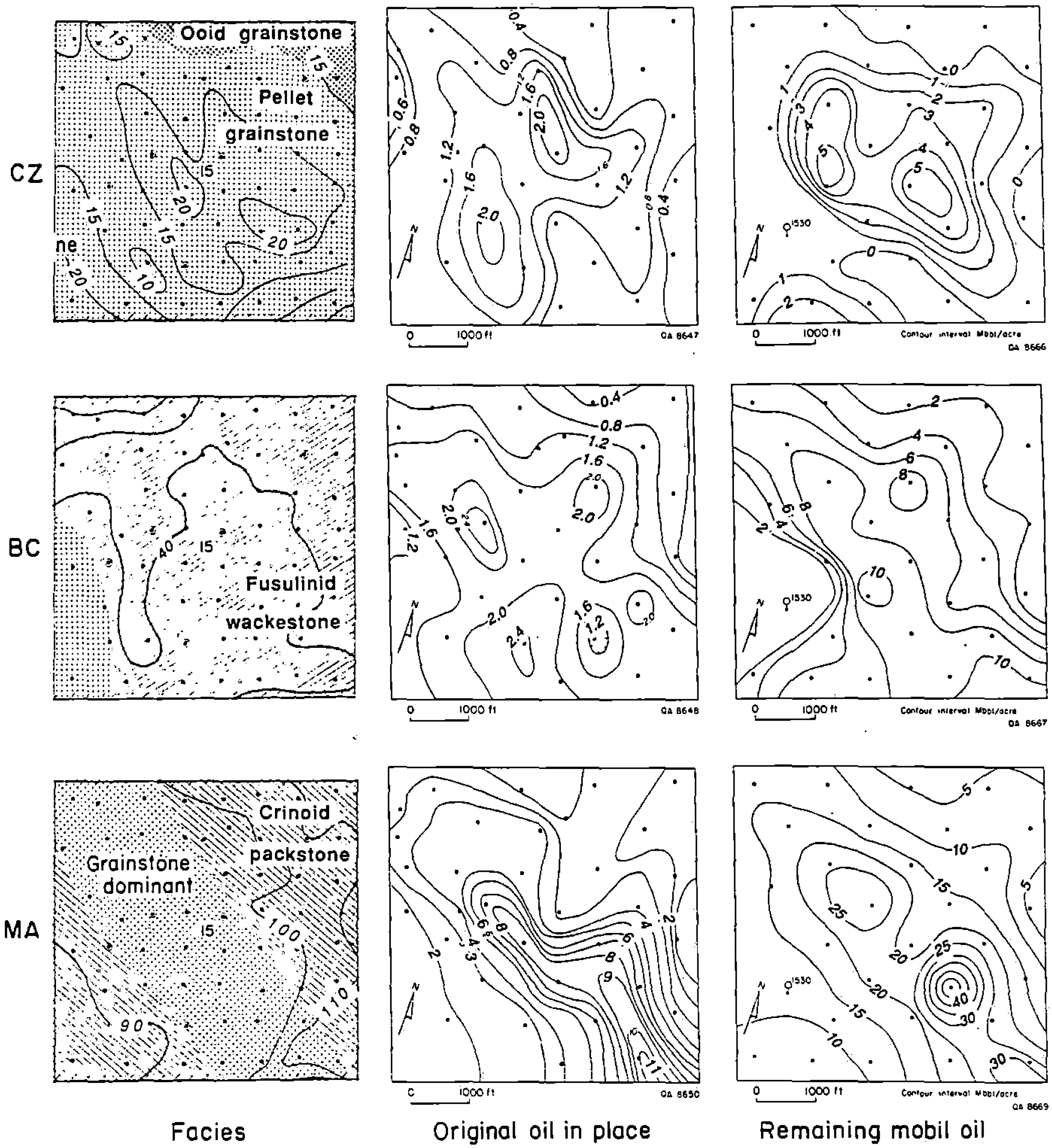

Figure 20. Facies, OOIP, and remaining-mobile-oil maps of the MA, BC, and CZ zones.

more than half of this, 58 percent, resided in the MA zone, and 25 percent was in the BC zone (table 24). Vertically, these zones are separated by the AB zone, which has low OOIP (fig. 20).

Cumulative Production

Cumulative production of oil and water is among the more reliable information normally available from old fields. Although there are usually insufficient pressure data to estimate fluid migration between wells, isoproduction contours can provide patterns of the areal distribution of production capacity.

The cumulative production map for Section 15 (fig. 17) shows a pronounced northwest-southeast trend of high production with the highest production in the southeast quadrant. Depositional facies maps of the MA and the CZ zones show trends of grainstones similar to those of the isoproduction contour map. The map is based on production information from wells drilled in the initial development program between 1954 and 1957, and only production data from these wells through December 1980 are included so that any production in response to waterflooding is excluded. However, because waterflooding was initiated in areas bordering Section 15 between 1969 and 1971, some of the production before January 1981 may be in response to these bordering waterflooding operations.

Cumulative-production figures show regional depletion of the field, but they provide little insight into pattern (areal recovery) or conformance (vertical recovery) efficiency of the recovery process. Since most wells are completed in multiple zones and have been pumping most of the time, the stratigraphic distribution of production from each well is unavailable from production statistics alone. However, using permeability data calculated from logs, production was allocated to individual zones, resulting in three-dimensional geographic displays of the remaining mobile oil in the field.

Table 24. Original oil in place by zone in Section 15 (from Bebout and others, 1987).

Zone	*OOIP (MMbbl)*	%
ZY	0.98	3
CZ	2.44	8
BC	7.72	25
AB	1.74	6
MA	18.02	58
Total	30.90	100

Distribution of Remaining Mobile Oil

Mobile oil is that oil in the reservoir that is free to move and is producible through natural reservoir drive mechanisms aided by gas or water injection. Remaining mobile oil is the amount of mobile oil available to be produced by conventional means and is calculated by subtracting produced oil and residual oil from the OOIP.

As of January 1988, 11 MMSTB of oil had been produced from Section 15. Using a residual-oil value of one-third the overall oil in place, about 10 MMSTB of mobile oil remains in the reservoir in Section 15.

Remaining mobile oil for each reservoir zone in Section 15 (fig. 20) was calculated by subtracting the produced oil and the residual oil from the OOIP. Thirty-eight percent of the total oil produced from Section 15 came from the CZ zone even though the zone contained only 8 percent of the OOIP. This high productivity is due to the high average permeability for the CZ zone. Only 200 MSTB of mobile oil remain in the CZ zone in Section 15. Forty-two percent of the total oil produced came from the MA zone, which originally contained 58 percent of the OOIP. As a result, the MA zone contains by far the largest volume of remaining mobile oil: 7.3 MMSTB, or 73 percent. The BC zone contains 2.5 MMSTB of remaining mobile oil, or 25 percent. Little oil has been recovered from the AB zone, resulting in 886 MSTB of remaining mobile oil, which is not considered an immediate target because the zone has low permeability.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

Ten million barrels of remaining mobile oil still reside in the Grayburg Formation in Section 15 of the Dune field. This oil is located in northwest-trending carbonate sand bars developed in three major geological zones: MA (7.3 MMSTB), BC (2.5 MMSTB), and CZ (0.2 MMSTB).

Because of the complexity and discontinuity of the permeability within these sand bars, geologically targeted infill wells are required to improve recovery.

Production rate increased as a result of the infill-drilling program initiated in 1978 (fig. 21); however, the second infill-drilling and waterflood-modification phase, using geological and engineering information provided by Bureau research, increased production by 60 percent. Mobil is planning additional infill drilling after obtaining results of a tracer survey now under way to determine flow direction of flood water.

Recovery efficiency as of November 1987 in the MA zone of Section 15 is estimated at 45 percent of mobile oil originally in place, or 26 percent of OOIP. Well spacing in Section 15 of the Dune field is already small enough to tap larger scale heterogeneities produced by depositional facies. However, smaller scale, interwell heterogeneities that cause compartmentalization and bypassing of oil continue to hamper oil recovery efficiency. Results of reservoir modeling show the effects of interwell heterogeneity on fluid flow and oil recovery efficiency through several simulation experiments that were conducted using two-dimensional cross sections of the oil-rich MA zone in Section 15.

Both deterministic and stochastic simulations of permeability distribution were conducted to determine why recovery efficiency is low and how it might be improved with infill drilling (fig. 22). The deterministic interpretation involved correlating permeability values from well to well and assuming gradational changes in permeability where lateral discontinuities occurred. This technique produces relatively high pay continuity. The stochastic technique known as conditional simulation was used to generate numerous permeability patterns that are thought to be more realistic. The permeability patterns range from high to low continuity.

The results of the black-oil simulation experiments indicate that targeted infill drilling would significantly increase mobile oil recovery efficiency. The low-continuity models produced oil recovery and water/oil ratio values that closely resemble field recovery and thus suggest that continuity between wells is low. With the current well spacing of 10 acres, mobile oil recovery efficiency is 45 to 50 percent. In the model, the addition of two infill wells reduced well spacing to

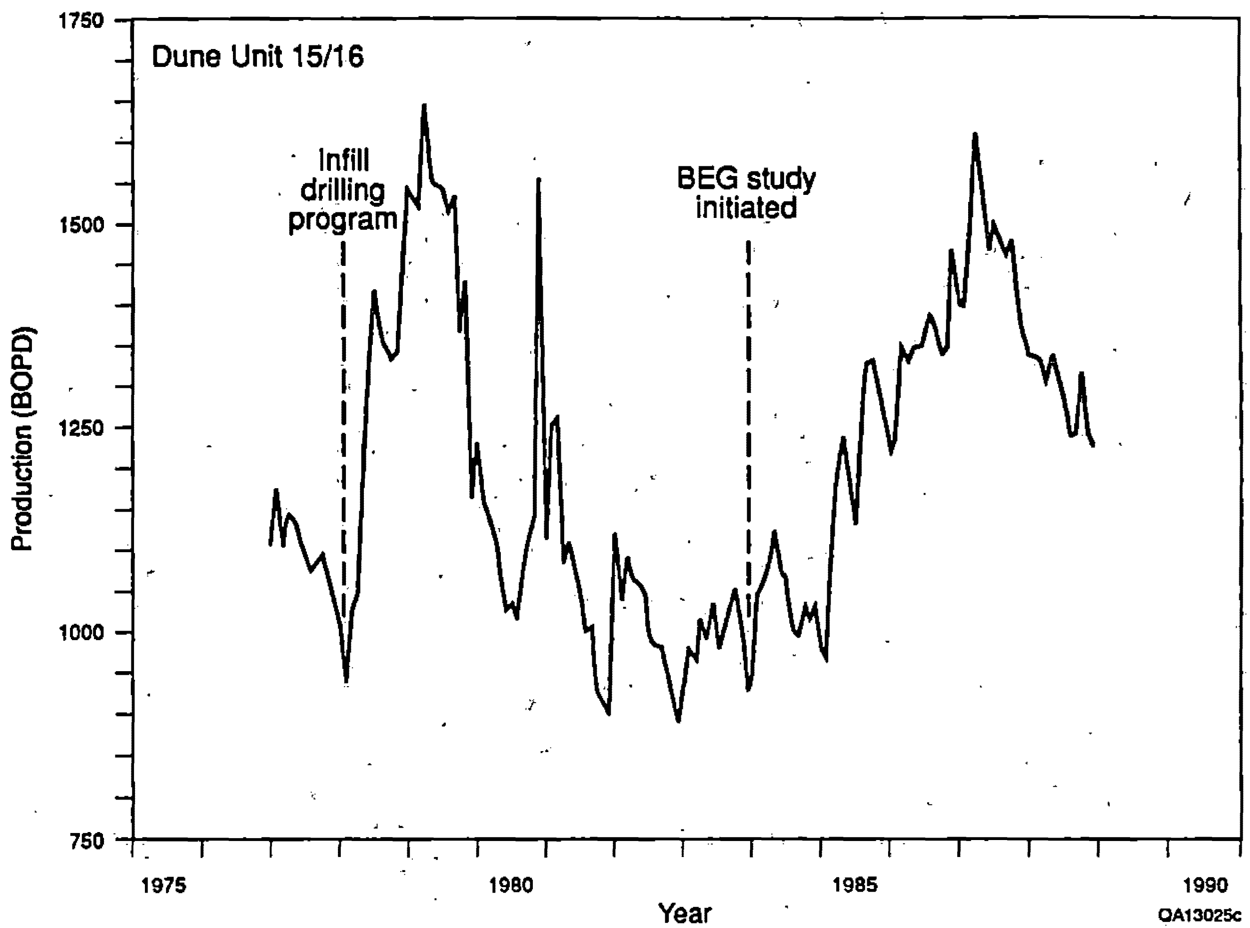

Figure 21. Production rate (average monthly barrels of oil per day) versus time from 1977 to 1989 for the Mobil University Unit 15/16.

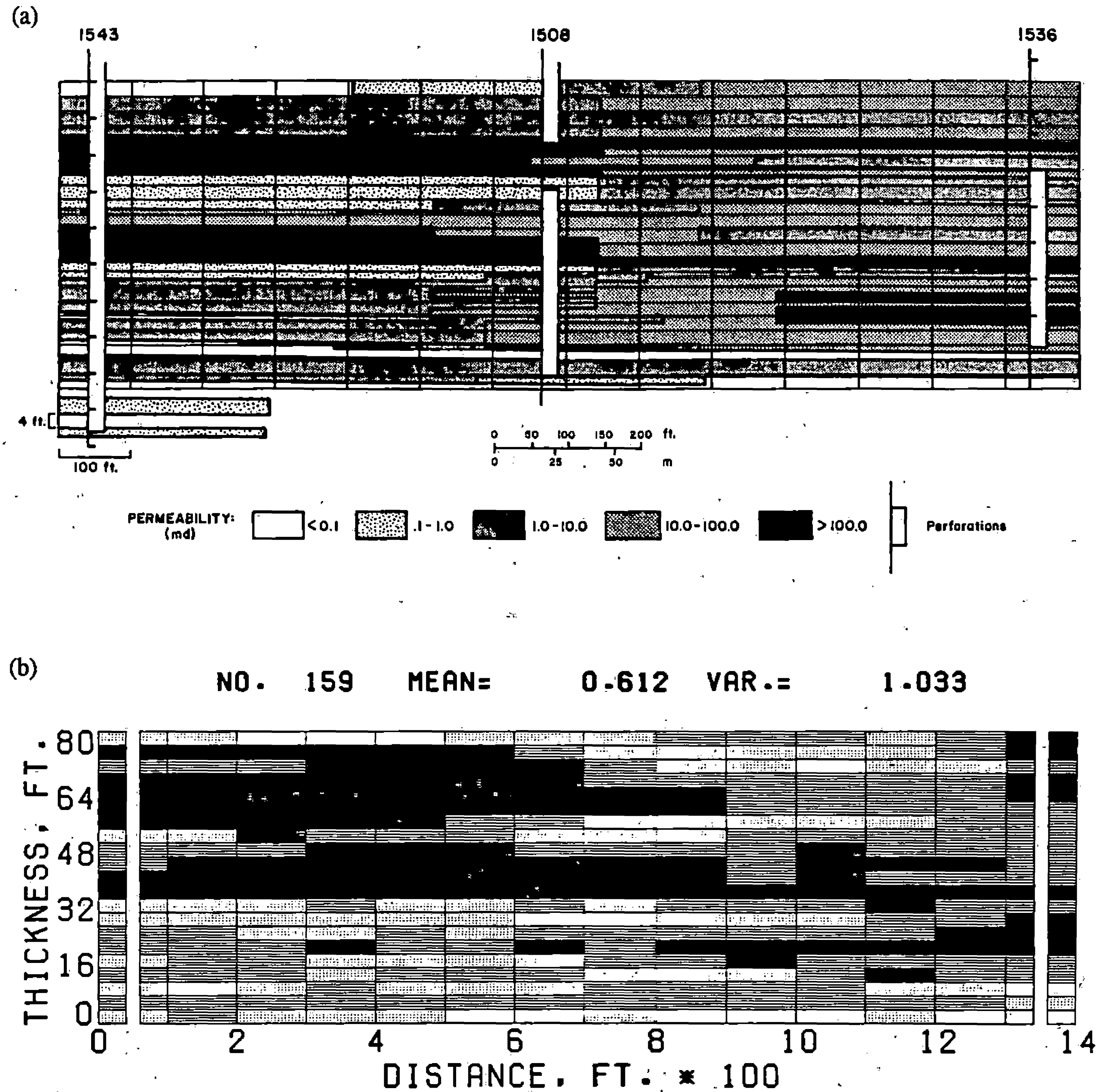

Figure 22. Permeability cross sections between Mobil University wells 1543 and 1536. (a) Deterministic cross section with superimposed 4- by 100-ft grid; (b) stochastic realization for relatively low permeability and continuity.

2.5 acres and increased mobile oil recovery efficiency by 27 to 32 percentage points. Adding four infill wells (1.7-acre well spacing) increased mobile oil recovery efficiency to 84 to 92 percent (fig. 23).

The Dune field study indicates 17.8 MMSTB of OOIP in the MA zone of Section 15, of which 12.4 MMSTB is mobile oil. Figure 23 indicates that infill drilling from 10- to 5-acre well space would increase recovery by about 15 percentage points, which is equal to an additional recovery of 1.86 MMSTB of oil from the MA zone. Remaining mobile oil in the MA zone is concentrated in the 160 acres that encompass the grainstone trend. Targeted infill drilling of this 160 acres to 5-acre spacing would require 16 wells for a per-well recovery of about 110 MSTB.

Bureau research on Dune field has stimulated interest by other operators holding adjoining leases to the Mobil Unit 15/16. On the basis of the trends established by the Bureau, Citation Oil Company obtained the lease just to the east. Citation significantly increased production by drilling two new wells and recompleting existing wells to contact the most prospective MA zone. More wells in this lease are planned.

J. Cleo Thompson geologists and engineers have been briefed on the probable extension of the MA trend directly across their lease to the south. They plan to drill a new well to test this zone.

EMMA SAN ANDRES RESERVOIR

INTRODUCTION

The Emma San Andres field (fig. 14), which is in south-central Andrews County, is currently operated by the Hondo Oil and Gas Company (previously operated by ARCO). Emma field is typical of many San Andres/Grayburg reservoirs in West Texas. After discovery in 1937, early wells produced at initial rates as high as 1,600 barrels per day. Water injection began in 1965, by which time cumulative production had reached about 11 MMSTB. As of 1987, the reservoir had produced nearly 100 percent of the projected ultimate recovery (about 20 MMSTB).

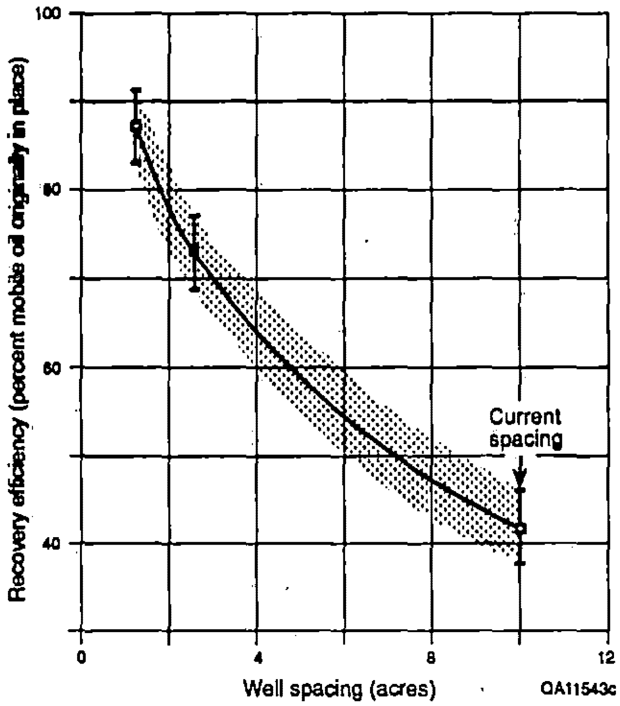

Figure 23. Recovery efficiency versus well spacing. The error bars represent the difference between results obtained with high and low continuity realizations.

In this study, the entire Emma San Andres field—an area of about 3,800 acres—has been investigated. This area includes the Emma San Andres Unit as well as the Emma Cowden field to the southwest. About 50 percent of the total reservoir is on University Lands, located on Blocks 9 and 10 (fig. 24).

GEOLOGICAL SETTING

Emma field is one of several that have been developed along the eastern margin of the Central Basin Platform. Like many fields containing San Andres reservoirs on the Central Basin Platform, Emma field is developed on an asymmetrical, northwest-trending anticline (fig. 24) that is subparallel to the eastern margin of the Central Basin Platform. Until recently, hydrocarbon production has been largely restricted to the axis of the anticline. In the late 1970's, however, significant new production was established further downdip on the southwest limb of the fold.

Oil production in the field is confined to about a 250-ft interval in the upper 350 ft of the San Andres Formation (fig. 25), which is composed of dolostone and relatively small amounts of nodular and poikilotopic anhydrite. Thin beds of terrigenous siliciclastics are present in the uppermost part of the formation above the producing interval (fig. 25). These beds are persistent in the area and thus form readily traceable markers.

Facies and Depositional Environments

The upper San Andres Formation in Emma field comprises nine intergradational but distinct lithofacies (fig. 25) that represent four major depositional environments: open platform, shoal, restricted inner platform, and supratidal (fig. 26). Development of reservoir-quality porosity and permeability, however, is restricted to the Shoal and Open Platform facies (fig. 27).

Open Platform. Open Platform deposits comprise three distinct lithofacies that collectively form the lower porosity zone in the reservoir: fusulinid packstone/wackestone, fusulinid/crinoid

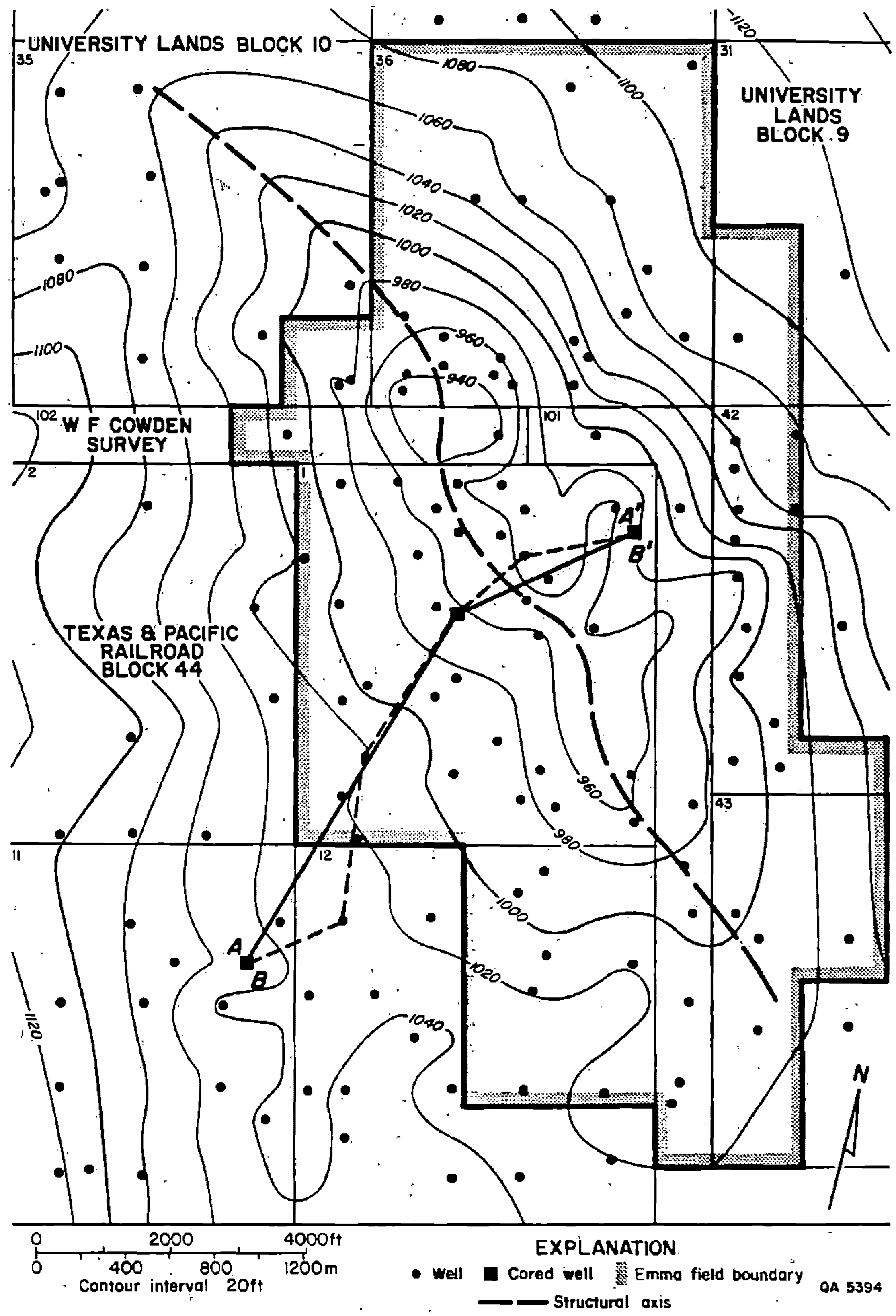

Figure 24. Structure map contoured on top of the San Andres Formation, Emma field area. Most production has come from wells along the axis of the field structure. In 1977, however, new production was established downdip on the southwest flank of the structure. Cross section A-A′ shown in figure 25; cross section B-B′ shown in figure 27.

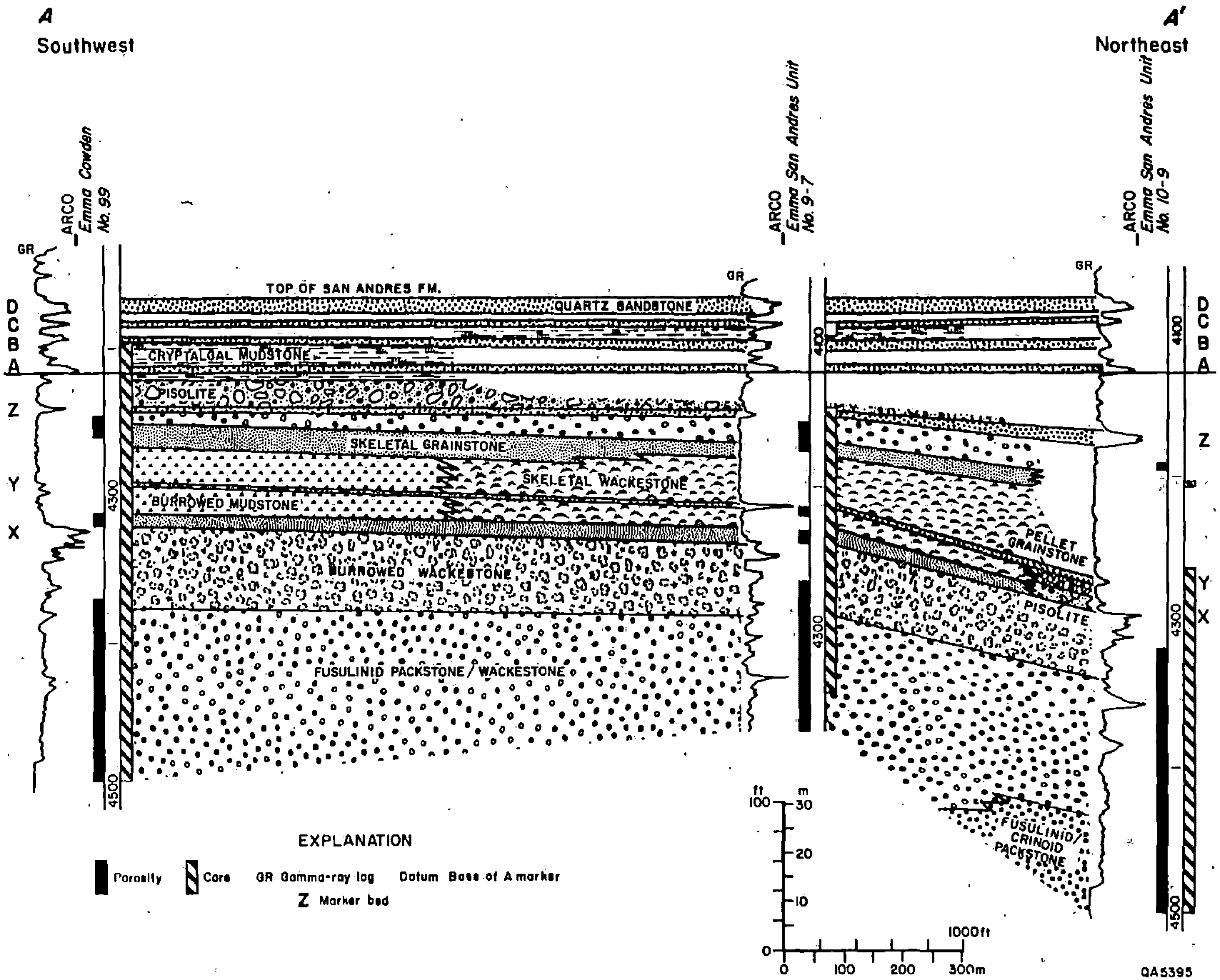

Figure 25. Cross section A-A′ through the Emma field, depicting vertical and lateral facies relations. Line of section is shown in figure 24.

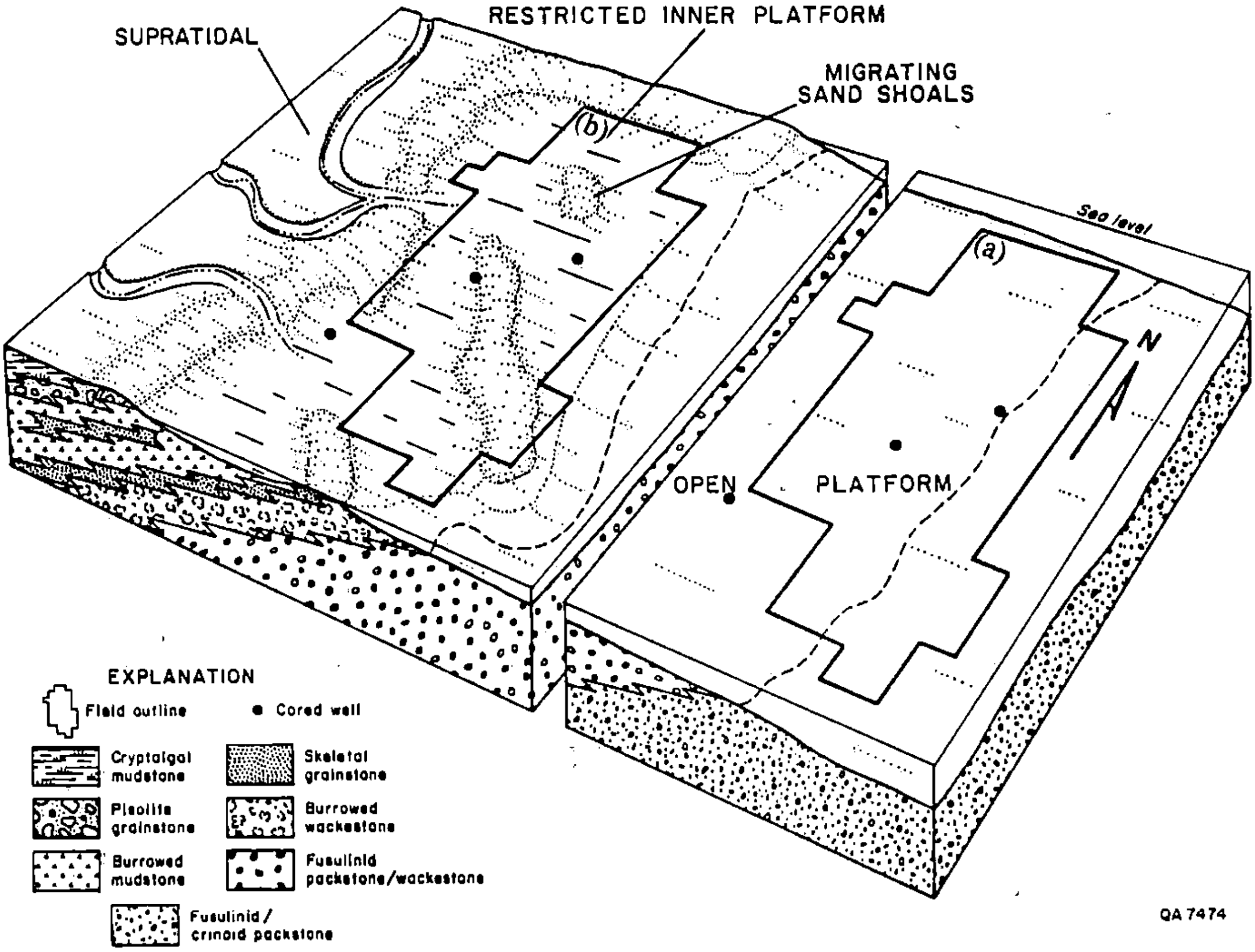

Figure 26. Paleoenvironmental reconstruction of the Emma field area during development of (A) the lower reservoir interval and (B) the upper reservoir interval.

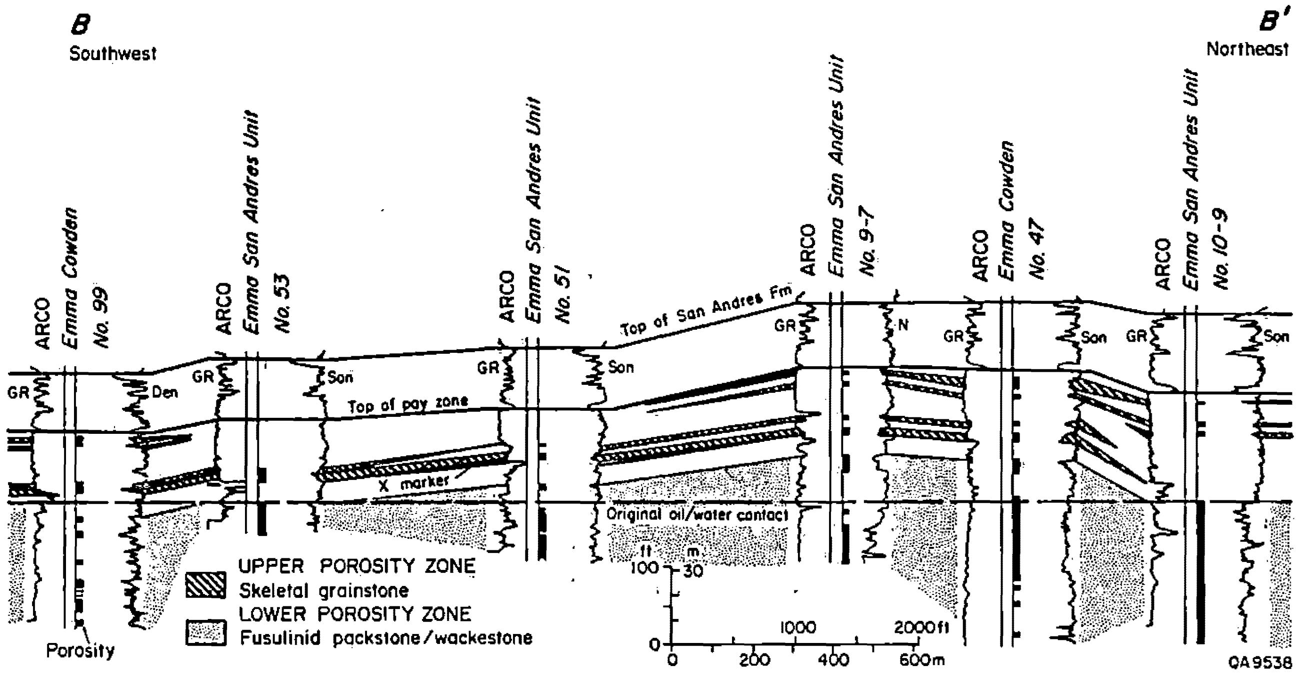

Figure 27. Cross section B-B′ illustrating the distribution of the two reservoir pay zones in the Emma San Andres reservoir. Note lateral and vertical variations in the thickness and extent of the upper (Shoal grainstone reservoir) porosity interval. Line of section is shown in figure 24.

packstone, and burrowed wackestone (fig. 25). Throughout most of the area, the base of the reservoir section is formed by a thick, continuous blanket of fusulinid packstone/wackestone (fig. 27). These rocks are characterized by abundant fusulinids and anhydrite nodules. Where not filled with anhydrite, fusulinid molds account for much of the observed reservoir porosity. Fusulinid/crinoid packstone is present in the lowermost part of the section in the eastern part of the area only (fig. 25).

The presence of fusulinids and crinoids in the lower part of the Open Platform sequence indicates that these deposits accumulated in a normal-marine setting.

Shoal. Shoal deposits consist of thin (10 to 20 ft), laterally discontinuous intervals of skeletal grainstone in the upper part of the San Andres section between the X and Z markers (figs. 25 and 27). These rocks, which directly overlie Open Platform rocks throughout most of Emma field, contain abundant clasts of calcareous algae and fusulinids. Thickest accumulations of grainstone define northwest-trending axes (fig. 28). The thickest axis in part coincides with the present structural axis in the field; however, significant thick areas are also present off structure to the north and south (compare figs. 24 and 28). Intervals of grainstone exhibit distinct lateral and vertical discontinuities throughout the area because Shoal grainstones and packstones are interbedded with muddier Restricted Inner Platform deposits (fig. 25). Shoal grainstone constitutes the upper porosity zone in the reservoir.

Skeletal grainstone and associated packstone are interpreted to represent deposition in a migrating complex of skeletal sand shoals (fig. 26). Variations in mud content and lateral and vertical continuity (figs. 25 and 27) probably reflect lateral migration of shoals and deposition in slack-water areas developed on and around the shoal complex. The orientation of thickness trends, oblique to subperpendicular to regional depositional strike, suggests that accumulation of these deposits may have been controlled by current-modified tidal or storm-related processes. Similarly trending grainstone accumulations have been reported from the Grayburg Formation in Dune field (Bebout and others, 1987), suggesting that controls on their accumulation may have been widespread on the Central Basin Platform.

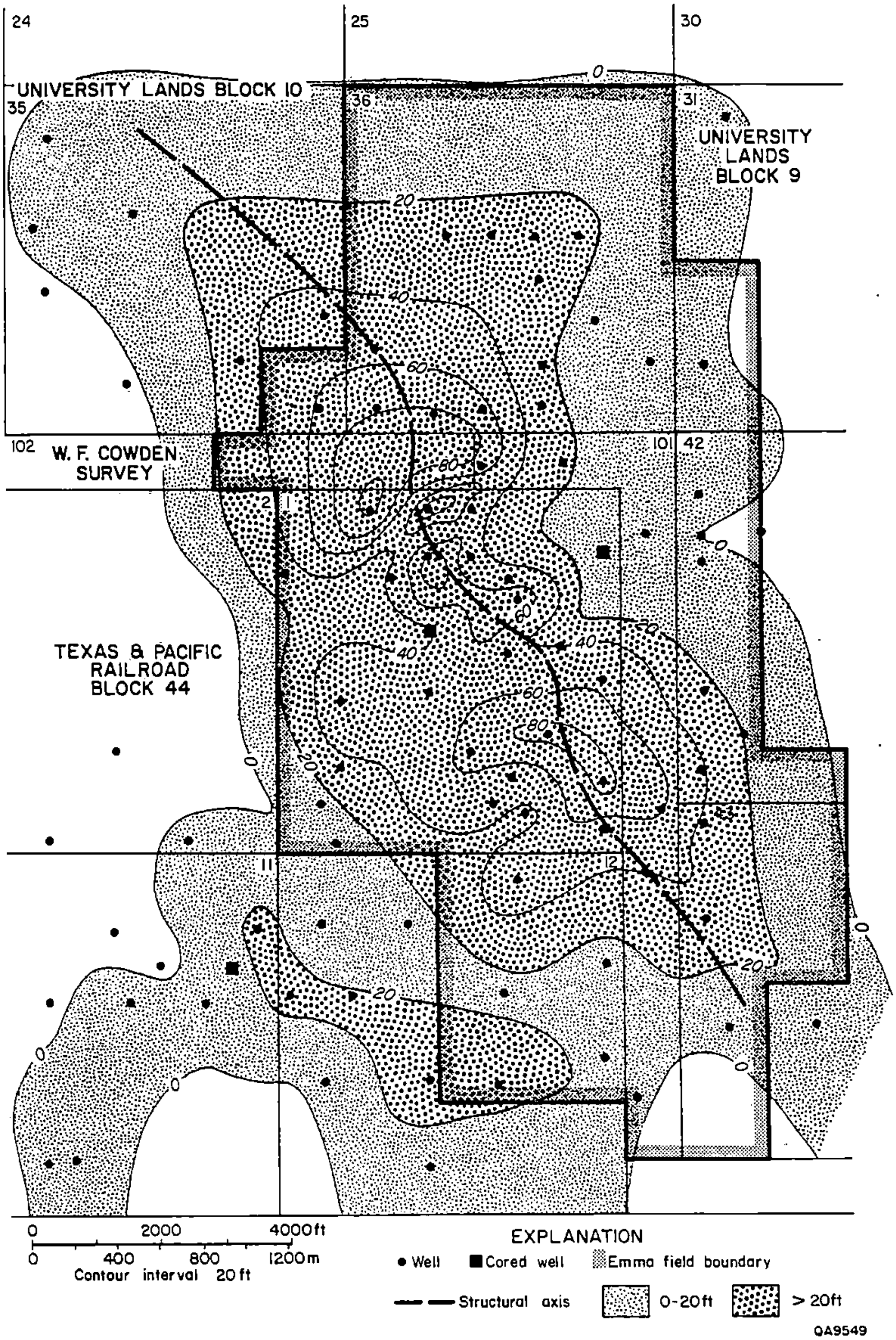

Figure 28. Thickness and distribution of porous skeletal grainstone (Shoal facies). Note that this map is also a net-pay map for the upper reservoir interval.

The Shoal grainstone facies is overlain by peritidal and supratidal rocks of the Supratidal facies. These rocks, which are interbedded with laterally continuous siliciclastic beds, are rich in carbonate mud and anhydrite and form the top seal of the reservoir.

Paleogeography and Depositional History

From the vertical sequence of facies documented above it is apparent that the upper San Andres Formation in Emma field consists of an upward-shallowing sequence of shallow subtidal to peritidal and supratidal deposits that accumulated on a shallow-water carbonate ramp (fig. 26). Open Platform packstone and wackestone represent deposition in a moderately low energy (near effective fair weather wave base), shallow-water subtidal setting that apparently became somewhat more restricted (lower energy) through time. Shoal grainstone accumulated in shallower water, high-energy conditions. These shoal deposits sharply overlie Open Platform rocks and suggest a major shift in paleoenvironments at this time, perhaps caused by sea-level fall and subsequent rise.

Diagenesis

San Andres rocks in Emma field have been substantially modified since deposition by a complex series of diagenetic events. These events have recently been detailed by Ruppel and Cander (1988 a, b). From the standpoint of porosity evolution, three main stages in the diagenetic history are significant: dolomitization, sulfate emplacement, and sulfate removal. Although pervasive, dolomitization of the San Andres in the Emma field area was primarily, if not exclusively, replacive. Because of this, primary porosity was not markedly altered. Processes of sulfate emplacement and removal, however, have had a much more significant effect on porosity development and distribution.

Following dolomitization, sulfate (either in the form of gypsum or anhydrite) filled existing void space and replaced dolomite, both grains and matrix. Although difficult to quantify, porosity reduction during sulfate emplacement was substantial. The Emma San Andres reservoir locally contains as much as 20 to 30 percent anhydrite.

