APPLICATION OF ADVANCED RESERVOIR CHARACTERIZATION, SIMULATION, AND PRODUCTION OPTIMIZATION STRATEGIES TO MAXIMIZE RECOVERY IN SLOPE AND BASIN CLASTIC RESERVOIRS, WEST TEXAS (DELAWARE BASIN)

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ABSTRACT

The objective of this Class III project is to demonstrate that detailed reservoir characterization of clastic reservoirs in basinal sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico is a cost-effective way to recover more of the original oil in place by strategic infill-well placement and geologically based field development. Reservoirs in the Delaware Mountain Group have low producibility (average recovery <14 percent of the original oil in place) because of a high degree of vertical and lateral heterogeneity caused by depositional processes and post-depositional diagenetic modification. Detailed correlations of the Ramsey sandstone reservoirs in Geraldine Ford field suggest that lateral sandstone continuity is less than interpreted by previous studies. The degree of lateral heterogeneity in the reservoir sandstones suggests that they were deposited by eolian-derived turbidites. According to the eolian-derived turbidite model, sand dunes migrated across the exposed shelf to the shelf break during sea-level lowstands and provided well sorted sand for turbidity currents or grain flows into the deep basin.

Cyclic changes in sea level were an important cause of vertical heterogeneity in the reservoir interval at Geraldine Ford field. Ramsey sandstones were deposited during periods of relative sea-level fall in high-order cycles. Laterally continuous organic-rich siltstones, which were deposited in periods of relative sea-level rise during the high-order cycles, create vertical flow barriers within the reservoir. The sealing facies above the Ramsey sandstone is interpreted to be a particularly effective trap because it was deposited at a time of sea-level rise at three scales of cyclicity.

Genetic models of basinal sandstones and mapped sandstone-body geometry indicate that dimensions of reservoir flow units are commonly smaller than the distances separating even the most closely spaced wells (20-acre well spacing). Reservoir strata comprise thin, higher permeability sandstone lenses encased in nonreservoir siltstones. The internal arrangement and stacking patterns of the Geraldine Ford sandstones suggests that they may have been deposited as compensation lobes that formed by individual beds being deposited in the adjacent topographic

depression created by deposition of the immediately preceding bed. The amount of channelization in these distal, basin-floor deposits is uncertain. The reservoir facies may represent submarine-channel deposits encased within lower permeability lobe deposits or, alternatively, the reservoirs may be thick-bedded sandstone lobes and the nonreservoir facies are interbedded thin-bedded lobe-fringe deposits.

Permeability measurements and petrographic relationships indicate that during burial diagenesis additional heterogeneity was caused by nonuniform precipitation of authigenic calcite and clays in reservoir sandstones. The porosity and permeability data were subdivided and evaluated by stratigraphic unit and examined vertically through the unit. The Ramsey 1A, 1B, 1C, and 2 sandstone units have remarkably similar permeability characteristics, with distributions skewed from the expected log normal distribution and modal values of about 32 md. The skewed distribution is tentatively interpreted as the result of combining more than one population with different permeability characteristics. Permeability varies systematically with position in each Ramsey sandstone unit, with highest values as well as the highest average permeability at the top of each unit and lowest average immediately (~1 ft) below. Some of the samples at the top of the unit have slightly higher permeability relative to porosity on a porosity versus permeability cross plot, which might indicate permeability enhancement as a result of leaching. The low values may correspond to calcite cementation commonly observed about 1 ft below the top of some units.

Because of these complex reservoir heterogeneities, it is likely that untapped and poorly drained compartments lie within most Delaware sandstone fields.

EXECUTIVE SUMMARY

Slope and basin clastic reservoirs in sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico contained more than 1.8 billion barrels (Bbbl) of oil at discovery. Recovery efficiencies of these reservoirs have averaged only 14 percent since production began in the 1920's, and thus a substantial amount of the original oil in place remains unproduced. In this project, the Bureau of Economic Geology, The University of Texas at Austin, and Conoco Inc. are deploying advanced reservoir characterization strategies to optimize recovery from Geraldine Ford and Ford West fields, which produce from the two most prolific horizons in the Delaware Mountain Group in Texas. The goal of the study is to demonstrate that reservoir characterization, using 3-D seismic data, high-resolution sequence stratigraphy, and other techniques, and integrated with reservoir simulation, can optimize infill drilling and Enhanced Oil Recovery (EOR) projects. Through technology transfer workshops and other presentations, the knowledge gained in the comparative study of these two fields with 89 MMbbl of remaining oil in place will then be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs, which together contain 1.6 Bbbl of remaining oil.

Work performed during the first year of the contract focused on tasks associated with project start-up activities, data collection, and initial reservoir characterization. A major task accomplished this year was designing, acquiring, and processing a 3-D seismic survey from a 36 square mile area over Geraldine Ford and Ford West fields and the nonproductive area in between. Reservoir characterization this year was focused on the larger field, Geraldine Ford, to evaluate large-, intermediate-, and small-scale heterogeneities. Evaluation of large-scale heterogeneity is being done primarily using the seismic reflection data. Intermediate- to small-scale heterogeneity caused by depositional and diagenetic processes are being studied using well logs, outcrop data, cores, and SEM imaging. Geophysical log and core data have been assembled, and core-analysis data from 171 Geraldine Ford wells were entered into spread sheets. Log curves were digitized, and old gamma-ray curves were normalized to API units. Important marker horizons in the reservoir interval and the nonproductive section above and below were correlated on all logs in Geraldine Ford field, and the data have been entered into a Landmark OpenWorks™ data base.