Subsequent removal of void-filling sulfate has restored some previously occluded porosity. Sulfate dissolution has also, at least locally, created new porosity. Ruppel and Cander (1988a) documented sulfate replacement of dolomite. Subsequent dissolution of this anhydrite has actually increased porosity. Much of the porosity in the highly porous and permeable skeletal grainstone interval was created in this way.

Porosity and Permeability

Significant porosity development is restricted to two major zones (fig. 27): an upper zone of thin beds (Shoal grainstone) and a lower, thicker zone (Open Platform packstone and wackestone).

Lower Porosity Interval (Open Platform deposits). Porosity in Open Platform fusulinid wackestone/packstone deposits ranges from about 4 to 15 percent and extends well below the reservoir interval (a thickness of at least 200 ft locally). Permeability in this lower porous interval averages less than 2 md but reaches 25 md in some thin zones.

Both moldic and intercrystalline pore space is common in Open Platform rocks. Open fusulinid molds (average, 1 to 2 mm wide) are locally abundant and contribute to porosities of as much as 18 percent in fusulinid packstone and wackestone. However, such zones are rare and thin (usually less than 1 ft).

Intercrystalline porosity is locally abundant in Open Platform rocks. Visual estimates from thin sections suggest that intercrystalline pore volume locally ranges as high as 10 percent. In most cases, intercrystalline pores range in size from a few to a few hundred (very rare) micrometers. Intercrystalline porosity in Open Platform rocks is noticeably higher in irregular, generally lighter colored "recrystallized" patches. These features are present in several other San Andres/Grayburg reservoirs on the Central Basin Platform, including Dune (Crane County), Taylor-Link (Pecos County), Penwell (Ector County), and Jordan (Ector and Crane Counties). Preliminary data from

Jordan field indicate that these zones are much more permeable than surrounding unaltered dolomite (Major and Vander Stoep, 1988; Major and others, in press). These patches may play a major role in the development of porosity and permeability in Open Platform rocks in Emma field and elsewhere.

Upper Interval (Shoal facies). The upper porous interval within the Emma San Andres reservoir comprises skeletal, shoal grainstone, packstone, and wackestone. Although porosity (average 8 percent) and permeability (average 3.5 md) in these deposits is about the same as in the lower porous interval, in mud-free grainstone intervals, porosities of 10 to 15 percent and permeabilities of 50 to 100 md are common.

Shoal grainstone contains interparticle, intercrystalline, moldic, and intraparticle pore space. Interparticle pore size typically ranges from 200 to 400 µm; intraparticle pores vary in size to 700 µm in diameter. In extensively leached zones, intercrystalline porosity is high where not filled with anhydrite or calcite.

Distribution of Porous Facies. The two major intervals of porosity in the Emma reservoir exhibit significantly different distributions across the field area. Open Platform rocks, which constitute the lower interval, extend as a blanket deposit across the area (figs. 25 and 27). Although porosity varies locally on a small scale, porosity development in the lower reservoir interval is widespread across the area. The upper, Shoal grainstone porosity interval, on the other hand, is much more restricted in its overall distribution and contains distinct local variations in thickness. Porous grainstone intervals vary in number and thickness across the field (fig. 27).

The distribution of net pay in the lower porosity interval reflects the influence of structure because it is limited by the field oil-water contact (fig. 27). Because of its stratigraphically higher position, however, the upper porosity interval is almost entirely above the oil-water contact in the area (see fig. 27). Thus, the distribution of net pay in the upper interval is not primarily controlled by structure. Although maximum net-pay thickness trends correspond to the structural axis, there is significant net pay off structure to the southwest and north. The distribution of these rocks is a function of original deposition.

PRODUCTION DATA

Cumulative production of oil in the Emma San Andres reservoir (including the Emma San Andres Reservoir Unit, discovered in 1937, and the Emma Cowden reservoir, discovered on the southwest flank of this field in 1977) totals nearly 20 MMSTB. Based on conventional estimates this represents more than 95 percent of the projected ultimate recovery. In recent years annual production from the reservoir has dropped markedly. Only 0.156 MMSTB were produced in 1986; most of this came from the southwest flank of the field (Emma Cowden reservoir).

Cumulative oil production prior to unitization and waterflooding (May 1965) totaled about 11 MMSTB. Although production during that time generally came from areas along the field structure, production patterns correlate more closely with the distribution of porous grainstone in the upper porosity interval than with structure. Particularly obvious in this regard is the volume of production obtained from areas off structure in the northern part of the reservoir unit on University Lands Blocks 9 and 10.

Production trends since the onset of waterflooding are generally similar to those observed prior to waterflooding with one notable exception. In the late 1970's production was established on the southwest flank of the field structure well downdip from previous producing wells. This new production has accounted for about 1.4 MMSTB of the total recovery from the reservoir. As is the case in the rest of the field, production patterns in this area show a close correlation to the distribution of skeletal grainstone of the upper porosity interval.

Permeability calculations suggest that most of the production in the Emma San Andres reservoir came from the upper part of the reservoir. This idea is supported by the similarity between the distribution of skeletal grainstone and production patterns (compare figs. 28 and 29). Completion history data are consistent with this conclusion.

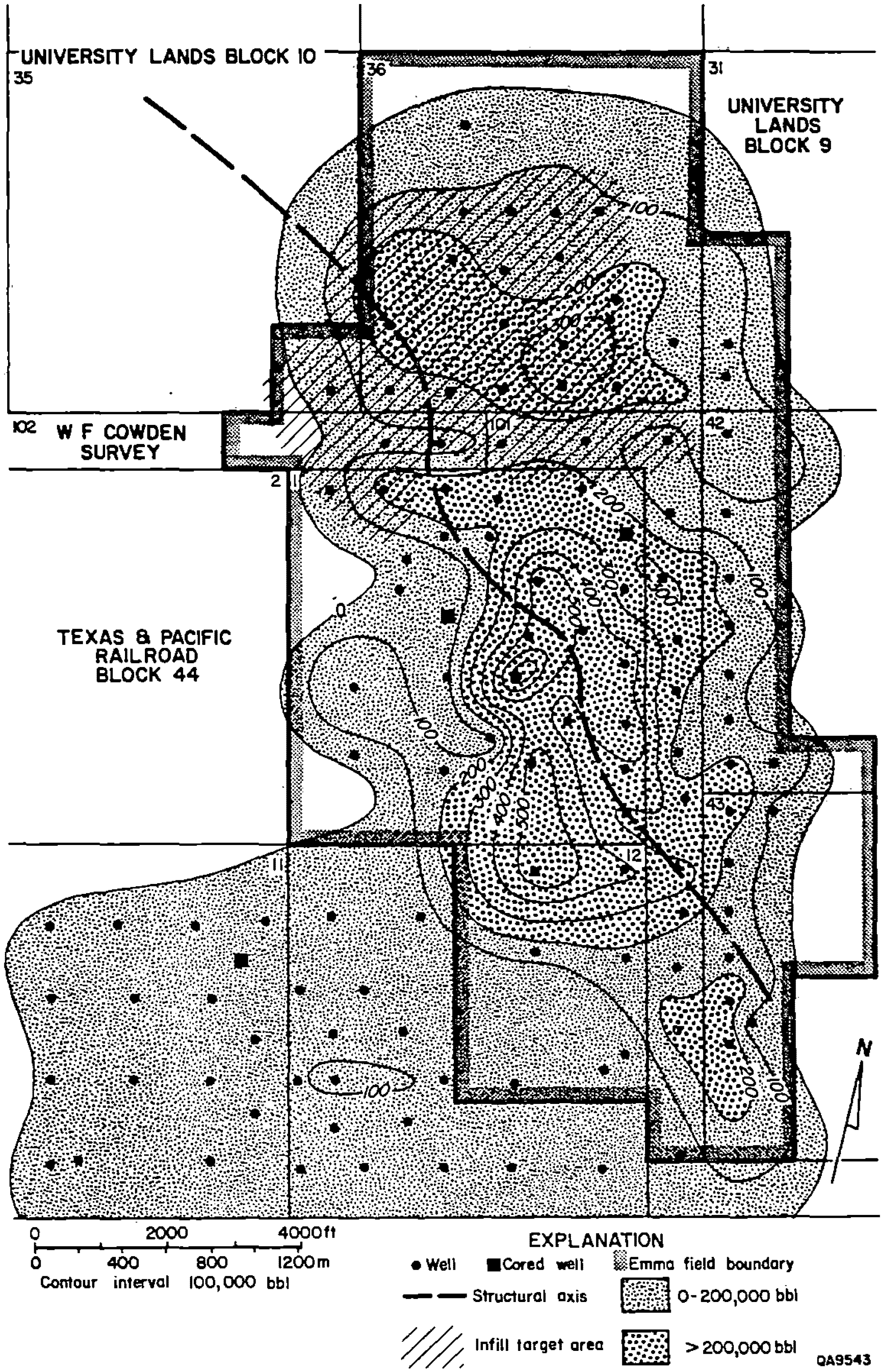

Figure 29. Isoproduction map for the Emma reservoir as of January 1986. Comparison with figure 28 illustrates several areas in the northern part of the field where drainage from this, the major reservoir zone in the field, is incomplete.

VOLUMETRICS

The volume of OOIP has been calculated to be 48.4 MMSTB for the entire Emma San Andres reservoir inclusive of University and non-University Lands. Individual determinations of OOIP for the upper and lower reservoir intervals give values of 34.3 and 14.1 MMSTB, respectively. Cumulative production from University Lands is 7.9 MMSTB and for the entire reservoir is about 19.5 MMSTB. These data indicate a recovery efficiency of more than 40 percent, which is well above average for reservoirs in this subplay (table 6).

Despite the apparently efficient recovery in the Emma reservoir, calculations indicate approximately 15.0 MMSTB, or 43 percent of the original mobile oil, remains in the reservoir. Of this total, approximately 7.8 MMSTB, or 52 percent of the oil, remains in the upper porosity interval; about 7.2 MMSTB lies in the lower porosity interval. Total remaining mobile oil on Emma University Lands in the San Andres reservoir is 5.3 MMSTB.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

Consideration of permeability data and production history data suggests that much of the produced oil (as much as 85 percent) has come from the upper skeletal grainstone porosity interval. The high apparent recovery efficiency calculated for the Emma San Andres may be the result of the fact that most oil has been produced from this interval, which contains relatively high and uniform permeability.

Despite the apparently high recovery efficiency, conservative calculations indicate that a significant amount of mobile oil (as much as 8 MMSTB) still resides in the upper skeletal grainstone reservoir interval.

Because of its favorable reservoir characteristics (pore types and distribution and facies geometry) the upper skeletal grainstone reservoir interval must be considered the primary target for future infill drilling and recompletion development. Comparison of isoproduction maps with the net-pay map for this reservoir interval (figs. 28 and 29) indicates several areas in the field that are potential sites for infill because of poor recovery relative to the thickness of skeletal grainstone. Especially prominent among these is an area in the southeastern corner of Section 35 and southwestern corner of Section 36 (University Lands Block 10), and immediately adjacent parts of Section 102 (W.F. Cowden Survey). This area contains up to 60 ft of porous skeletal grainstone (fig. 28) and is high on the field structure (fig. 24). However, wells in this area have produced relatively small volumes of oil (fig. 29). Effective exploitation of the skeletal grainstone reservoir zone must consider the lateral and vertical variations in the thickness and distribution of these skeletal grainstones (fig. 27) in recompletions and new drilling.

The lower reservoir interval is considered a secondary target for recovery of remaining oil. Although calculations suggest that this zone may contain as much as 7 MMSTB of remaining oil, the difficulty of mapping porosity and permeability distributions in this zone will make effective exploitation of this interval impossible without further detailed study.

EAST PENWELL SAN ANDRES UNIT

INTRODUCTION

Penwell field is located approximately 15 mi west of the eastern margin of the Central Basin Platform in University Block 35, Ector County (fig. 14). Penwell is the northernmost field in a five-field complex that produces oil from a combined structural and stratigraphic trap on the east flank of a broad, asymmetric anticline (Major and others, 1988). Production is from the Permian (Guadalupian) San Andres Formation reservoir at a depth of approximately 3,500 ft (fig. 30).

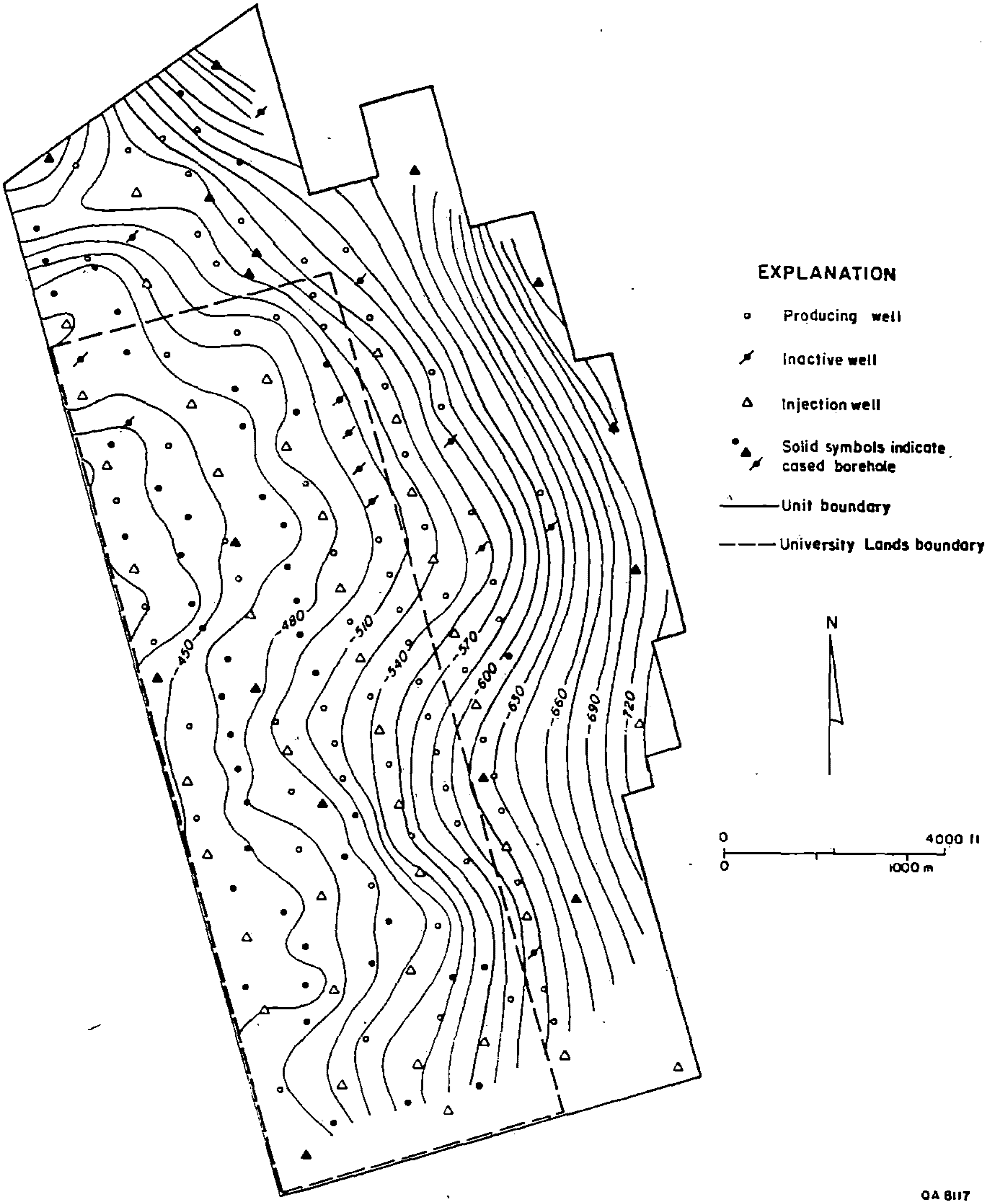

Figure 30. San Andres Formation structure map for the East Penwell San Andres Unit. The unit produces from the east flank of an anticline.

The field was discovered in 1927 and has been on waterflood since 1970. The waterflood is a modified five spot, and current producing spacing is approximately 20 acres per well.

The University has a 65-percent interest in the East Penwell San Andres Unit. There are two reservoir zones at Penwell. The main reservoir zone, which is the subject of this report, has been produced since discovery in 1927. A lower San Andres reservoir zone was not penetrated until 1985, and very few data are currently available from this new zone. The University's share of the main San Andres reservoir zone contained approximately 48 MMSTB of original mobile oil in place (OOIP was 109 MMSTB) and has a cumulative production of 27.5 MMSTB. Proved reserves are approximately 2 MMSTB, leaving 19 MMSTB of unrecovered mobile oil at projected abandonment (calculated from data in the files of the Railroad Commission of Texas).

The San Andres Formation reservoir exhibits heterogeneous porosity and permeability distribution, and recovery of remaining mobile oil may be more efficiently accomplished through targeted infill drilling based on integrated geological/engineering studies. The potential for exploitation of this substantial volume of remaining mobile oil in the East Penwell San Andres Unit is the impetus for this study.

GEOLOGICAL SETTING

Depositional Facies

The main San Andres reservoir at the East Penwell San Andres Unit is composed of an upward-shoaling sequence of shallow-water ramp facies. The reservoir rocks are primarily porous open-marine grainstone/packstone overlain by generally nonporous tidal-flat mudstone and pisolite packstone. The following facies descriptions are based on examination of 13 cores from the unit.

Pellet Grainstone/Packstone. The volumetrically dominant open-marine facies in the upper San Andres Formation at Penwell field is thoroughly dolomitized grainstone/packstone composed of spherical to ovoid fecal pellets. Common accessory skeletal grains are fusulinids and mollusks, which are rarely preserved and most commonly evident as molds. Where fusulinids or mollusks compose 10 percent or more of grains, this facies is described as pellet-fusulinid grainstone/packstone or pellet-mollusk grainstone/packstone. Burrow structures are rare, but a complete lack of bedding suggests that this sediment was thoroughly bioturbated. This thorough bioturbation and the presence of abundant normal-marine fossils indicate deposition in an open-marine setting similar to Holocene open-marine pelleted mud seaward of the tidal flats in the Bahamas (Shinn, 1983).

Pellet grainstone/packstone is the primary San Andres reservoir rock at Penwell field. Interparticle porosity is commonly well preserved and results in a relatively high permeability rock. Fusulinid and mollusk molds contribute somewhat to reservoir porosity but had little effect on permeability.

Algal Grainstone. Algal grainstone, with both micritized and well-preserved dasycladacean algae grains, occurs in thin and discontinuous beds. Some algal grainstones are bedded and some are crossbedded. Pervasive dolomitization has somewhat obscured the depositional texture, but algal grainstone generally contains little mud matrix. This facies commonly occurs interbedded with pellet grainstone/packstone at or near the boundary of pellet grainstone/packstone and superjacent pisolite packstone or mudstone. This stratigraphic position and the suggestion of local relatively high original depositional energy, in contrast to that of adjacent pelleted rocks as evidenced by crossbedding and the small amount of mud matrix, suggest that algal grainstone was deposited in tidal channels similar to those that cross the Holocene tidal flats of the Bahamas (Shinn, 1983) or to the Holocene tidal channels that transport relatively coarse sediment across the muddy open-marine sediments of Florida Bay (Jindrich, 1969). The algal grainstone facies is interpreted as having formed as tidal-channel deposits in a relatively high energy ramp-interior setting. Where not thoroughly cemented by sulfates, this facies has high effective interparticle porosity and high permeability.

Sponge-Algal Boundstone. Thin zones of sponge-algal boundstone occur near the bottom of cores interbedded with pellet grainstone/packstone and generally 200 ft or more below pisolite packstone and mudstone. These bioherms lack any evidence of subaerial exposure or mechanical abrasion due to wave action and are apparently discontinuous. These zones are only 1 to 2 ft thick and, although they contain some interparticle porosity, are not of sufficient volume to be considered a significant portion of the reservoir. The association with the stratigraphically deeper portion of the pellet grainstone/packstone facies and the lack of evidence of high-energy conditions suggest that these rocks were formed as isolated ramp-margin reef mounds. The occurrence of these reef mounds is apparently restricted to the downdip (east) side of the anticlinal structure at Penwell field.

Crinoid Grainstone. Crinoid fragments occur as rare accessory grains in pellet grainstone but are observed in sufficient quantities to constitute a separate facies in only one core. Crinoid grainstone is poorly sorted and apparently free of mud matrix, although it is thoroughly cemented by dolomite and is not part of the reservoir. The presence of this facies as thin beds interbedded with the stratigraphically deeper parts of pellet grainstone/packstone suggests that these rocks formed as crinoid meadows in the deeper portion of the open-marine ramp margin.

Mudstone. Much of the reservoir seal in the San Andres at Penwell field is dolomitic mudstone. These rocks are the lithified equivalents of carbonate mud; in some cases they are finely laminated and generally not pelleted, presumably because high environmental stress isolated these sediments from the organisms that produce pellets and bioturbate the sediment in deeper water, open-marine environments. The mudstone facies is generally cream colored and barren of fossils, although algal laminites and rare fusulinids and mollusks do occur in these rocks. This facies is commonly interbedded with pisolite packstone and occurs stratigraphically above the open-marine pellet grainstone/packstone. This stratigraphic position and association with pisolite rocks that contain evidence of subaerial exposure (see pisolite-packstone section below) suggest that the mudstone facies was deposited in hypersaline ponds on a tidal flat landward of the open-marine facies. The rare fusulinids and mollusks were probably transported by storms from deeper water, open-marine environments.

Pisolite Packstone. The pisolite packstone facies in the San Andres section exhibits evidence of syndepositional subaerial exposure. These rocks are composed of poorly sorted and fitted-fabric pisolites and are characterized by sheet cracks, fenestrae, and desiccation cracks. Pisolite packstone is commonly interbedded with mudstone and is characteristically the same cream color. This facies is also generally barren of skeletal grains. Intergranular pores in the pisolite packstone facies are generally thoroughly filled by anhydrite. Rare, thin, partially cemented zones only 1 to 2 ft thick may be high-permeability floodwater thief zones. Minor karst dissolution is indicated locally by severe brecciation and infilling by greenish-gray siltstone. The abundant evidence of syndepositional desiccation, association with fossil-barren mudstone, and presence of minor karst dissolution indicate that the pisolite packstone facies formed in a tidal-flat environment that was frequently subaerially exposed.

Siltstone. Siliciclastic siltstone beds occur interbedded with the mudstone and pisolite packstone (tidal flat) portion of the upper San Andres at Penwell field. Some of these siltstones are finely laminated, but most are massive. These rocks are often carbonaceous and in transitional contact with tidal-flat mudstone and pisolite packstone/grainstone. The presence of this facies interbedded with rocks containing evidence of subaerial exposure and the lack of any regional sources for siliciclastic detritus suggest that these sediments were transported to the tidal-flat environment by eolian processes. Some reworking in shallow water subsequent to eolian transport is suggested by the laminations.

Depositional Model

The succession of facies in the upper San Andres Formation at Penwell field comprises rocks formed from an upward-shoaling sequence of open-marine to tidal-flat sediments. The open-marine section was characterized by pelleted mud and open-marine fauna, mostly fusulinids and mollusks, and sparse sponges, algae, and crinoids. The open-marine section contained rare, isolated sponge-algal bioherms. The shoreward tidal-flat environment was characterized by tranquil, high-salinity waters in which environmental stress excluded most fauna, resulting in deposition of barren carbonate mud. High-exposure tidal flats were sites of pisolite formation and desiccation features such as sheet cracks and fenestrae. Lack of a continuous shelf-margin facies, such as a barrier reef or continuous grainstone shoal, and the lateral, sheetlike geometry of the pellet grainstone/packstone facies suggest that these rocks were deposited in a carbonate ramp setting (Ahr, 1973). The tidal-flat and open-marine portions of the ramp were locally cut by dip-oriented, relatively high energy tidal channels. These deposits were characterized by skeletal grainstones in which the grains are dominantly dasycladacean algae. The interpreted depositional environments are illustrated schematically in figure 31.

Diagenesis

Induration of soft pelleted mud began early in the diagenetic history of the San Andres Formation at Penwell field. Where induration resulted in good pellet preservation, interparticle porosity is now preserved. Where pellets were compacted, most of the porosity is now destroyed. Thus, this early diagenetic event influenced the formation of lateral porosity heterogeneities in the pellet grainstone facies, which in turn control the heterogeneous distribution of remaining mobile oil.

The entire section has been pervasively dolomitized, and dolomitization of the original carbonate sediment was the major diagenetic event. Strontium-isotope values (Leary and Vogt, 1986; Ruppel and Cander, 1988a, b) indicate that dolomitization took place during Guadalupian time. Oxygen and carbon isotopic data (Leary and Vogt, 1986; Ruppel and Cander, 1988a, b) indicate dolomitization by hypersaline waters that originated through evaporation of sea water. Therefore, these San Andres carbonates were probably dolomitized by hypersaline water that originated on arid tidal flats and percolated through the shallow subsurface during the Guadalupian. This hypersaline brine was also probably the source of the anhydrite and gypsum common in the San Andres Formation.

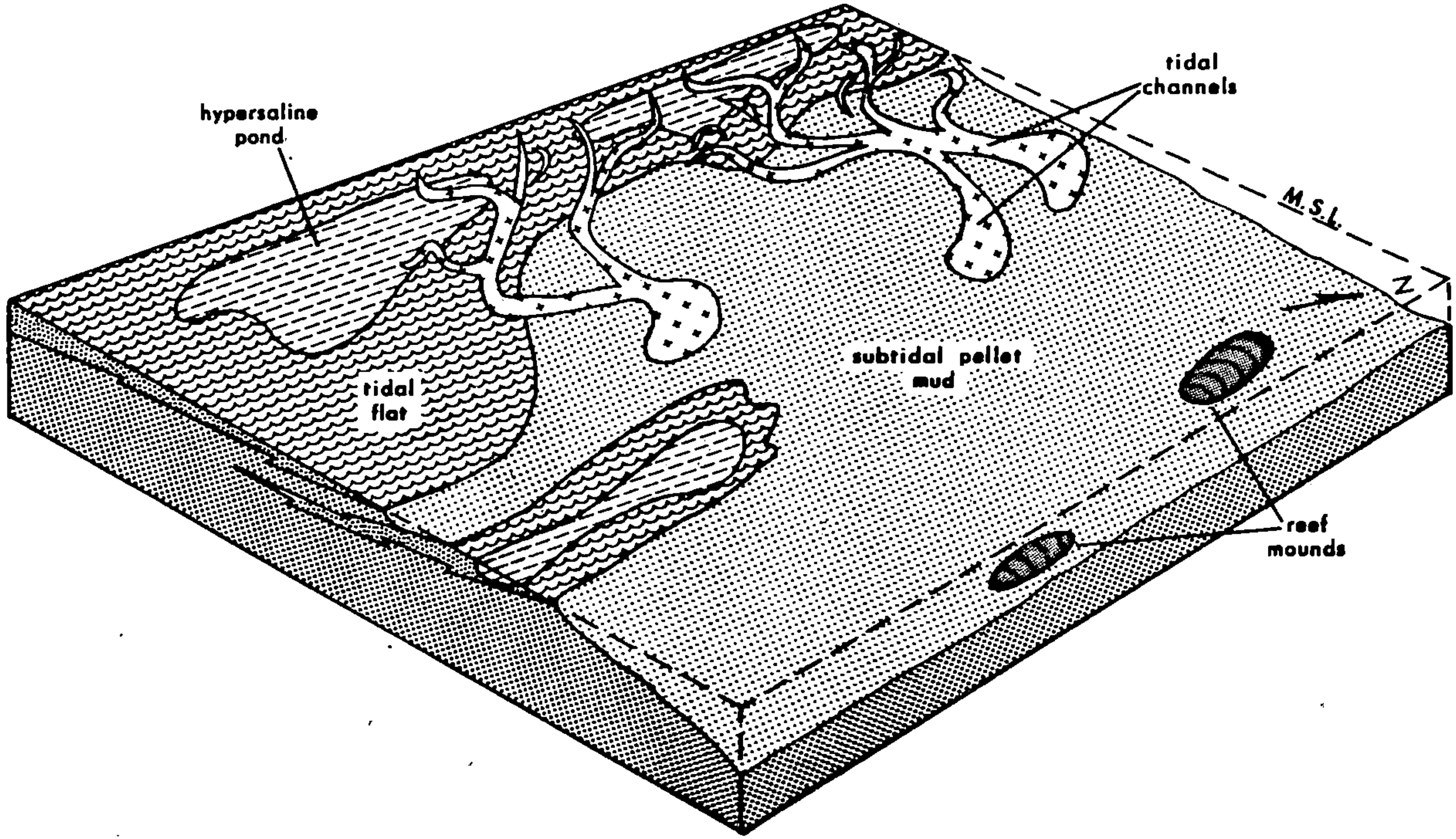

Figure 31. Schematic summary of depositional environments in the East Penwell San Andres Unit.

Petrographic evidence suggests that sulfates were probably entirely anhydrite at some time during the diagenetic sequence and are now partly hydrated to gypsum. Presence of gypsum in the formation is especially noteworthy because the bound water in this mineral affects interpretation of core-analysis data and wireline logs (see review of this phenomenon in the Dune field section of this report).

Facies Isopachous Maps

Thirteen cores are available from the upper San Andres Formation, and these data points may be used to construct facies isopachous maps. Cross plots of wireline-log data were used in an attempt to identify facies from log data so that wells without cores could be used as data points for mapping. However, no distinguishable patterns were observed in log cross plots, and maps can be made only with data from cored wells.

The isopachous map of net-tidal-flat facies (mudstone and pisolite packstone) indicates that these facies are generally thicker in the western portion of the East Penwell San Andres Unit and thin downdip to the east. Modifying this general pattern is an area of relatively thick tidal-flat sediments in the southern third of the unit. The net-algal-grainstone data are sufficiently sparse that they could be contoured in more than one manner with equal degrees of confidence. The net-algal-grainstone isopachous map is contoured with a generally east-west grain, approximately parallel to structural and depositional dip, consistent with the petrologic interpretation of algal grainstone as tidal-channel deposits.

PRODUCTION PATTERNS

Production maps are useful tools for evaluating reservoir heterogeneity. In the case of old fields such as Penwell, however, production data are generally unavailable on a per-well basis. In the East Penwell San Andres Unit, production data are available from the operator on a per-well basis only for the years postdating initiation of the waterflood in 1970. Production data before 1970 are available in the files of the Railroad Commission of Texas on a per-lease basis. These per-lease data may be apportioned to wells using the results of periodic tests. Thus, by combining records available from the operator and in the files of the Railroad Commission of Texas, the per-well production history of the unit can be reconstructed.

The long production of old fields such as Penwell results in a mixture of wells that have been on production for decades with wells that have been on production for only a few years. Moreover, the well spacing in this unit is uneven. These factors introduce "cultural effects" in production maps that obscure production patterns controlled by reservoir heterogeneity. To minimize these cultural effects the production for each well was divided by the number of years that well had been producing, yielding an average production value. Next, average production for each well was apportioned within a 40-acre grid such that a single data point, expressed as Mbbl/year/acre, was assigned to each cell in the grid. The resulting map (fig. 32) removes cultural effects and illustrates production anomalies resulting from reservoir heterogeneity. The low average cumulative production values in the southern part of the unit represent the relatively thick, nonreservoir tidal-flat sediments in this area. The elongated east-west zones of high production in the northern part of the unit represent inferred tidal channels.

LOG ANALYSIS

Porosity logs must be calibrated with cores to provide porosity data in wells for which cores are unavailable. A major consideration in evaluating the log and core data in the East Penwell San Andres Unit is that this reservoir contains gypsum, as has been discussed earlier. A calibration of acoustic transit time from wireline logs with core porosity collected using low-temperature analytic techniques yielded an excellent correlation ($r = 0.90$, $n = 298$), and this relationship allows calculation of porosities in wells for which low-temperature core analysis data are unavailable.

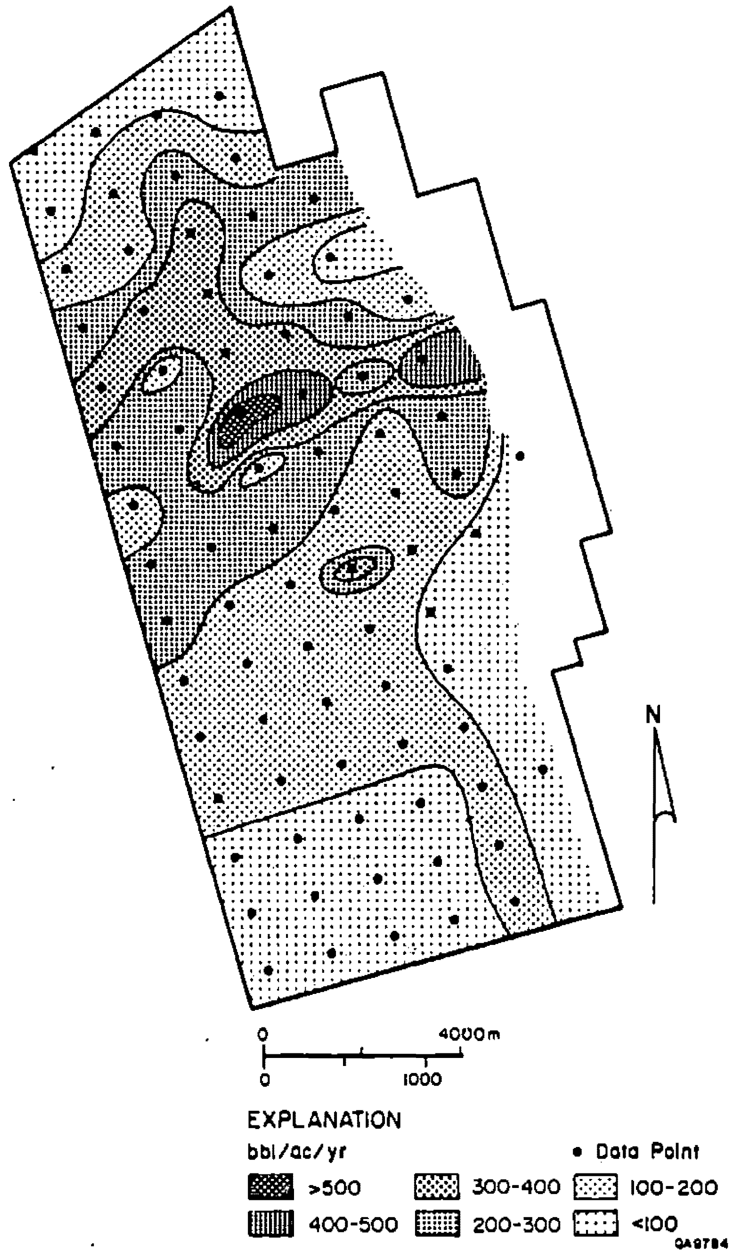

Figure 32. Average cumulative production for the East Penwell San Andres Unit. The east-west-trending areas of highest average cumulative production represent the trends of inferred tidal channels.

Oil saturations were calculated from wireline logs with the Archie equation (Archie, 1942), using the acoustic log calibration based on low-temperature core analysis and a cementation factor derived from point-count data collected from more than 50 thin sections. The Archie equation also requires a water resistivity value. Inasmuch as Penwell field has been waterflooded for many years and all resistivity logs in the unit were run after the initiation of the waterflood, the values of water resistivity vary across the field. Water analysis data provided by the operator were used to calculate water resistivity values, which were used to calculate oil saturations in wells for which both an acoustic log and a resistivity log are available.

LOCATION OF ORIGINAL AND REMAINING MOBILE OIL

Original mobile oil was located using the saturations calculated by the methods outlined earlier. Whereas the top of the reservoir is clearly defined by the top of the San Andres Formation, the bottom is not as well defined. No clear free-water level is present in the original producing zones, and recent wells encountered deeper zones capable of producing oil. The bottom of the reservoir, for the purpose of locating original mobile oil, was taken to be 130 ft below an arbitrarily chosen gamma-ray marker, the approximate depth to which most wells were drilled. The combined effects of most wells not reaching the base of the reservoir and many wells not having a complete log suite resulted in an original mobile oil map that covers only 70 percent of the unit area, although the most prospective updip and northern parts of the unit have adequate data for evaluation.

The cumulative production data were subtracted from the original mobile oil in place data to yield a map of remaining mobile oil (fig. 33). Note that there are no data points posted on the map illustrated in figure 33 because it is the difference of two contour maps constructed from different data points. The key feature illustrated in figure 33 is the concentration of remaining mobile oil in the northwestern part of the unit. This feature corresponds to the tidal-channel trends illustrated in

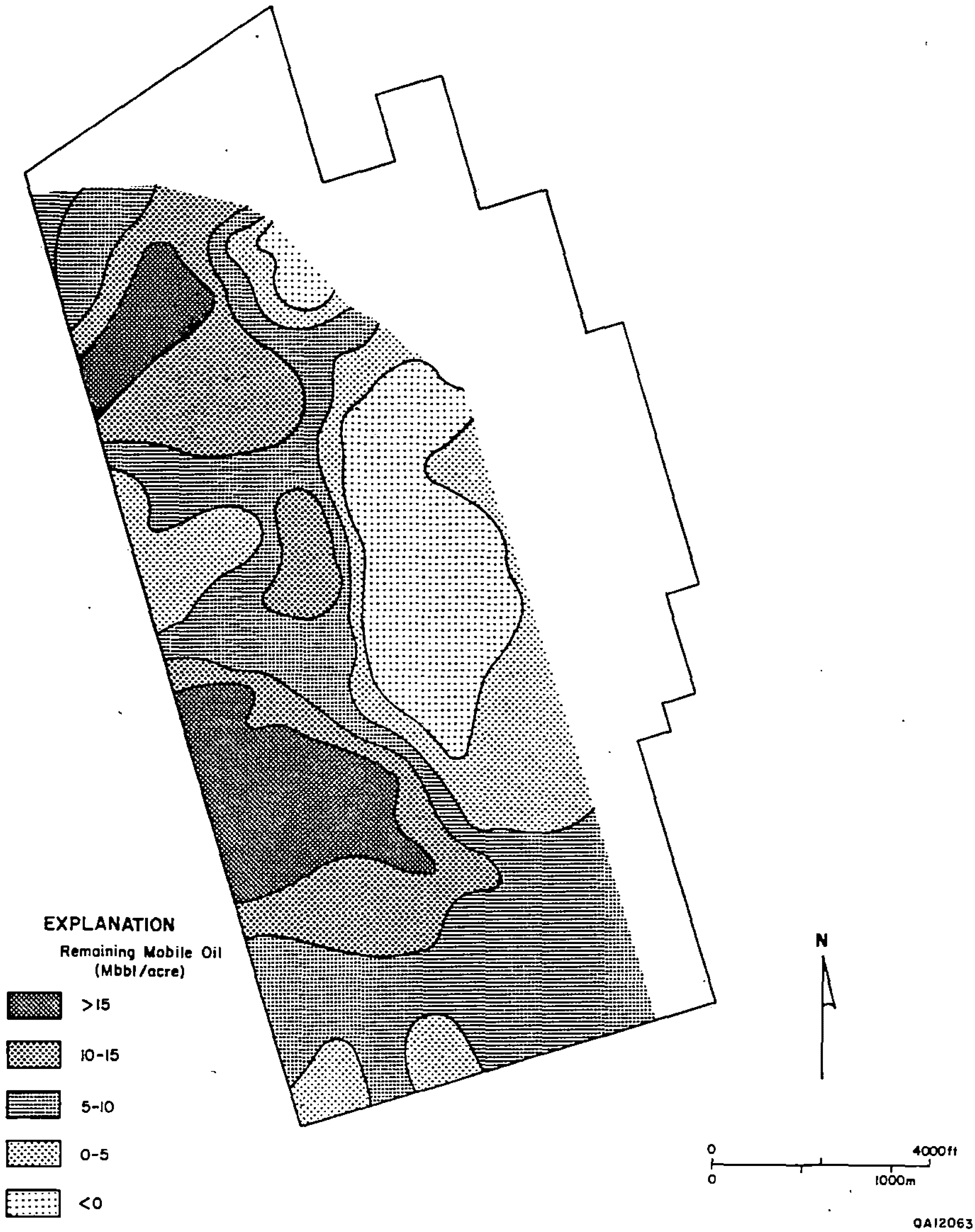

Figure 33. Remaining mobile oil map calculated using Rw values obtained from analyses of produced water.

figure 32. This concentration of remaining mobile oil in the updip portion of this trend is associated with high primary porosity preserved in pellet grainstone adjacent to porous algal grainstone, which was deposited in tidal channels.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

The University Lands share of the East Penwell San Andres Unit contains 21 MMSTB of remaining mobile oil. The remaining mobile oil map indicates this oil is concentrated in pellet grainstone adjacent to tidal-channel deposits in the updip portion of the unit. This geologically located concentration of remaining mobile oil is targeted for infill development drilling. It is emphasized that this volume of remaining mobile oil resides in the main reservoir at Penwell and that the newly drilled deeper zone will probably increase reserves substantially.

The unit operator, Fina Oil and Chemical Company, plans an extensive infill drilling program, involving the drilling of 20 or more geologically targeted wells. Fina representatives have visited the Bureau to review the results of the Penwell study and have been provided with copies of maps, cross sections, production data, and other geologic and engineering products of Bureau research to guide their development program. Additionally, Fina plans to collect more cores from the new deeper pay zone in the upper San Andres Formation, where they will use low-temperature, non-gypsum-destructive analytic techniques to evaluate these valuable materials.

In the course of studying the San Andres reservoir at Penwell field it became apparent from review of old records, some of which are available at the University Lands Office but were not in the files of the unit operator, that gas production in the 1930's, 40's, and 50's demonstrated the existence of a reservoir in the Grayburg Formation at Penwell field. Current production at Penwell is exclusively from the San Andres Formation. The resulting Grayburg play, which will be described in the "Field Extension" part of this report (p. 240), has the potential to significantly increase revenues from University Block 35 through exploitation of a new pay zone.

JORDAN SAN ANDRES RESERVOIR

INTRODUCTION

Jordan field is located on the eastern margin of the Central Basin Platform, on the Ector and Crane county line (fig. 14). The field is part of a five-field complex that produces oil from a combined structural and stratigraphic trap on the east flank of a broad, asymmetric anticline (fig. 34) (Major and others, 1988). Discovered in 1937, Jordan produces oil from a Permian (Guadalupian) San Andres Formation reservoir at a depth of approximately 3,500 ft (fig. 34). A program of infill drilling, well deepening, and conversion of producing wells to water-injection wells began in 1969, following peripheral waterflooding in 1968. By 1971 the University Lands part of the field was on a modified five-spot waterflood with a producing well spacing of approximately 20 acres per well.

The two Jordan field units on University Lands together have produced 68 MMSTB of the 182 MMSTB of OOIP. An estimated 40 MMSTB of mobile oil will remain in the University Lands part of the reservoir under the current development program (calculated from data available in the files of the Railroad Commission of Texas). This high remaining mobile oil resource prompted a combined geological and engineering study of the Jordan San Andres reservoir on University Lands to develop strategies for recovering this remaining mobile oil.

GEOLOGICAL SETTING

Introduction

Lithologic description of the San Andres reservoir at University Lands Jordan field is based on examination of 7 cores from two University Lands units, augmented by 2 Jordan field cores from immediately west of the University Lands boundary and 13 cores from the East Penwell San

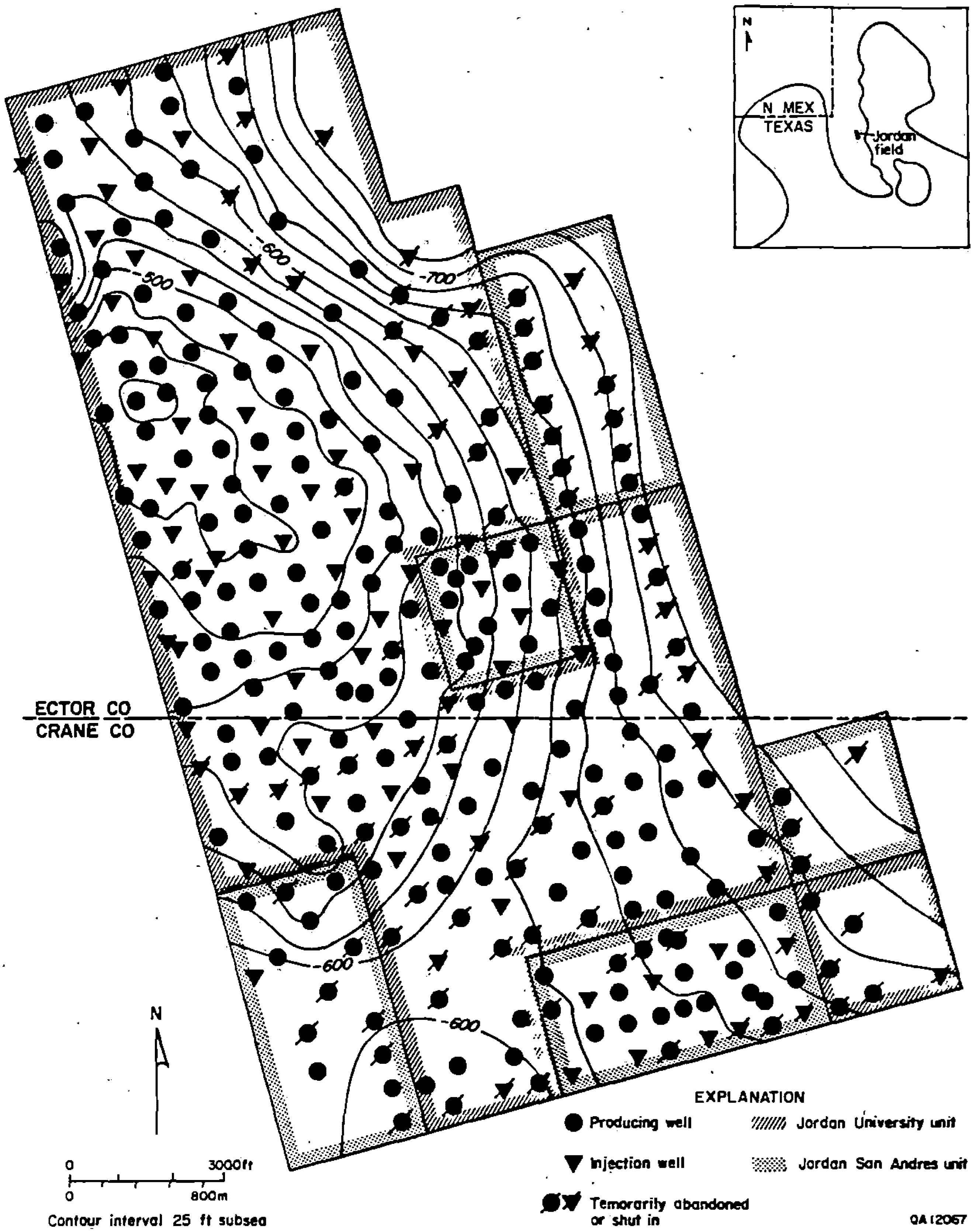

Figure 34. San Andres Formation structure map for University Lands Jordan field, which lies on the east flank of an anticline.

Andres Unit, which offsets Jordan field to the north (Major and others, 1988, Major and others, in press). The reservoir is composed of thoroughly dolomitized carbonate rocks cemented by sulfates.

Depositional Facies

The San Andres Formation at Jordan field is composed of an approximately 400-ft-thick, upward-shoaling sequence of rocks deposited as shallow-water ramp sediments (Major and others, 1988). It is convenient for this discussion to divide description of depositional facies into two parts, rocks deposited as tidal-flat sediments and rocks deposited as open-marine sediments.

Tidal-Flat Depositional Facies. Tidal-flat facies are pisolite packstone and mudstone. Pisolite packstone is composed of symmetrical and asymmetrical pisolites having diameters generally in the range of 0.2 to 4 mm and fine-grained muddy matrix. Pisolites commonly have a fitted fabric. This facies is characterized by abundant caliche, fenestrae, desiccation cracks, and sheet cracks. Locally the pisolite packstone facies contains karst collapse breccias generally less than 1 m thick. This facies is generally nonporous but locally is both porous and permeable. The presence of caliche, collapse breccia, and desiccation features indicates periodic subaerial exposure, and the pisolite packstone facies is interpreted to have been deposited in an intertidal or supratidal environment.

Mudstone is composed of cream-colored, generally massive dolostone, although some mudstone is faintly laminated. Stromatolitic laminae are present but rare. Mudstone composed of generally smaller-than-0.02-mm dolomite crystals and is barren of fossils, suggesting it was deposited in a hypersaline environment in which stromatolites could survive but marine invertebrates were excluded. The absence of fossils and the close association with the pisolite packstone facies suggest deposition in hypersaline ponds on a tidal flat that was isolated and probably landward of the open-marine depositional environment.

Tidal-flat facies are interbedded with three intervals of peritidal siliciclastic silt that may be correlated regionally using gamma-ray logs. Tidal-flat facies are separated from subjacent open-marine facies by an interval of greenish-gray organic-rich shale that may be correlated throughout Jordan field using gamma-ray logs.

Open-Marine Depositional Facies. Open-marine facies are pellet packstone/grainstone and bioherms composed of bryozoans, algae, and corals with associated flanking facies of skeletal grainstone. The pellet packstone/grainstone facies is composed of spherical to ovoid fecal pellets approximately 0.2 to 0.5 mm in diameter and variable amounts of mud matrix. Fossils of open-marine invertebrates are common, especially fusulinids and bivalves. Burrow structures are rare, and laminations are generally absent because of bioturbation. Fecal pellets were deposited as soft carbonate mud and exhibit a wide range in degree of preservation. Where pellets are well preserved, the rock has interparticle porosity; where pellets have been destroyed by compaction, porosity is low and is generally intercrystalline and/or moldic. The thorough bioturbation and presence of abundant fossils of open-marine invertebrates indicate that this sediment was deposited in a shallow subtidal setting, similar to subtidal pelleted mud common in Holocene carbonate shelf and ramp settings.

Bryozoan, algal, coral bioherms occur locally and discontinuously in the lower part of the subtidal section. Crinoid fragments are a common accessory grain in this facies. Bioherms contain abundant internal mud matrix, and geopetal structures are common. Bioherms are generally nonporous. Skeletal grainstone composed principally of bryozoan and crinoid fragments and, less abundantly, fusulinid and mollusk fragments, are closely associated with bioherms. The presence of abundant fossils of open-marine organisms, lack of desiccation features, and association with pellet packstone/grainstone indicate that bioherms and associated skeletal grainstone were deposited in a subtidal environment.

Diagenetic Effects

Tidal-flat pisolite packstone is generally nonporous because fenestrae and sheet cracks are cemented with sulfates. Locally sulfate cementation was either incomplete or did not occur or, more probably, sulfate cements were leached. Where little or no cement occurs in pisolite packstone, this facies is porous and permeable. The volumetrically dominant pore type is fenestral (vuggy). This diagenetically controlled porous texture is important because, where present, the pisolite packstone facies is part of the reservoir, but where this facies is nonporous it is part of the reservoir seal.

Open-marine facies have been partially to completely altered by a postburial leaching event. The "diagenetically altered" dolostone can be identified on slabbed core surfaces as tan- to brown-colored dolomite that contrasts with the dark-gray color of unaltered dolomite. Altered dolomite in some cases mimics the geometry of burrows, whereas in other cases it forms aureoles around stylolites, indicating that the fluids that caused this alteration preferentially flowed through burrows and along stylolites. This association demonstrates that diagenetic alteration was a postburial, postcompaction event.

The diagenetically altered dolomite is more permeable than the unaltered dolomite. Permeability data collected from slabbed core face using a minipermeameter (Eijpe and Weber, 1971, Chandler and others, 1989) indicate that unaltered dolomite has a permeability of approximately 1 md, whereas altered dolomite has permeabilities of approximately 10 md (minipermeameter analyses were courtesy of M. G. Kittridge, Department of Petroleum Engineering, The University of Texas at Austin). Importantly, the irregular geometry of this diagenetic alteration results in such close spatial association of these two rock types that this order-of-magnitude difference in permeability is commonly below the resolution of conventional core plug or whole-rock permeability analyses.

Higher permeability, diagenetically altered dolomite is characterized by hollow and corroded dolomite rhombs visible at the scanning electron microscope level of resolution, indicating that the alteration was a carbonate leaching process. Diagenetically altered dolomite is commonly closely associated with anhydrite nodules rimmed by gypsum, and thin section point-count data confirm the association of diagenetically altered (leached) dolomite and gypsum. Some samples of diagenetically altered rock contain as much as 20 percent gypsum. It can be inferred from this relationship that the fluids that caused the leaching of the dolomite also altered some of the anhydrite nodules and cements to gypsum.

ENGINEERING AND PRODUCTION ATTRIBUTES

Calibration of Logs and Cores

Acoustic, neutron, and density porosity logs are available at Jordan field. As shown earlier in this report, the presence of abundant gypsum in the reservoir precludes the use of neutron and density logs for porosity measurements. All of the cores available from University Lands Jordan field were analyzed using high-temperature gypsum-destructive methods and were, therefore, not suitable for calibration of logs. Low-temperature core analysis data were available from four San Andres cores from wells adjacent to University Lands Jordan field, and these data yielded an excellent correlation with acoustic transit time ($r = 0.90$, $n = 369$). Importantly, this acoustic log calibration is valid for both open-marine facies, in which porosity is dominantly interparticle, and tidal-flat facies, in which porosity is dominantly fenestral (vuggy).

Because responses of neutron and acoustic logs to gypsum-bearing rocks differ, these two logs can be used to identify diagenetically altered rock textures in wells that are not cored. As indicated previously, the high-permeability diagenetically altered rock contains more gypsum than unaltered rock. Thus, altered reservoir rock containing abundant gypsum may be identified on wireline logs where dolomitic neutron log porosity exceeds acoustic porosity normalized to a dolomite matrix.

Flow Units

The University Lands Jordan San Andres reservoir is divided into four flow units on the basis of both depositional and diagenetic facies. Subtidal rocks are divided into three flow units defined by the stratigraphic patterns of diagenetically altered dolomite as identified with wireline logs. The lowermost A zone is 100 percent or nearly 100 percent altered-texture rock characterized by a neutron log–acoustic log porosity curve separation. The overlying B zone is composed of diagenetically unaltered rock characterized by a normalized neutron log that is in good agreement with a normalized acoustic log. The overlying C zone is composed of a mottled mixture of diagenetically altered and unaltered rock and is characterized by a normalized neutron log–normalized acoustic log separation.

The uppermost D zone is composed of tidal-flat rocks that occur above the organic-rich shale identified by a gamma-ray marker. This marker can be correlated across the field. Porosity in the tidal-flat section occurs in pisolite packstone in which fenestrae and sheet cracks are not plugged with sulfate cements.

Reservoir storage capacity (ϕh) maps were constructed for three flow units using the acoustic transit time/porosity relationship developed for low-temperature core data. A porosity cutoff of 5 percent was used to construct these maps. A reservoir storage capacity map was not constructed for the A zone because no well bores penetrate the base of this zone and because very few wells penetrated to the depth of this zone before the period of well deepening and infill drilling in the early 1970's, immediately before initiation of the waterflood. Before the waterflood was initiated, most wells were open-hole completed.

The B zone ϕh map (fig. 35) indicates relatively low reservoir storage capacity in this zone in the downdip northern and eastern parts of the University Lands Jordan field and relatively high

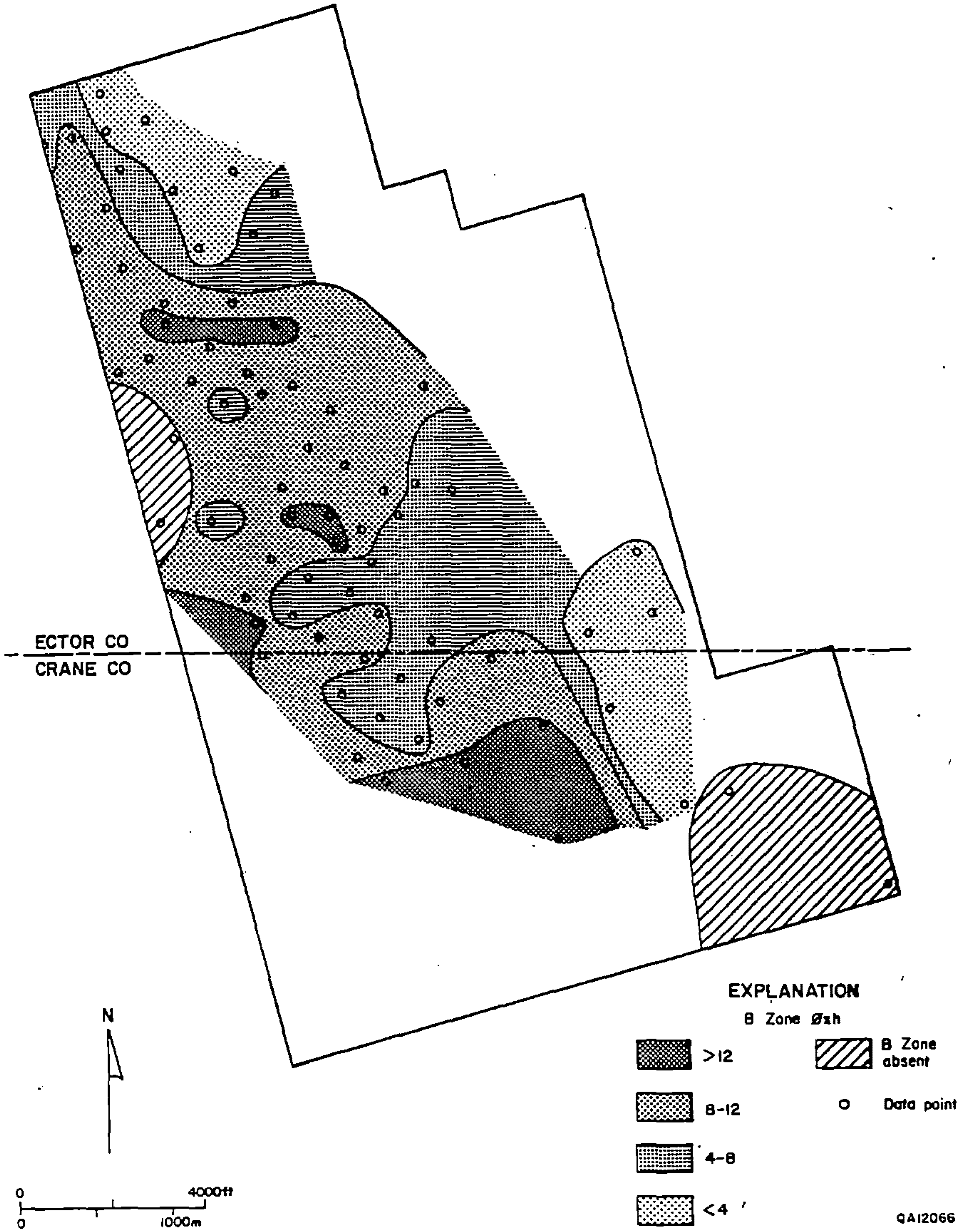

Figure 35. B zone reservoir storage capacity (ϕh) map. The area of highest reservoir storage capacity occurs in an updip position in the western and southwestern parts of the field.

storage capacity in the southwestern updip part of the field. The updip central western boundary and the downdip southeastern corner of the field are areas where the B zone is absent and the A zone and C zone cannot be differentiated.

The C zone ϕh map (fig. 36) illustrates a trend of relatively high reservoir storage capacity extending from the updip central western boundary of the field to the downdip southeastern corner. A zero ϕh contour separates this trend from the downdip northeastern corner and the updip southwestern corner of the field.

The D zone ϕh map (not shown) has an irregular pattern of isolated areas of relatively high reservoir storage capacity. The zone of highest storage capacity occurs in the downdip eastern part of the field.

Production Patterns

To evaluate the patterns of reservoir storage capacity illustrated by the ϕh maps, we need to view production in map view at various times during the production history of the reservoir. Per-well production data are available from the operators only for the period after the waterflood—1969 to the present. Prewaterflood production data by lease and periodic well test data are available from the Railroad Commission of Texas. These data were used to construct average production maps on a 40-acre grid in a manner similar to that used in the Penwell production maps discussed earlier in this report.

The map of averaged cumulative production to 1988 (fig. 37) exhibits a trend of relatively high production extending from the updip central western margin of the University Lands Jordan field to the downdip southeastern corner. The updip southwestern corner of the field is an area of relatively low production. A cumulative production map for prewaterflood production (1969 cumulative production) and production map for postwaterflood production (1969 to 1988 production) have similar patterns.

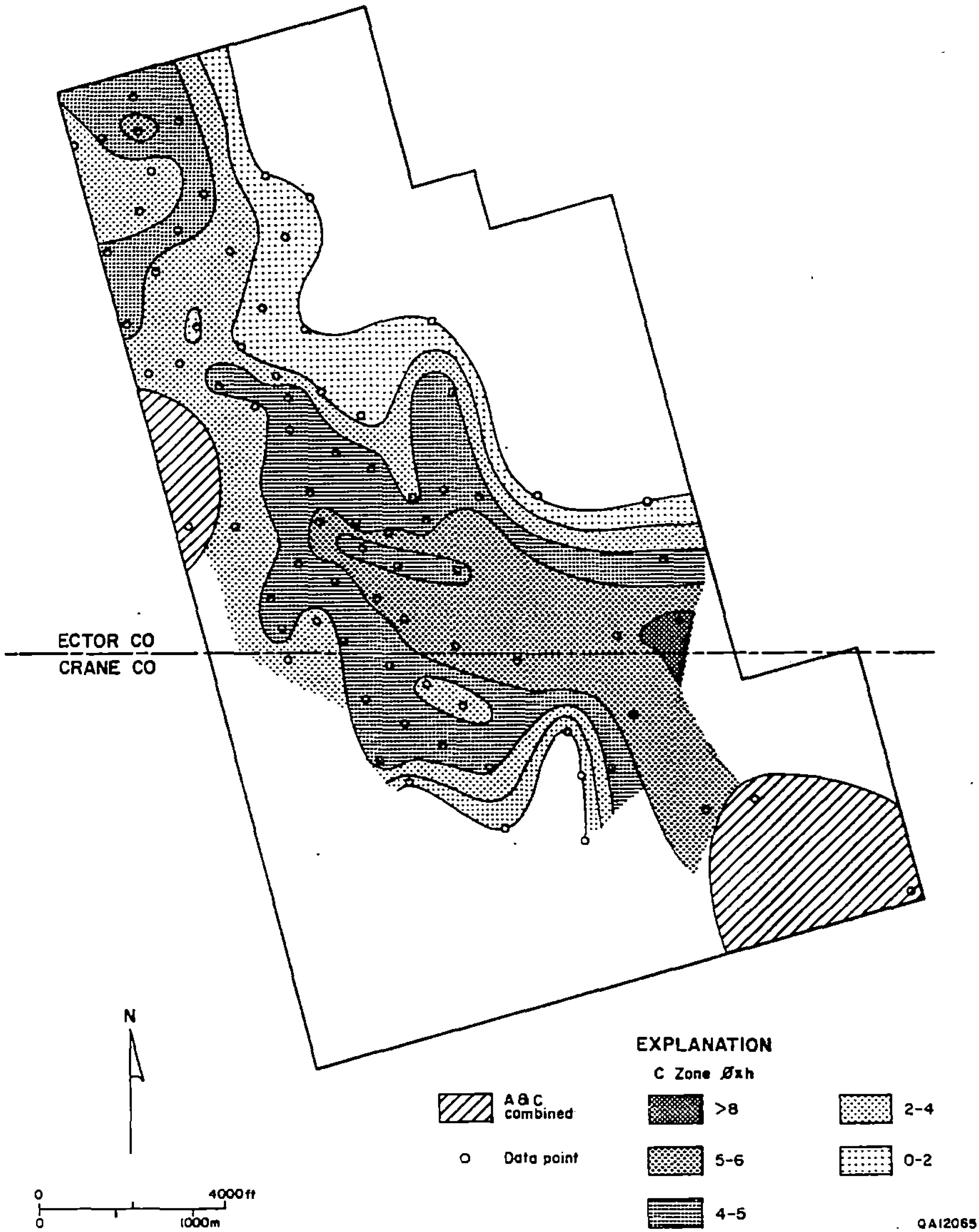

Figure 36. C zone reservoir storage capacity (ϕh) map. The area of highest reservoir storage capacity occurs along a trend that crosscuts structure from the central western to the southeastern parts of the field.

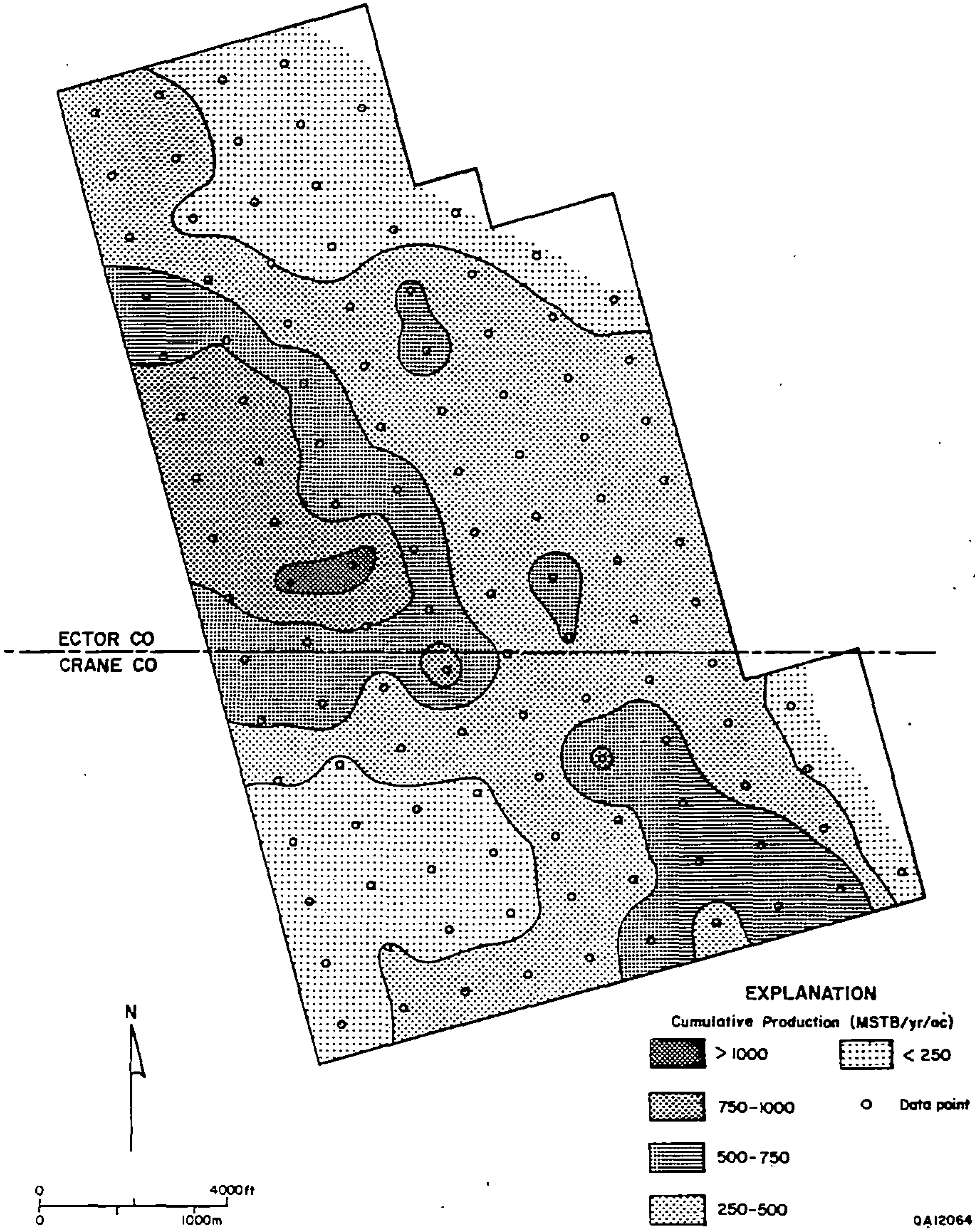

Figure 37. Average cumulative production to 1988 for University Lands Jordan field. The trend of highest production crosscuts structure from the central western to the southeastern parts of the field.

Discussion

Comparisons of the ϕh maps (figs. 35 and 36) with the cumulative production map (fig. 37) indicate some correlations. Note that when comparing these maps, the ϕh data points are limited to those wells for which both acoustic and neutron logs are available. In contrast, the cumulative production map data points are averaged production normalized on a 40-acre grid. Thus, the data control for these two types of illustrations is very different. Note also that the similarities in the patterns in the 1988 cumulative production map, the 1969 cumulative production map, and the 1969 to 1988 production map indicate that the waterflood did not alter the loci of relatively high and relatively low production in the field.

The northwest-trending zone of high reservoir storage capacity in the C zone (fig. 36) cross-cuts structure and correlates well with the trend of relatively high production (fig. 37), indicating that this diagenetically altered, high-permeability zone is the main source of oil for both prewaterflood and postwaterflood production. The updip southwestern area of high reservoir storage capacity in the B zone (fig. 35) corresponds to an area of relatively low cumulative production (fig. 37), indicating that this diagenetically unaltered, relatively low permeability zone was not a large contributor to prewaterflood production and has been inefficiently swept by the waterflood. The irregular reservoir storage capacity pattern in the D zone (not shown) reflects the discontinuous distribution of porous pisolite packstone.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

The University Lands Jordan San Andres reservoir is composed of an approximately 400-ft-thick sequence of upward-shoaling, shallow-water carbonate facies now thoroughly dolomitized and cemented with sulfates. Postcompaction, postburial diagenetic alteration leached carbonate and partially altered gypsum to anhydrite. This diagenetic alteration, which affected some parts of the reservoir but not others, increased permeability.

The locus of highest oil production is from the C zone, which was affected by this permeability-increasing diagenetic alteration. The B zone, which was not diagenetically altered, is a zone of relatively low oil production and has been inefficiently swept by the waterflood. The B zone contains an area of high reservoir storage capacity in the updip southwestern part of the unit (fig. 35). Selective well-bore plugging and perforation squeezing may focus injection water into the B zone in the southwestern part of the unit, thus contacting much of the bypassed mobile oil that would otherwise remain in the reservoir. Alternatively, new horizontal drilling technologies now make it cost-effective to drill boreholes that efficiently drain low-permeability reservoirs. A few carefully targeted horizontal wells in the B zone could vastly increase production from the southwestern part of the unit. We have discussed our results with the principal Jordan field operator, Shell Western Exploration and Production Company, and we have provided them with reprints of our first publication resulting from this study (Major and Holtz, 1989).

FARMER GRAYBURG RESERVOIR

INTRODUCTION

The Farmer field on University Blocks 47, 48, 49, and 50, Crockett and Reagan Counties (fig. 14) was discovered in 1953 and had produced 17 MMSTB of oil through 1987; most of this field is on University Lands. Waterflooding has not yet been implemented, and primary recovery efficiency is only 8 percent. Remaining mobile oil is calculated to be 36 MMSTB. Because this field is in early stages of development, results of Bureau recovery research have the potential of having significant impact on development strategies by the operators.

The Farmer Grayburg reservoir study (fig. 38) involves Sections 4, 5, 8, and 9 of Block 50 and Section 10 of Block 47, all in Crockett County. Initial drilling in the 1950's was on 40-acre

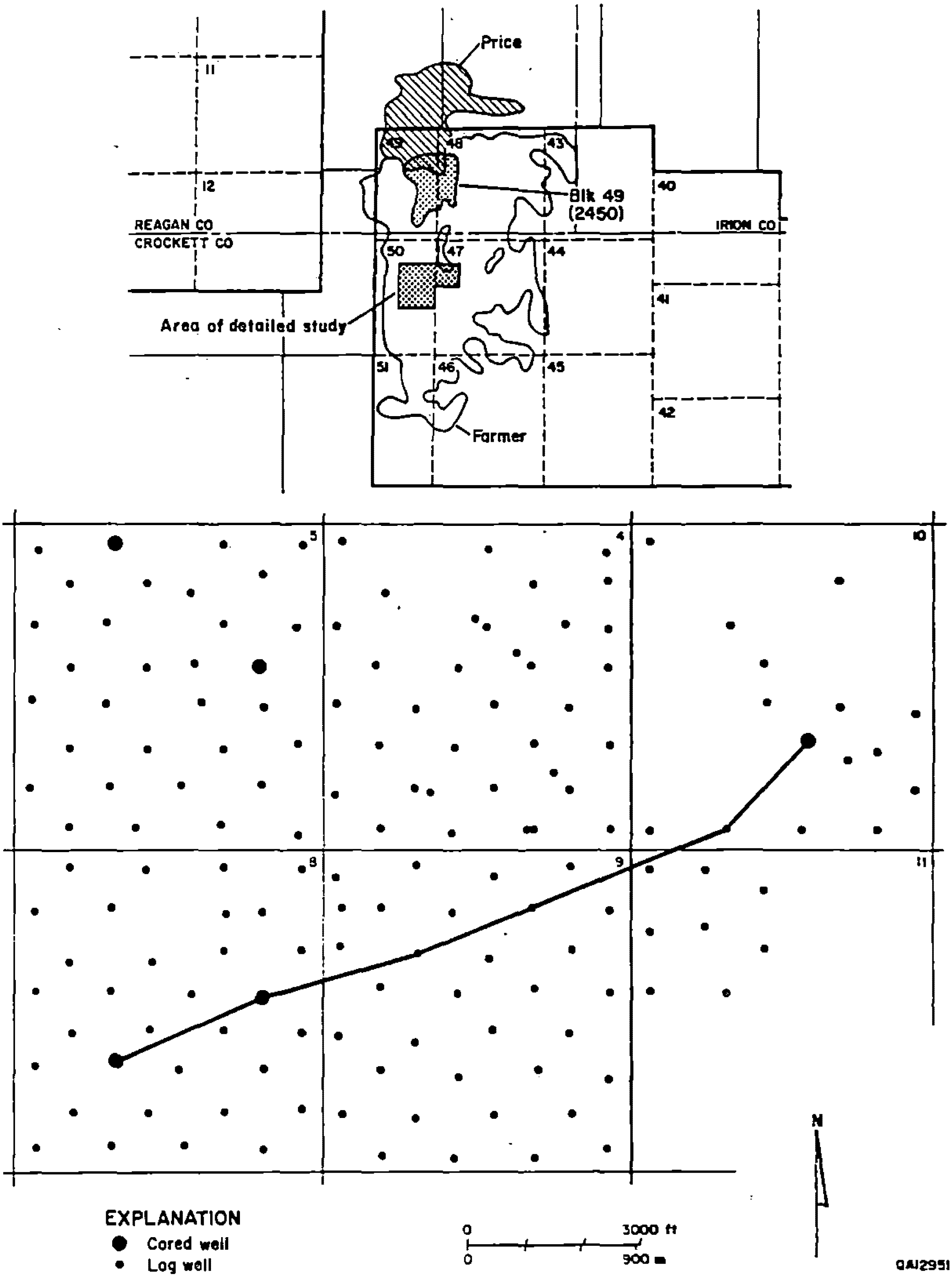

Figure 38. Map showing location of the study area within the Farmer field, well density within the study area, and facies cross section shown in figure 39.

spacing. Twenty-acre spacing was accomplished in Sections 4, 5, 8, and 9 in 1987; Section 10 now includes 18 undrilled 20-acre locations. Produced formation water has been injected back into the reservoir from two wells in this study area (Phillips No. 8, Section 4; Warren No. 5, Section 9).

Only cased-hole gamma-ray and neutron/density logs were obtained from wells drilled before 1987, and the few cores that were taken were subjected to high-temperature analyses. The presence of abundant gypsum in the reservoir section renders these analyses ineffective because high temperature drives water out of gypsum, thereby producing anomalously high porosity readings. However, wells drilled in 1987 and 1988 were logged with resistivity and sonic tools in addition to the gamma-ray and neutron/density logs, and cores were analyzed using low-temperature techniques not destructive to gypsum. The availability of long cores from four wells and modern wireline logs from all wells drilled in 1987 and 1988 was an important factor in selecting the study area. Production histories for all wells in the area were provided by the operators.

GEOLOGICAL SETTING

Introduction

The Farmer field is located on the Ozona Arch at the south end of the Midland Basin. At the time of deposition of the reservoir section, the Midland Basin was restricted in areal extent and very shallow, and the Ozona Arch represented a low threshold across which water was exchanged between the open ocean to the south and restricted basin to the north. Tidal currents and energy from waves breaking on the shallow-water platform probably formed carbonate sand waves, bars, and islands. Migration of these sand bodies across the stable platform resulted in the accumulation of multiple thin, upward-coarsening cycles.

Facies Distribution

The approximately 350-ft-thick reservoir section is composed of at least 14 major cycles (fig. 39), which range in thickness from 15 to 40 ft. Characteristically, each cycle is represented by siltstone and silty mudstone to wackestone in the lower part and packstone to grainstone in the upper part. The silty mudstone to wackestone contains a low-diversity fauna of mollusks and dasycladacean algae, suggesting conditions were unfavorable for fusulinids, crinoids, and brachiopods, which are present in most Permian subtidal sediments. Burrows are the common structure. This lower section accumulated in subtidal, low-energy conditions, probably under somewhat restricted conditions.

The upper part of each cycle contains considerably more grains and varies from packstones to grainstones. The grainstones are more common and are generally finer grained and pelletal in the lower part and coarser grained toward the top. The top few feet are again finer grained, perhaps indicating reworking of the top sediment of the grainstone bar. The coarser grained portions of some cycles are made up of ooids, skeletal grains, or intraclasts. Burrows are the dominant structure in the finer grained grainstones; laminations, crossbedding, and graded bedding are rare and occur only in the coarser grained grainstone facies. Because of the abundance of burrows, most of the fine-grained grainstones are interpreted to have accumulated on a stable grain flat leeward of a bar complex. The high-energy bar environment is represented by the less-common laminated and crossbedded ooid facies, which occurs in only a few cycles.

ENGINEERING CHARACTERISTICS

Rock Fabrics

The geologic description was converted into an engineering model by relating the rock fabrics to petrophysical parameters. In the Farmer field, rock fabric studies revealed two basic pore

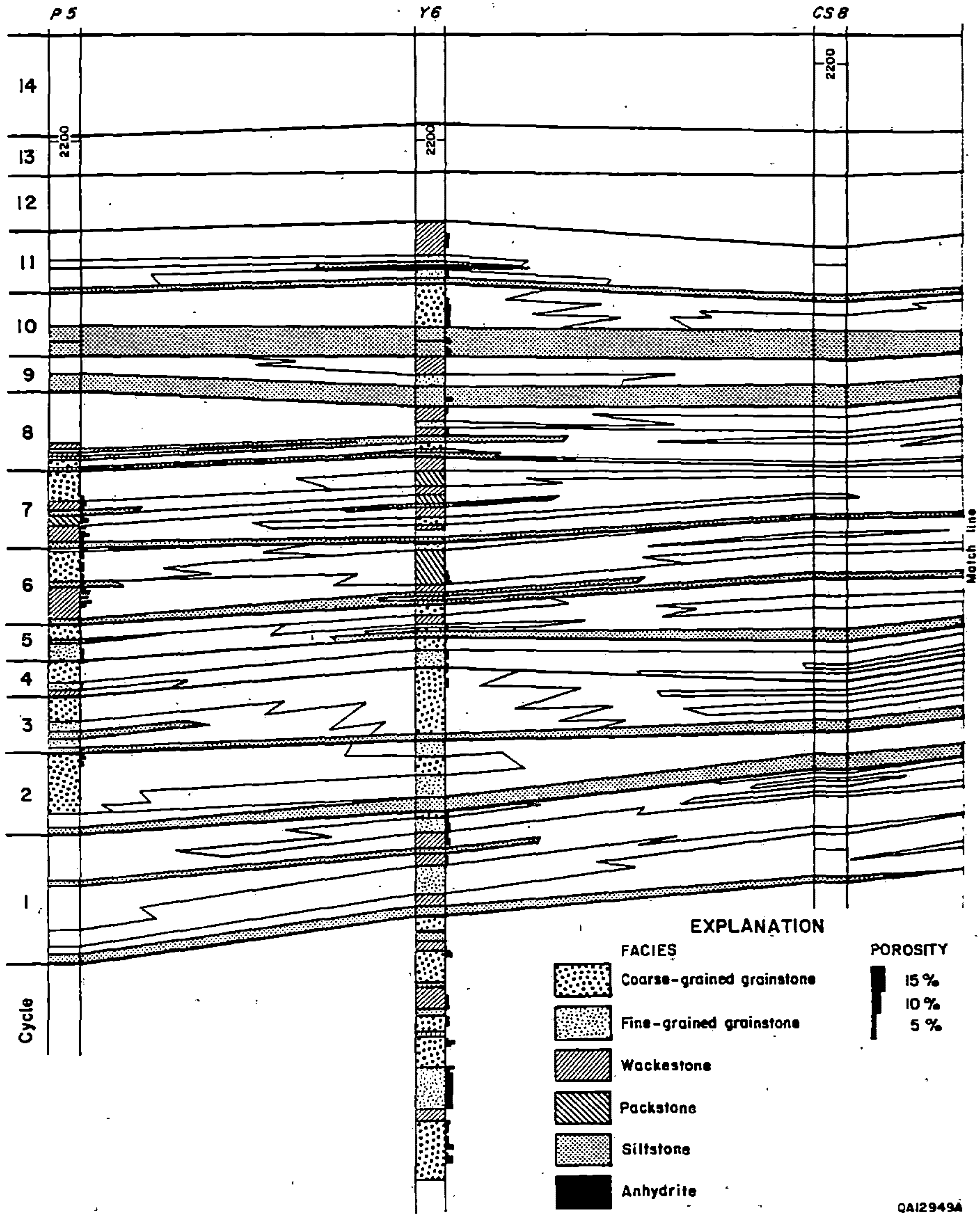

Figure 39. East-west facies section across the study area using wells with core for identification of the facies. Line of section shown in figure 38.

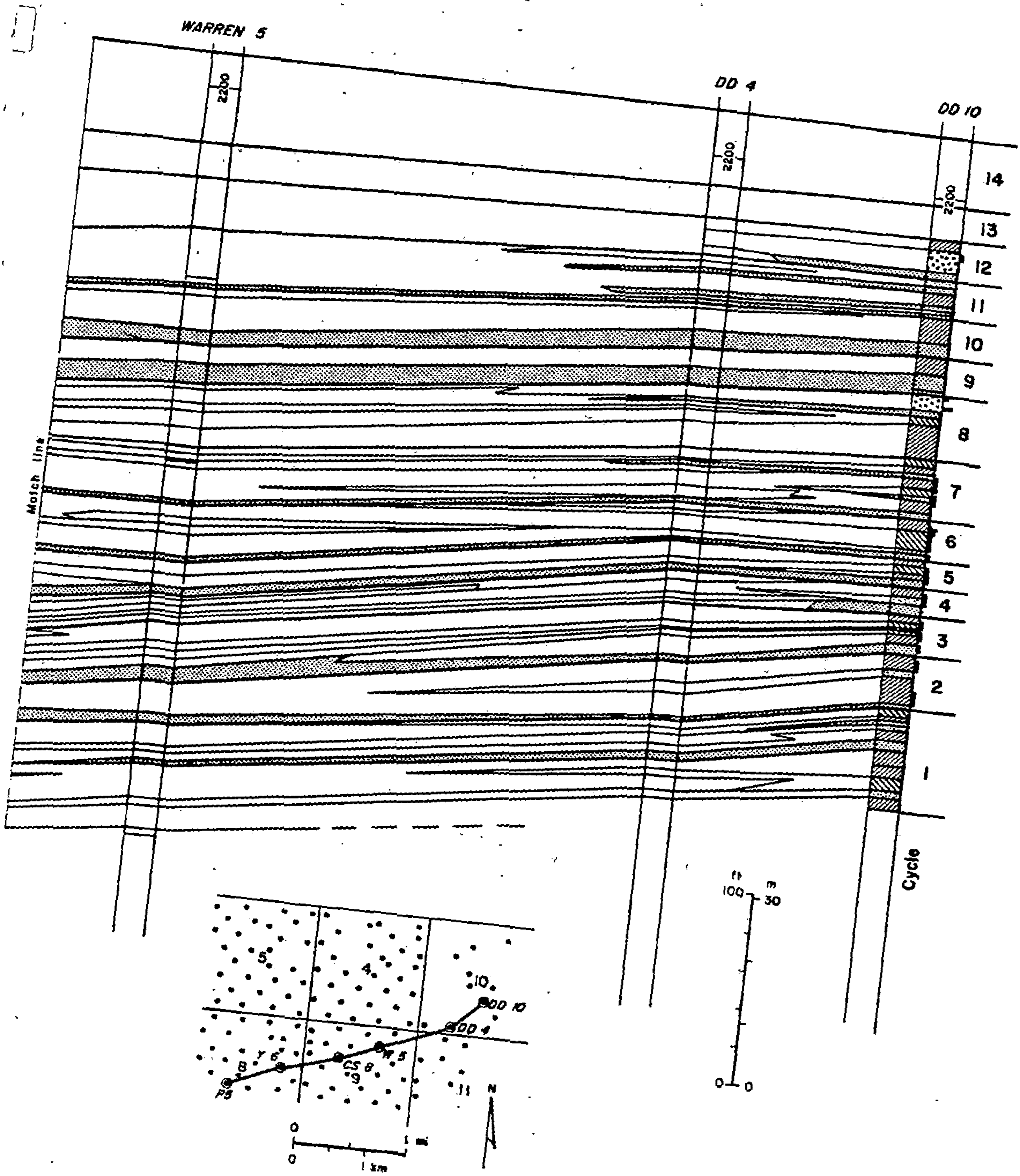

Figure 39 cont.

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fabrics; mud-dominated packstones, wackestones, and mudstones with intercrystalline pores between 10-µm dolomite crystals and grain-dominated packstones and grainstones with intergranular pores and intragranular microporosity. Pure intergranular pore space was observed in a few grainstones with high permeability, but these are exceptional.

The presence of intragranular microporosity in the grainstones increases the irreducible water saturation and reduces the permeability over what normally would be expected of a porous grainstone. This effect, together with the characteristic low permeability and high irreducible water saturation of the microcrystalline porosity in the mud-dominated sediments, results in a reservoir characterized by low-permeability pay zones in a cyclic upward-shoaling geologic sequence.

Hydrocarbon Distribution

The reservoir was divided into 15 intervals, the interval between the base of cycle 1 and free water table contains 14 upward-shallowing cycles. The free water table was located at 36 ft subsea on the basis of interval tests and capillary pressure curves. The top of the reservoir was placed at the top of cycle 12; cycles 13 and 14 are characterized as tidal-flat cycles with anhydrite beds and very shaly dolomite. The lateral dimension of the reservoir is undefined. The updip field limit to the east may be located where the grainstone facies changes to the anhydritic red-bed facies (Ward and others, 1986). The downdip limit to the north, south, and west is probably defined by a subsea structure contour about 100 to 200 ft above the free water level, a structural level well outside of the present boundaries of the Farmer field. Facies changes yet to be described also could mark the downdip boundaries of the reservoir.