Initial reservoir characterization indicates that the productive Bell Canyon sandstones in Geraldine Ford field are more heterogeneous both vertically and laterally than previously recognized. A new depositional model has been proposed to explain the distribution, texture, and geometry of these sandstones—accumulation in compensation lobes in an eolian-derived turbidite system. This model interprets the reservoir interval at Geraldine Ford field as being composed of many small-scale sandstones that amalgamate into a 2-mi-wide submarine-lobe complex. Within the larger lobe complex, high-permeability reservoir sandstones are encased in low-permeability, nonreservoir sandstone and siltstone.

Permeability distribution in the reservoir is also influenced by diagenetic changes, particularly non-uniform precipitation of authigenic clays, calcite, and anhydrite, and subsequent dissolution of some calcite and anhydrite. Permeability varies systematically with position in each Ramsey sandstone unit, with highest average permeability at the top of each unit and lowest average immediately below.

In the coming year, this depositional and diagenetic model will be tested and refined in Geraldine Ford and Ford West fields using seismic, log, core, and outcrop data, in order to develop a better understanding of the depositional processes that formed the reservoir sandstones and the diagenetic processes that modified them during burial. Outcrop studies will be particularly important to determining the size of sandstone bodies. Subsurface data indicate that the dimensions of reservoir sandstones are commonly smaller than the distances between wells, but their size cannot be determined from subsurface data alone. Outcrop investigations will provide critical information on sandstone dimensions that will be used in simulations of the reservoir in the demonstration area. Because Geraldine Ford and Ford West fields produce from the two most prolific horizons in the Bell and Cherry Canyon Formations, reservoir characterization of these two fields will provide insights that can be applied to these zones in other fields in the basin.

INTRODUCTION

Summary of Project Objectives

The objective of this project is to demonstrate that detailed reservoir characterization of slope and basin clastic reservoirs in sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico is a cost effective way to recover a higher percentage of the original oil in place through strategic placement of infill wells and geologically based field development. One of the most important lessons learned from 75 years of reservoir development experience in the Permian Basin is that comprehensive geologic and engineering investigations of reservoir character (that is, description of the geologic controls on engineering attributes and the effects of internal heterogeneity on the distribution of hydrocarbons) are essential prerequisites for designing efficient production strategies (Ruppel and others, 1995). Primary production, infill drilling, waterflooding, and enhanced oil recovery operations undertaken without thorough reservoir characterization will not realize maximum potential production. The goal of this project is to demonstrate that reservoir characterization incorporating 3-D seismic and reservoir simulation can optimize infill drilling and enhanced oil recovery (such as CO_2 flood) projects and thus increase production and prevent premature abandonment of slope and basin clastic reservoirs in mature fields.

Project Description

This project involves a comparative reservoir characterization study of two prolific middle Permian slope and basin clastic reservoirs in the Delaware Basin, West Texas, followed by a field demonstration in one of the fields. The fields being investigated are Geraldine Ford and Ford West (4100) fields in Reeves and Culberson Counties, Texas (fig. 1). Geraldine Ford field, which is operated as the Ford Geraldine unit by Conoco, Inc., produces at 2,600 ft from a stratigraphic trap in the upper part of the Bell Canyon Formation of the Delaware Mountain Group. The 99 million bbl of original oil in place (Pittaway and Rosato, 1991) makes it the largest Delaware Mountain Group field in the basin. Thirteen years of primary production and 26 years of secondary (waterflood) and tertiary (CO_2 flood) development in the Ford Geraldine unit have resulted in a recovery efficiency of only 26 percent. This recovery efficiency is higher than that of most reservoirs in this play because the Ford Geraldine unit is one of the first to undergo tertiary development. Thus, secondary and tertiary recovery programs at Ford Geraldine unit resulted in incremental recovery, but overall recovery efficiency remains poor because reservoir heterogeneity causes serious producibility problems.