Water saturations were determined using relationships between porosity, rock fabric, and height above the free water level. The Archie method was not used because the numerous thin porous beds made resistivity values unreliable. Porosity was calculated from the acoustic log calibrated to core analysis; neutron and density logs were not used because of the large volumes of gypsum present. A gamma-ray log value of 30 API units was used to distinguish the cleaner grain-dominated fabrics from the more radioactive mud-dominated fabrics.

Correlation of oil-bearing intervals shows lateral continuity from several miles to less than 1,000 ft. Types of lateral pay discontinuities observed include permeable dolograinstone intervals changing laterally and vertically into tight dolograinstones, probably due to pore-filling sulfate minerals, and permeable dolowackestones changing laterally and vertically into both low-porosity, cemented, and compacted dolowackestones and high-porosity, silty, and shaly dolowackestones with less than 0.1 md permeability.

Volumetrics

The total OOIP value for the Farmer San Andres reservoir varies considerably depending upon the method used for calculation. With the conventional method, using average reservoir area, net pay, porosity, and water saturation, the OOIP is calculated to be 216 MMSTB. With the cumulative production of 18 MMSTB, recovery efficiency is 8 percent.

Volumetric calculations obtained from a detailed cycle-by-cycle study in part of the reservoir yielded values considerably higher than did the conventional method. This cycle-by-cycle method was based on a knowledge of the geologic fabrics represented in each cycle and their associated petrophysical characteristics, as discussed previously. The stock-tank volume of oil in each cycle, divided into mud- and grain-dominated fabrics was calculated for the *five-section study area* by preparing an isopach map of SoPhiH values; the results are tabulated below. The total STOOIP is 220 MMSTB of oil, or about 40 MMSTB per section (table 25). The greater Farmer San Andres reservoir covers an area of 25 sections, and extrapolation of this value of STOOIP per section to the larger area results in an estimated 1 BSTB of OOIP on University Lands. The current estimate is that half of the oil is mobile.

To date, only 5.9 MMSTB of oil (2.7 percent) of the estimated 220 MMSTB of OOIP has been produced from the five-section study area. Under current producing operations, only about 7

Table 25. Volumetrics of STOOIP for the five-section Farmer study area, calculated by the rock-fabric method.

Cycle	Mud dom. MMbbl	Grain dom. MMbbl	Total MMbbl	Cumulative MMbbl
12	8.1	6.0	14.1	220.1
11	17.8	22.9	40.7	206.0
10	10.4	18.6	29.0	165.3
9	12.9	5.3	18.2	136.3
8	13.3	5.7	19.0	118.2
7	16.2	14.0	30.2	99.2
6	5.3	5.5	10.8	69.0
5	4.8	2.9	7.7	58.2
4	3.4	2.4	5.8	50.5
3	4.1	2.6	6.7	44.7
2	6.8	5.6	12.4	38.0
1	10.1	6.1	16.2	25.6
0	7.0	2.4	9.4	9.4
Total	120.2	100.0	220.2	1,240.5

MMSTB of primary oil will ultimately be produced, leaving more than 200 MMSTB of oil in the reservoir. The reasons for the low recovery include the low-permeability characteristics of the reservoir, discontinuous character of many of the productive intervals, and lack of perforations in many of the oil-bearing intervals.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

The principle strategies for improved recovery from the Farmer reservoir are improved methods for identifying and perforating productive intervals, development of a waterflood program, and infill drilling in the most prospective areas. The shallow depth of this reservoir suggests that, despite the low production rates, economical methods could be developed to recover a significant additional portion of the 200 MMSTB of oil that will remain in the study area.

Neutron and density logs are the most common porosity logs run in this field, and the presence of large amounts of gypsum makes these logs very difficult to interpret. As a result, many prospective pay zones have been overlooked and need to be reevaluated. Proper evaluation of these zones requires running improved cased-hole logs in existing wells and using evaluation techniques that incorporate the geologic characteristics of the reservoir in new infill wells.

As an example, Marathon Oil Company drilled 11 infill wells in 1987 from which they obtained new cores and wireline logs. These new data allowed the identification of numerous pay intervals that were not perforated in the original development wells. Production from these new pay intervals has increased production on Marathon leases from 24 MSTB of oil per year to 95 MSTB per year in the study area. This small infill program should increase reserves by about 500 MSTB.

An optimally designed waterflood will increase recovery. Any waterflood program should take into account the individual cycles and their lateral continuity and characteristics. It is clear that closer spaced wells and new cores and logs will be needed to properly waterflood this reservoir. A special effort should be made to identify intervals of dolograinstone with intergranular pore space because these intervals could give high initial primary production but will also act as thief zones in a waterflood program.

TAYLOR-LINK WEST RESERVOIR

INTRODUCTION

The Taylor-Link West San Andres reservoir (fig. 14) provides an excellent example of the importance of integrating geological and engineering information and using relationships between rock fabrics and petrophysical parameters to better understand reservoir performance. Taylor-Link represents a class of San Andres fields that have an overprint of karsting. It is similar to the Yates San Andres reservoir but differs from most other University Lands San Andres reservoirs in that they lack the impact of karsting on reservoir performance. The effects of karsting are particularly evident in the waterflood performance.

The Taylor-Link field was discovered in 1928 and covers approximately 2,000 acres on University Blocks 16 and 18, Pecos County, Texas. The reservoir zone is in the San Andres Formation, and the siltstones of the basal Grayburg Formation form the seal. The trap is structural, being defined by a nearly symmetrical northeast-trending elongate dome. The crest of the structure is at 980 ft subsea, and the oil-water contact is at approximately 875 ft.

Since discovery, the reservoir has produced about 10 MMSTB of the approximately 48 MMSTB of OOIP. The initial development phase was from 1930 through 1945. Field production peaked in 1941 and has generally declined since that time. The field has produced very large volumes of water, some of which is from the overlying Cretaceous Trinity Sandstone aquifer. Water from this aquifer has been flowing down well bores for a number of years, producing an uncontrolled dump flood. A centered five-spot waterflood was initiated in 1985 following infill and relocation drilling of 114 new wells. High volumes of water were initially injected into the reservoir with limited results. Oil/water ratios of 0.01 or less were common and injection rates ranged from 450 thousand to 1,400 thousand barrels of water per month.

This field was selected for study because of the availability of cores, cooperation of the operating company, and poor performance of the waterflood. A total of 1,345 ft of core was taken from 12 wells during the redevelopment phase. Geologic descriptions and petrophysical analyses from these cores and modern logs from the new wells provided an excellent data base for the reservoir study. The field operator was very cooperative and provided production and other engineering data that were most helpful. Waterflood performance indicated that the layered-reservoir model used in the initial analysis was inadequate to predict performance of the reservoir and that a new model based on geologic characterization of the field is needed.

GEOLOGICAL SETTING

Introduction

The Taylor-Link West San Andres Unit lies along the southern margin of the Central Basin Platform along the Sheffield Channel. The field is located approximately 5 mi landward of the platform margin in a position comparable to the most interior portions of the sand-shoal complexes rimming the margins of the Bahama Platform (Hine, 1977).

Depositional History

The San Andres reservoir section in the Taylor-Link West field comprises an upward-shallowing succession of (1) bryozoan-crinoid-fusulinid packstone/grainstone, (2) crinoid-brachiopod wackestone, (3) mudstone, (4) fusulinid wackestone, and (5) ooid-fusulinid grainstone/wackestone (fig. 40). Production is from the grainstone facies that cap the sequence. Facies of the unconformably overlying Grayburg Formation include (1) basal carbonate pebble

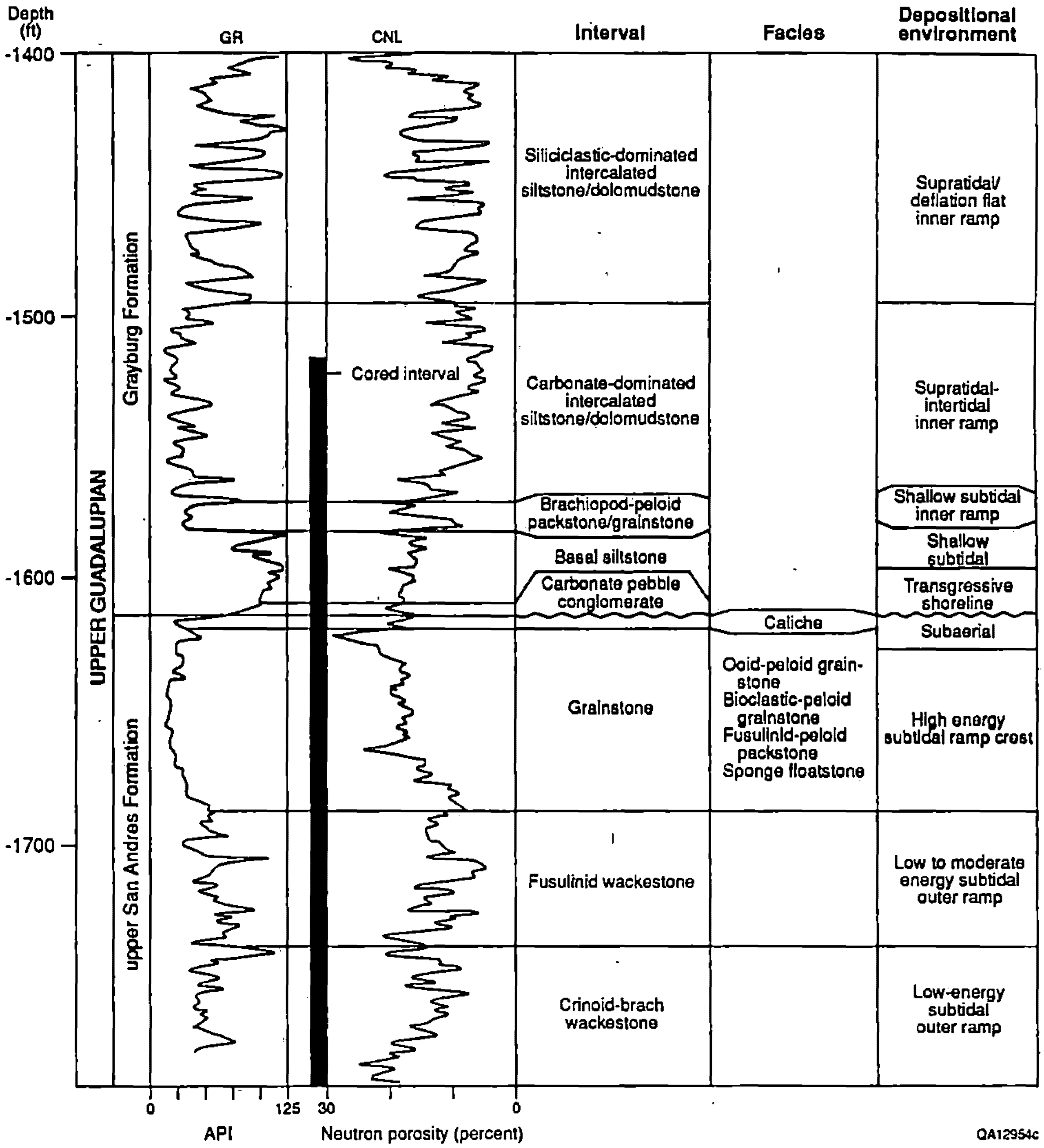


Figure 40. Representative gamma-ray/neutron log for the upper San Andres Formation at Taylor-Link West field showing characteristic lithologies of stratigraphic intervals and their interpreted depositional environments.

conglomerate and locally developed caliche, (2) siltstone/fine sandstone, (3) brachiopod-peloid packstone/grainstone, (4) dolomudstone, and (5) pisolite packstone.

The grainstone interval makes up more than 80 percent of the San Andres reservoir. Thus, knowledge of the geometry and internal heterogeneity of this interval is essential for understanding reservoir performance. The grainstone interval contains four facies that can be recognized in core and thin section, but not from log signatures. These facies are (1) ooid-peloid grainstone, (2) fine-grained bioclastic-peloid grainstone, (3) fusulinid-peloid wackestone/packstone, and (4) sponge floatstone.

Ooid-peloid grainstone comprises 60 percent of the facies and consists of 200-μm-diameter peloids and poorly preserved ooids; variable amounts of primary interparticle porosity occur in the grainstone facies. Thin (1- to 2-ft-thick) beds of fine-grained bioclastic-peloid grainstone are locally interbedded with the ooid-peloid grainstone facies. The texture is characterized by 50- to 100-μm-size particles and abundant small separate vugs occurring as moldic pores after leached bioclasts (probably brachiopods and/or mollusks). The grainstone interval comprises 1- to 3-ft-thick beds of fusulinid-peloid wackestone/packstone facies (containing between 10 and 20 percent fusulinid molds).

The sponge-floatstone facies of the grainstone interval is characterized by poorly preserved molds of unidentified (probably calcareous) sponges in a dense, commonly microfractured, light-tan micritic matrix. Porosity is moldic and fracture related. This facies occurs in cores from three wells and averages 10 ft thick.

The distribution of the grainstone facies was mapped using core descriptions and application of log-facies mapping techniques. The distinctive low gamma-ray signature of the ooid-peloid grainstone and bioclastic-peloid grainstone was used to generate an isopach map of these facies for the grainstone interval (fig. 41a). The outstanding feature of the grainstone-facies isopach is a northeast-trending belt of thick grainstone extending from the southeastern corner of Section 14 and adjacent southwestern corner of Section 13, through the northeastern part of Section 13 and the southeastern quarter of Section 12. This northeast-trending belt is characterized by massive

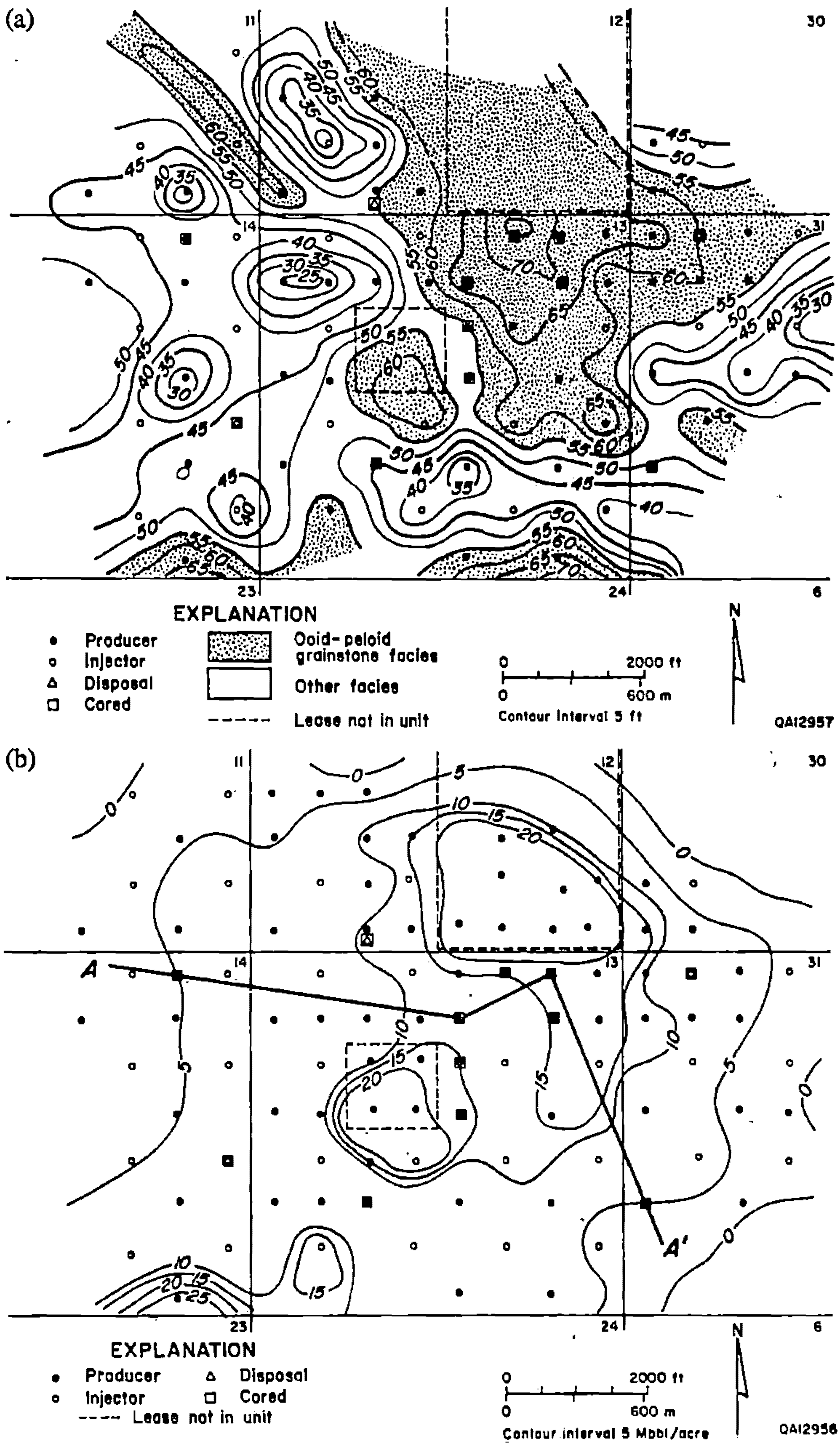


Figure 41. (a) Isopach map of the San Andres grainstone interval showing feet of gamma-ray response greater than 50 API units. Isopach values greater than 55 ft are interpreted to be areas where the ooid-peloid grainstone facies is dominant. (b) Isopach map of the remaining mobile oil in thousands of barrels per acre. Cross section A-A′ shown in figure 43.

clean gamma signatures indicating clean grainstone facies of between 55 and 75 ft in thickness. Core examination reveals thick areas of ooid-peloid grainstone in this belt. Cores from the northwest-trending belts within the northeast trend show a high percentage of fusulinid-peloid packstone and sponge floatstone relative to ooid-peloid grainstone.

Cores from the east side of the ooid-grainstone belt show a vertical transition from more abundant fusulinid-peloid packstone facies, at the base of the grainstone interval, to clean ooid-peloid grainstone facies, toward the top. On the western margin of the reservoir, core descriptions show the grainstone interval to consist of a combination of dark-gray, fine-grained, bioclastic-peloid packstone, fusulinid-peloid packstone-grainstone, and lesser ooid-peloid grainstone facies. An area of mainly clean ooid-peloid grainstone with thin mud-rich interbeds occurs between the ooid-grainstone belt and the more muddy facies on the western margin of the reservoir.

Fractures, Microbreccias, and Large Vugs

The response of the Taylor-Link reservoir performance to the recently introduced waterflood shows significant deviations from the anticipated response, with an average oil/water ratio to date of 1 to 2 percent. Explanations for the high water and low oil volumes are found in the complex diagenetic history of the Taylor-Link carbonates that produced a system of interconnected large vugs, microbreccias, and fractures—referred to as a touching-vug system later in this report.

The origin of the fracture, large-vug, and breccia system found throughout the reservoir is important because these features have a significant effect on reservoir performance, particularly performance of the waterflood. Fractures described from the Taylor-Link West cores are grouped into simple and wide-aperture fractures and microbreccias (dense fracture networks). Simple fractures are those having little or no visible aperture, a straight, near-vertical orientation, and no lining or filling cements. Wide-aperture fractures range from less than 1 mm to 4 to 5 mm in aperture width, as measured on core slabs, but are typically short (4 to 10 cm) and display a random orientation in individual core sections. Large vugs are 1- to 10-cm, oval-shaped voids commonly lined with scalenohedral calcite crystals that occur in the muddier sediments. Microbreccias occur in equidimensional areas several centimeters across that contain a dense network of randomly oriented, interconnected fractures outlining breccia fragments.

Fractures, microbreccias, and large vugs are far more common in cores taken from the low-energy lagoonal facies tract along the western portion of the reservoir than in the cores from the grainstone bar area (fig. 41a). A strong vertical separation in fracture and breccia density occurs in cores from the central grainstone bar complex. Fracturing and brecciation in the ooid-peloid grainstone facies are minor compared with that in the underlying fusulinid-wackestone and crinoid-brachiopod-wackestone facies. The distribution of large vugs also shows a similar correlation with depositional facies, marked by a downward increase in abundance of vugs in the San Andres section.

The origin of the pore system of fractures, microbreccias, and large vugs is found in the diagenetic history. Abundant evidence found in the Taylor-Link West cores indicates three major stages in the early diagenetic history of the San Andres Formation: (1) penecontemporaneous hypersaline-reflux dolomitization; (2) emplacement of replacive and cementing calcium sulfates; and (3) subaerial exposure accompanied by karstification and pervasive sulfate dissolution and calcification. The near wholesale dissolution of this sulfate, excluding the minor (up to 10 percent) calcite/quartz replacements, has been largely the cause of the extensive system of interconnected vugs, microbreccias, and fracture porosity.

PETROPHYSICS, ENGINEERING, AND PRODUCTION ATTRIBUTES

Petrophysical Study

The conversion of the geologic model to an engineering model was accomplished by the use of core data from the 12 cores from wells drilled during the 1983–85 redevelopment program. Core data were used exclusively because wireline logs from the original wells cannot be calibrated and dump flooding has altered the water resistivities sufficiently to make saturation calculations from modern logs questionable. Therefore, core descriptions, core analyses, and capillary pressure measurements from cores were used to reconstruct the original oil saturation and to define flow characteristics.

Volumetrics

Capillary-pressure relationships were used to calculate original water saturations because of the lack of reliable wireline-log saturation calculations. Average original water saturations in the producing interval were determined from 15 brine capillary pressure curves and 7 mercury curves, assuming an average height of 150 ft above the free water level (FWL). Water saturations corresponding to 150 ft above the FWL were read off the capillary pressure curves and plotted against porosity (fig. 42a). Because water saturation is partly controlled by particle size (Lucia, 1983), the capillary pressure curves were divided into two particle size fabrics, a grain-dominated fabric with 200-µm average grain size, and a mud-dominated fabric with 15-µm average dolomite crystal size (fig. 42b). The grain-dominate fabric corresponds primarily to the ooid-peloid facies of the grainstone interval, whereas the mud-dominated fabric characterizes most of the other facies.

Stock tank OOIP values were calculated for the grainstone and fusulinid wackestone intervals as well as for various facies within the grainstone interval. The results show a total of 48.2 MMSTB of OOIP, which is in good agreement with volumetric calculations using averaged data (table 8). The highest concentration was in the ooid-peloid grainstone facies, which contained 16.7 MMSTB.

Remaining mobile oil is calculated by subtracting produced oil and residual oil to waterflood from OOIP. A residual oil saturation of 0.28 was used (Galloway and others [1983]). Cumulative production values were based on an analysis of data carried out at the Bureau in cooperation with Taylor-Link Operating Company.

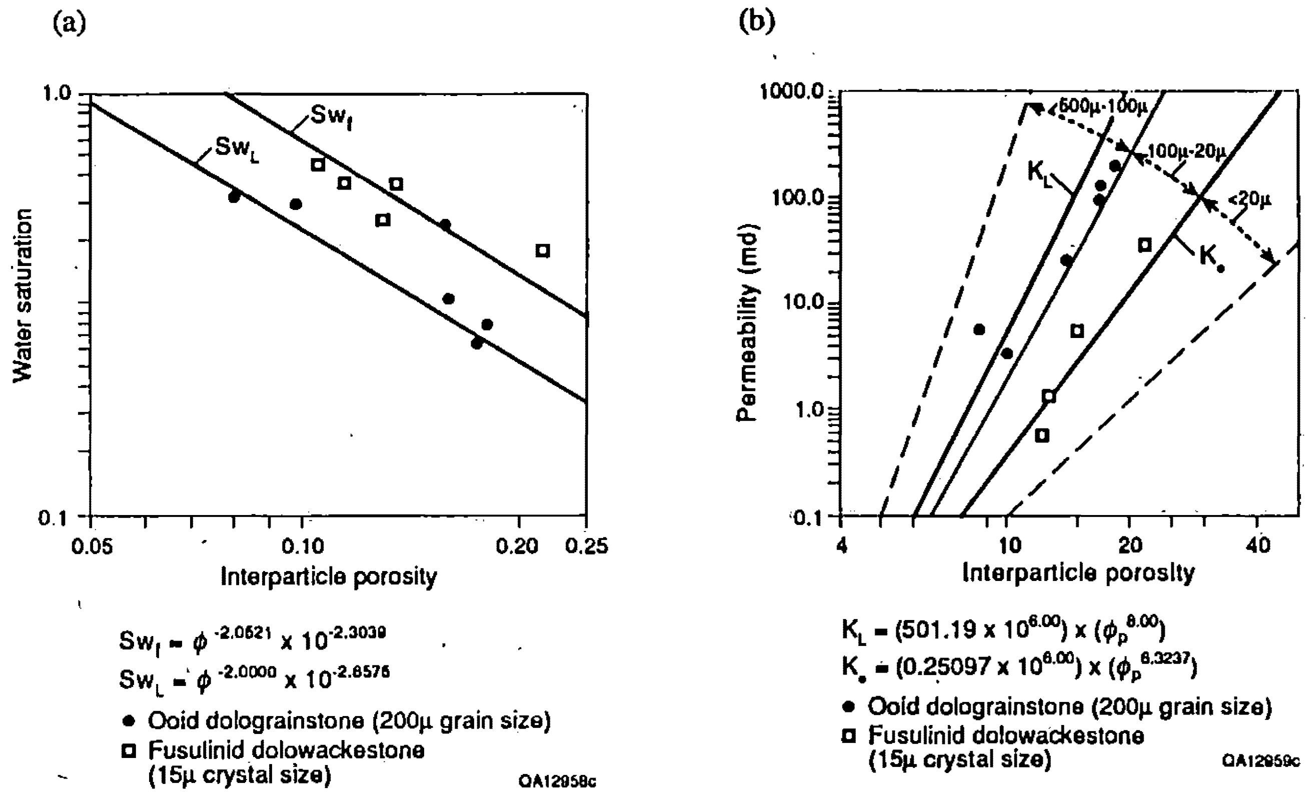


Figure 42. Petrophysical/rock fabric relationships showing (a) the relationship between particle size, interparticle porosity, and water saturation and (b) the relationship between particle size, interparticle porosity, and permeability.

The volume of remaining mobile oil is calculated to be about 20 MMSTB. The highest concentration is found in the ooid-peloid grainstone facies (fig. 41b), which has 7.1 MMSTB of remaining mobile oil, or a per-acre value of 18 MSTB.

Flow Model

Volumetric calculations indicate 48 MMSTB of OOIP, of which 10.6 MMSTB has been produced, for a recovery efficiency of 22 percent. Engineering analysis of Taylor-Link production by Taylor-Link Corporation indicates a proved reserve of 1.5 MMSTB of oil. This leaves 36 MMSTB remaining in the reservoir; 20 MMSTB is mobile oil recoverable by conventional methods, and 16 MMSTB is residual oil that will require advanced extraction techniques for recovery. Geologic and engineering characterization of the reservoir shows that the highest concentration of remaining mobile oil (18 MMSTB/acre) is in the ooid/peloid-grainstone facies of the central productive area. Recovery of additional oil from this reservoir requires an accurate model of the flow (permeability) characteristics.

Geologic observations show the reservoir to be composed of two pore-type groups: a matrix group and a touching-vug (fracture) group. Characterization of fluid flow can best be accomplished by separating touching-vug from matrix permeability. Matrix permeability was estimated using relationships between grain size, interparticle porosity, and permeability developed for the Taylor-Link West field (fig. 42b). Fracture permeability was estimated by subtracting matrix permeability from laboratory whole-core permeability measurements.

Within the ooid-peloid grainstone facies of the grainstone interval, most of the permeability can be accounted for by matrix permeability. In the other facies of the grainstone interval and in the fusulinid wackestone interval, the permeability is primarily due to the touching-vug pore system.

Reservoir Model

Fluid flow in the Taylor-Link West reservoir, therefore, can be characterized by two basic flow units: in flow unit A interparticle permeability dominates, and oil saturations are high, whereas in flow unit B, fracture, microbreccia, and large-vug permeability dominates, and oil saturation is low (fig. 43). The permeability values are similar in the two flow units but are controlled by different fabrics. Barriers to vertical flow are difficult to define because of the fracturing. However, the preferential concentration of calcite cementation of fractures, large vugs, and microbreccia in the fusulinid wackestone interval and in the lower part of the grainstone interval may result in local vertical permeability barriers.

The geologic/engineering model described above suggests that the high water volumes and low oil cut in this field result from injected water flowing through flow unit B, which has little oil saturation. This suggestion is supported by an injection test that shows that at a rate of 600 barrels of water per day (BWPD), 52 percent of the fluid is entering flow unit B and that when the rate is increased to 3,000 BWPD, 80 percent of the injected fluid is entering flow unit B. Thus, as the injection rate increases less water enters the oil-saturated ooid-grainstone facies, resulting in lower oil production and lower oil cut. Production history shows that the oil cut and oil production rate are inversely proportional to the water injection rate.

A bottom-hole pressure map prepared by T. Scott Hickman and Associates, Inc., dated September 13, 1988, shows a low-pressure area corresponding to the structural high despite the fact that the largest volume of water has been injected and produced in this area (Taylor-Link Corporation, personal communication, 1989). The low-pressure area corresponds, in general, to the area where the fractured wackestone interval is above the field water level. This coincidence of low pressure and the structurally high, fractured wackestone interval suggests that injection water is cycling through the fractures in the wackestone and not flooding the oil-saturated ooid-grainstone facies above.

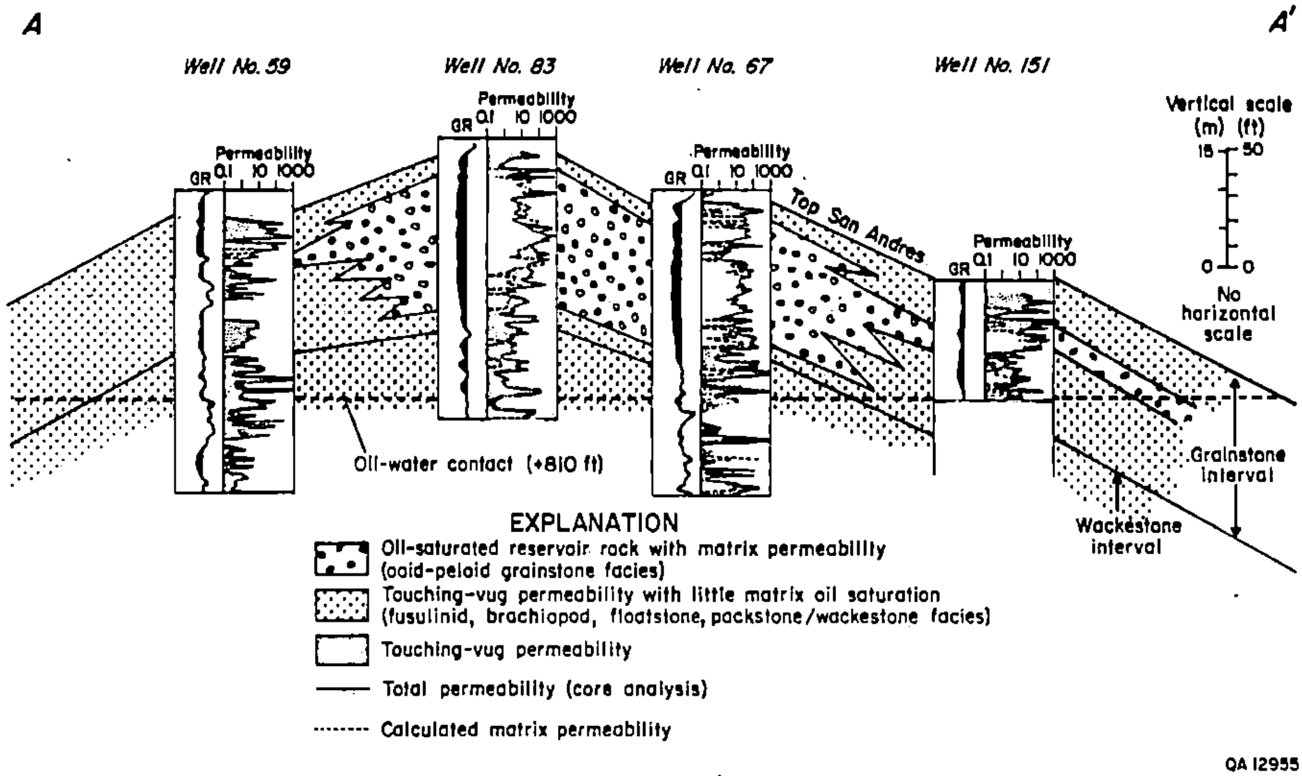


Figure 43. Structural cross section showing the reservoir flow model. The right side of the depth logs shows matrix permeability in white and fracture permeability in black. The gamma-ray log is shown on the left side. Line of section shown in figure 41.

Pressure data in injection wells 102 and 104 suggest the presence of a permeability barrier between the grainstone and wackestone intervals. Before the wackestone interval in these two wells was cemented off, the bottom-hole pressure was 271 and 335 psi, respectively. After the wackestone was cemented off, the pressure in the grainstone interval was found to be 201 and 265 psi, respectively. Pressures were normalized for depth. These data suggest that water injected into these wells entered the touching-vug system in the wackestone interval and that a horizontal flow barrier kept water from crossing up into the grainstone interval.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

Approximately 20 MMSTB of mobile oil will remain on University Lands in the Taylor-Link field unless current production practices are improved. The reservoir characterization study shows that most of the remaining oil saturation in the Taylor-Link West reservoir is in the ooid-peloid grainstone facies, which has high matrix permeability. Therefore, the recovery problem is to concentrate the waterflood in the ooid-peloid grainstone facies. The Bureau has been working with the Taylor-Link Operating Company to develop three strategies for accomplishing this task: (1) infill drilling at closer spacing and penetrating only the grainstone interval, (2) cementing off the fusulinid wackestone interval in existing wells, and (3) using polymers to concentrate water injection into the ooid-peloid grainstone facies.

Taylor-Link Corporation has experimented with polymer injection in a pilot area. Injection rate per psi was significantly reduced in four of the six injection wells, but no change in oil- or water-production rate was observed that could be attributed to the polymer injection.

Three injection wells and two producing wells have been plugged back to within the grainstone interval. The rates of injection and production of water have been reduced by about 50 percent, whereas oil-production rates have remained about the same. This effort, together with an intense surveillance program, has kept the field on production and added 1.5 MMSTB of reserves. Taylor-Link Operating Company plans to expand this effort.

A strategy of drilling closer spaced wells targeted for the ooid/peloid-grainstone facies has not been tried because of current economic constraints. The field is currently on 20- to 40-acre spacing of producing wells, which is larger spacing than currently exists in most San Andres fields. It seems likely that closer spacing will maximize water flow through the oil-saturated ooid facies as well as tap undrained compartments, thus recovering a significant amount of the 20 MMSTB of remaining mobile oil.

THREE BAR DEVONIAN RESERVOIR

INTRODUCTION

Devonian oil production was established in the Three Bar field on University Lands Block 11 (fig. 14) in March 1945. Production was extended northward, off University Lands, by Humble in 1948. Both areas were unitized in 1951, Amoco operating the southern part as the Stanolind Three Bar Unit and Exxon operating the northern part as the Humble Parker Unit; together these units constitute the Three Bar field (fig. 44).

During the first several years, the Three Bar field was produced by solution-gas drive. In November 1952, both Amoco and Exxon began injection of CO_2 gas to maintain reservoir pressure. By that time reservoir pressure had dropped in the Amoco Three Bar Unit from an original pressure of about 3,200 to about 2,000 psia. Although the gas injection program reduced the rate of pressure decline, production rates began to fall sharply as the gas-oil ratio increased. Waterflooding commenced in the Exxon Parker Unit in 1960; Amoco started waterflood operations in their unit in June 1961. Waterflood response, in the form of increased reservoir pressure and production rates, was apparent within 1 year.

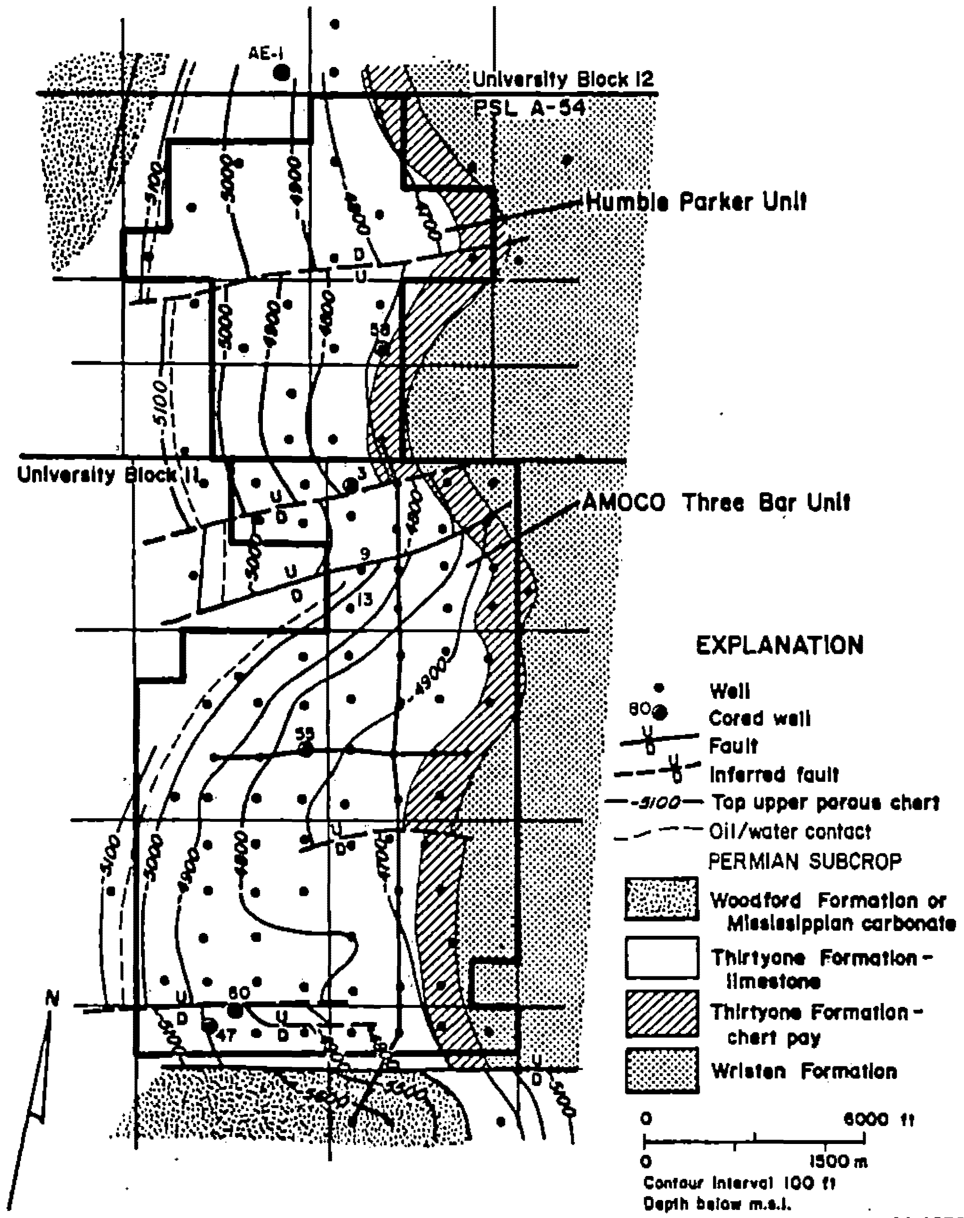


Figure 44. Structure map contoured on top of main chert pay and subcrop of porous cherts beneath the Permian unconformity. Sealing fault defined by sharp changes in bottom-hole pressure is shown by solid line. Lines of cross sections are shown in figures 46 and 47.

The Three Bar Devonian reservoir is developed in a sequence of interbedded chert and carbonate at the base of the Devonian Thirtyone Formation. Similar carbonate/chert sequences occur throughout much of the Permian Basin area south of the Three Bar area. Reservoirs developed in these rocks account for more than 50 percent of all production from Siluro-Devonian rocks in Texas, which currently totals about 1.5 BSTB and as much as 58 percent (270 MMSTB) of the total cumulative production from Siluro-Devonian reservoirs on University Lands.

The Three Bar reservoir was selected for study because it is the largest Siluro-Devonian field, in terms of cumulative production, on University Lands for which cores could be obtained. It is the sixth largest Siluro-Devonian field on University Lands (the third largest in the Thirtyone Formation Chert subplay) and the ninth largest Siluro-Devonian reservoir in the state overall. Cumulative production from this reservoir was more than 36 MMSTB at the end of 1987.

Characterization of the Three Bar Devonian reservoir provides a basis for further exploitation of the remaining mobile oil in the field and should serve as a model for other Devonian chert reservoirs on University Lands as well as those throughout West Texas. Seven cores were available from the Three Bar field. Data derived from detailed study of these cores were supplemented with wireline log data, core analyses provided by the operators, and production data obtained from the Railroad Commission of Texas and the operators.

GEOLOGICAL SETTING

Introduction

The Three Bar field is located in southwestern Andrews County near the northern limit of the Devonian subcrop. The reservoir is developed in chert in the Devonian Thirtyone Formation, which overlies carbonate mudstone of the Silurian Wristen Formation (Frame Member), and is overlain by conglomerates and shales of apparent Permian age that are informally termed the "Permian detrital" (fig. 45). The chert interval, which averages about 90 ft in thickness, can be

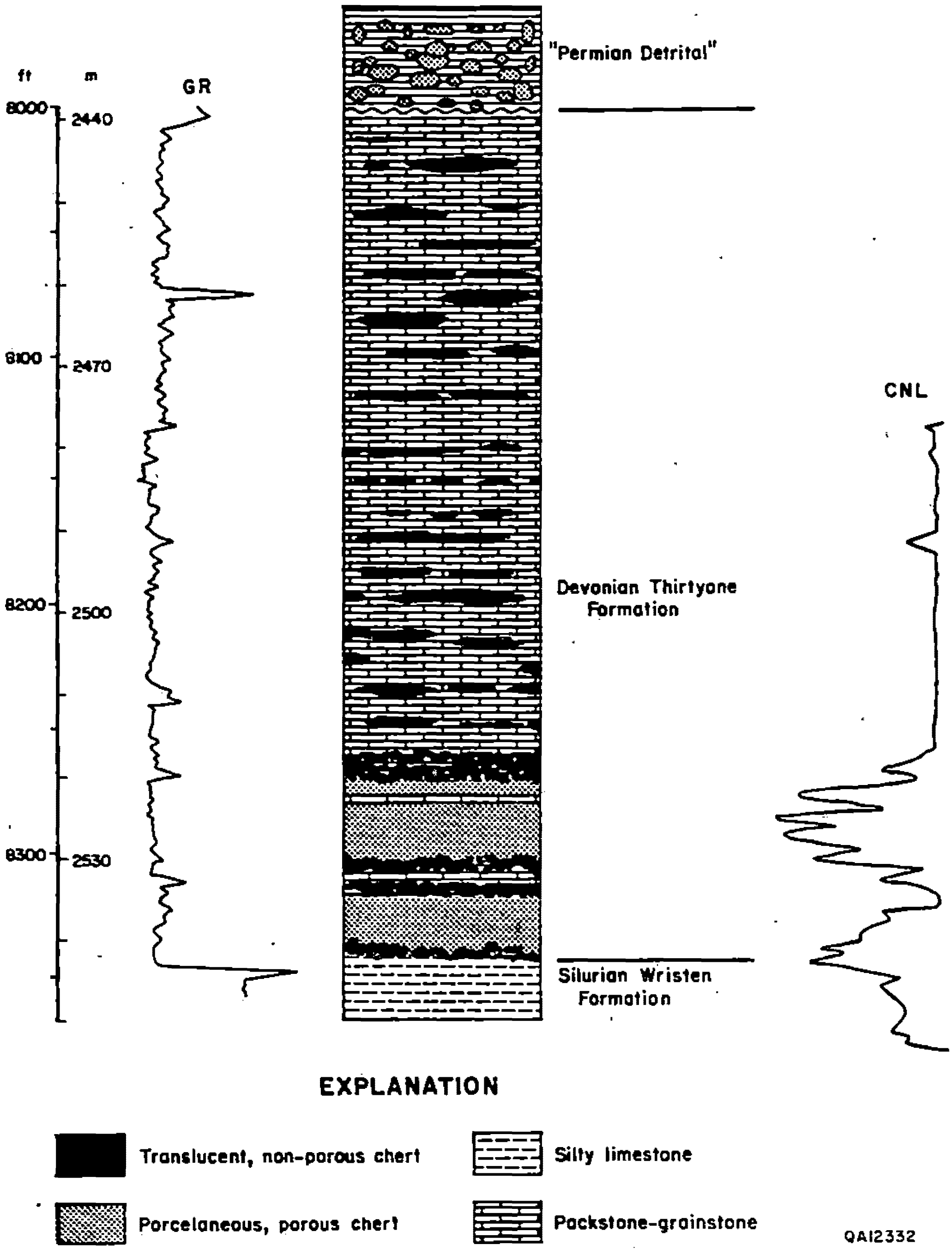


Figure 45. Representative log and typical lithologic sequence in the Three Bar reservoir.

traced for more than 40 mi in southwestern Andrews, northeastern Winkler, and northern Ector Counties and forms the main pay zone for all of the major Siluro-Devonian fields in this area. Regionally, the Thirtyone Formation is unconformably overlain by dark shales of the Upper Devonian Woodford Formation, which has been erosionally removed in Three Bar field.

Structure

Three Bar is located along the west flank of a major north-south-trending anticlinal ridge (fig. 44). This structure extends north to the Devonian pinch-out in University Block 12 and south into the Block 11, Goldsmith, and TXL Devonian fields. Truncation of the Woodford Formation across the top of the field structure suggests that it formed during Pennsylvanian/Permian uplift of the area. Devonian strata in Three Bar field are overlain by Permian clastic rocks (the "Permian detrital"), which forms the top seal (figs. 46 and 47). Productive limits of the field are controlled by (1) erosional truncation updip to the east, (2) a major east-west-bounding fault on the south (figs. 44 and 47), and (3) the oil-water contact on the west. In addition to the southern bounding fault, which has a displacement of about 800 ft, several other faults in the field produce vertical offsets of as much as 100 ft (figs. 44 and 47). Systematic, near-vertical fracture sets occur in chert and limestone throughout the field. Calcite cement partly fills some fractures. Within the upper, limestone part of the Thirtyone Formation fractures appear to have been enlarged by solution and are filled with red and green mudstone. Fracture length and spacing are related to bed thickness, lithology, and structural position.

Depositional Facies

The Thirtyone Formation in the Three Bar field comprises two distinct lithofacies: an upper, cherty, low-porosity carbonate and a lower, porous chert with carbonate interbeds (fig. 45). The carbonates consist of packstones and grainstones composed dominantly of well-sorted and abraded pelmatozoan debris. Upward-fining sequences are locally present. Burrows are commonly

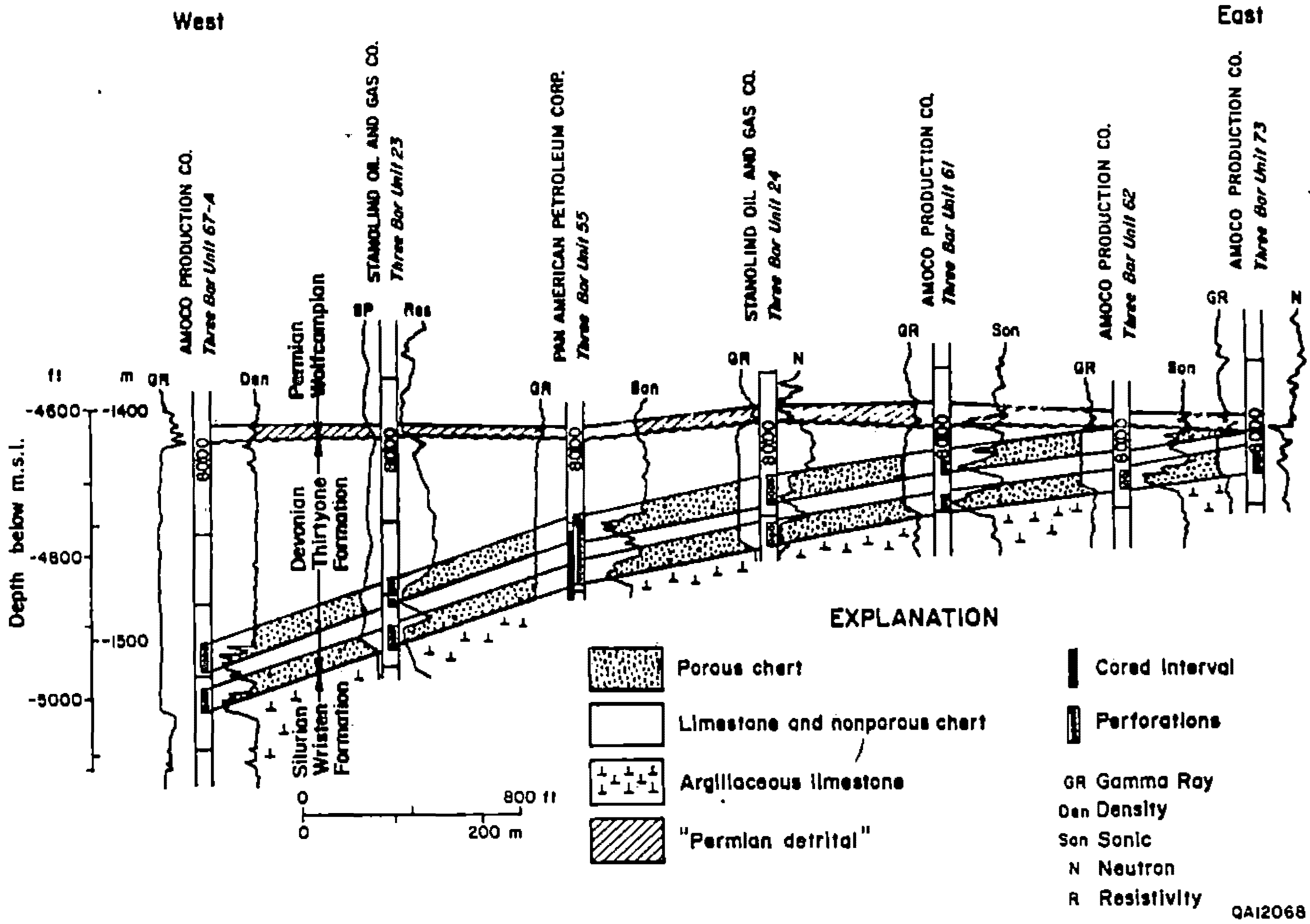


Figure 46. West-east cross section perpendicular to structural strike, showing updip truncation of reservoir pay zone beneath the Permian unconformity. Note continuity and consistency of chert pay zone. Line of section is shown in figure 51a. Datum is sea level.

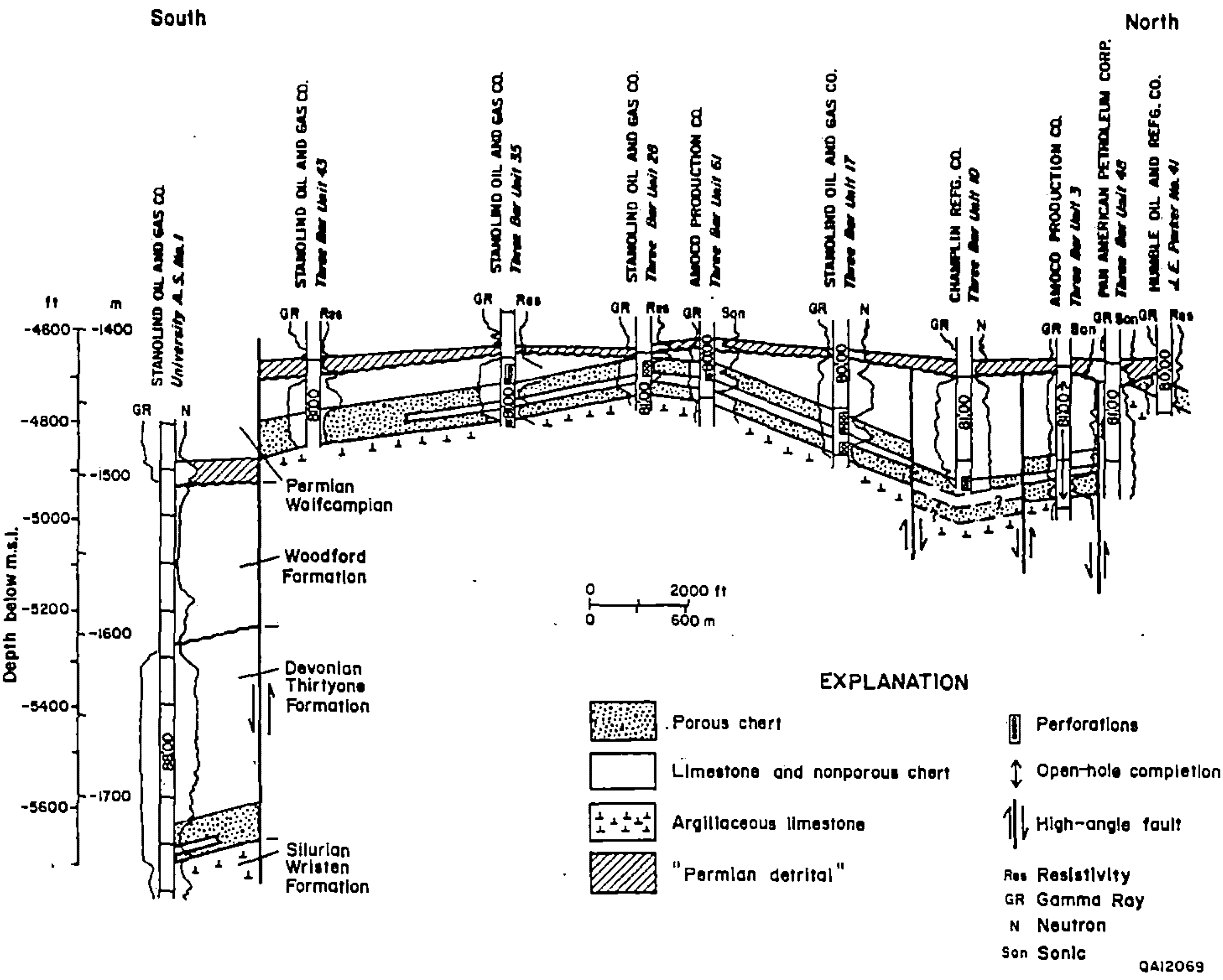


Figure 47. North-south cross section parallel to structural strike, showing southern bounding fault and other faults within the field. Thickness variations across the southern boundary fault are the result of multiple episodes of reactivation. Line of section is shown in figure 51a. Main field area was more intensely eroded than area to south of fault.

restricted to the upper parts of laminated sequences. Ostracodes replace pelmatozoans as the abundant organism in carbonate in the lower, cherty part of the section.

Visual examination of the cores available from the upper carbonate interval in the Thirtyone Formation shows porosity in these rocks to be limited to fractures. Core analyses reveal that maximum matrix porosities are about 5 percent (fig. 48). Permeabilities associated with these open fractures are highly variable, ranging from less than 0.1 to more than 100 md (fig. 48). Solution-enlarged fractures and karst breccia observed in core are not porous because they are filled with clay and calcite cement.

The lower 100 ft of the Thirtyone Formation is composed primarily of chert and can be subdivided into five stratigraphic units: two intervals containing porous chert separated and bounded by three intervals of nonporous chert and carbonate (fig. 45) The two porous chert intervals are traceable throughout the Three Bar field (figs. 46 and 47) and well beyond. The middle nonporous interval contains thick (up to 10 ft) carbonate beds. The thickness of this middle nonporous unit varies indirectly with that of porous chert. In the northern part of the field, the unit thickens as the chert thins. In the central and southern parts of the field, the nonporous interval thins to zero as chert thickness increases.

Porous chert contains abundant molds of siliceous sponge spicules. Sedimentary structures in chert include small, oval, chert-filled or carbonate-filled burrows and irregular, discontinuous, millimeter laminations. Discontinuous, thin limestone beds are composed of skeletal packstones similar to those in the upper parts of the section and have sharp contacts with enclosing chert. Brecciation is common in the porous chert and typically takes the form of subrounded chert clasts in a chert matrix.

Three types of pores are present in chert: (1) molds, (2) 5- to 15-μm pores within the chert matrix, and (3) fractures. Total chert porosity locally exceeds 35 percent, the molds contributing more than half of this total. Pore types recognized within the chert matrix include interparticle pores between quartz aggregates and micropores within the aggregates. Mercury injection data from petrologically similar cherts in the nearby Bedford field (3 mi west) indicate that as much as

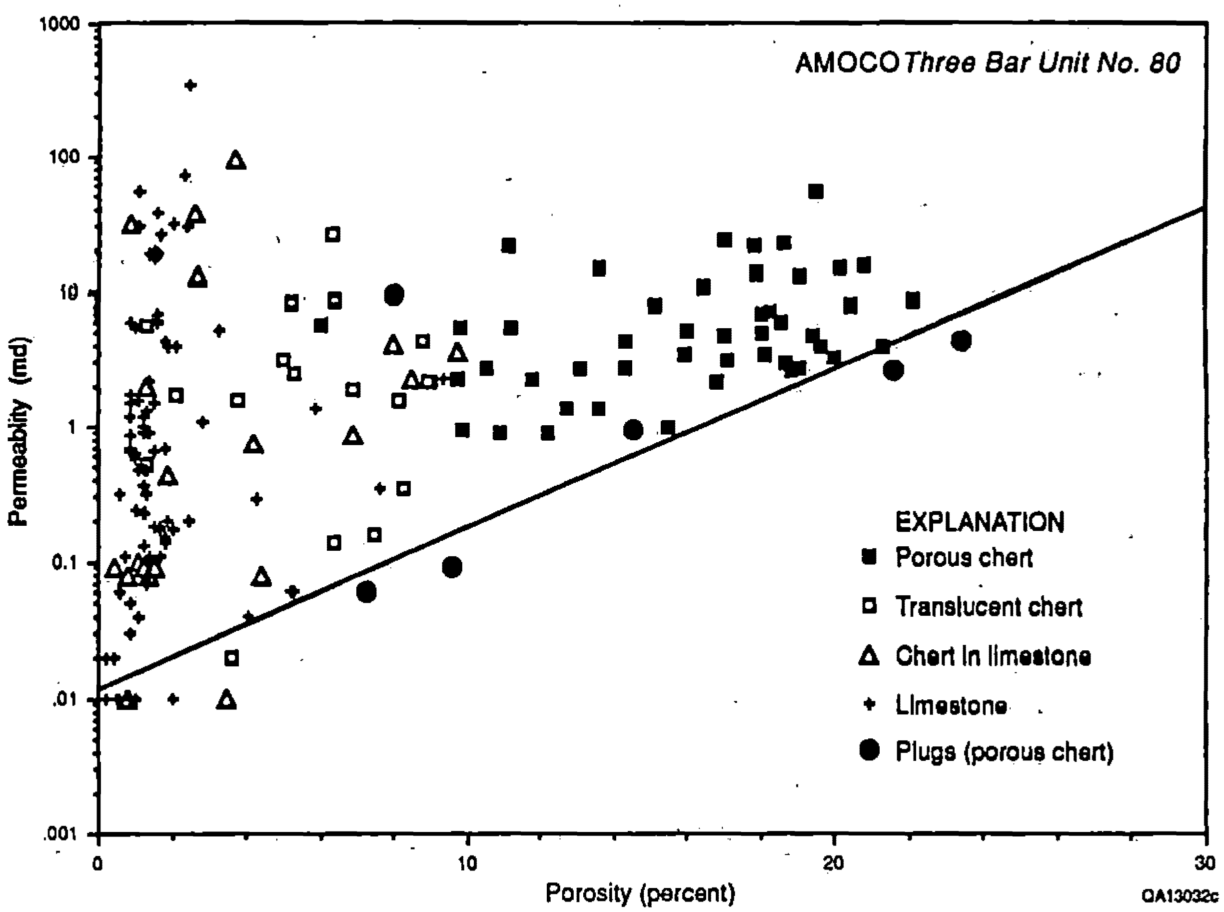


Figure 48. Crossplot of porosity versus permeability data from core analysis. High and variable permeabilities associated with low porosities in limestone are attributed to fractures.

half the total chert porosity is composed of these micropores; a similar relationship is likely in Three Bar.

Depositional Environments

The Thirtyone Formation in Three Bar field represents deposition in a relatively quiet water, outer ramp to slope setting. The absence of cross bedding and other indications of current energy suggest that skeletal packstones accumulated below wave base. The presence of burrowing organisms further attests to the lack of major current reworking.

Regionally, Thirtyone carbonates exhibit a general north-to-south decrease in grain size and faunal diversity. This change is attributed to the aggradation and southward progradation of the Early Devonian carbonate ramp. Regional textural and faunal variations in the Thirtyone suggest that sites of carbonate production lay well to the north in areas that, in large part, have been subsequently denuded of Devonian sediments.

Controls of chert-precursor sediment accumulation are less easily understood. Diagenetic alteration of opaline sponge-spicule sediment into chert has obscured grain/matrix relationships; therefore, the depositional relationship between opaline and carbonate sediments is conjectural. Fine lamination, bedding, burrowing, and interbedded carbonate indicate that environmental conditions during opaline sediment deposition were in some ways similar to those during carbonate deposition. Brecciation patterns indicate variation of sediment consistency from soft ooze to stiff consolidated sediment.

Regional studies illustrate that chert is increasingly abundant southward, away from the shallow-water carbonate platform to the north. This distribution suggests that siliceous sediments accumulated in relatively deep water. Such an interpretation is also consistent with global reconstructions of Early Devonian paleogeography that indicate that the West Texas area lay on the southern margin of the Laurentian paleocontinent and was bordered on the south by an oceanic basin. The source of silica can be attributed to biogenic silica production favored by upwelling, nutrient-laden waters from this deep basin.

Siliceous sediments thus accumulated in quiet, relatively deep waters removed from the influx of allochthonous sediment; carbonate rocks were deposited in a more proximal setting on, and downslope from, an aggrading carbonate platform. As the carbonate platform prograded, carbonate sediments were shed southward into deeper waters where they became interbedded with chert deposits already forming there. In general, grain size and percent carbonate increase upsection, reflecting this southward progradation. This relationship can be recognized in Three Bar and all other Thirtyone reservoirs in West Texas.

FACIES/FLOW-UNIT ARCHITECTURE

Heterogeneity in the Three Bar Devonian reservoir is the result of three processes: deposition, diagenesis, and structural deformation. The basic architecture of the field is the result of original depositional processes. Thick, tabular chert layers, which form the main pay in the reservoir, formed by the accumulation of biogenic silica in an environment largely free from the influx of allochthonous debris following a major sea-level rise in the Early Devonian. The remarkable continuity of these deposits indicates uniform topography and depositional conditions across a large area. Heterogeneities within these cherts are in part a function of the episodic input of carbonate debris from the prograding platform to the north. An example of this heterogeneity is the nonporous, carbonate-rich zone that separates the chert section vertically into upper and lower pay zones and that exhibits thickness variations across the field, at least partly related to differential carbonate influx.

Porosity in the chert intervals is the result of diagenetic alteration of these zones and was probably associated with the conversion of biogenic opal to quartz. Chert porosity is heterogeneous on a mesoscopic to microscopic scale. This heterogeneity may be partly due to original variations in depositional facies; however, high-porosity zones developed along the updip margins of the field are probably the result of karstification. Evidence of karstification is strongest in areas interpreted to be more highly faulted and fractured, such as the northeastern part of the unit (Section 4) and the south-central part of the unit (Sections 16 and 17).

Faults and fractures are abundant in the field and effect reservoir heterogeneity on several scales. Bottom-hole-pressure data indicate that at least one fault (fig. 44) has produced distinct reservoir compartments. In the southern part of the field, zones of abundant faults and fractures are associated with increased fracture permeability. These areas are associated with wells having very high productivity, suggesting that variations in fracture density may locally contribute to productivity. Preliminary analysis of waterflood patterns reveals irregular water movement and supports the contention that fractures zones control fluid movement in parts of the reservoir.

Although most of the net pay is relatively continuous and sheetlike in geometry, several vertical and lateral discontinuities are present. Most notable among these is the variation in the thickness of the middle nonporous unit (fig. 47). At two locations, one in the central part and one in the south central part of the field, this zone thins to zero. Concomitant with this thinning is a thickening of the upper chert pay zone. Well productivity from these areas, based on prewaterflood production patterns, is the highest for the field. The correlation between greater productivity and the absence of the middle nonporous unit suggests that this unit is a vertical flow barrier that may produce some degree of compartmentalization and poorer recovery efficiencies elsewhere in the field.

A second variation in net-pay distribution is the presence of localized zones of high porosity above the main chert pay. Although of limited lateral extent, these zones locally reach thicknesses of 20 to 30 ft. For the most part, these porous zones occur in two areas: in the northeast part of the unit (Section 4) and in the south (Sections 16 and 17). Both of these areas exhibit evidence of both faulting and karstification. It is not clear whether these zones are chert or carbonate or both.

PRODUCTION CHARACTERISTICS

Cumulative oil production from the entire Three Bar Devonian reservoir, as of January 1988, is more than 38.5 MMSTB. Approximately 94 percent of this total, or 36.1 MMSTB, has come from the University Lands Amoco Three Bar Unit. Only 2.4 MMSTB has been produced from the Exxon Parker Unit, which lies outside of University Lands.

Prewaterflood oil production trends (fig. 49) compare favorably with predicted distribution of calculated reservoir storage capacity based on matrix porosity determinations (fig. 50). Maximum productivity was associated with two areas in the field where the middle nonporous unit is thinned or absent and the upper chert unit is thickened (fig. 49). These same areas apparently exhibit the highest øh values in the field (fig. 50).

Postwaterflood production trends indicate two different types of well response to waterflood. Many wells have exhibited the classic gradual increase in watercut expected in reservoirs dominated by matrix porosity. Several other wells, however, went rapidly to high watercuts after water breakthrough, suggesting water migration along fractures. The distribution of these end-member types is highly variable, suggesting that fractures are at least locally present throughout the reservoir.

VOLUMETRICS

The current expected ultimate recovery from the Three Bar field, based on analysis of production decline rates, is 37.9 MMSTB; remaining reserves are thus 1.8 MMSTB. This ultimate recovery represents a potential recovery efficiency of only 27 percent of the OOIP, which is estimated to be about 140 MMSTB. Actually, OOIP was probably higher because the small pore throat size that characterizes most of the matrix porosity most likely caused a thick oil/water

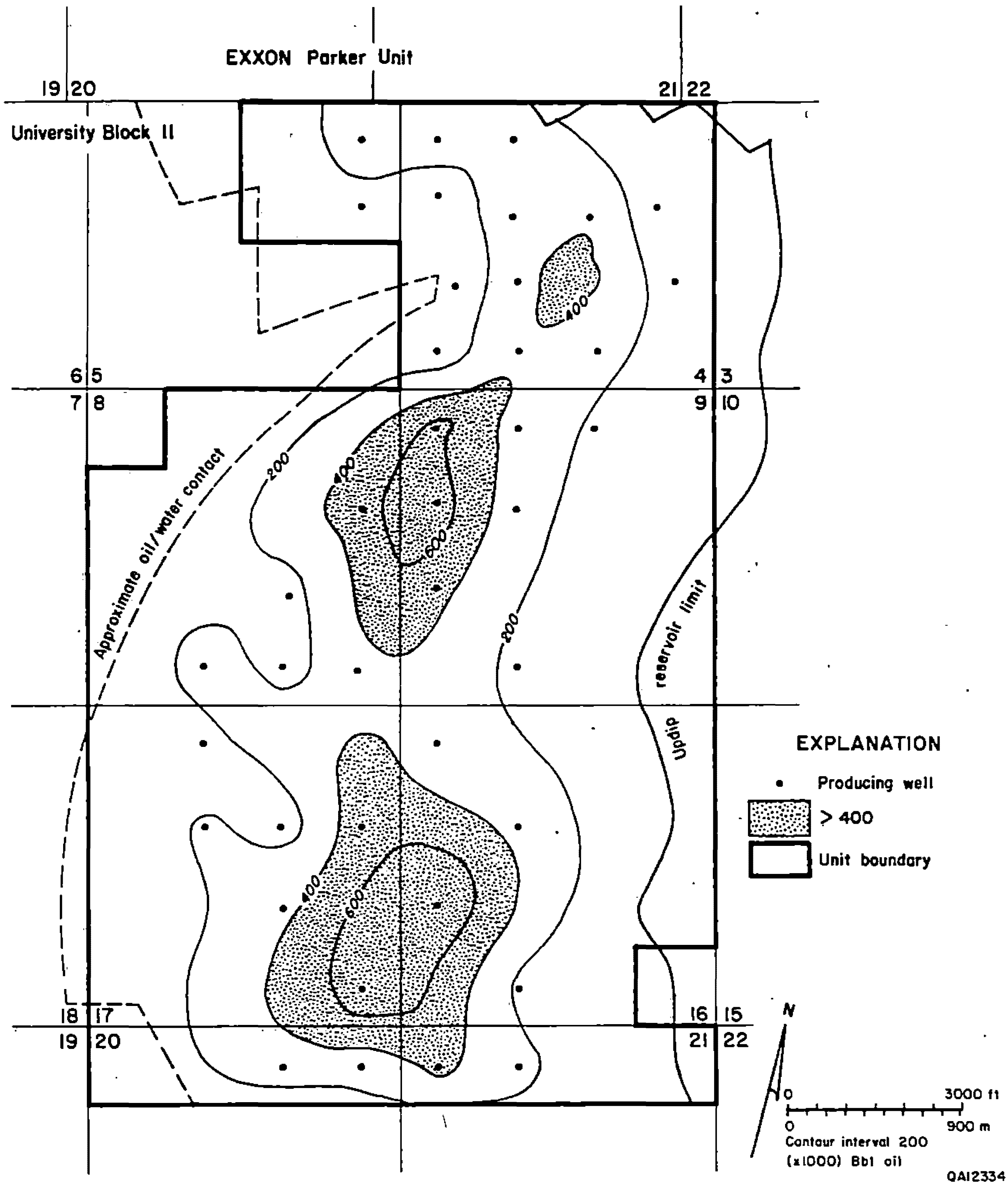


Figure 49. Isoproduction contour map showing distribution of prewaterflood production.

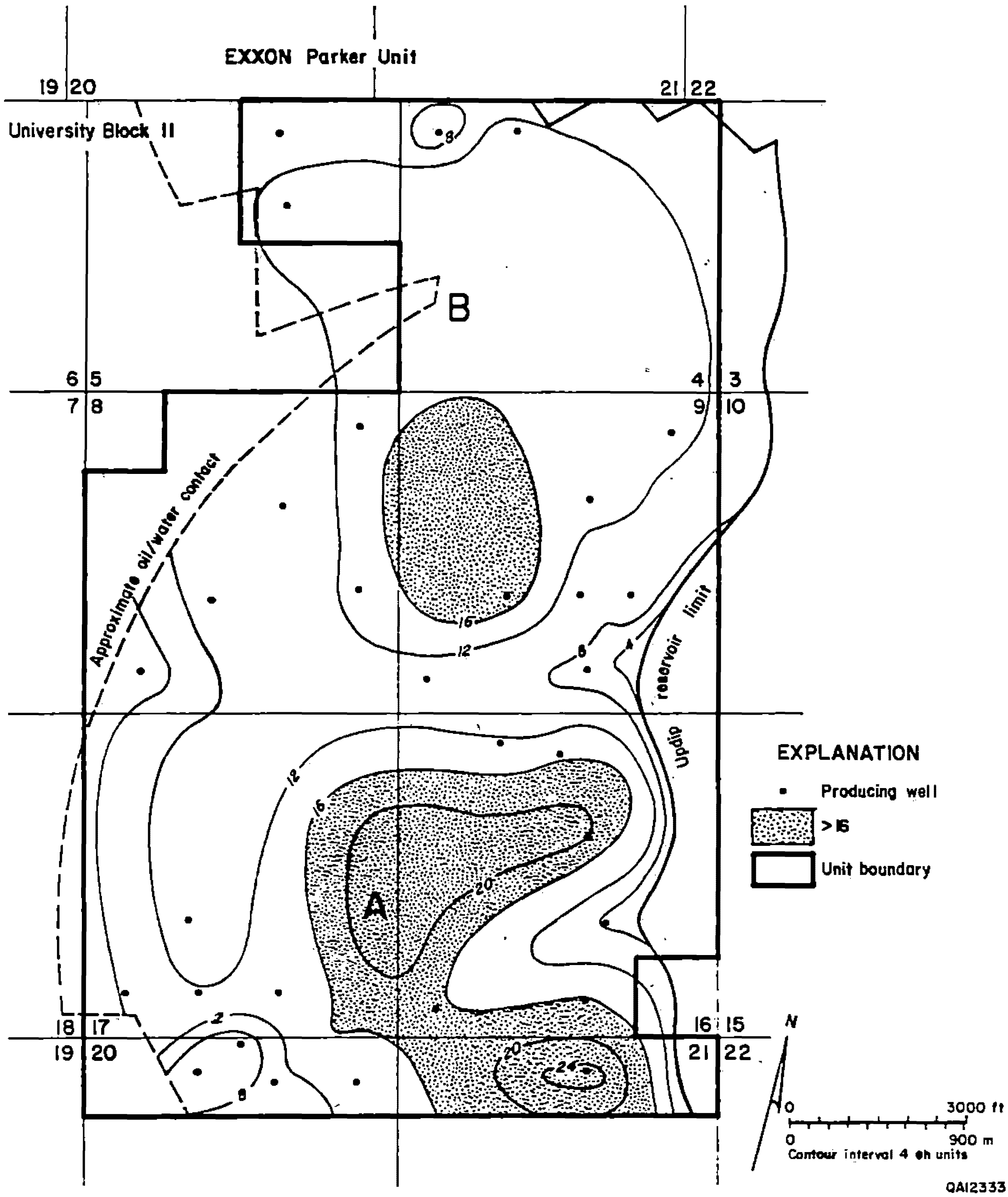


Figure 50. Map of øh values calculated for wells having porosity logs. Area A is a prime candidate for infill drilling because of its high øh and the presence of additional chert pay zones. Area B also contains porous chert above the main reservoir zone.

transition zone to form. Calculations of remaining mobile oil (73 MMSTB) are based on a residual oil saturation value of 0.14 obtained from special core analysis (TBU No. 55). Although this value is low, it is generally consistent with values obtained from some analogous fields, for example, Crossett Devonian field, elsewhere in West Texas (Galloway and others, 1983, p. 86).

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

Further exploitation of the Three Bar Devonian reservoir will require a reconsideration of this seemingly homogeneous reservoir in terms of its multifaceted heterogeneity. At least three factors, original depositional geometries, fracturing, and diagenesis, must be considered.

Variations in original depositional geometries apparently cause chert sequences to thicken in the central and south-central parts of the field. These thick areas correspond to areas of high øh (fig. 50) and with areas of maximum prewaterflood oil production (fig. 49). Evidence of faults and fractures and of diagenesis (primarily karstification) is greatest in the northern and southern parts of the field. Reservoir heterogeneity is thus expected to be greater in these areas than in the central part of the field where there is less indication of these processes.

The preceding reservoir findings indicate several opportunities for further development. The most prospective part of the reservoir is the southernmost of the two high-ϕh areas mentioned above. This area exhibits the highest ϕh values for the entire reservoir and has three undrilled 40-acre spacing locations (fig. 50). One of these locations (point A, fig. 50) has the potential of encountering additional pay in the form of an isolated porosity zone that exists above the main chert pay zone in this part of the field. Similar porous zones may also exist throughout the southwestern part of the field.

An additional porous zone also exists in the northern part of the field. This zone is especially well developed in Three Bar Unit wells 9 and 13 (fig. 44; Area B); nearly all the production in one of these wells (Three Bar Unit No. 9) came from this "stray" zone (more than 100 MSTB).

Mapping of suspected karst features suggests that zones like this one extend throughout the northeast corner of the field.

Although available geologic data suggest fracturing and faulting are more prevalent in the northern and southern parts of the field, well-performance data imply more widespread involvement of fractures. Critical to more efficient recovery of mobile oil in the Three Bar reservoir is better modeling of the distribution of these fracture pathways. This can be done most effectively by mapping injection-water movement through the field using tracer data and by considering pressure variation. Producing wells lying along fracture pathways from injection wells are not likely to recover as high a percentage of the oil held in the matrix as those lying at right angles to fracture trends. Mapping of these trends and subsequent redeployment of injectors and producers should result in considerably higher recovery efficiencies in the field.

EMMA ELLENBURGER RESERVOIR

INTRODUCTION

The Emma Ellenburger (fig. 14) reservoir provides an excellent example of a karst-compartmentalized carbonate oil reservoir. The paleogeographic setting and style of reservoir heterogeneity of the Emma Ellenburger reservoir is representative of the Ellenburger Karst-Modified Restricted-Ramp Carbonate subplay (fig. 10). This subplay contains nearly 98 percent of oil production from the entire Ellenburger and 91 percent of University Lands Ellenburger production. This overview summarizes (1) basic reservoir parameters, (2) characteristic depositional facies, (3) karst development within Ellenburger strata, (4) a geologic model for development of depositional and karst facies, and (5) a reservoir model to explain performance in terms of integrated geologic/engineering parameters.

This discussion is restricted to the University Lands portion of the Emma Ellenburger reservoir, but examination of data from non-University Lands parts of the field indicate that similar relationships apply to the rest of the reservoir. The depositional facies scheme and general karst model for the Ellenburger were developed during a regional analysis of University Lands Ellenburger reservoirs, and results of the regional analysis are covered in more detail in Kerans (1988; 1989).

The Emma Ellenburger reservoir was discovered in 1953, reaching peak production of 3.5 MMSTB/yr in 1957. The University Lands portion of the reservoir accounts for 39 MMSTB (74 percent) of the total cumulative production of 53.4 MMSTB. The reservoir has been in decline since 1957, and currently only 8 wells of 113 on University Lands remain open in the Ellenburger interval. Reservoir-drive energy is bottomwater and edgewater.

The University Lands portion of the reservoir covers 4,158 acres in University Blocks 9 and 10, south-central Andrews County. Emma is the largest Ellenburger reservoir on University Lands in terms of cumulative production and original oil in place (167.5 MMSTB). These statistics, coupled with the somewhat low recovery efficiency of 23.3 percent made Emma the logical choice for a University Lands reservoir-characterization study.

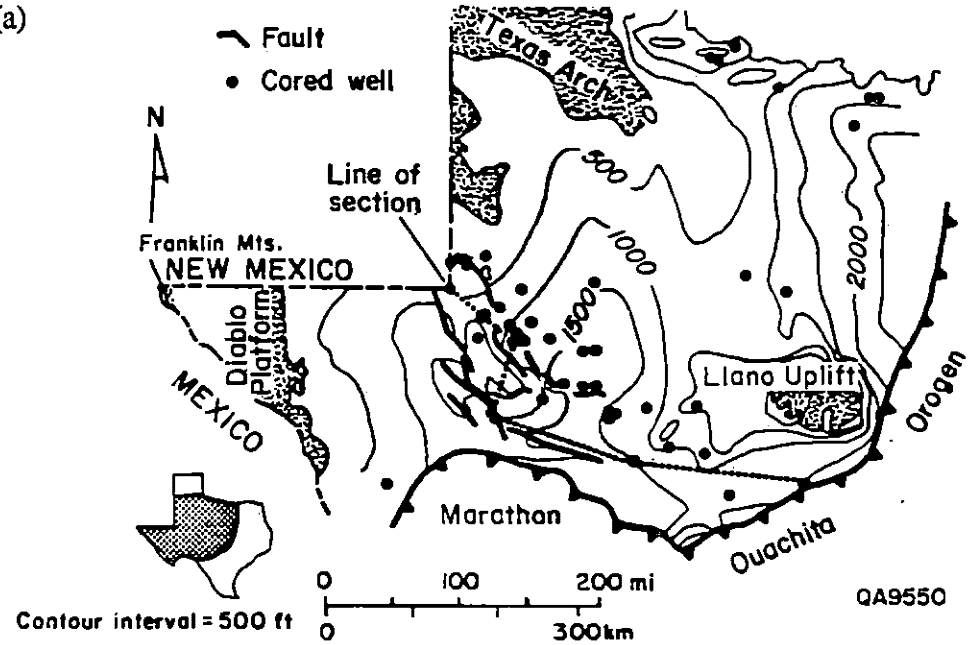
Core of the producing interval was limited to three cores averaging 400 ft of section with each intersecting all three karst facies described below. Production data in this nonunitized reservoir are largely available on a per-lease basis, but per-well production data from 1973 through 1985 were available from the Mobil University 36 lease. These data, in combination with test data from wells on adjacent leases, provide critical insight into reservoir performance.

GEOLOGICAL SETTING

Introduction

The Emma Ellenburger reservoir is in the restricted interior portion of the Ellenburger ramp approximately 40 mi south of the erosional zero-edge of the Ellenburger against the Texas Arch (fig. 51a). The reservoir is a structural trap formed by a doubly-plunging northeast-trending, fault-

(a)



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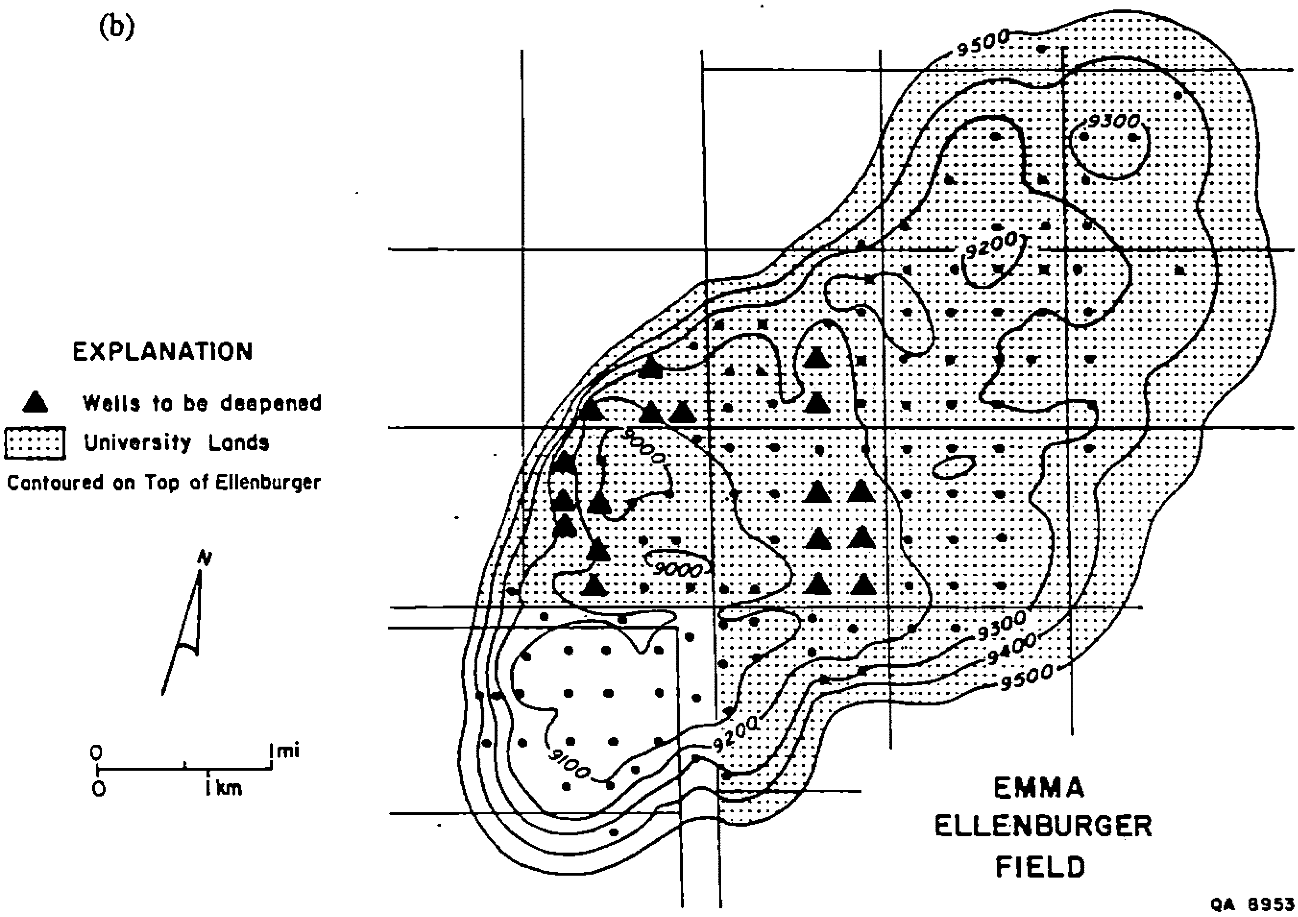

Figure 51. Geologic setting of the Emma reservoir. (a) Isopach map of the Ellenburger Group, showing gradual thickening in direction of platform margin, which approximately paralleled the Marathon–Ouachita orogen (modified from Texas Water Development Board, 1972). (b) Structure-contour map of the Ellenburger at Emma field. Closely spaced contours on the northwest margin of the reservoir have been interpreted as indicating a possible normal fault.