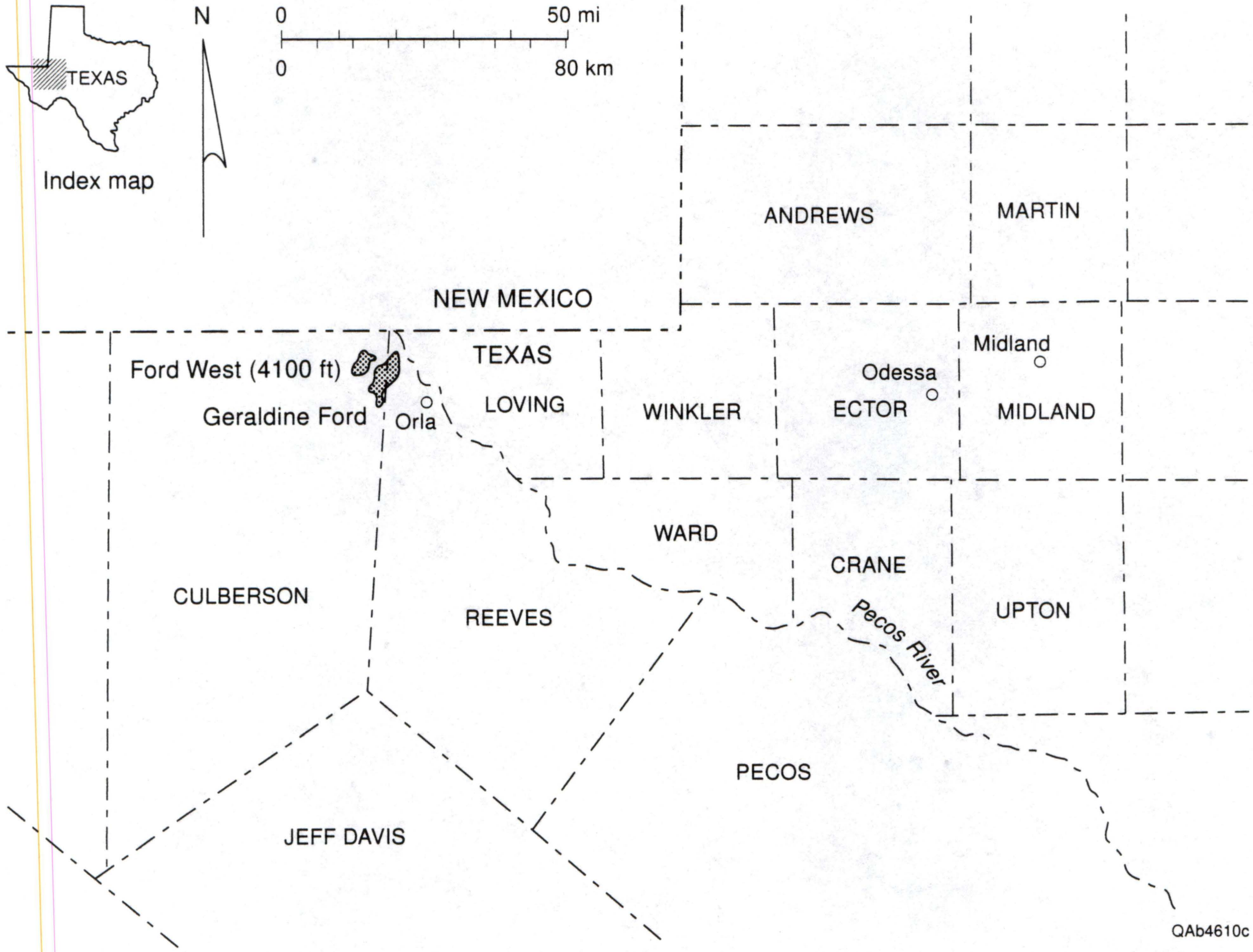


Figure 1. Location of Geraldine Ford and Ford West (4100') fields in Reeves and Culberson Counties, Texas.

The other field being studied, Conoco's Ford West (4100) field, is still in primary production from deeper (3,400 ft) slope and basin clastic reservoirs. This field located 2 mi to the west is an updip extension of Geraldine Ford and produces from a similar style trap in the upper part of the underlying Cherry Canyon and basal Bell Canyon Formations (fig. 2). After 19 years of development, an estimated 5 percent of the original oil in place has been recovered at Ford West. Although the reservoir zones in Geraldine Ford and Ford West fields are among the most prolific slope and basin clastic reservoirs in the Delaware Basin, at these low recovery efficiencies much of the oil will remain in the ground unless new recovery methods are developed.

Project Structure

Project objectives are divided into two major phases. The objectives of the reservoir characterization phase of the project are to provide a detailed understanding of the architecture and heterogeneity of the two fields, Ford Geraldine unit and Ford West field, and to compare Bell Canyon and Cherry Canyon reservoirs. Reservoir characterization will utilize 3-D seismic data, high-resolution sequence stratigraphy, subsurface field studies, outcrop characterization, and other techniques. Once the reservoir-characterization study of both fields is completed, a pilot area of approximately 1 square mile in one of the fields will be chosen for reservoir simulation.

The objectives of the implementation phase of the project are to (1) apply the knowledge gained from reservoir characterization and simulation studies to increase recovery from the pilot area, (2) demonstrate that economically significant unrecovered oil remains in geologically resolvable untapped compartments, and (3) test the accuracy of reservoir characterization and flow simulation as predictive tools in resource preservation of mature fields. A geologically designed, enhanced-recovery program (CO_2 flood, waterflood, or polymer flood) and well-completion program will be developed, and one to three infill wells will be drilled and cored. Through technology transfer workshops and other presentations, the knowledge gained in the comparative study of these two fields can then be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs.