(c)

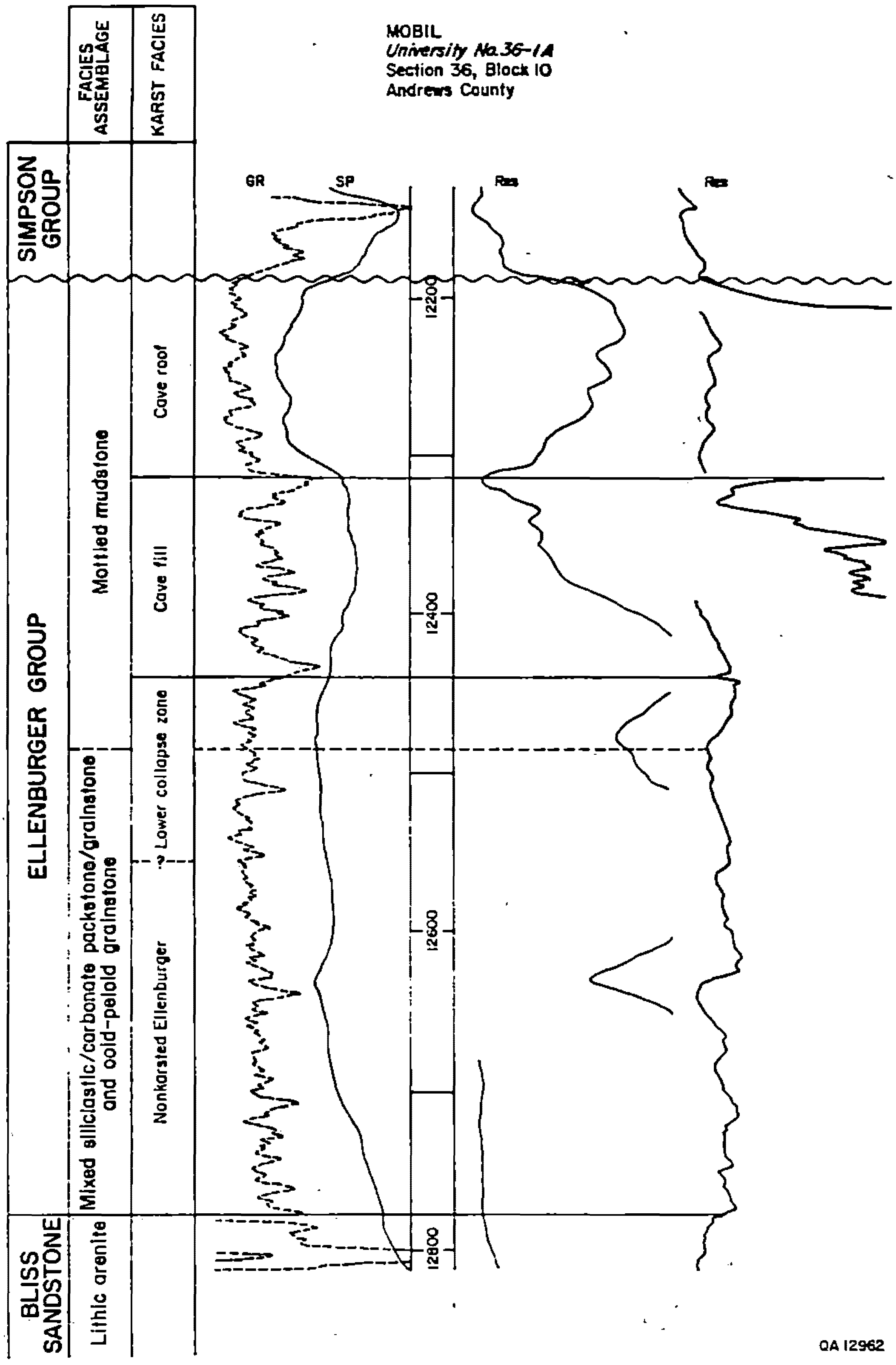

Figure 51. (c) Electric log from Mobil University 36-1 well, showing position of main facies assemblages and karst facies at Emma.

bounded anticline of probable Pennsylvanian age sealed by Middle Ordovician shales and shaly carbonates of the unconformably overlying Simpson Group (figs. 51b and 51c). The anticline provides 450 ft of closure above the original oil-water contact (9,450 ft subsea); the crest of the anticline lies at a depth of 12,186 ft (9,000 ft subsea). The Ellenburger section at Emma is only 590 ft thick (compared with 1,700 ft thick farther south in Val Verde County) as shown by the Mobil University 36-1A well near the axis of the field (fig. 51c).

Regional relationships, log-facies interpretations, and description of the three cores from the reservoir suggest that the 590-ft-thick Ellenburger section at Emma records only the lower half of the group, much of the upper section being absent because of pre-Simpson Group erosion as well as depositional thinning by onlap. The basal 30 ft of the Mobil University well 36-1 consists of a zone of high gamma-ray response that represents retrogradational siliciclastics of probable Bliss Formation affinity (fig. 51c). The remaining 560 ft of Ellenburger contains mud-dominated dolomitized shallow-water facies modified to variable degrees by pre-Simpson Group karstification. The overlying Middle Ordovician Simpson Group includes a basal 30- to 40-ft-thick shale-rich dolomitic limestone (Joins Formation) followed by a series of upward-coarsening shale to sandstone cycles (Connell, Waddell, and McKee Formations) capped by a carbonate-dominated unit (Bromide Formation).

Facies Distribution

Regional facies analysis of Ellenburger strata in West Texas has defined six facies assemblages that are broadly correlative throughout West Texas (Kerans, 1988). Cores from Emma were taken from only the upper 400 ft of the Ellenburger and document the presence of both the ooid-peloid grainstone and mottled mudstone facies assemblages. The laminated-mudstone facies assemblage that commonly caps the Ellenburger west of Reagan County is absent in cores from Emma and in other cores from Andrews County, probably as a result of erosion associated with subaerial exposure prior to deposition of the Simpson Group.

The mottled-mudstone facies assemblage composes the upper 200 ft of the Ellenburger reservoir at Emma and consists of peloid wackestone and mudstone with small-scale bioturbation structures. Where not modified by karst processes, there is little or no primary intergranular or separate-vug porosity. Beneath the mottled-mudstone facies assemblage is the ooid-peloid grainstone facies assemblage that consists of variably silicified grainstones and packstones that are crossbedded to massive. This facies assemblage typically displays slightly greater intergranular porosities in some of the grainstone lithologies. However, many grainstones are commonly tightly cemented and, as in the mottled-mudstone facies assemblage, the dominant pore type is secondary, touching-vug/fracture porosity associated with the karst.

Karst Facies

The development of an extensive karst system in the upper portion of the Ellenburger Group during pre-Simpson Group exposure and erosion has been shown to be an important factor controlling compartmentalization and heterogeneity in most of the large Ellenburger reservoirs, particularly in those occurring beneath the Simpson Group (Kerans, 1988; 1989). At Emma this karst system is represented by the a three-fold karst facies sequence typical of this subplay (fig. 52), which, from bottom to top, consists of cave roof, cave fill, and lower collapse zones. The cave-roof facies averages 109 ft thick and consists of a relatively uniform fracture or mosaic breccia. These breccia types have formed by in situ compaction-related fracturing of brittle dolostone over more readily compactable shale-rich sediment of the cave-fill karst facies. Pore networks in the cave-roof fracture/mosaic breccias are restricted to partly cemented fracture systems.

The cave-fill karst facies averages 110 ft thick and is made up of a variety of lithologies, dominated by siliciclastic-matrix-supported chaotic breccias. These breccias contain fragments of Ellenburger dolostone and Simpson Group sandstone and shale floating in a matrix of sandstone

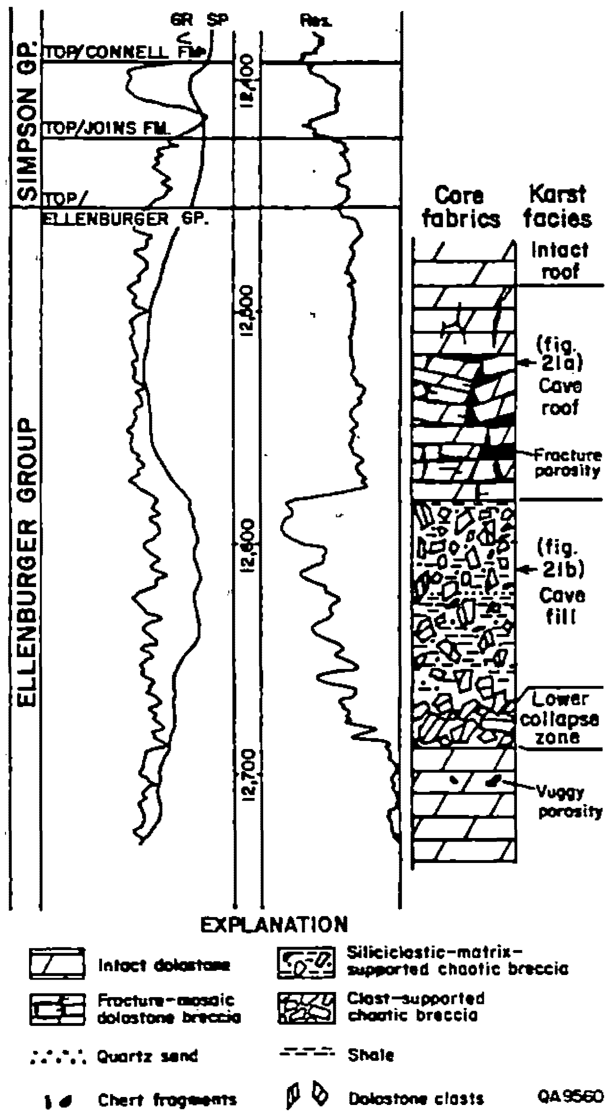

Figure 52. Comparison of log signature and karst facies developed in Gulf 000-1 TXL well in northeastern part of Emma Ellenburger reservoir, showing basis for log picks shown in figures 51 and 54.

and shale (also presumably of Simpson Group source). This facies has low porosity and permeability throughout the reservoir.

The lower collapse zone is composed of clast-support chaotic breccias, essentially a jumble of various Ellenburger dolostone clasts resting one upon the other and cemented to varying degrees by saddle dolomite, calcite, and anhydrite. Porosity within this facies is controlled by precipitation of saddle dolomite between clasts; visual estimates of porosity range up to 15 percent. The thickness of this facies cannot be accurately evaluated without extensive core control because the log signature of a dolostone breccia with dolomite cement is not significantly different from that of the unbrecciated cave-floor dolostone. None of the cores from Emma penetrate the entire lower collapse interval, which, based on cores from nearby reservoirs, can be as much as 400 ft thick.

Genesis of Ellenburger Facies

Depositional facies assemblages within the reservoir interval at Emma include the ooid-peloid grainstone and mottled mudstone. Deposition of both units took place on a broad carbonate ramp with relatively little lateral facies variability, particularly on the scale of the Emma reservoir. Water depths during deposition were on the order of 5 to 20 ft, and hypersaline conditions are suggested by the marked lack of fossils.

Genesis of karst facies at Emma can be causally linked to a globally extensive sea-level lowstand causing prolonged subaerial exposure of Ellenburger strata during the early Middle Ordovician, prior to transgression and deposition of Simpson Group sediments. The extensive modification of Ellenburger strata at Emma as a result of this exposure event and subsequent burial can be summarized in seven main stages:

1. Deposition and pervasive dolomitization of Ellenburger strata on a shallow restricted ramp
2. Relative sea-level fall and exposure of Ellenburger strata

3. Dissolution by downward percolating rainwater, the greatest corrosion and cave formation being focused along a regionally extensive ground-water table approximately 100 ft below the erosional land surface of exposed Ellenburger strata
4. Mechanical breakdown of some cave-roof material and deposition on the cave floor to form breccias of the lower collapse zone
5. Flooding of the Ellenburger karst plateau during the Middle Ordovician transgression and associated deposition of Simpson Group shale and sandstone atop the erosional surface and within the open cave systems, forming the relatively impermeable cave-fill facies (fig. 53a)
6. Continued burial of the Ellenburger beneath younger strata (Simpson Group, Montoya, Fusselman, Wristen, Thirtyone, and Woodford Formations), causing fracture and mosaic breccias to form in uppermost Ellenburger strata (cave-roof facies) as brittle dolostone collapsed into unfilled cave systems and was deformed during differential compaction over more readily compacted cave-fill shale and sandstone (fig. 53b)
7. Differential cementation of breccia porosity by saddle dolomite during phases of basinal fluid migration, probably some time in the Late Mississippian or Early Pennsylvanian

This simplified model for the diachronous formation of Ellenburger karst facies applies broadly to many of the reservoirs within the Ellenburger Karst-Modified Restricted-Ramp subplay, with the knowledge that significant local variations should be expected. Multiple cave levels have been recognized in several reservoirs, including Emma Ellenburger and Pegasus Ellenburger, and large structural depressions that may represent laterally restricted collapse "sinkholes" have been identified at Shafter Lake and Andector.

(a)

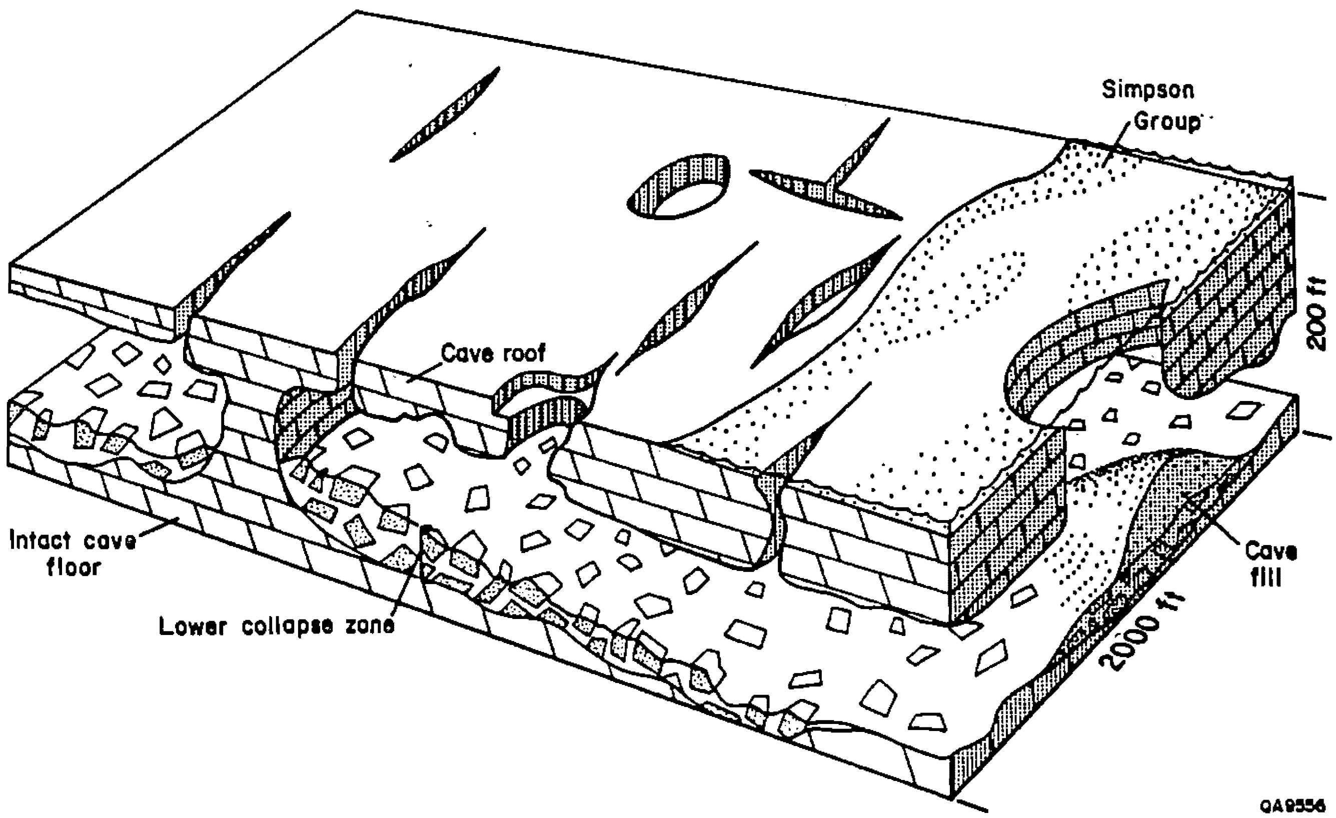

Figure 53. (a) Schematic block diagram showing Middle Ordovician development of laterally extensive cave system beneath subaerially exposed upper surface of the Ellenburger Group. Collapse breccias lining cave floor are covered by siliciclastic material from transgressing Simpson Group (lower right).

(b)

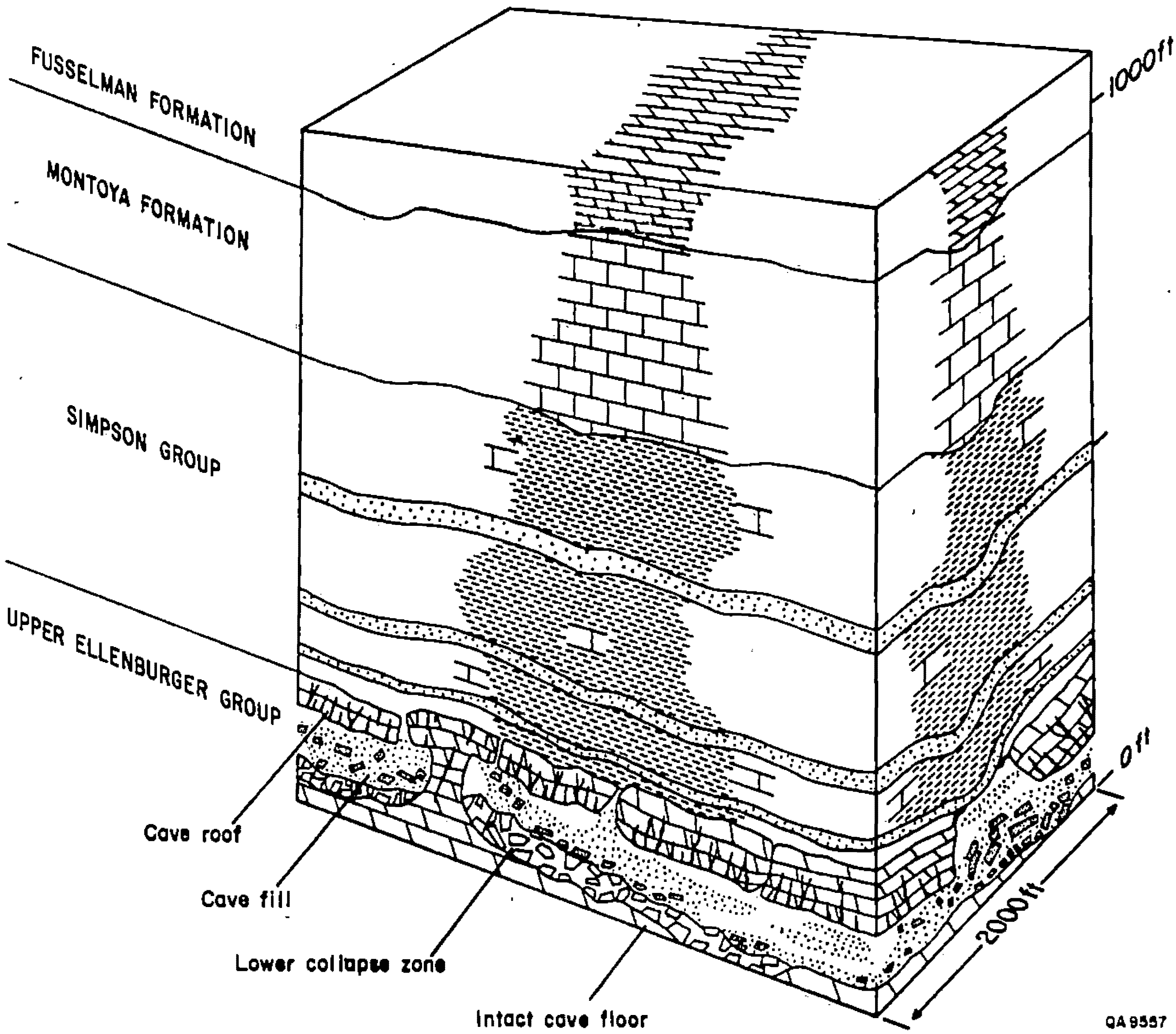

Figure 53. (b) Model of Emma reservoir, showing infill of cave systems by relatively impermeable cave-fill sediments and separation into cave-roof and lower collapse zone reservoirs.

FACIES, FLOW UNITS, AND RESERVOIR PERFORMANCE

Porosity in the Emma reservoir is dominated by karst-related secondary porosity. Accordingly, this discussion will be restricted to treatment of the control of karst facies on reservoir performance. The few percent of matrix porosity within non-karsted dolostone is largely homogeneously distributed, but slightly higher values occur in the ooid-peloid grainstone. This matrix porosity serves as storage space, but its low total percentage and relatively homogeneous distribution causes it to have little influence on flow-unit geometry or reservoir compartmentalization.

Previous methods of reservoir development for the Ellenburger assumed the presence of a strong bottom-water drive and geologic homogeneity of pore systems. Thus, many (but not all) Ellenburger development wells were completed in the upper 50 to 100 ft of the reservoir. This completion practice was done to avoid the potential for coning of water into the well bore that would force abandonment of the well. This approach appeared reasonable as long as it could be assumed that no internal barriers existed within the Ellenburger that would limit effective draining of the entire reservoir section. The reservoir model described below incorporates both geologic data presented above and relevant engineering data to show that significant barriers to vertical flow do exist in the Ellenburger section, requiring multiple completion of selected well bores to achieve maximum recovery efficiency. This second approach has been applied only partly at Emma.

The three-fold karst stratigraphy described above is here applied to an understanding of reservoir structure. Core-analysis porosity/permeability data for the three cores studied were not available, and log suites were limited to older electric (gamma-ray, spontaneous-potential, resistivity) logs. General conclusions concerning the relative permeability of the three karst facies were compared by use of 30-minute shut-in-pressure test data from zone-selective drill-stem tests. These data (fig. 54) show higher shut-in pressures in the cave-roof and lower collapse zones, and

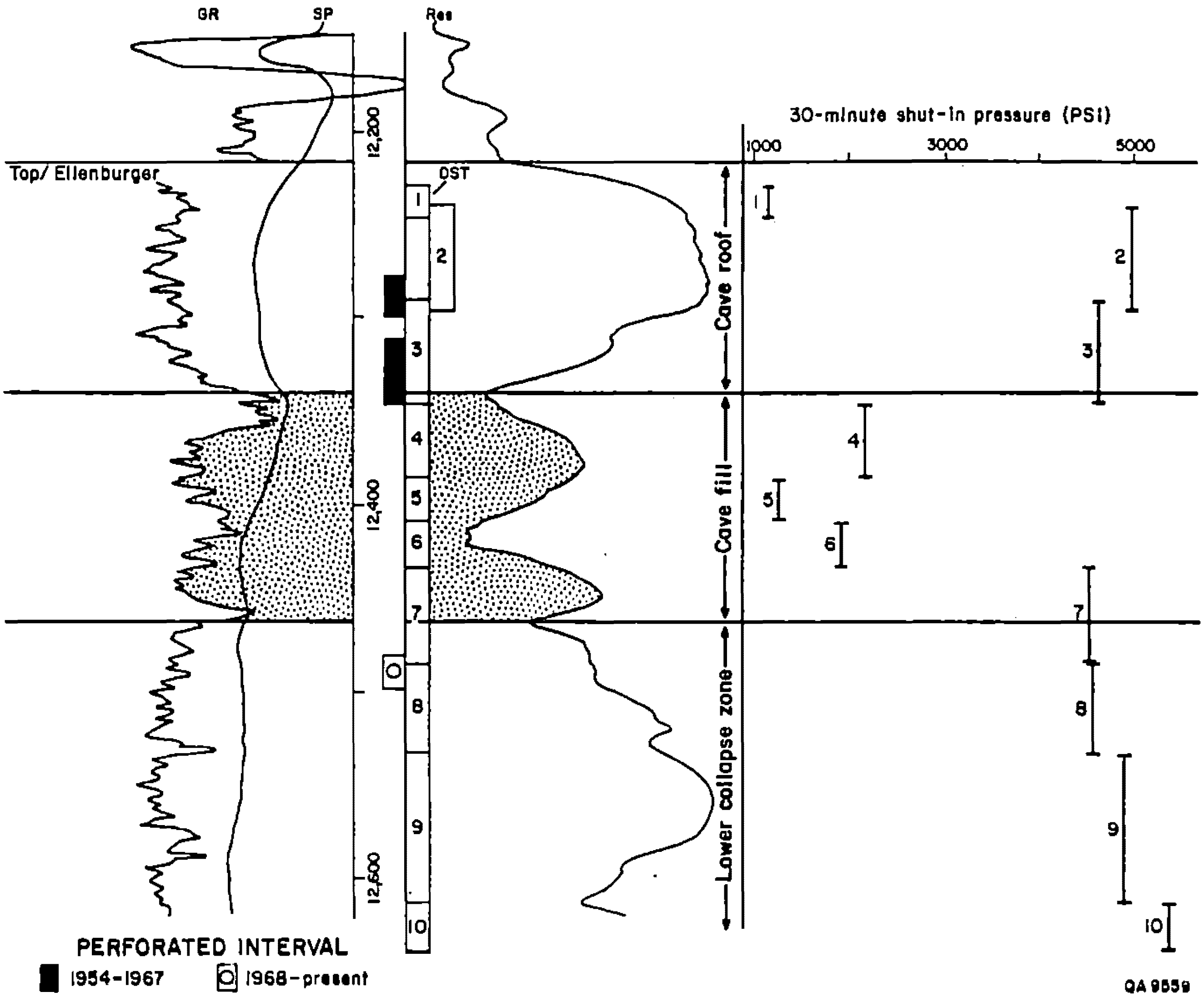

Figure 54. Typical log signature of Emma Ellenburger reservoir, showing subdivision into cave-roof, cave-fill, and lower collapse facies. Results of 30-minute shut-in pressure tests show that cave-fill facies is acting as a low-permeability barrier separating cave-roof and lower collapse reservoir units. Recompletion of well in lower collapse zone in 1968 resulted in production of a minimum of an additional 200,000 bbl of oil, which would not have been produced by initial (cave roof) completion (Mobil University 36-1 well).

the middle cave-fill zone yielding shut-in pressures approximately half an order of magnitude lower. It can be inferred from these data that the cave-roof and lower collapse zone define permeable intervals separated by the relatively low permeability, cave-fill section.

The effectiveness of the cave-fill seal in compartmentalizing the Emma Ellenburger reservoir is further demonstrated by production data for individual wells (fig. 55). All eight wells in the Mobil (Superior) University Block lease (east half of Section 36, University Block 10, Andrews County) were originally drilled through the cave-roof and cave-fill section and into the lower collapse zone in the early to middle 1950's but were plugged back and completed only in the cave-roof zone. These same well bores were recompleted in the lower collapse zone between 1968 and 1983 on the basis of favorable original drill-stem test data. Five of the eight wells initially showed large increases in annual oil production and oil/water ratio, followed by gradual decline. The Mobil University 36-1 well was recompleted in the lower collapse zone in 1968, producing an additional 200 MSTB of oil that would not have been produced by the earlier completion in the then-watered-out cave roof. Annual production data for the Mobil University 36-2 well also document a dramatic increase in oil production and decrease in watercut associated with deepening into the lower collapse zone in 1977. Since that time, the Mobil University 36-2 well has produced approximately 235 MSTB of oil, compared with the maximum estimated production of 35 MSTB it would have produced had production been restricted to the cave-roof reservoir (fig. 55).

The relative contribution of the cave-roof and lower-collapse-zone reservoirs at Emma can only be accurately assessed where zone-selective test and/or production data are available on a per-well basis. Figure 56 shows a compilation of zonal per-well production and test data for the central portion of the University Lands acreage at Emma. Data from Mobil wells on the eastern half of Section 36, Block 10, show that 32 percent of production from this lease is from the lower collapse zone. Although zonal production data are not available from adjacent leases, test data from the cave roof and lower collapse zones in these leases indicate a similar potential for the lower collapse zone (fig. 56).

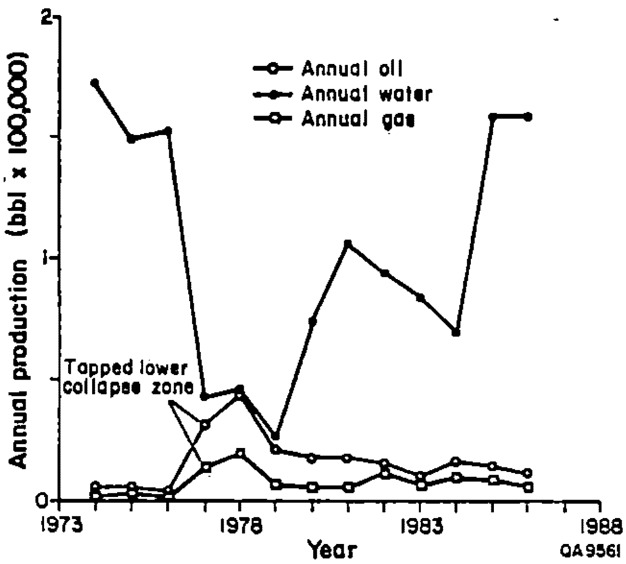

Figure 55. Production data for 1973-1986 for Mobil University 36-2 well, Emma field. Pronounced increase in oil production and temporarily decreased watercut resulted when well was squeezed off in cave-roof zone (where it had been producing since 1956) and recompleted below fill in lower collapse zone. This well has produced 235,000 bbl since 1977, as opposed to only 35,000 bbl anticipated between 1977 and 1986 on the basis of projection of constant 1976 oil production rate.

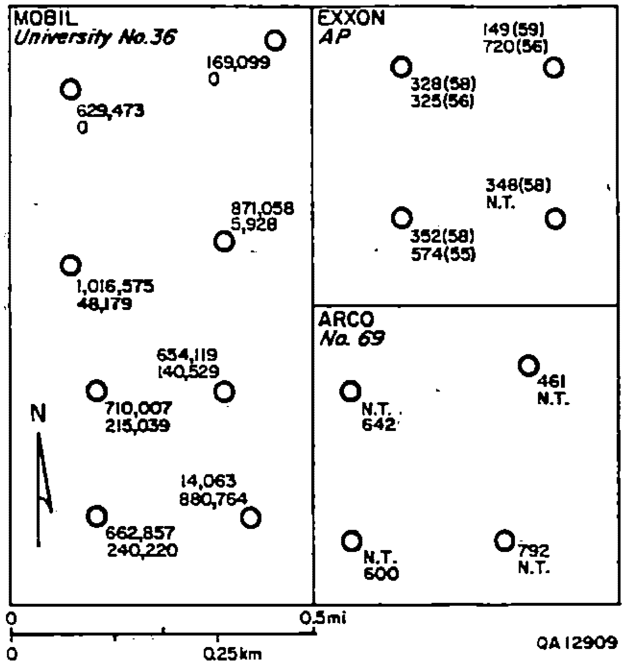

Figure 56. Per-well production data for the Mobil University 36 lease and initial potential test data for the Exxon AP and ARCO 69 leases. Production data from Mobil wells show significant (32 percent of cumulative) production from the lower collapse zone reservoir with a marked south-to-north fall-off in potential. Initial potential data for both Exxon and ARCO leases indicate equal potential for cave roof and lower collapse zone reservoirs.

Modern log suites and core data are not available for the reservoir. In lieu of these data, a method was developed for estimating potential for wells not yet completed in the lower collapse zone. Per-well production of those wells completed in only the cave roof was compared with that of wells completed in both the cave-roof and the lower collapse zones. This method shows that those wells completed in both zones have an average production of 550 MSTB, whereas those completed in only the cave roof average 250 MSTB. Average production from the lower collapse zone in wells completed in this interval is 200 MSTB, based on data from the Mobil lease. Some wells in the reservoir do not have potential in the lower collapse zone because of their low structural position that places the lower collapse zone below the oil-water contact. On the basis of the karst model a minimum of 12 wells, however, can be identified that have potential in the lower collapse zone. Assuming these wells produce an average of 200 MSTB from this lower zone, there still remains some 2.4 MMSTB of estimated reserves residing in this partly tapped lower reservoir compartment.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

Using a regional geologic model, cores, and engineering data, it has been possible to construct a reservoir model that explains the distribution of geologic facies and their influence on reservoir performance in the karsted Ellenburger reservoirs of West Texas. Depositional facies assemblages in the Emma reservoir include basal lithic arenite, mixed siliciclastic-carbonate packstone (not cored), ooid-peloid grainstone, and mottled mudstone (cored), the latter two comprising the reservoir interval. Although a slightly greater percentage of intergranular porosity occurs in the ooid-peloid grainstone relative to the mottled mudstone, neither unit contains sufficient matrix porosity to significantly affect reservoir performance.

The three-fold karst stratigraphy of cave roof, cave fill, and lower collapse zone causes segmentation of the reservoir into upper (cave-roof) and lower (lower-collapse-zone) reservoir zones separated by an intrareservoir flow barrier (cave fill). This karst stratigraphy evolved during exposure of the Ellenburger ramp prior to Middle Ordovician transgression and deposition of Simpson Group mixed siliciclastics and carbonates. Regional analysis of this exposure event shows it to be widespread throughout most of the Ellenburger reservoirs of West Texas and to be particularly well developed in those preserved beneath the Simpson Group.

Reservoir-zone production data from the Mobil University 36 show that wells with completions only in the cave roof do not effectively drain oil residing in the lower collapse zone. These zones act as separate reservoirs during the course of field development. Although most of the wells in the University Lands portion of the Emma Ellenburger reservoir have now been completed in both productive intervals, 12 wells with an estimated 2.4 MMSTB of reserves still remain untapped in the lower zone.

MCFARLAND AND MAGUTEX QUEEN RESERVOIRS

INTRODUCTION

The McFarland Queen reservoir, Andrews County (fig. 14), was discovered May 8, 1955; 72 percent of the reservoir resides on University Lands. The McFarland East Queen reservoir is an extension of the McFarland field. The discovery of the Magutex field, 2 mi to the east, followed 3 years later. Magutex Queen reservoir lies completely on University Lands. By 1963 the fields had been developed to 40-acre well spacing. This complex accounts for 73 percent, or 175 MMSTB, of the oil within the Queen Tidal-Flat Sandstone play. Typical wells initially flowed approximately 100 barrels of oil per day and then decreased to approximately 10 barrels on pump within 2 to 3 years. In the early 1960's waterflood programs in many of the units began to increase rates and improve recovery. The McFarland/Magutex reservoir complex currently has 311 producing, 100 injection, and 106 shut-in wells.

The Queen reservoir study was undertaken at two levels of investigation. A subregional-scale geological investigation provided the framework for a detailed engineering study of an information-rich smaller area that was concentrated on the State University Queen Consolidated 1 and 2 Units located in the south-central portion of the McFarland Queen reservoir (fig. 57). This study focused on core analyses from 38 wells (cores from all but one of these had been discarded), well-test data on file with the Railroad Commission of Texas for 1956–1962, and antiquated gamma-ray/neutron logs that could be used for qualitative analysis only. The geologic study area includes Block 4, which contains the portion of the McFarland Queen reservoir on University Lands, and the area of Block 5 containing the Magutex Queen reservoir. Cores were available for seven wells, two of which have modern log suites. Also available were more than 500 pre-1963 gamma-ray and neutron logs.

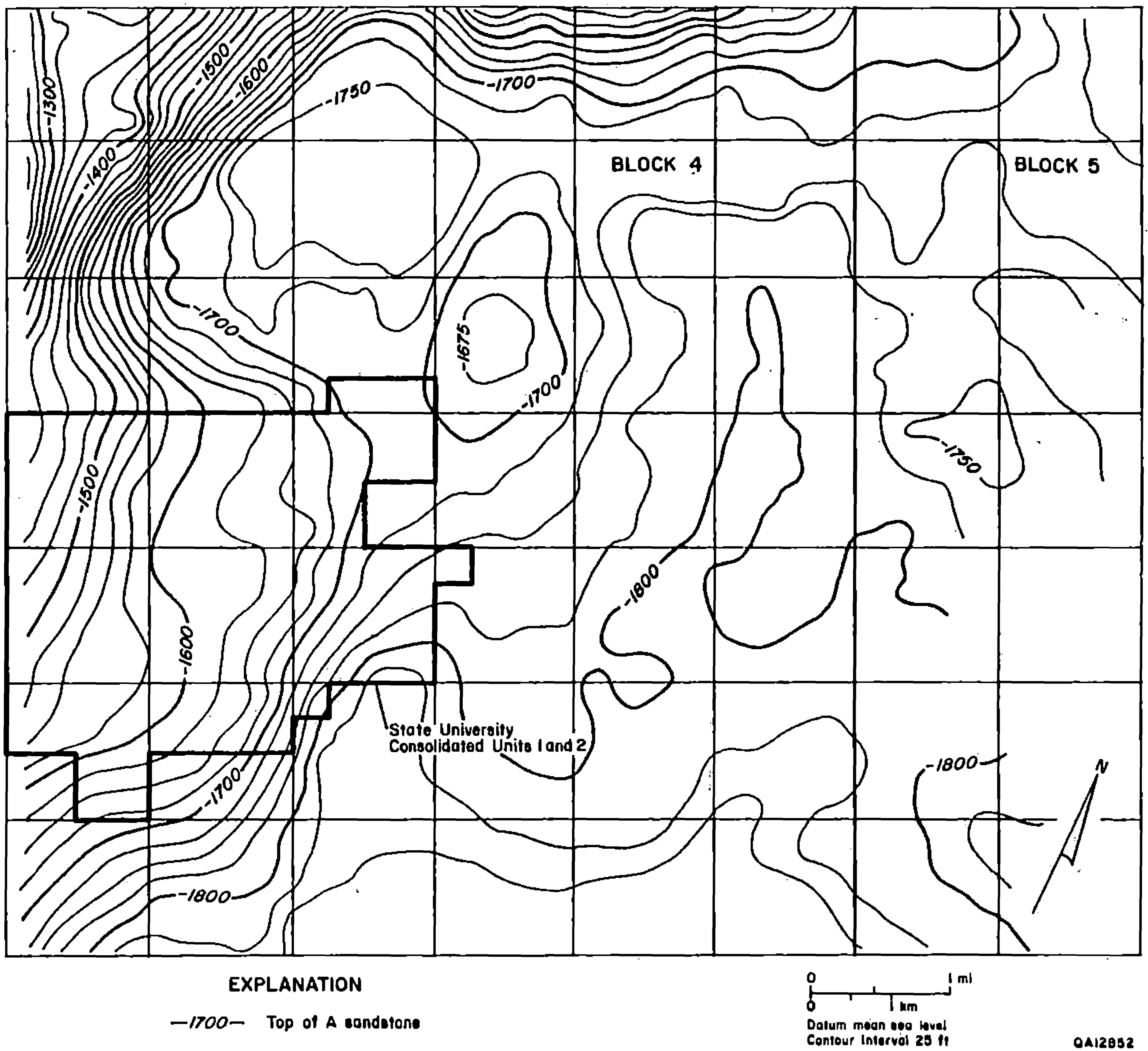

Figure 57. Structure map contoured on top of the Queen Formation for University Block 4 and west half of Block 5 with State University Consolidated Units No. 1 and 2 outlined.

GEOLOGICAL SETTING

Introduction

Most of the Queen reservoirs are located along the west side of the Central Basin Platform. The McFarland/Magutex Queen reservoir complex is, however, one of a group of a smaller number of Queen reservoirs located on the east and south sides of the Central Basin Platform. Within the Queen Formation the reservoir complex produces oil from two sandstone beds, the upper denoted the A sandstone and the lower called the B sandstone. These two sandstone beds are separated by a supratidal facies flow barrier consisting of dolomite mudstone and massive anhydrite.

Structure

Structure maps on the top of the A (top of the Queen Formation) and B sandstones (fig. 57) in University Blocks 4 and 5 indicate dip to the east and south, with local highs. The eastern dip forms a nose that extends halfway into Block 4. A high with 50 ft of closure is centered in Section 15, Block 4; a trough extends from the northeastern area of Block 4 to the south to separate the McFarland Queen and Magutex Queen reservoirs.

The structure appears to be the result of compactional deformation (drape) of the Queen Formation over preexisting paleotopography. The Queen structural highs are coincident with, and are underlain by, similar Devonian, Strawn, and Ellenburger structures, which are also productive. The Queen thickens where the structural lows exist in the underlying formations and thins where they are high. This relationship between thickness of the Queen and underlying structure suggests differential compaction over a preexisting paleostructure.

Development drilling of this reservoir complex was influenced by this structure. Nearly all of the developed area is on structural highs. This pattern implies that initial development proceeded on the premise that oil was trapped by structure. There are producing wells downdip of undeveloped areas, however, indicating a highly complex oil-water contact that has stratigraphic as well as structural control. This points to the potential for drilling additional infill wells.

Stratigraphy and Facies

The reservoir consists of two sandstone beds (A and B) that lie within two prograding depositional cycles (fig. 58). Each cycle grades upward from tan to red, very fine to silty sandstones at the bottom into massive red to gray-blue anhydrite at the top. Each depositional cycle has a sharp contact at the base and is overlain by a combination of intertidal-flat, tidal-channel, and shoreface sandstone facies. These sandstones grade into dolomudstones, which in turn grade into massive anhydrite, representing a sabkha facies. The cycles thicken toward the east and south, and a local thick lies in the northwestern area of Block 4, coincident with a local structural low.

Both the A and B sandstones extend throughout the reservoir complex. They both are of uniform thickness on the western edge of Block 4. To the east, off structure, both sandstones thicken with local thicks (channels) subparallel and subperpendicular to present structural strike. The highest production in the McFarland Queen Units is coincident with those areas where either the A or B sandstones are thicker.

Four main depositional facies are recognized within Queen reservoirs. These are intertidal-flat, tidal-channel, shoreface, and supratidal facies. The intertidal-flat facies is characterized by root traces, algal laminations, and flaser bedding. These sandstones also display a mottled texture that is interpreted to have been produced by bioturbation. Tidal-channel facies are inferred from sandstone isopachous maps, cross sections, and sedimentary structures. Basal channel-lag deposits in this area have been described by Holley (1988). This facies has channel-floor erosion at the base, followed by planar laminations, crossbeds, and climbing ripples, and capped by small ripples grading into planar to massive bedding.

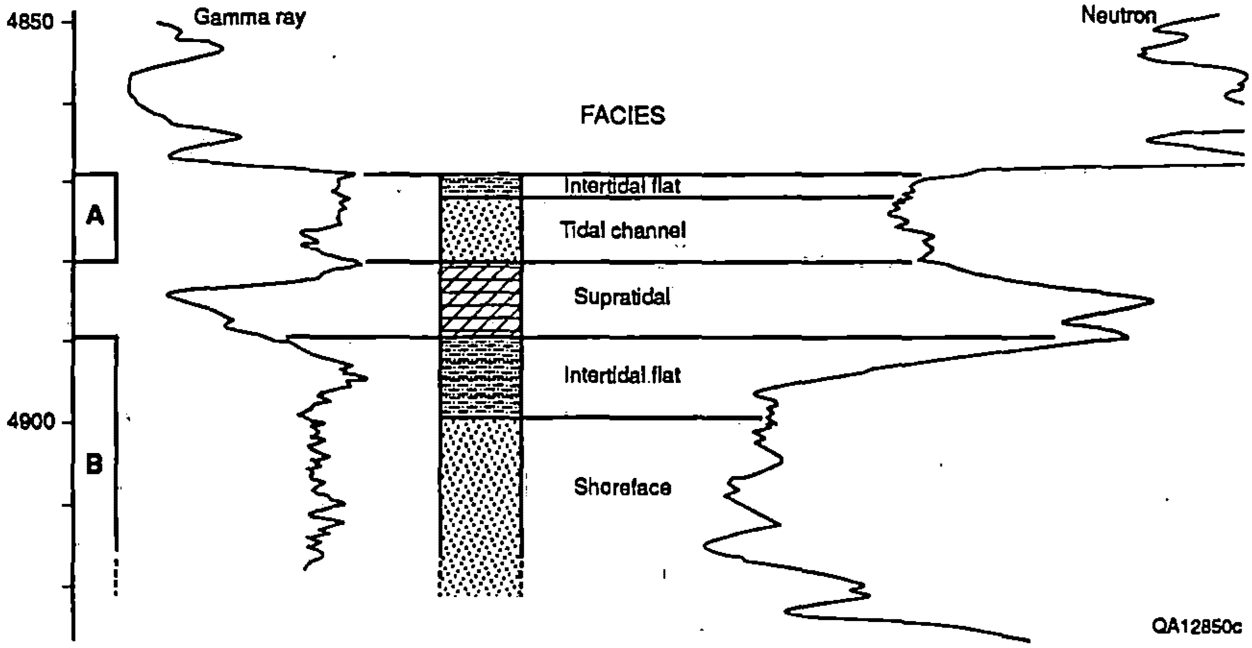

Figure 58. Type log for the McFarland/Magutex reservoir complex.

The shoreface facies is characterized by parallel and massive bedding. The massive sandstone is commonly poorly consolidated and friable. Where observed in core, this facies is heavily oil stained and contains well-developed porosity and permeability, making it a relatively highly productive facies.

The supratidal facies consists of massive anhydrite and dolomudstone. An isopachous map of the lower supratidal facies displays a regional thinning to the northwest with localized thicks in present structural lows. This thinning is the result of reduction of the massive anhydrite component in the supratidal facies and is also coincident with present structural highs. The anhydrite contains various structures, including 1- to 2-cm-thick layers, nodular mosaics, and vertical gypsum pseudomorphs. Dolomudstone is light tan and very finely crystalline. The mudstone contains nodular anhydrite and algal laminates and is barren of fossils. The structures and rock types suggest that this supratidal facies was deposited in hypersaline ponds on a tidal flat and was affected by only minor subaerial exposure.

Lithology and Porosity Description

The A and B sandstones are arkosic with anhydrite and dolomite cement. The sandstones average 40 percent detrital quartz, 15 percent feldspar, and 25 percent anhydrite and dolomite cement. Minor (up to 5 percent) clay and lithic fragments are also present. Both detrital and authigenic feldspar occur in the A and B sandstones. The detrital feldspar consists of plagioclase and orthoclase feldspar in a partially leached state. Authigenic potassium feldspar is present as 5-μm euhedral crystals, which preferentially nucleated on detrital feldspar. Electron back scatter imagery indicates a high potassium content within the sandstones and lack of uranium or thorium. Thus, the high gamma-ray response on well logs indicates relative amounts of potassium; because there is much more feldspar than clay minerals, the gamma-ray log actually displays the relatively high amount of feldspar.

Clay minerals are present throughout both the A and B sandstones in varying amounts. Clay types include illite, chlorite, and smectite. The chlorite occurs as mixed layers with smectite. The clay coats both quartz and feldspar detrital grains.

Porosity and permeability in the reservoirs is directly related to the amount of anhydrite and dolomite cement present. Anhydrite occurs as poikilotopic cement and small, 1-cm-diameter nodules. Dolomite occurs cementing detrital grains or as authigenic, multifaceted pore-filling dolomite. Dolomite cementation often follows sedimentary structures and small fractures.

Porosity is categorized into three types: interparticle, separate vug, and microporosity. Interparticle porosity constitutes from 50 to 85 percent of the total and occurs between detrital quartz and feldspar grains. Separate-vug porosity resulted from partial or total feldspar dissolution. This porosity type constitutes from 10 to 40 percent of the total. Microporosity occurs along feldspar cleavage planes enlarged by dissolution and between clay blades.

PETROPHYSICS AND VOLUMETRICS

The engineering portion of the field study concentrated on the State University Queen Consolidated No. 1 and No. 2 Units because of the large number of core porosity and permeability analyses available from this area. Log data for the area consist of 93 gamma-ray/neutron logs, most of which are pre-1960 vintage. Core analyses were available from 38 of these wells, although the cores had been discarded. Semilog crossplots of core porosity versus neutron counts for individual wells give excellent correlations, with correlation coefficients of approximately 0.9. However, use of crossplots for wells without core yielded poor results because the logs were the products of more than 10 different logging companies, each using different radiation sources, sonde spacing, and radiation counting scales. Tool response to porosity was, therefore, vastly different. Attempts to normalize the logs using the sealing massive anhydrite as one baseline and neutron peaks at various horizons as another baseline proved unsatisfactory. Thus, core analysis was considered the only useful measure of porosity and permeability.

Net pay for the cored wells was determined using a cutoff of 4 percent porosity and 0.1 md permeability. Maps were constructed that display the distribution and amount of net pore volume (fig. 59) for both the A and B sandstones. Assuming initial water saturation is 0.34, formation volume factor of 1.16, and a residual oil saturation of 0.25, there were originally 10.3 MMSTB of mobile oil and 6.2 MMSTB of residual oil in the A sandstone and 22.3 MMSTB of mobile oil and 10.3 MMSTB of residual oil in the B sandstone. As of December 1987, these two units have collectively produced 9 MMSTB, leaving 23.6 MMSTB of mobile oil remaining in these units.

Relating oil in place to production patterns was complicated by the lack of individual well production data. Well-test and lease production data for the period between 1956 and 1963 were available at the Railroad Commission of Texas; however, well data are not available after 1963 when water injection began. Production by lease in the early years was apportioned to individual wells according to the ratio of an individual well's test to the sum of the well tests on the lease (fig. 60). Wells that had produced for only 1 year and had anomalously high values were discarded because they had not begun the steep production decline that affects the value of other data points. Comparison of the production map (fig. 60) with the pore-volume map (fig. 59) shows some similarities. Lows on both maps, extending from the north-central area to the southwest, are the most obvious similarity. This area contains the more tightly cemented intertidal-flat sandstones with porosity of less than 10 percent and permeability below the detection limit of the measuring devices. Both maps also exhibit a high that trends from the east edge of Section 32 toward the west edge of the study area. The reservoir storage capacity map in this area is heavily influenced by the B sandstone, which is interpreted to be a thick tidal-channel deposit with high porosity and permeability. The most obvious dissimilarity is in Section 28 on the southeast edge of the study area, where the reservoir storage capacity map shows a high, whereas production is low. In this southeastern area many of the wells are only perforated in one of the two sandstones.

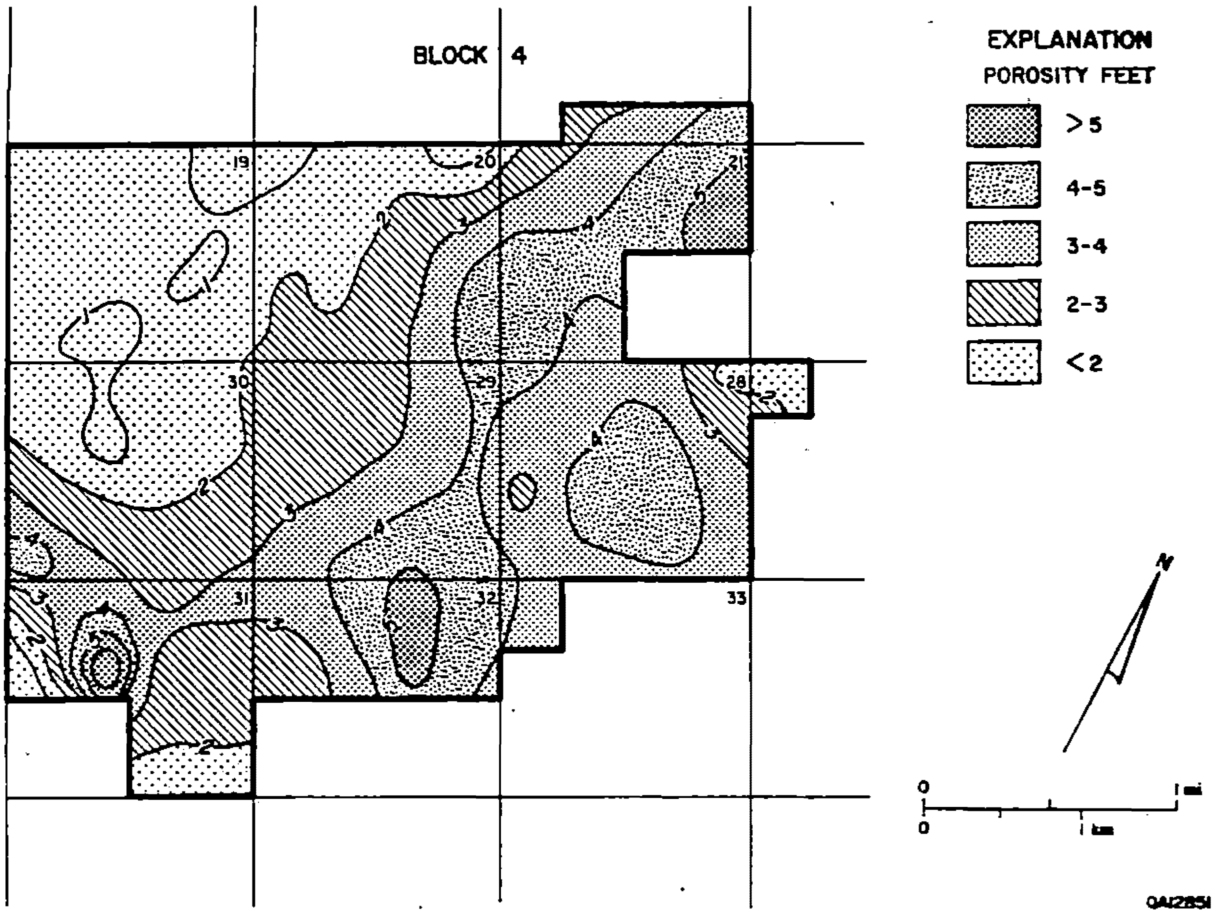

Figure 59. Map of reservoir storage capacity expressed in terms of porosity feet for State University Queen Consolidated Units No. 1 and 2.

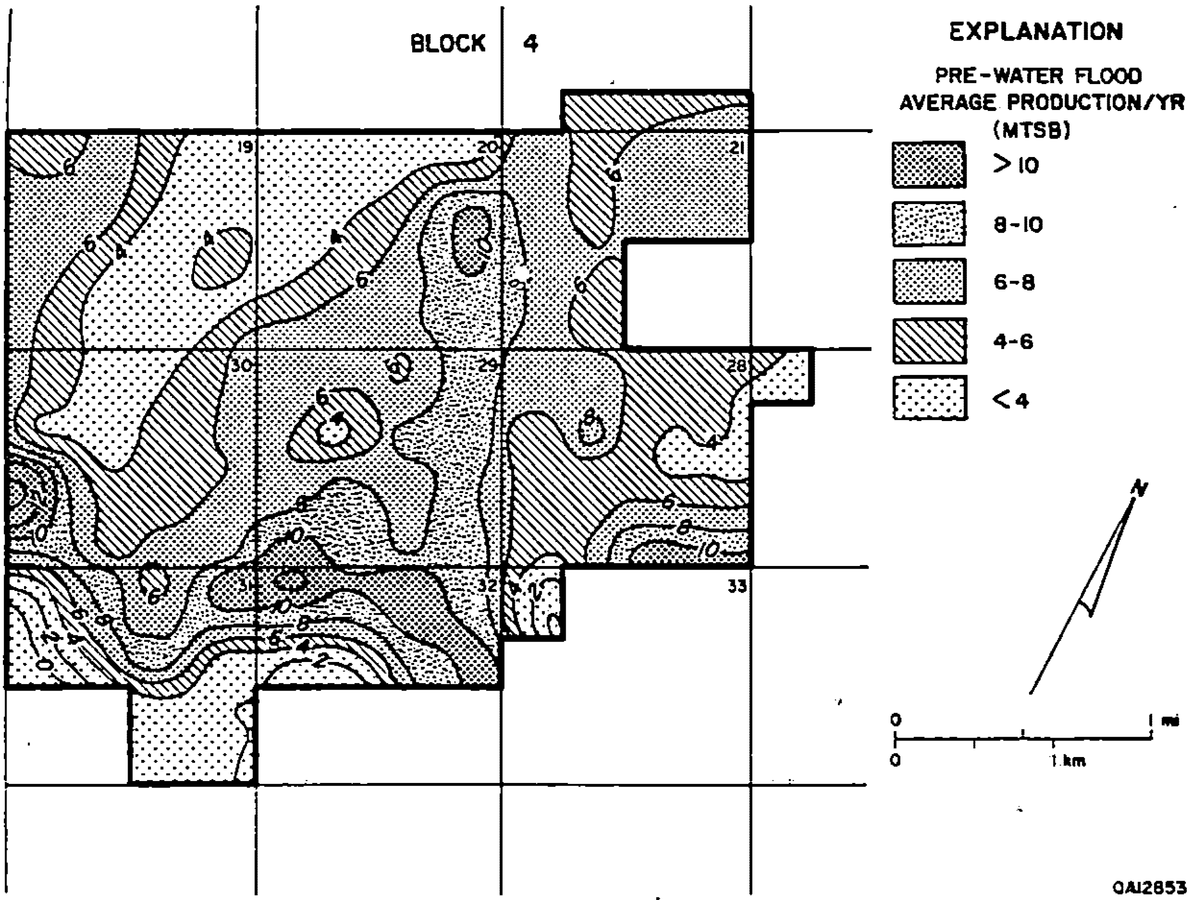

Figure 60. Map of the average annual production before waterflood for wells in the State University Queen Consolidated Units No. 1 and 2. Production values are estimated from well-test and lease-production data filed at the Railroad Commission of Texas.

STRATEGIES FOR RECOVERY OF REMAINING MOBILE OIL

There are 23.6 MMSTB of mobile oil remaining in the study area. Much of this oil is concentrated in thick tidal-channel sandstones. The reservoir is currently drilled on 40-acre spacing, but evidence suggests a targeted infill drilling program can increase production and recovery efficiency. In 1988 two wells drilled approximately 0.5 mi south of the study area had initial potential tests pumping 110 barrels of oil in one well and flowing 203 barrels of oil in the other. This area previously was the site of abandoned and stripper wells. Sirgo-Collier is currently studying an infill-drilling program in the study area. Thicker tidal-channel sandstones should be isolated as the primary target for infill wells. Existing completions should also be reviewed to locate oil behind pipe. As discussed earlier, many wells have been opened to only one production interval. Recompletions in the untapped sandstones should result in an immediate boost to production.

BENEDUM SPRABERRY RESERVOIR

INTRODUCTION

Benedum is one of several oil fields in West Texas that produce from terrigenous clastic reservoirs in the Spraberry and Dean Formations of Early Permian, Leonardian age (fig. 9). The field is located in the Benedum anticline and adjacent area, in the south-central part of the Midland Basin. Benedum was generally included in the Spraberry Trend during early field development. However, the Railroad Commission of Texas assigned Benedum the status of separate reservoir upon consolidation of the Spraberry Trend Area field in 1961.

Benedum field encompasses approximately 30,273 acres (47.3 mi^2, or 122.5 km^2) in east-central Upton County and west-central Reagan County. About 14,653 acres of the field is in University Lands in Upton County. The field is a multipay, combination stratigraphic and structural trap that first produced from Ellenburger reservoirs (Ordovician) in December 1947. Production from Spraberry reservoirs was first obtained in the Republic Natural Gas Barnett No. 1 well in 1950. The field produces by solution-gas drive. The Benedum Spraberry waterflood unit (BSU), operated by Marathon Oil Company and covering about 20,600 acres of the greater Benedum field, was formed in 1967. The southernmost part of the BSU occupies approximately 4.5 mi^2 (11.66 km^2) in University Lands Blocks 3 (Section 5 and part of Section 4) and 8 (Sections 12 and 13 and parts of sections 11 and 14). The University of Texas System has a 17.48-percent participation in the BSU.

This report summarizes the results of research on the reservoir stratigraphy and production characteristics of the BSU. Similarly to other Spraberry fields, the BSU was developed on the assumption of laterally extensive, stratigraphically homogeneous reservoirs linked by natural fractures that can be efficiently drained by wells drilled on 160-acre centers. Investigations on the BSU form part of a research program conducted at the Bureau on deep-water, very fine grained, low-recovery oil reservoirs of the Midland Basin. Research on waterflood units of the Spraberry Trend has been reported by Guevara (1988) and Tyler and Gholston (1988). Results of these studies will help define reservoir management strategies for extended development and reexploration aimed at maximizing ultimate recovery from these stratigraphically complex oil reservoirs.

GEOLOGIC SETTING

Structure

The main structural feature in the BSU and vicinity is the Benedum anticline, which is one of several local folds (for example those of the Pegasus, Parks, and Flat Rock oil fields) on an otherwise gently westward-dipping monocline that forms part of the Eastern Shelf, which is the eastern flank of the asymmetric Midland Basin. The anticline is asymmetrical. Its axis extends for almost 8 mi in the BSU, near the eastern boundary of the waterflood unit, trending northwest-southeast north of the apex and northeast-southwest south of the apex. Its eastern flank, located mostly outside the BSU, is steep particularly in the area adjacent to the apex of the structure. Its western limb, in contrast, shows gentler dips and has locally superimposed structural noses.

Fieldwide Stratigraphic Framework

The Spraberry Formation is approximately 1,000 ft (305 m) thick in the Benedum field (fig. 61). It comprises calcareous shales and thin carbonates locally interbedded with coarse siltstones and very fine grained sandstones that for brevity are herein referred to as sandstones. Fifteen sand-rich intervals (operational units) were delineated fieldwide (fig. 61). Stratigraphic distribution and vertical sequences of the operational units, which were determined using core and log data, permitted the subdivision of the Spraberry Formation into upper, middle, and lower parts. The upper and lower Spraberry comprise mostly terrigenous clastics. The middle Spraberry consists of about 650 ft of mostly dark-gray to black shale and thin carbonate mudstones locally bounding beds of sandstone and siltstone. Studies focused on operational units of the upper and lower Spraberry that contain the best oil reservoirs in the SBU.

The upper Spraberry comprises six operational units forming two stacked, upward-coarsening and upward-thickening sequences (fig. 61). The upper sequence is made up of units

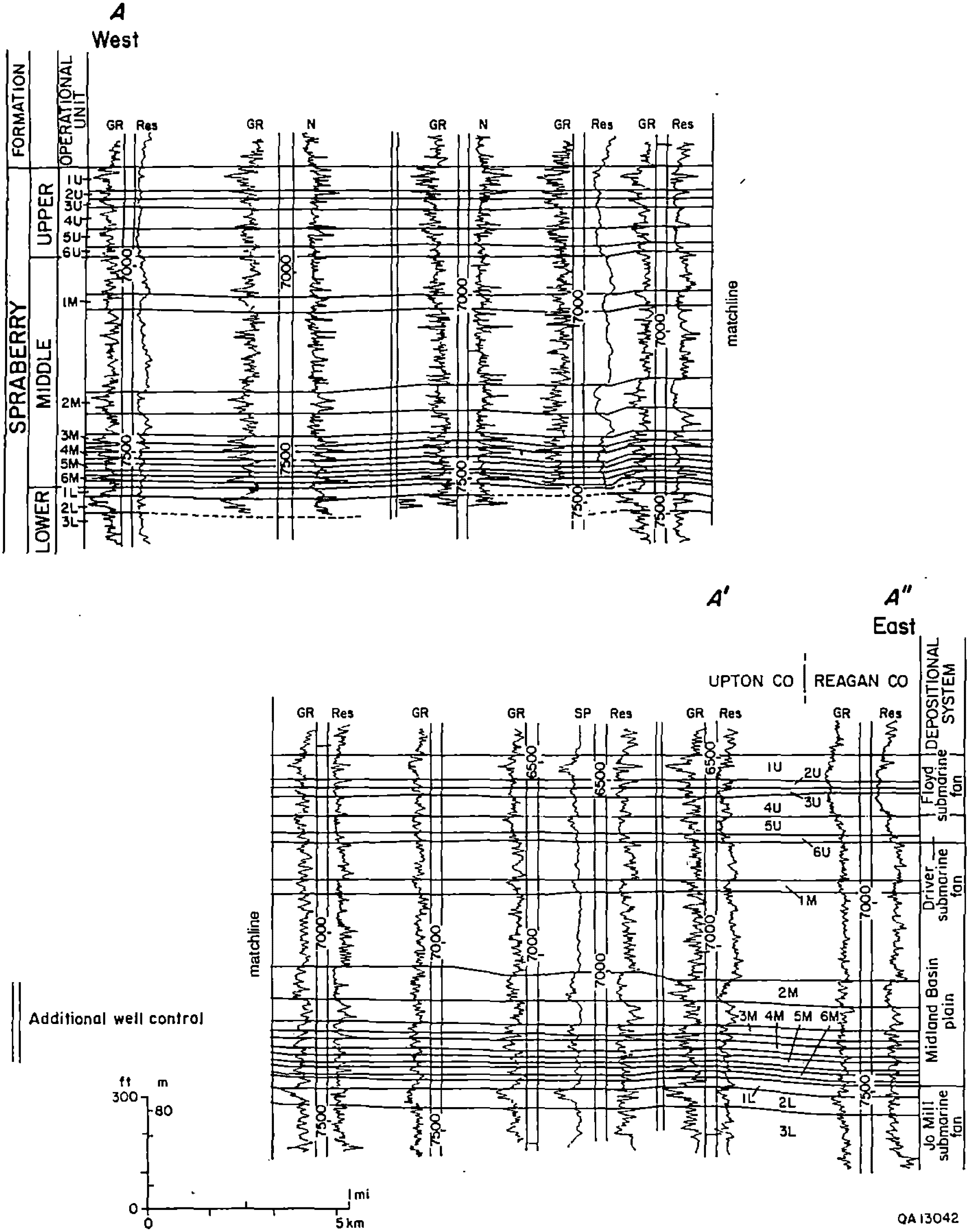

Figure 61. Stratigraphic cross section, northern part of the Benedum Spraberry waterflood unit.

1U through 4U and the lower sequence comprises units 5U and 6U. The lower Spraberry comprises three stacked operational units named 1L through 3L from youngest to oldest. Small lateral variations in thickness of the operational units give the Spraberry Formation a conspicuous layer-cake stratigraphic framework (fig. 61). Sandstone beds, however, are laterally highly discontinuous. They occur mostly in the upper parts of operational units forming the tops of upward-coarsening and upward-thickening sequences (1U, 5U, and 2L, fig. 61). Fieldwide isolith maps of upper and lower Spraberry operational units indicate that areas of maximum thickness of sandstone and siltstone occur in belts subparallel to the basin axis.

DEPOSITIONAL MODEL

Regional studies indicate that the Spraberry and Dean Formations were deposited as submarine fans and associated basin-plain facies in a relatively deep basin that was surrounded by carbonate platforms except in the south (Silver and Todd, 1969; Handford, 1981; Guevara, 1988; Tyler and Gholston, 1988). Sandstones and siltstones in this stratigraphic unit are the deposits of turbidity currents that transported sediment into a cratonic basin having a relief of approximately 2,000 ft (600 m) from the shelf edge to the basin floor (Handford, 1981). They form part of upward-thickening sequences that compose the upper Spraberry Floyd and underlying Driver submarine-fan systems and the lower Spraberry Jo-Mill submarine-fan system. Mud-rich facies of the Midland basin-plain system vertically separate the Driver and Jo-Mill fans (fig. 61).

Producing intervals in the SBU form part of outer-fan deposits composing the upper and lower Spraberry. Reservoirs are submarine-fan channel and associated overbank facies occurring mainly in sand-rich belts (fig. 62) that are similar to those mapped by Guevara (1988) and Tyler and Gholston (1988) in the neighboring Spraberry Trend field. Sandstone depositional axes in the BSU, however, generally have lower net-sandstone values and are narrower and more complexly anastomosing than in the Spraberry Trend, reflecting a generally more distal depositional setting.

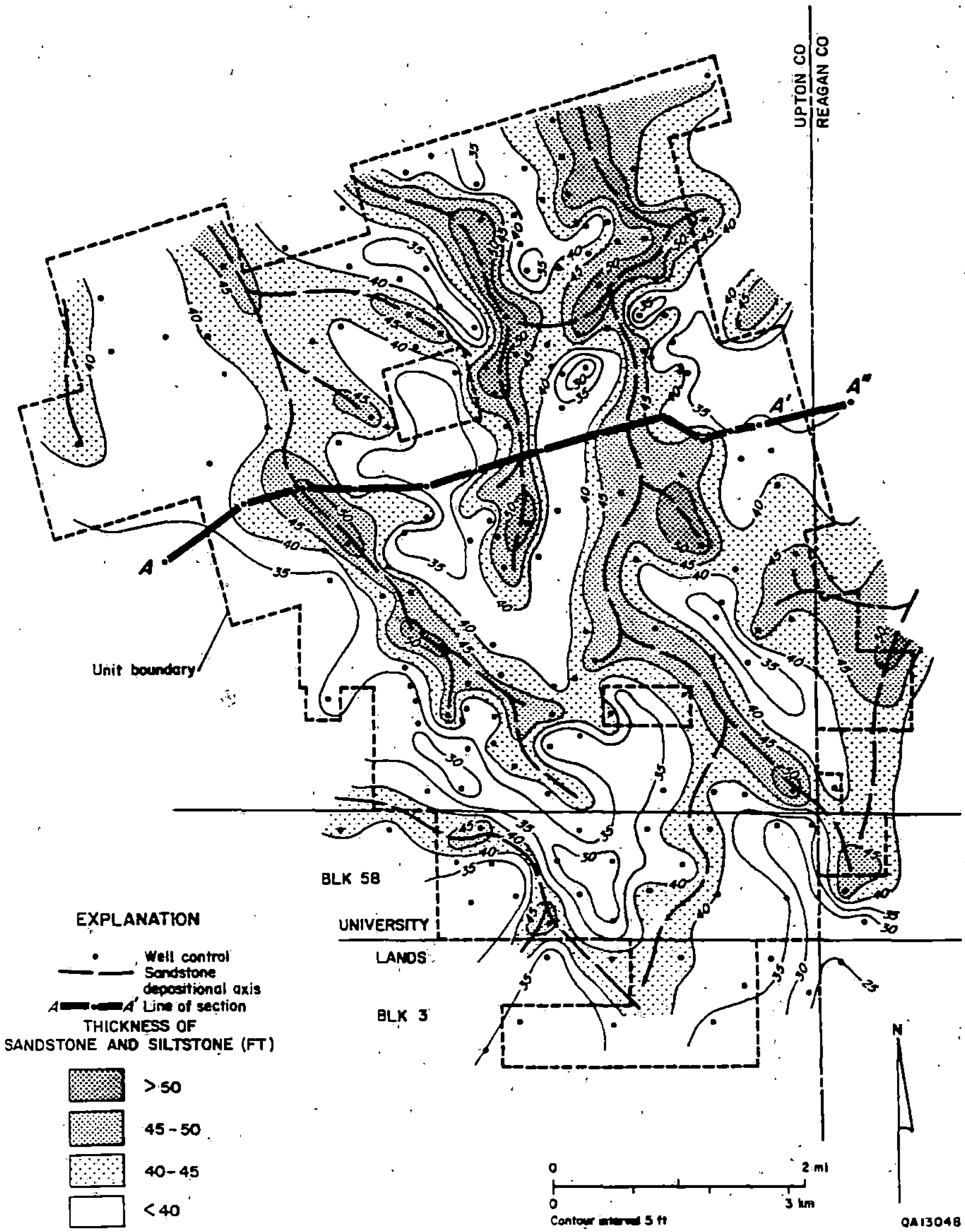

Figure 62. Map of net sandstone and siltstone, operational unit 1U, upper Spraberry, Benedum Spraberry waterflood unit.

SANDSTONE DISTRIBUTION PATTERNS

Upper Spraberry

The upper Spraberry is 220 to 230 ft thick over most of the BSU. It thins from 235 to 245 ft in the north to 201 to 220 ft in the south, along a distance of about 5 mi. Sandstones occur mainly in the upper parts of upward-coarsening operational units (1U and 5U) that generally have thin upward-fining tops. Isolith maps delineate meandering to anastomosing sandstone depositional axes generally 0.5 to 1.5 mi wide. The most continuous sandstone depocenters generally transect the BSU from the northwestern to the south-central parts and from north to south near the eastern unit boundary.

Operational unit 1U. Operational unit 1U is 60 to 65 ft thick in the north of the BSU and 55 to 60 ft thick in the south; extreme interval thicknesses occur locally in the northwest (67 ft), northeast (68 ft), and south (52 to 54 ft). The thickest sandstone beds occur near the top of the operational unit. Total sandstone thicknesses range from 50 to 54 ft mostly in the north-central part of the BSU to 25 to 30 ft in the southern part (fig. 62). The 40-ft isolith delineates two main sandstone depocenters. One sand-rich belt nearly parallels the eastern unit boundary until its junction, in the south-central part of the BSU, with another sandstone depocenter that trends northwest–southeast in the west-central part of the BSU. The merged belts continue southeastward south of this junction. Less extensive sand-rich belts occur in the north, between the two converging sandstone depocenters, and in the northwest, southwest, and southeast.

Lower Spraberry

Operational units 1L and 2L, in the upper part of the lower Spraberry, were studied because they contain the best oil reservoirs in the BSU. Structure at the top of operational unit 2L is similar to that at the top of the Spraberry Formation. Total interval thickness of combined operational units 1L and 2L generally is 70 to 80 ft. Extreme values occur in the south (85 ft) and locally in the northern and central parts (67 to 70 ft).

Operational unit 2L. Operational unit 2L is 45 to 50 ft thick over most of the BSU. Sand-rich belts are narrower and values of total sandstone thickness are smaller than in operational unit 1U. Total thickness of sandstone and siltstone generally ranges from 25 to 35 ft. Two main and three less extensive, sand-rich anastomosing belts trend northwest–southeast in the west and northeast–southwest to north–south in the east.

ENGINEERING AND PRODUCTION ATTRIBUTES

Porosity and Permeability

Results of core analyses indicate that the best porosities and permeabilities in the BSU generally correspond to relatively thick beds of sandstone and siltstone in operational units composing the upper parts of the submarine fans. The data indicate that the best reservoirs in the BSU occur in upper Spraberry operational units 1b and 5U in lower Spraberry operational unit 2L. Porosities range from less than 5 to approximately 18 percent but generally are less than 10 percent. Matrix permeabilities are less than 1 md. Field determinations of anisotropic permeabilities in the adjacent Spraberry Trend have been attributed to the occurrence of natural fractures (Elkins, 1953; Elkins and others, 1968).

Stratigraphic Heterogeneity and Well Completions

The occurrence of sand-rich belts containing outer-fan channel facies results in layered and laterally compartmentalized oil reservoirs in the BSU. Cross sections showing percent sandstone and intervals open to production in operational units of the upper and lower Spraberry illustrate the relations between current production practices and reservoir stratigraphic heterogeneities in the interwell areas (fig. 63). Local areas having more than 70 percent sandstone occur mostly in the

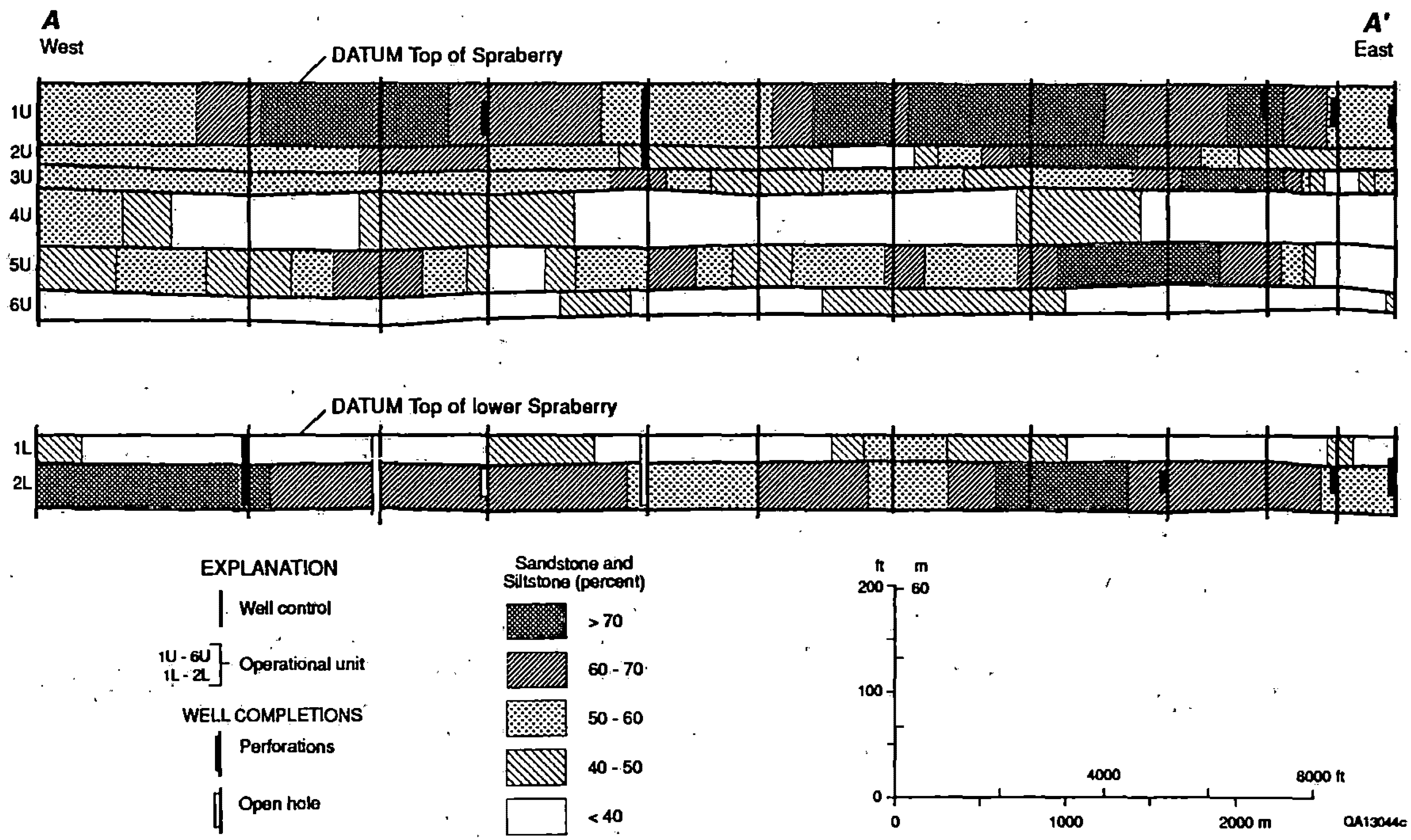

Figure 63. Stratigraphic cross section showing percent sandstone and siltstone in operational units of the upper and lower Spraberry, northern part of the Benedum Spraberry waterflood unit.

upper parts of submarine-fan deposits, in operational units 1U, 5U, and 2L. The data also indicate that intervals open to production locally do not correspond to intervals having high values of percent sandstone. Conversely, some sand-rich intervals are not open to production.

Most wells are open to production in operational units 1U and 2L. In addition, several wells in the northwest were tested or are open to production in operational unit 5U. Moreover, some wells in the west were tested or are open to production in middle Spraberry sandstones. Commonly haphazard distribution of completion intervals results in reservoir compartments remaining untapped or being only partly drained.

Production Trends and Stratigraphic Heterogeneity

Analysis of production data was undertaken to assess the relations between production trends, reservoir stratigraphy, and structure. As in most Spraberry fields, common completion and production practices preclude detailed analysis of the relations between reservoir stratigraphy and reservoir performance in the BSU. No data are available to identify the reservoirs and corresponding volumes of oil contributed to production at a given time in wells producing from commingled upper and lower Spraberry reservoirs. However, analysis of the available data strongly suggests that stratigraphic heterogeneities control oil distribution and recovery in the BSU.

A map of total cumulative oil production by well from June 1968 to June 1986 shows local areas of superior production containing "sweet spots," or the best productions (fig. 64). Most wells having the best cumulative productions from the upper Spraberry only or from the lower Spraberry only (fig. 64) are within or adjacent to the corresponding upper or lower Spraberry depositional axes. Six wells completed only in the lower Spraberry have cumulative productions ranging from approximately 60 to 147 MSTB. They are located in the northwestern, central, and southeastern parts of the BSU. Eleven wells producing only from the upper Spraberry have

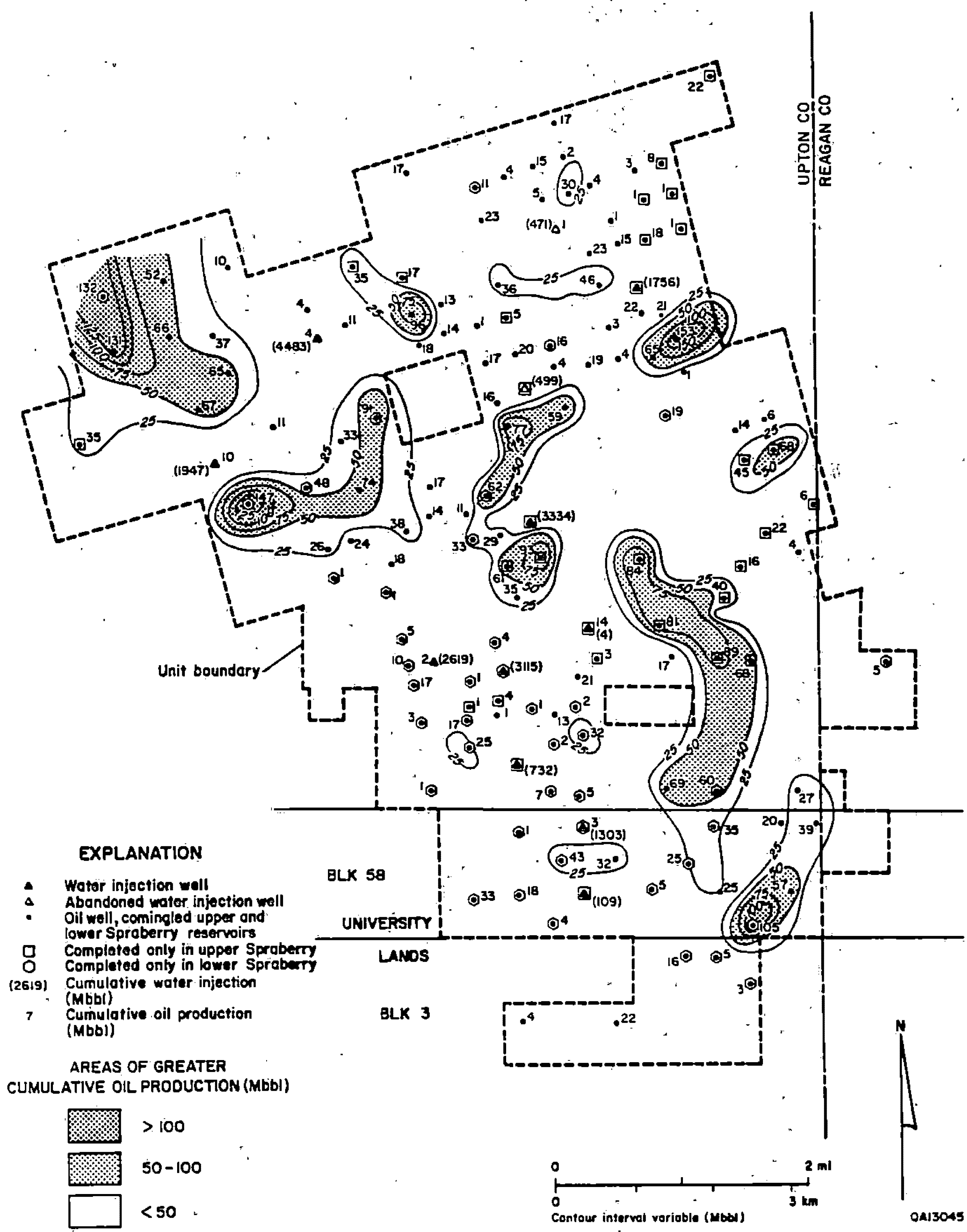

Figure 64. Map of total cumulative oil production by well from June 1969 to June 1986, Benedum Spraberry waterflood unit.

cumulative productions ranging from about 40 to 93 MSTB; they are located northeast of the lower Spraberry sweet spots.

Areas of superior oil production in the BSU are largely related to the field structure. They occur on the Benedum anticline and on a structural nose in the northwestern part of the BSU. In addition, specific locations of superior production areas and sweet spots on the structures are closely related to the sandstone depositional axes (fig. 64). Trends on production maps generally parallel those of isolith maps, and areas of superior production occur mostly within or immediately adjacent to the sandstone depositional axes of units 1U and 2L. The variability of cumulative productions (fig. 64) reflects the complex reservoir stratigraphy. It is also at least partly the result of differences in drilling, completion, and stimulation technologies used along the history of the BSU. In addition, local lack of correlation between sand-rich belts in units 1U and 2L and superior oil production may also be, in part, the result of feldspar dissolution and carbonate cementation in the thickest and originally most porous sandstone beds, as proposed by Tyler and others (1987) in the Spraberry Trend. Additional research using cores, modern logs, and detailed production and pressure data by operational unit is needed to further assess the influence of reservoir stratigraphy, diagenesis, well spacing, and completion techniques and other mechanical factors on oil production and final recovery in the BSU.

Water Injection

Waterflooding in the BSU started in 1968. A total of 12 wells located mostly in the west-central and southwestern parts have been used to reinject mainly produced water (fig. 64). Cumulative water injection totaled approximately 20.4 MMbbl by June 1986, when injection was underway in six wells in a mostly salt-water disposal operation. Waterflooding of lower Spraberry reservoirs ceased in the mid-1970's.

VOLUMETRICS

Original oil in place in University Lands in the Benedum field is estimated at 162.56 MMSTB. Cumulative production in 1989 was 5.0 MMSTB at a recovery efficiency of 3.1 percent. Remaining mobile oil, the target for reserve growth, is estimated at 57.48 MMSTB, assuming a residual oil saturation of 40 percent (table 13).

OPPORTUNITIES FOR ADDITIONAL OIL RECOVERY

The irregular distribution of well completions with respect to the sandstone depositional axes results in opportunities for infield reserve growth. Sandstone depocenters contain the production sweet spots in some waterflood units of the Spraberry Trend field (Guevara, 1988; Tyler and Gholston, 1988). Particularly, wells drilled within the sand-rich belts in the Preston and Shackelford waterflood units have cumulative productions that are as much as six times higher than those in wells drilled outside the belts (Tyler and Gholston, 1988). The relation between production and stratigraphic trends in the BSU, although modified by the field structure and further locally by diagenesis, suggests that production sweet spots are directly related to sandstone depocenters in the BSU. Therefore, as in other Spraberry fields, the reservoir stratigraphic framework is the underlying control of oil recovery in the BSU. This is mainly a result of the greater oil storage capacity of channel deposits.

Development programs must be designed using the working hypothesis of sandstone depocenters as the main controlling factor on oil distribution and recovery in the BSU. Three main types of opportunities for extended development exist using this hypothesis: well recompletions, well deepenings, and geologically targeted infill drilling. Sandstone depositional axes delineated on isolith maps of operational units 1U (upper Spraberry) and 2L (lower Spraberry), which contain the best reservoirs, are the basis for the definition of these opportunities (figs. 65a and 65b). Wells in the east-central and northeastern parts of the BSU that are open to production only in the upper Spraberry could be deepened or completed in the lower Spraberry. Similarly, wells mainly in the western parts of the BSU that are completed only in the lower Spraberry could be recompleted in the upper Spraberry. Upper Spraberry reservoirs near the injection wells are probably watered out. In addition, well spacing commonly in excess of 80 acres allows infill drilling targeting the sandstone depocenters, especially in the western flank of the structure and particularly in the structural nose in the northwestern part of the BSU.

Recent developments in well completion and stimulation techniques, such as those that have been successfully used locally in the Spraberry Trend (Barba, 1987, 1988), will help improve oil recovery in geologically targeted, recompleted, deepened, and newly drilled wells. These techniques consist mainly of large fracture treatments applied to selected target intervals (such as operational units 1U, 5U, and 2L) along which a minimum number of casing perforations are made. They result in induced fractures having relatively large lateral extent and vertically affecting thin stratigraphic intervals. In wells in the Spraberry Trend producing from Dean/Wolfcamp oil reservoirs, which are comparable to Spraberry reservoirs, Barba (1987) reported initial potentials averaging about 100 STB/day if the technique was used and about 50 STB/day if it was not. Similarly, oil production in Spraberry Trend wells using this technique averaged 3,233 STB per well more than in wells not using it over a 4-month period (Barba, 1987). New log, core, and reservoir pressure data acquired during infill drilling or well recompletions will help further determine development possibilities for the recovery of the significant volumes of oil that otherwise will be left in place at field abandonment.