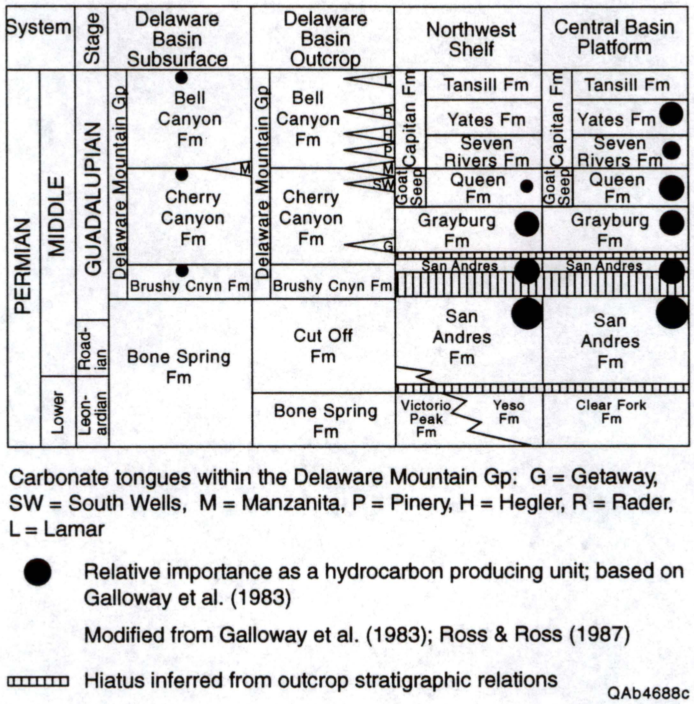


Figure 2. Stratigraphic nomenclature of the Delaware Mountain Group in the Delaware Basin subsurface and outcrop areas and time-equivalent formations on the surrounding shelves (from Gardner, 1992).

Characterization of Reservoir Heterogeneity

The architecture of sandstones in clastic reservoirs has a direct impact on hydrocarbon recovery efficiency. Internal features within reservoir sandstone units define the geometry of fluid pathways that control the efficiency of hydrocarbon migration to the well bore and therefore provide fundamental constraints on the ultimate volume of oil and gas that remain in the ground when the reservoir is abandoned (Tyler and others, 1992). Understanding the details of reservoir architecture and its inherent control on fluid migration is critical to efficiently targeting the remaining recoverable oil resource in mature reservoirs.

Slope and basin clastic systems are characterized by a high degree of vertical heterogeneity, which results in low recovery efficiency, generally less than 20 percent (Tyler and Gholston, 1988). Delaware Mountain Group reservoirs are no exception. Original oil-in-place in the Delaware Basin Submarine-Fan Sandstone Play (or simply Delaware play) was estimated to be 1.8 billion barrels (Bbbl) (M. Holtz, personal communication, 1994). By 1994, cumulative production from this play was approximately 251 million barrels (MMbbl), an average recovery efficiency of 14 percent.

Lateral heterogeneity in slope and basin clastic systems has not generally been considered a major control on recovery efficiency (Tyler and Gholston, 1988), but recent work suggests it is more important than has previously been recognized. Outcrops studies of deep-basin turbidite deposits of the Jackfork Group in Arkansas (Slatt and others, 1992) have demonstrated that lateral heterogeneity is commonly greater than can be recognized from gamma-ray logs spaced 150 to 185 m apart (fig. 3), and deep-water sandstones may be mistakenly interpreted from subsurface data as being more laterally continuous than they actually are. Identifying the vertical and lateral heterogeneity in the Delaware Mountain Group sandstone reservoirs and taking that information into account to design the pilot project are the goals of the reservoir characterization phase of this project.