(a)

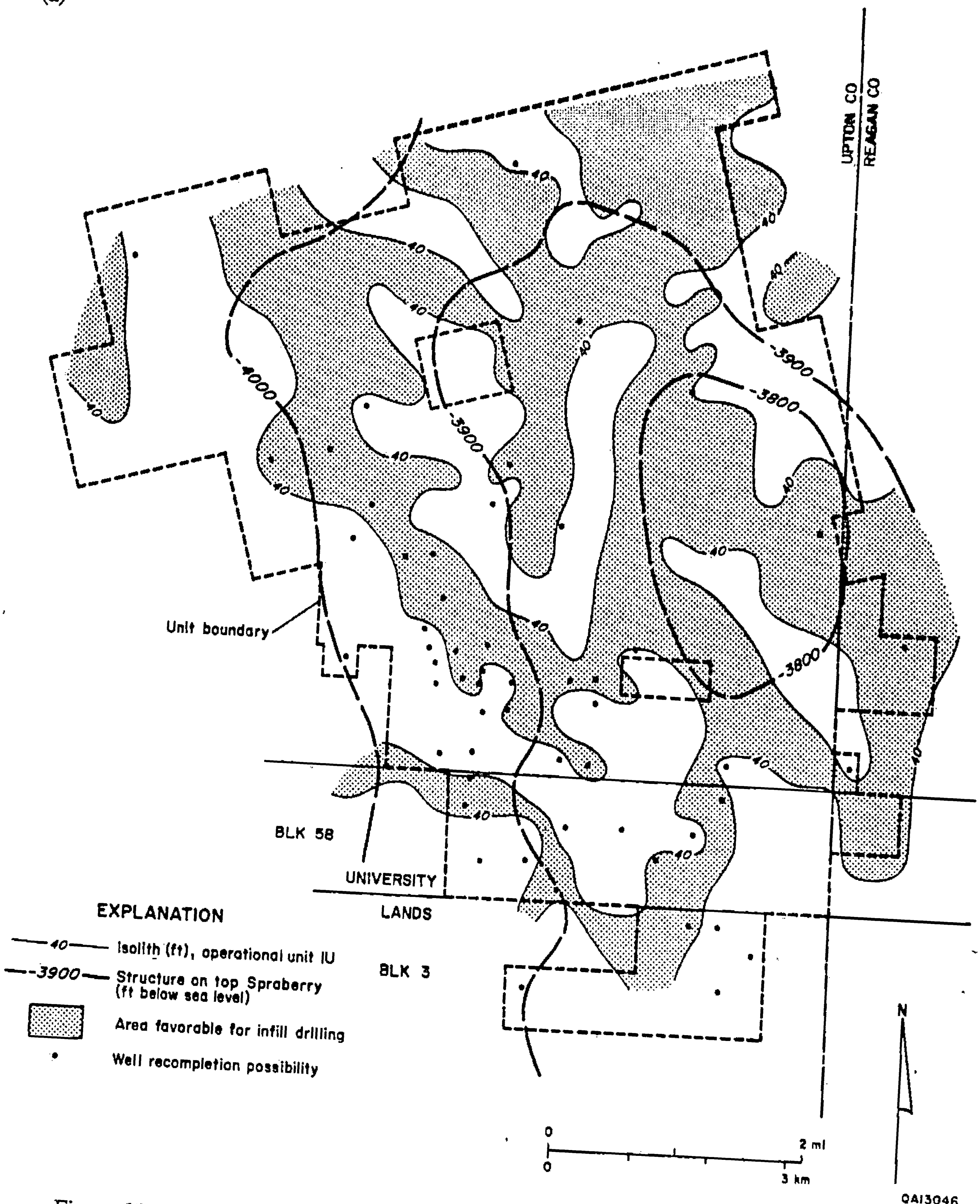

Figure 65. (a) Map of target areas for extended development, upper Spraberry, Benedum Spraberry waterflood unit.

(b)

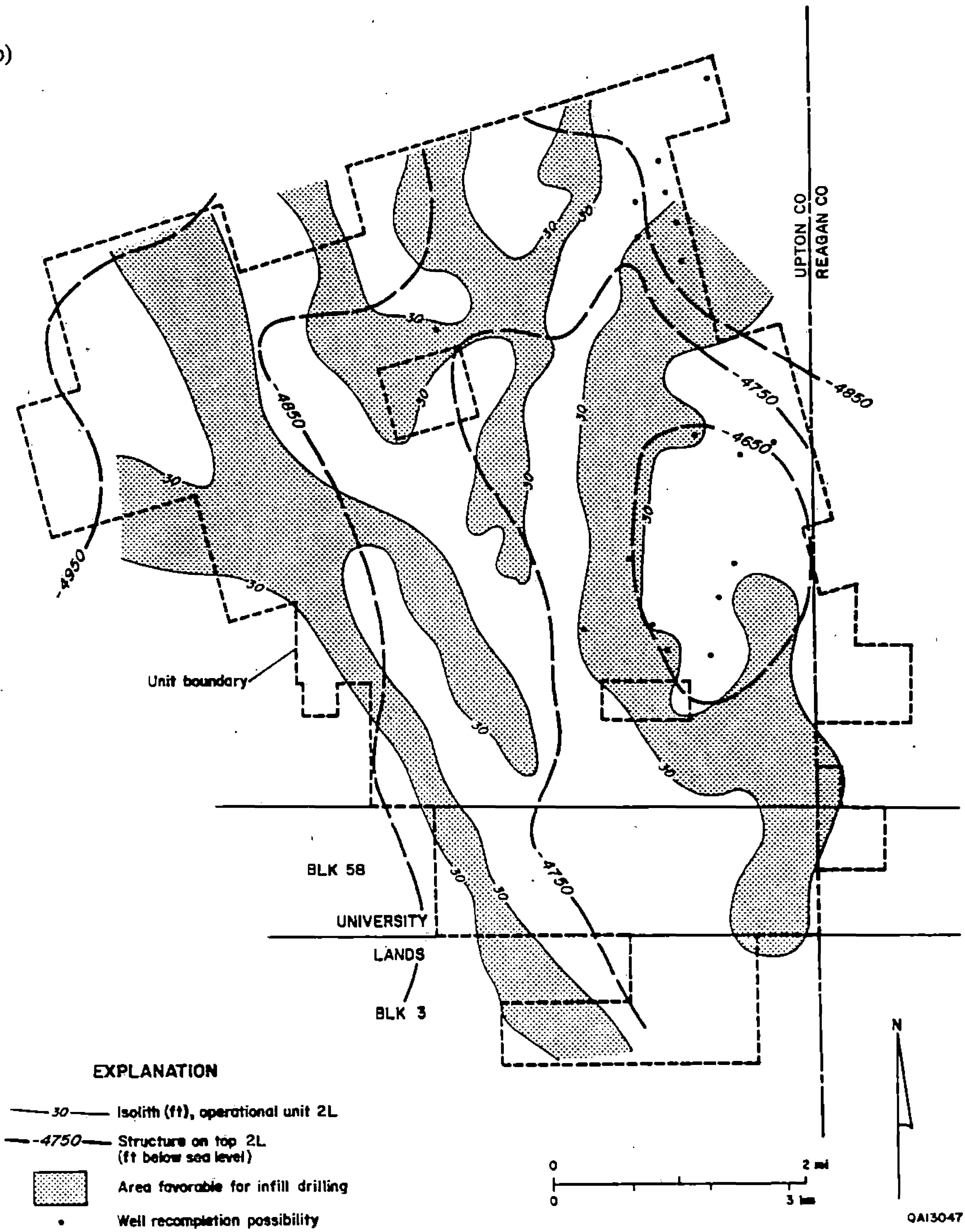

Figure 65. (b) Map of target areas for extended development, lower Spraberry, Benedum Spraberry waterflood unit.

STRATEGIES FOR IMPROVED OIL RECOVERY FROM UNIVERSITY LANDS RESERVOIRS

The large unrecovered mobile oil resource base of 2.2 BSTB, a volume of oil 1.5 times greater than historical University Lands production and an order of magnitude greater than remaining reserves, provides an immediate objective for additional recovery. Improved mobile oil recovery is a low-cost alternative to more expensive enhanced oil recovery techniques and is low risk compared with new-field wildcatting. Oil reservoir reexploration for extended development is an optimal strategy in today's (1990) financial climate for the following reasons: (1) Reexploration of existing reservoirs takes place in a data-rich environment. Well logs, cores, engineering and production data, production histories, and, rarely, advanced seismic information provide the necessary elements for detailed characterization of the remaining saturation distribution. (2) Infield exploration is relatively low cost because the production, storage, and transportation infrastructure is already in place. (3) As comparison between success ratios of targeted infill drilling versus new-field wildcats attests, reexploration is relatively low risk. Thus, improved mobile oil recovery through improved conventional techniques is an optimal strategy for recovery efficiency enhancement.

Quantification and delineation of volumes of remaining oil saturations require synergistic interdisciplinary collaboration among petroleum geologists, reservoir engineers, petrophysicists/well log analysts, and geophysicists (fig. 15). The labor intensiveness of reservoir characterization has been used to argue against its cost effectiveness. However, when compared with the costs of drilling dry holes or uneconomic wells in marginal locations, and more importantly, the intangible cost to lessees and to The University of Texas System of leaving this huge resource untapped in the subsurface, this counterargument pales. Further, the immediate benefits of using data derived through reservoir characterization on increased daily production have been displayed in Dune field Section 15, where a redesigned waterflood resulted in a 60-percent increase in daily production.

The fundamental reason for lack of recovery of remaining mobile oil is geologic heterogeneity. Because heterogeneity is a product of depositional and diagenetic processes that cause the formation and burial modification of reservoir rocks, it is predictable. Heterogeneity is expressed at varying degrees of intensity as vertical and lateral permeability variability. Vertical variability, expressed as permeability stratification, results in hydrocarbon saturation being underridden or overridden (that is, bypassed) by either natural or injected water influx. Lateral heterogeneity results in reservoir compartmentalization and in pockets or chambers of saturation being uncontacted by the well, and furthermore, bypassed by the waterflood front. The interrelationships between vertical and lateral heterogeneity govern the nature and distribution of remaining mobile oil saturations. Thus strategies for incremental recovery of mobile oil must address the style of heterogeneity inherent within the target area.

Technologies at hand for implementation of improved recovery are geologically targeted infill drilling and horizontal wells to be applied in reservoirs that are laterally variable and recompletion and waterflood redesign in reservoirs that are vertically heterogeneous. Because reservoirs can display varying degrees of lateral and vertical heterogeneity, infill drilling (either vertical or horizontal) may be applied in conjunction with targeted waterflooding, for example. This drilling approach applies to most of the thickly developed carbonate reservoirs on the Central Basin Platform and to submarine-fan reservoirs in the adjacent basins.

The following sections of this chapter discuss the application of appropriate conventional recovery technologies to University Lands reservoirs based on the style of heterogeneity characteristic of the reservoir. It is here that the play concept emerges as an important tool because results of detailed characterization studies may be extended with confidence throughout the play. In addition to the conventional recovery techniques addressed above, results of detailed studies can lead to possibilities for field extension; one such opportunity is also addressed in the following section.

TARGETED INFILL DRILLING IN CONJUNCTION WITH WATERFLOOD REDESIGN

SAN ANDRES AND GRAYBURG OPEN-MARINE PLATFORM SUBPLAYS—CENTRAL BASIN PLATFORM

Together, these two subplays contain almost 0.5 BSTB of unrecovered mobile oil. They are typically shallow, occurring at depths of 3,000 to 5,000 ft, and thus drilling costs are relatively low. In response to the interplay between lateral and vertical heterogeneity, oil is not evenly distributed vertically throughout the formation or geographically across reservoirs. For example, in the Mobil University Unit 15/16, Dune field, most of the remaining mobile oil is located in two geological zones, the MA and BC zones. The most favorable area in this unit is in the MA zone along a narrow, northwest-trending grainstone belt across the center of Section 15 that contains 7 MMSTB of unrecovered mobile oil, most of it concentrated in a 0.25 mi^2 area (fig. 20). More effective recovery of the remaining mobile oil from this unit and other Grayburg reservoirs requires drilling of additional infield wells in specific geologically targeted areas such as the grainstone belt and selective perforation of production and injection wells. Reservoir simulation suggests targeted infill wells could be economic at 5-acre spacing in sweet spots such as the grainstone trend.

Most of the remaining mobile oil in San Andres reservoirs is concentrated in pellet packstone/grainstone facies; the orientation of belts of this facies is dependent upon the depositional process by which it was deposited. For example, in the East Penwell San Andres Unit, University Block 35, there are 20 MMSTB of remaining mobile oil in east-west-elongated zones associated with tidal channels.

Because of the cyclic nature of the San Andres section, vertical heterogeneity must be taken into consideration to effectively drain all compartments of a reservoir. In the Jordan San Andres reservoir, the gross reservoir section is divided into four zones on the basis of porosity type and permeability characteristics. A zone of relatively low permeability and a thick porous zone have been bypassed by the waterflood. Modification of the waterflood to sweep this zone more efficiently has the potential to dramatically improve ultimate recovery from this reservoir. There are 43 MMSTB of unrecovered mobile oil in this reservoir.

In the Emma San Andres reservoir on University Blocks 9 and 10 more than half of the remaining oil resides in the upper of two porous zones in skeletal grainstone facies. These grainstones are thickest along northwest-trending belts, which are potential sites for strategic infill drilling designed to contact this remaining oil. Although the field is developed on an average of 20-acre spacing, no production wells have been drilled through the entire grainstone-thick section, and production from several wells has been poor. Future development should concentrate on selective infill drilling and recompletion of both production and injection wells to drain these favorable reservoir components efficiently.

CLEAR FORK PLATFORM CARBONATE PLAY

The estimated unrecovered mobile oil target for the Clear Fork Platform Carbonate play is 333 MMSTB, a significant amount to improve ultimate recovery. Moreover, the extremely high vertical and lateral heterogeneity characteristic of this play and the resulting relatively low recovery efficiencies of these reservoirs support the need for detailed reservoir characterization and geologically targeted infill drilling.

Barber and others (1983) reported that infill drilling had a particularly favorable impact on cumulative production in the Fullerton Clear Fork Unit. This field was discovered in 1942 and was originally developed on 40-acre spacing. Waterflood operations began in 1961. Sixty-one wells were drilled during Phase I infill drilling, and 151 wells were drilled during Phase II infill drilling. In 1983 production from all infill wells accounted for 71 percent of production in the entire unit, and projected ultimate recovery for infill wells averaged approximately 97 MSTB per well. Thus, the infill-drilling program at the Fullerton Clear Fork Unit significantly delayed production decline in the unit and increased projected cumulative production by some 24.6 MMSTB. Geologically targeted infill drilling elsewhere in this play supplemented by an efficient waterflood has the potential to likewise dramatically increase the ultimate recovery of these reservoirs.

SPRABERRY/DEAN SUBMARINE-FAN SANDSTONE PLAY

The large volume of unrecovered mobile oil (314 MMSTB) makes Spraberry and Dean reservoirs prime candidates for infield reserve growth. The good results of infill drilling in the early 1980's (Barba, 1988) confirm the existence of ample opportunities for additional nontertiary oil recovery from these reservoirs. Well spacing in most Spraberry fields is 160 acres, but some wells, especially those drilled during early development, are on 40-acre centers. The predominant well spacing is locally too large with respect to the width of the sandstone depositional axes and results in untapped and partly drained reservoir compartments. Furthermore, some pools have been bypassed and are currently behind pipe as a result of well completions that generally are stratigraphically haphazard and therefore do not systematically tap the stacked accumulations. Additional oil recovery will be obtained through infill drilling and recompletion programs that take into account reservoir stratigraphy in addition to fracture data. The best results will be obtained in well locations and completion intervals for oil production and water injection that aimed at uncontacted and partly drained accumulations in the sandstone depositional axes that contain the production sweet spots.

UPPER GUADALUPIAN PLATFORM SANDSTONE PLAY

Selective geologically targeted infill drilling in conjunction with modifying waterflood patterns and possibly alkaline waterflooding can improve recovery efficiencies and prolong reservoir life. Detailed geologic description of Upper Guadalupian Platform Sandstone reservoirs is essential because of the multiple productive sands that vary in permeability and porosity horizontally and also thicken and thin vertically. Proper correlation of productive sands would point to intervals not yet produced or incompletely swept because of interwell heterogeneity. This can give insight into additional targeted infill drilling and waterflood pattern modification. Alkaline waterflooding is an additional method under study that could increase reservoir recovery efficiency. Raimondi and others (1987) described how a test alkaline waterflood project in the Ward-Estes North field displayed increased oil recovery over the conventional waterflood. The target resource in this play is relatively small, however, being only 22 MMSTB.

DELAWARE SUBMARINE-FAN SANDSTONE PLAY

All three reservoirs in the play are essentially on primary production. Well density is relatively low (only 40- to 80-acre spacing). The first step to improving recovery would be infill drilling in channel thicks. These sands should be waterflooded concomitant with infill drilling. Experience in other channelized systems shows that they respond rapidly to floods. Injected-water flow paths are generally confined to the channel base in the thickest part of the channel. Once watercut rises, advanced secondary recovery would have to be implemented notably by the injection of polymers to seal off the high-permeability stringers at the channel base.

Conventional play-wide ultimate recovery is projected to be 19 percent. Application of advanced recovery techniques directed toward the unrecovered mobile oil resource of 9 MMSTB using strategies outlined could realize recovery of an additional 3 MMSTB. These prospective additional reserves amount to 150 percent of the current reserve base.

TARGETED INFILL DRILLING (VERTICAL WELLS)

ELLENBURGER KARST-MODIFIED RESTRICTED-RAMP SUBPLAY

University Lands Ellenburger reservoirs in the karst-modified subplay are all relatively old reservoirs that are well into the decline phase of their history, two of them (Block 12 Ellenburger and Fullerton South Ellenburger) being considered depleted. The number of existing wells per acre in this subplay ranges from one well per 260 acres to one well per 1,164 acres (table 14). At Emma, where there remains an estimated 67 MMSTB unrecovered mobile oil, only 8 well bores are still producing.

At Emma field, an estimated 2.4 MMSTB of reserves are projected to reside within the incompletely tapped lower-collapse zone of the reservoir that could be tested either through recompletion in lower portions of existing well bores or by drilling new wells. The latter strategy may be more effective initially considering the aged condition of most of the Ellenburger wells in this reservoir. Currently (1989) American Exploration is attempting to approve deep tests within portions of Section 36, Block 10, and Chevron has approved testing of the lower collapse zone in a portion of their extensive holdings in Block 9.

Studies of the Ellenburger Embar, University Block 13 (Ader, 1980; Kerans, 1988), Martin, Block 12 East, Midland Farms Northeast (Mear and Duffrena, 1984), Block 31, Shafter Lake, and University Waddell reservoirs indicate a similar reservoir stratification controlled by cave-fill intrareservoir flow barriers. An engineering analysis of the University Block 13 Ellenburger reservoir (Ader, 1980) defined the existence of a comparable low-permeability zone (equivalent to the cave-fill section of this study) within this reservoir and showed increased production statistics resulting from deepening of all wells that previously drained only the cave-roof zone to lower-collapse zone reservoir. It is interesting to note that this is the only reservoir that was systematically completed in both the cave-roof and lower-collapse zones and appropriately it has a 60-percent recovery efficiency, far greater than that of any other reservoir in this subplay (table 14).

Recent activity in the Shafter Lake Ellenburger reservoir by Chevron has also identified a previously untested lower-collapse pay zone in this reservoir. The deep test, which was justified on the basis of Bureau studies of adjacent University Lands Ellenburger reservoirs, came in at 129 STB/day.

Additional activity on University Lands that is designed to test potential in lower zones of the Ellenburger based on the Bureau's karst-modified ramp model is in the Block 12 East Ellenburger reservoir where Fina and Texaco are planning to drill a multiple-target well to evaluate a previously untested lower-collapse zone in this reservoir.

Limitations on testing deep Ellenburger potential relate largely to the depressed economic state of the industry in general. Clearly the 800-MMSTB remaining mobile oil target in reservoirs of the Karst-Modified Restricted-Ramp subplay on University and non-University Lands has provided substantial interest in additional drilling. The specific target focused on in this study is the deeper portions of the Ellenburger within the lower-collapse zone. Significant additional potential may also be realized when the lateral compartmentalization of these deeper reservoirs is examined in more detail. The current development status of Ellenburger reservoirs, with well spacings of 40 acres or greater, combined with the probability that marked lateral heterogeneity exists within these reservoirs, indicates that future development activity in this subplay based on advanced geologic models will be well rewarded. An example of the potential for geologically targeted infill drilling in reservoirs of this subplay is provided by a more detailed study of the Emma Ellenburger reservoir presented in this report. This reservoir, with an estimated 35 MMSTB remaining mobile oil on University Lands, serves as a model for the substantial potential throughout this subplay.

QUEEN TIDAL-FLAT SANDSTONE PLAY

With most of the reservoirs drilled on 40-acre spacing, there is opportunity for a strategic infill-drilling program to increase recovery efficiencies in this play. The resource target in this play amounts to 101 MMSTB. By mapping the thickest productive sands in conjunction with production characteristics, areas of greatest potential, such as tidal channels, can be targeted. This potential for further development has been demonstrated in the Queen A Unit of the McFarland field. In 1987, the unit contained 14 shut-in wells and 4 production wells averaging less than 4 STB/day. Two infill wells drilled in 1988 had initial potential tests of 110 STB/day (pumping) and 203 STB/day (flowing) respectively. This unit is adjacent to and south of the detailed Queen field study presented in this report.

THIRTYONE FORMATION SKELETAL PACKSTONE SUBPLAY—SILURO/DEVONIAN PLAY

Porosity distribution in these reservoirs is a function of the original distribution of carbonate packstone. Thus, isolating remaining mobile oil depends on constructing detailed maps and models of the distribution of this facies. Because all of these reservoirs are developed only to 80-acre spacing, it is probable that large quantities of oil have not been contacted because of reservoir heterogeneities associated with the distribution of the packstone facies. Strategic infill drilling to 40-acre spacing combined with selected secondary recovery techniques (for example, waterflooding) should permit recovery of a substantial volume of the nearly 90 MMSTB of mobile oil remaining in this subplay.

TARGETED INFILL DRILLING USING HORIZONTAL WELLS

Rapid technological improvements in the drilling and completion of horizontal wells over the latter half of the decade, together with a theoretical three-fold improvement in production relative to conventional wells drilled in the same formation, suggest horizontal wells offer the promise of substantial increases in production. The use of horizontal wells is optimal where lateral heterogeneity is pronounced (Finley and others, 1990). Pronounced lateral heterogeneity implies a large number of smaller compartments separated by flow barriers, the effects of which are subsumed by drilling through the barriers with horizontal wells. Thus horizontal wells can drain multiple compartments in the same way vertical wells can drain multiple layers in a vertically variable sequence. Lateral heterogeneity can be a product of rapid facies changes such as in submarine-fan reservoir facies in the Spraberry Formation, of diagenetic complexity such as in selected Ellenburger reservoirs, or of natural fractures such as in the Spraberry and Thirtyone Formations.

SPRABERRY AND DEAN SUBMARINE-FAN SANDSTONE PLAY

The depositional complexity of Spraberry and Dean reservoirs has been discussed in this report where it was concluded that vertical infill wells be targeted to tap channel axes, which have better production characteristics than nonchannel facies. An additional heterogeneity is the presence of natural fractures. Two fracture sets intersect the Spraberry; a principal set oriented northeast and a conjugate set trending northwest. Naturally fractured and highly heterogeneous Spraberry reservoirs offer a prime target for horizontal infill wells. Ideally the infill wells should be targeted to tap sand axes and to be directed toward the north (at horizontality) to intersect both fracture sets and to remain in channel sands of better reservoir quality. An alternative strategy would be to direct horizontal wells toward the east to penetrate channel (and flow) boundaries and tap both channel and channel-proximal, interchannel facies as well as intersect both sets of fractures.

THIRTYONE FORMATION CHERT SUBPLAY

Formulation of advanced secondary recovery strategies for the reservoirs in this subplay must consider two major controls on reservoir heterogeneity: facies change and fracturing. Block 31 and University Waddell Devonian reservoirs exhibit marked lateral and vertical reservoir heterogeneity due to variations in carbonate content in the chert, which are a function of original deposition. Development strategies for these reservoirs must be based on mapping and modeling of these depositional facies.

In Three Bar, Block 11, and Block 11 Southwest Devonian reservoirs, facies variations are much less and heterogeneities are primarily the result of variations in fracture abundance. Exploitation of these reservoirs potentially by horizontal wells will require an assessment of fracture distribution and a determination of the relative involvement of fracture versus matrix permeability throughout the field. Characterization studies of the Three Bar Devonian reservoir (discussed in this report) provide basic data for modeling of reservoir heterogeneity and performance in all three of these reservoirs, specifically, as well as for all reservoirs in the Thirtyone Chert subplay in general.

ELLENBURGER SELECTIVELY DOLOMITIZED RAMP CARBONATE SUBPLAY

The recognition of multiple thin pay intervals that are probably laterally discontinuous because of complex dolomitization patterns requires careful evaluation of the entire oil column for each well. Many shallow old wells or those only completed in thin zones may need reevaluation if maximum recovery efficiency is to be attained. The potential for stratiform zones of greater fracture density associated with selectively dolomitized portions of the Ellenburger in these reservoirs and the relatively shallow depths of these reservoirs could indicate potential for horizontal completions.

WATERFLOOD IMPLEMENTATION AND/OR REDESIGN

Many University Lands reservoirs are still on primary production. Reservoirs of three subplays (the two Ellenburger subplays and the Wristen subplay) produce by strong water drives and are efficient under primary production. However, several Clear Fork, Delaware, Simpson, Spraberry, Thirtyone (skeletal packstone), and Wolfcamp subplay and play reservoirs, as well as the entire Fusselman and Grayburg High-Energy Carbonates—Ozona Arch subplays, are producing by solution-gas drive, which is generally known to be the least efficient natural drive mechanism. These reservoirs typically display recovery efficiencies of single digits (for example, the Grayburg Ozona Arch subplay, table 7) to the teens (table 26). In plays where weak solution-gas drives have been supplemented by waterfloods, recovery efficiencies show an increase of as much as 12 percentage points in those reservoirs on secondary recovery compared with recovery efficiency under primary production (table 26). Clearly, many of the solution-gas-driven reservoirs would benefit from application of secondary recovery techniques.

Detailed study of Farmer field (Grayburg-Ozona Arch subplay) indicates the low-recovery reservoirs (percent) of this subplay are characterized by many thin oil-bearing intervals that have limited lateral extent (1,000 ft to 1 mi). Prior to initiation of waterflooding existing wells must be reevaluated, using new cased-hole logs, and recompleted in zones of optimal saturation. Furthermore, communication between injection and production wells must be ensured. Infill drilling will aid in contacting the discontinuous intervals not otherwise tested by existing wells. After a pattern of closer-spaced wells is completed, a carefully designed waterflood program holds the potential to recover an incremental 38.6 MMSTB by increasing subplay-wide recovery efficiency by 17 percentage points (table 26).

Table 26. Comparison of primary recovery and primary plus waterflood recovery in selected reservoirs characterized by solution-gas-drive mechanisms. Potential for incremental recovery through waterflood implementation is also shown.

Play or Subplay	*OOIP**	*Averaged recovery (primary)*	*Averaged recovery (primary and secondary)*	*Potential incremental recovery†*
Thirtyone Formation Skeletal Packstone	16.3	15.6	27.8	1.9
Clear Fork Platform Carbonate	92.4	16.9	23.8	6.4
Simpson Group Marine Sandstone—Central Basin Platform	8.3	13.0	22.0	0.7
San Andres Open-Marine Platform—Central Basin Platform	7.0	14.0	25.4	0.8
Wolfcamp Carbonate	31.8	25.8	27.7	0.6
Spraberry and Dean Submarine-Fan Sandstone	118.0	4.9		5.9**
Fusselman Formation Shallow-Platform Carbonates	9.5	14.8	—	0.5**
Grayburg High-Energy Carbonates—Ozona Arch	230.0	8.2	32.0‡	38.6‡
Pennsylvanian Platform Carbonate	194.6	20.2	23.0§	5.8
			Total	61.2

* Oil in place in reservoirs still on primary production.

† Additional oil that could be recovered by waterflooding—determined by multiplying OOIP* by percentage point difference in recovery efficiency.

‡ Recovery of natural water-drive reservoirs in two-play default value of 25 percent used in calculation of additional recovery.

§ Recovery of natural water drive "reservoirs" in this play.

** No data; incremental value of 5 percentage points used.

Redesign of existing waterflood patterns to remedy inefficient drainage may also be necessary. Detailed reservoir characterization of waterflood on the Taylor-Link West field resulted in describing the distribution of 20 MMSTB of mobile oil that will not be produced under the current producing program. Studies of the flow characteristics of the reservoir show two flow units, one dominated by fracture flow with little oil saturation and one dominated by matrix flow with significant oil saturation. At present the injected water is being cycled through the oil-poor fracture-flow unit. As discussed earlier in this report, a solution to the problem of water cycling through the fracture-flow unit, is to (1) cement off this interval, (2) inject in the grainstone interval only, (3) test the use of polymers to concentrate injection in the oil-rich grainstone interval only, and (4) increase well density in prime reservoir acreage by selectively infill drilling the grainstone bar trend. Preliminary results show a 50-percent decrease in watercut and the addition of 1.5 MMSTB of reserves. As discussed earlier, waterflood optimization in Section 15 in Dune field resulted in a 60-percent increase in daily production.

An incremental 61 MMSTB of oil could be recovered by waterflooding larger reservoirs in the subplays shown in table 26. Clear Fork, Spraberry/Dean, Pennsylvanian Platform, and in particular, Grayburg–Ozona reservoirs would benefit from waterflood implementation. The Bureau is working with operators in Farmer field (Grayburg Ozona Arch subplay) to optimize waterflood design in that field.

FIELD EXTENSION

Although the detailed characterization studies were focused on specific field areas and reservoirs, improved understanding of depositional and diagenetic processes that cause reservoir evolution can also lead to the development of new-field discovery and field extension strategies. Analysis of the Penwell and Jordan field areas (University Block 35, Ector and Crane Counties) has led to the formulation of a potential exploration target basinward of the field areas (Major, in press).

Beginning as early as 1930 there have been a very few well completions in the Grayburg Formation in and adjacent to Penwell field. These wells produced gas that, given the low prices and very limited market at that time, was not considered commercial. In the 1990's, however, this gas will almost certainly be commercial. Moreover, this early production may indicate a gas cap overlying downdip oil. Current production at Penwell and Jordan fields is from the San Andres Formation only.

The general progradational nature of the San Andres and Grayburg Formations on the Central Basin Platform suggests that the best reservoir facies in the shallower Grayburg Formation are expected to occur basinward (east) of the main trend of San Andres reservoirs. The Grayburg pay zone structure map illustrated in figure 66 indicates the location of Grayburg gas shows in a position eastward and downdip of the main San Andres production.

The most important of these Grayburg gas wells is the Stanolind University "T" No. 1, which had an initial potential test of 5,020 Mcf/day in 1930 and tested at a rate of 7,663 Mcf/day in 1937. The cumulative production was 200 MMcf, although this volume is a minimum because no production was reported in the first 7 years after discovery. Moreover, well records indicate the gas was "for domestic use for the lease itself," and production records indicate irregular production. Thus, the gas was produced only as needed, and the well was not produced at maximum capacity.

The Stanolind well was planned as a San Andres well, but drilling was suspended in the Grayburg because of mechanical difficulties in the well bore. The well was completed in the Grayburg, and cable-tool drilling records indicate the gas was "sweet"; that is, it did not contain hydrogen sulfide. This well was twinned by the Stanolind University "T" No. 2, which was completed in the San Andres Formation and produced "sour" oil, that is, oil containing hydrogen sulfide, which is the type of oil now being produced from the main San Andres reservoir. The fact that Grayburg gas does not contain hydrogen sulfide demonstrates that the San Andres and Grayburg reservoirs are separate. Importantly, the very high gas initial potential test in the Stanolind University "T" No. 1 well demonstrates commercial gas production on University Lands

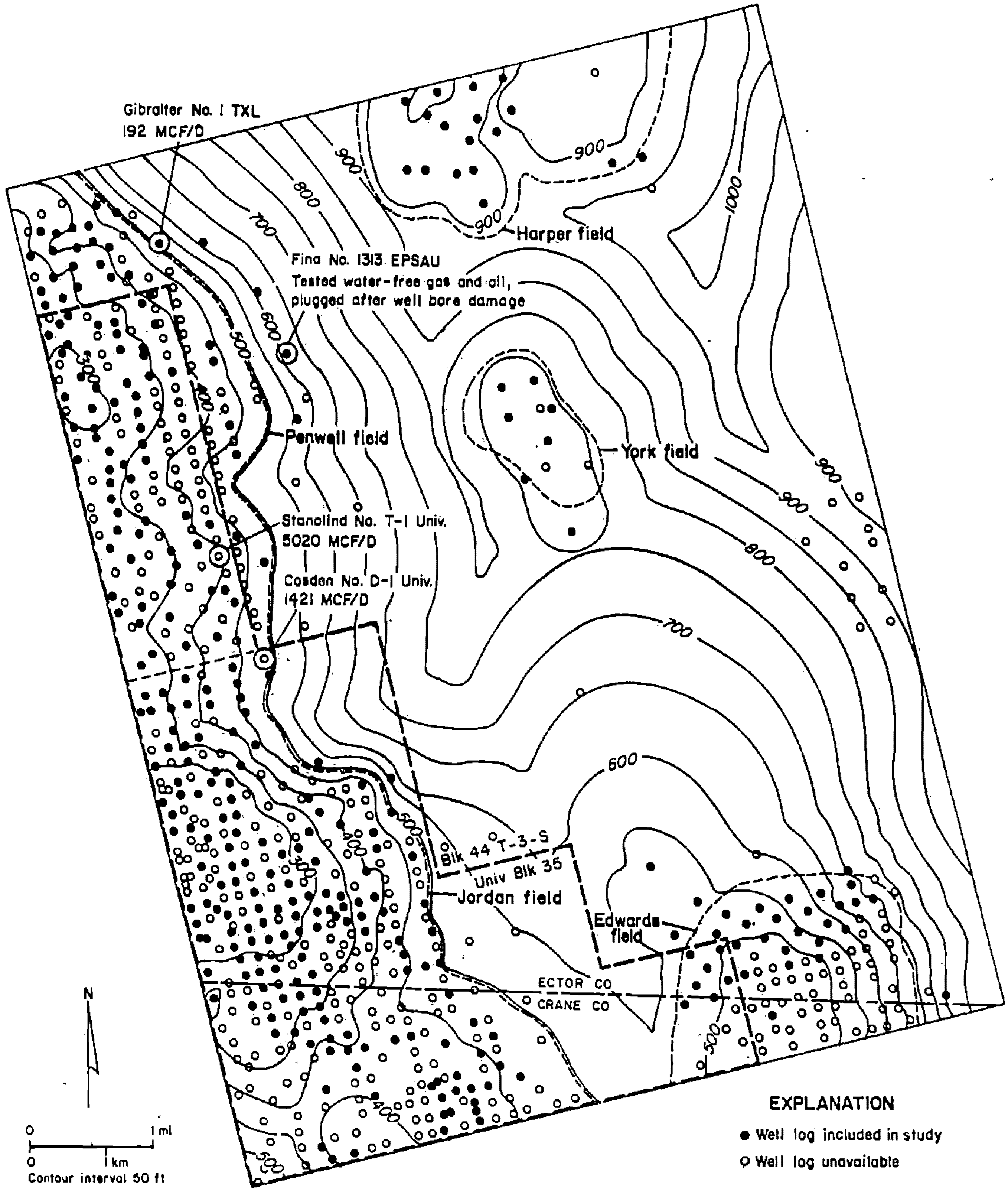

Figure 66. Structure map of the Grayburg Formation producing zone. Wells that tested gas from the Grayburg Formation in and adjacent to the East Penwell San Andres Unit are indicated. The gas may constitute a commercial gas pool and/or be a gas cap over an oil pool.

whether or not there is downdip oil in this reservoir. This play is illustrated schematically in figure 67.

Fina Oil and Chemical Company reentered an old well more than 200 ft downdip of the Stanolind University "T" No. 1 well in 1988. The well was completed in the Grayburg pay zone, made small amounts of water-free gas and oil, and was declared a producer and candidate for hydraulic fracture stimulation. Unfortunately, this old well bore was damaged during stimulation and has since been plugged. Fina is planning a new Grayburg test at a higher structural position.

INCREMENTAL RECOVERY FROM UNIVERSITY LANDS RESERVOIRS—SHORT- AND LONG-TERM GOALS

Of the 7.25 BSTB of OOIP discovered in University Lands reservoirs, 76 percent (5.5 BSTB of oil) will remain after recovery of current reserves. This large resource base represents the target for continued recovery from University Lands. Over the short term, an improvement in recovery efficiency resulting from implementation of strategies outlined herein, from the projected ultimate recovery of 24 percent of the OOIP by 6 percentage points to 30 percent, would transfer 435 MMSTB of oil from the resource category to reserves, would treble the remaining reserve base, and would foster stable production at current rates for the next 30 years.

Recent findings by the American Association of Petroleum Geologists (1989) provide guidance for estimating long-term production potential assuming advanced technology and efficiency as well as stability of oil prices at current levels. Within the context of these assumptions AAPG concluded that production of 45 percent of the unrecovered mobile oil and 6 percent of the residual oil is attainable at a national level. Given the relatively shallow depth of many University Lands reservoirs, an information-rich environment, readily available technology from research arms of The University of Texas System, and a ready supply of carbon dioxide for enhanced oil recovery, it is proposed that recovery of 50 percent of the unrecovered mobile oil and 20 percent of the residual oil is attainable over the long term. Accomplishing this objective would

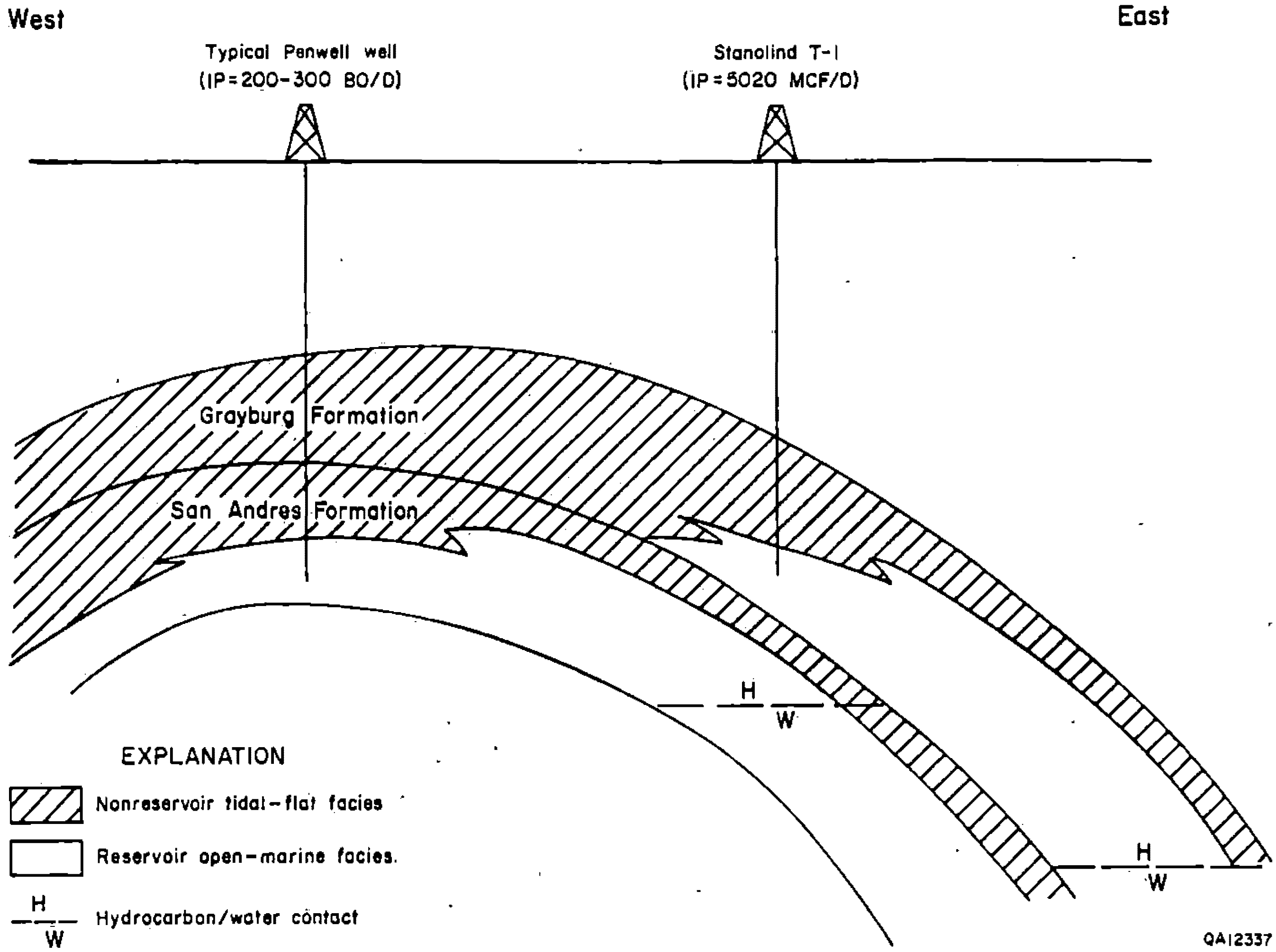

Figure 67. Schematic cross section illustrating the interpreted geometry of the Grayburg play at University Block 35 (Ector and Crane Counties). The Grayburg reservoir is east (downdip) of the main producing trend in the San Andres Formation.

result in the recovery of an additional 1.76 BSTB of oil, a volume of oil equivalent to projected ultimate recovery from University Lands at implemented technology and efficiency. Improved oil recovery at this level would raise the overall recovery efficiency of University Lands reservoirs to 48 percent and, more importantly, would assure current rates of production for the next 100 years.

CONCLUSION

There exists in University Lands reservoirs an extensive and readily accessible resource that, to a large extent, remains unaddressed. This resource is mobile oil that is prevented from migrating to the well bore by geological heterogeneities such as facies boundaries and pinch-outs, changes in diagenetic overprint, and structural discontinuities. Approximately 2.2 BSTB of unrecovered mobile oil remains in the 101 largest University Lands reservoirs, a volume that amounts to 30 percent of the oil originally discovered in these pools.

Resource assessment and play analysis carried out in this project have shown that much of the resource is concentrated in relatively few plays. Of the 18 plays and subplays delineated on University Lands, 3 (San Andres/Grayburg, Siluro/Devonian, and Ellenburger) dominate all aspects of the resource base. Reservoirs in these three formations contain 67 percent of the OOIP and account for 80 percent of the ultimate recovery. These reservoirs also contain 60 percent of the unrecovered mobile oil. The dominance of these formations in all aspects of the University Lands resource base resulted in the selection of these formations for detailed reservoir characterization. Analysis of the resource in the San Andres and Grayburg formations provided further impetus for selection of these reservoirs for detailed analysis. Collectively, shallow San Andres and Grayburg reservoirs contain one-quarter of the unrecovered mobile oil on University Lands; for this reason, 6 of the 10 reservoirs selected for investigation produce from these formations.

Detailed studies of all 10 reservoirs illustrate that locations and volumes of unrecovered mobile oil are readily delineated and quantifiable through integrated geological, petrophysical, and engineering analysis. These analyses, and the extended conventional development strategies that arise from the investigations, address a low-cost, low-risk resource, much of which is economically recoverable at 1990 prices.

Projected ultimate recovery efficiency, with implemented technology, from University Lands reservoirs is 24 percent of the OOIP. Increasing recovery from 24 to 30 percent of the OOIP over the near to intermediate term using strategies outlined in this report would triple reserves by adding more than 400 MMSTB to the reserve category and would ensure stable production at 1990 rates for the next 30 years. A long-term objective, which addresses both remaining mobile and immobile oil resources with advanced technology should be the recovery of 20 percent of the residual oil and 50 percent of the unrecovered mobile oil. Achieving this objective would provide a reserve base equal to the current projected ultimate recovery from University Lands and ensure continued royalty income to The University of Texas System well into the latter half of the next century.

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