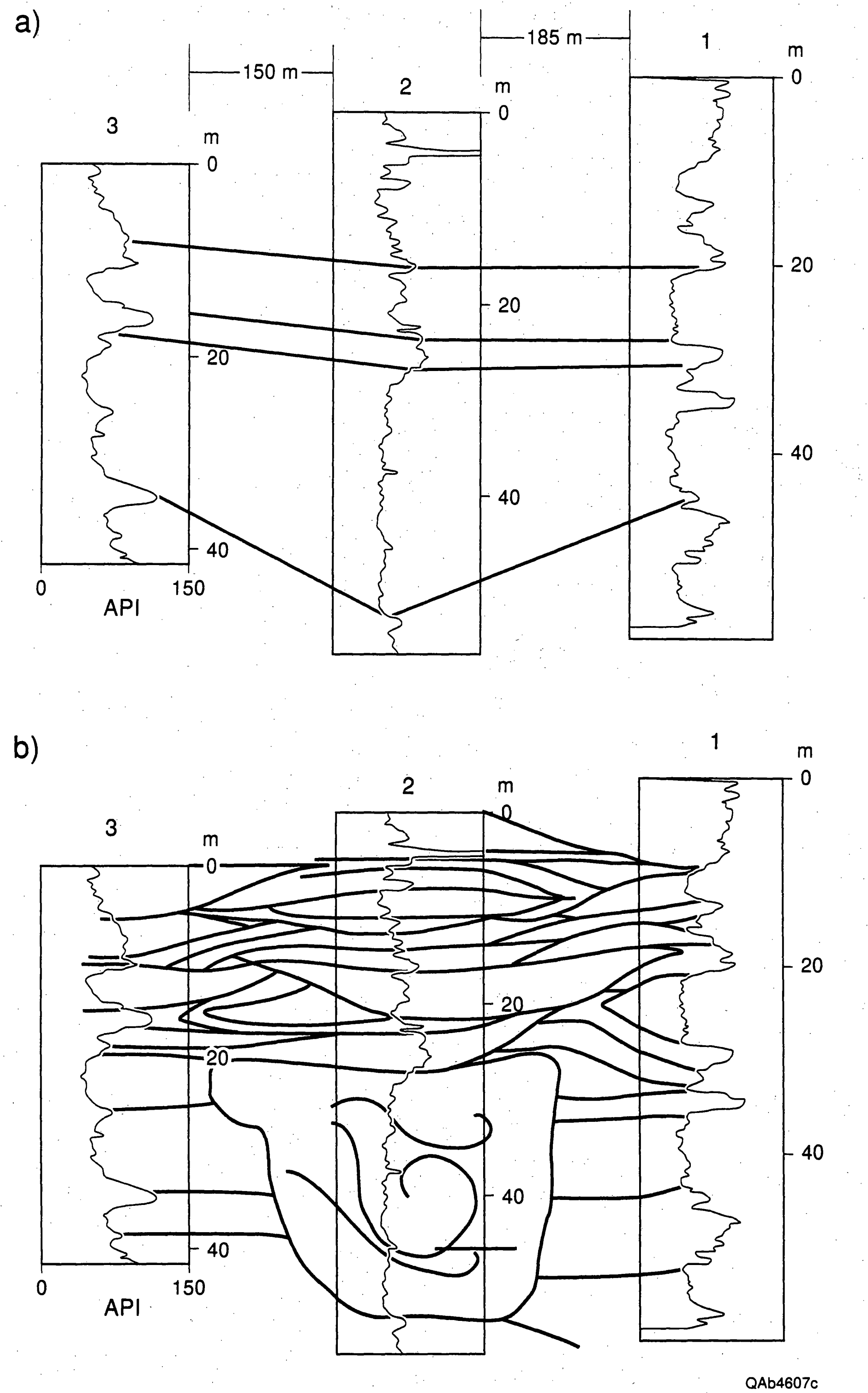


Figure 3. Gamma-ray log correlations of a turbidite system in Arkansas (a) before and (b) after viewing the rocks in outcrop (from Slatt and others, 1992).

Summary of Progress

This annual report documents technical work during the first year of the contract, from April 1995 through March 1996. Work performed during the reporting period focused on tasks associated with project start-up activities, data collection, and initial reservoir characterization. A major task accomplished this year was designing, acquiring, and processing a 3-D seismic survey from a 36 square mile area over Geraldine Ford and Ford West fields and the nonproductive area in between. Reservoir characterization began this year and is evaluating large-, intermediate-, and small-scale heterogeneities (Jackson and others, 1993; McRae and others, 1994). Evaluation of large-scale heterogeneity is being done primarily using the geophysical data. Intermediate- to small-scale heterogeneity caused by depositional and diagenetic processes are being studied using well logs, outcrop data, cores, and SEM imaging.

DELAWARE MOUNTAIN GROUP OIL PLAY

The Permian Basin is the most prolific, and one of the oldest, oil-producing basins in the continental United States, and it still contains an estimated 35 billion barrels (Bbbl) of remaining mobile oil (Holtz and Major, 1994). Middle Permian (Guadalupian) Delaware Mountain Group strata (fig. 2) comprise a 3,500-ft-thick succession of slope and basin reservoirs in the Delaware Basin that are important contributors to Permian Basin production. The Delaware Basin, the western subbasin of the Permian Basin, is located in west Texas and southeastern New Mexico (fig. 4) and extends from Pecos County, Texas northward to Eddy County, New Mexico. Fields in the Delaware play produce oil and gas from slope and basin sandstone deposits that form long, linear trends (fig. 5). Structural contours on limestone beds capping the reservoir sandstones indicate monoclinal dip to the east and southeast (fig. 5). Most hydrocarbons are trapped by stratigraphic traps formed by an updip lateral facies change from higher permeability reservoir sandstones to low permeability siltstones. Fields show minor structural closure because linear trends of thick sandstones formed compactional anticlines by differential compaction during burial

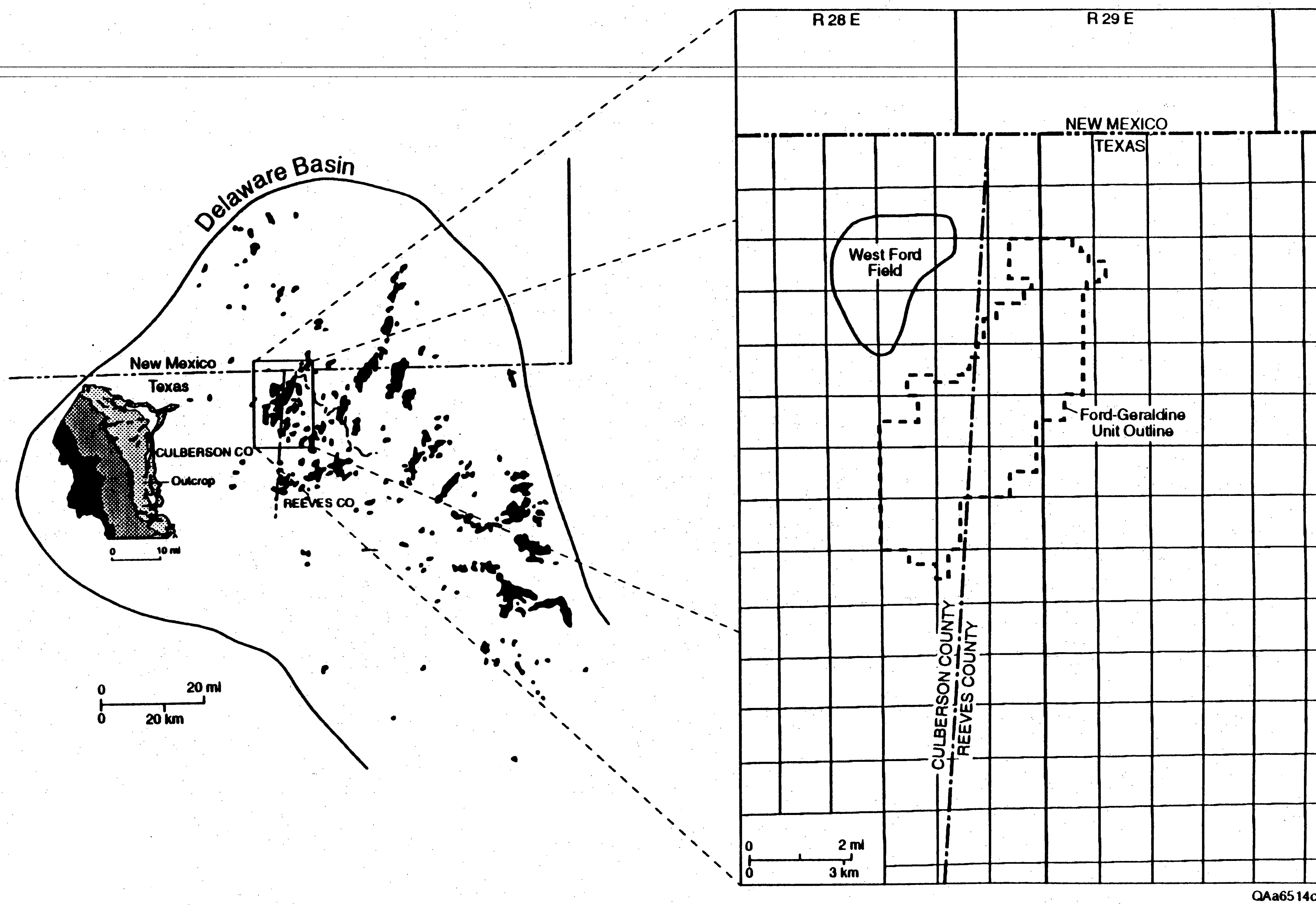


Figure 4. Delaware Mountain Group oil fields in the Delaware Basin, west Texas and southeast New Mexico, showing the parallel, linear alignment of the oil fields, the location of Geraldine Ford and Ford West fields, and the area of the Delaware Mountain Group outcrop (modified from Linn, 1985). Detailed location map shows the outline of the Ford Geraldine unit and Ford West field.

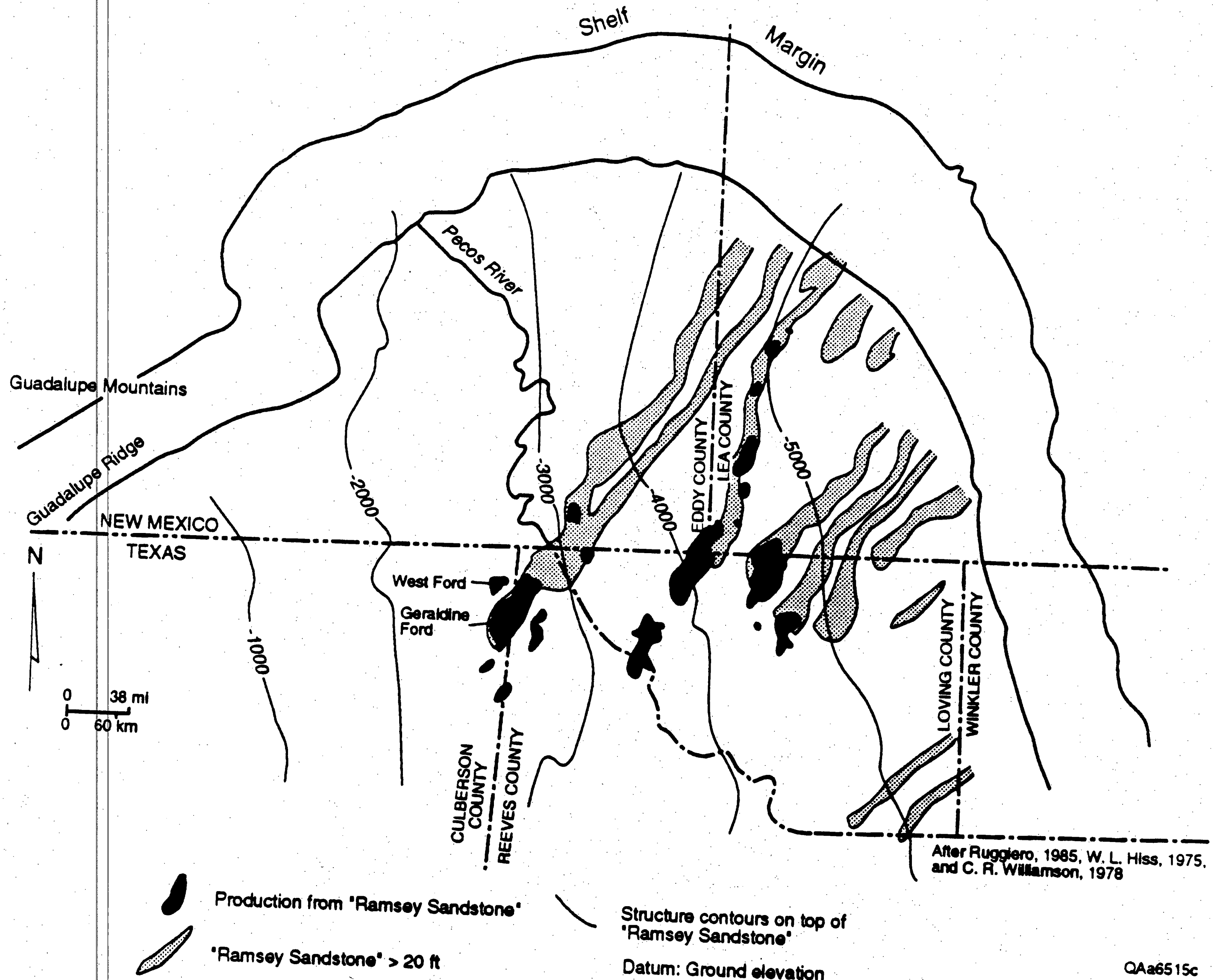


Figure 5. Alignment of fields in the Delaware Basin producing from the upper Bell Canyon Ramsey Sandstone corresponds to the linear trends of thick Ramsey sandstone deposits. Modified from Ruggiero (1985), after Hiss (1975) and Williamson (1978).

(Ruggiero, 1985). Many fields have multiple and tilted oil-water contacts and anomalously thick oil columns, indicating a hydrodynamic component to the trapping of hydrocarbons (McNeal, 1965; Linn, 1985).

Individual fields in the Delaware play produce from lenticular sandstone bodies interbedded vertically with organic-rich siltstone, pelagic carbonate mudstone, and laminated siltstone (Gardner, 1992; Bureau of Economic Geology, 1993). Reservoir sandstones are depositionally and diagenetically complex, with extreme heterogeneity demonstrated by an average 14 percent recovery efficiency from fields in the play. Dimensions of lenticular and discontinuous sandstone bodies are less than a 20-acre well spacing (933 ft), leaving a high number of untapped or poorly drained compartments. Deeper pool potential also exists in most Delaware Mountain Group fields. Early exploration typically drilled into the upper part of the Bell Canyon Formation only, leaving untapped many deeper horizons in densely drilled fields (Gardner, 1992).

The Delaware play is now mature and has a drilling history of progressive deeper pool discoveries in the Bell Canyon, Cherry Canyon, and Brushy Canyon Formations (fig. 2). In the 1920's, reservoirs were discovered in the Ramsey sandstone, the upper part of the Bell Canyon Formation. Geraldine Ford field was discovered in 1956 from shallow (2,600 ft) Ramsey sandstone reservoirs. By the late 1970s, more than 100 fields produced from the Bell Canyon Formation (Williamson, 1977, 1978). In 1952, deeper pools were discovered in the Cherry Canyon Formation (Linn, 1985). By 1985, 39 Cherry Canyon fields had been developed. Ford West (4100) field, which was discovered in 1976 as an updip extension of Geraldine Ford field, produces from the upper part of the Cherry Canyon Formation. More recently, deeper pool discoveries have been made in the Brushy Canyon Formation (DeMis and Cole, 1996).

The Delaware Basin is an ideal location for a reservoir-characterization study of slope and basin clastic reservoirs. Seventy years of exploration and development in the Delaware play provides a wealth of subsurface data. Furthermore, nearby outcrops showing the internal structure of reservoir strata are present within 24 miles of Ford West and Geraldine Ford fields (fig. 4). The present Delaware Basin configuration approximates the middle Permian depositional basin.

Geraldine Ford and Ford West fields are located near the paleogeographic center of the middle Permian Delaware Basin, about 65 miles from the paleo-shelf margin.

Models of Delaware Sandstone Deposition

The depositional processes that formed the sandstones of the Delaware Mountain Group have been debated for many decades. Modern workers agree that these sandstones were deposited in deep water, but several depositional hypotheses have been suggested, and to date, no agreement exists. The papers in the volume edited by DeMis and Cole (1996), in particular the paper of Harms and Brady (1996) summarize these theories in detail.

The major depositional hypotheses for Delaware Mountain Group sandstones are as follows: (1) submarine-fan complexes formed by turbidity-current deposition during lowstands of sea level (St. Germain, 1966; Jacka and others, 1968, 1972; Jacka, 1979; Zelt and Rossen, 1995); (2) saline-density currents flowing through narrow channels in the carbonate margin and down the slope onto the basin floor during relatively constant sea level (Harms, 1974; Williamson, 1978; Ruggiero, 1985, 1993; Harms and Williamson, 1988; Harms and Brady, 1996); and (3) eolian-derived turbidites, in which dunes migrated across an exposed shelf to the shelf break during sea-level lowstands and provided well sorted sand for turbidity currents or grain flows (Fischer and Sarnthein, 1988; Gardner, 1992; Gardner and Sonnenfeld, 1996). These hypotheses will be examined in more detail in the section on Characterization of Depositional Heterogeneity.

Cyclicity in Delaware Mountain Group Deposits

A major control on heterogeneity in basinal Delaware Mountain Group sandstones is cyclicity caused by changes in sea level. Three scales of cyclicity in Delaware Mountain Group sandstones have been recognized (Gardner, 1992; Kerans and others, 1992) and classified as low-, intermediate-, and high-order (fig. 6). The three low-order cycles correspond approximately to the Brushy, Cherry, and Bell Canyon Formations and are 900 to 1200 ft thick. Each low-order cycle

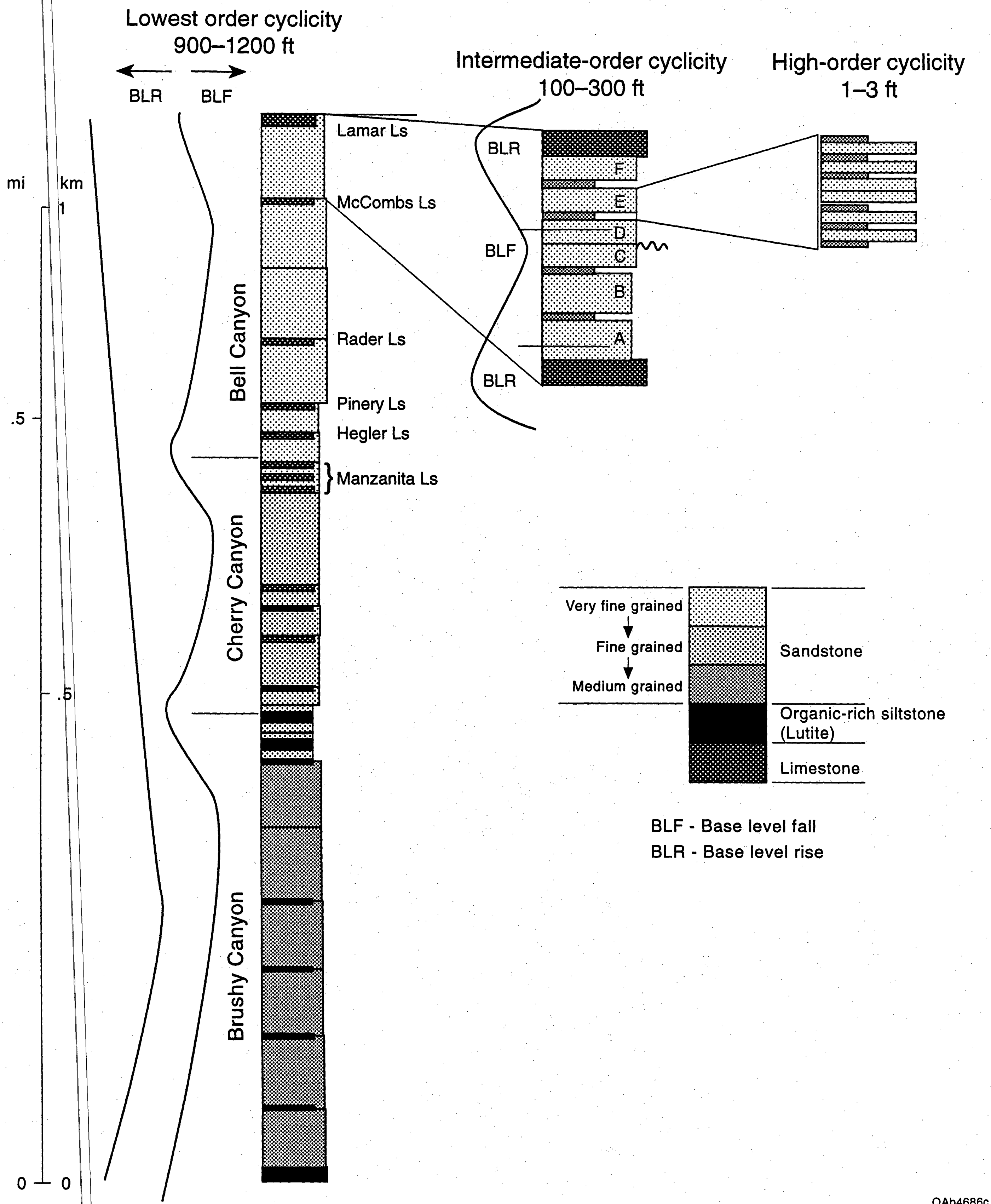


Figure 6. Simplified representation of cyclicity in basinal strata using a comparable low, intermediate, and high ranking (modified from Kerans and others, 1992).

is bounded by regionally correlative carbonate- and organic-rich siltstone beds that record periods of sediment starvation in the basin during periods of sea-level rise (Gardner, 1992). The low-order cycles are composed of 5 to 8 intermediate-order cycles (fig. 6) that are 100 to 300 ft thick. Intermediate-order cycles are composed of two to seven high-order cycles, which are 6- to 100-ft thick and bounded by thin, organic-rich siltstone beds. The best oil production from Delaware Mountain Group reservoirs has been from the top of the Bell Canyon and Cherry Canyon Formations, where the additive effect of sea-level deepening at all scales of cyclicity constructively combined to cause deposition of thick sealing beds of organic-rich siltstone (Gardner, in press). Reservoir sandstones were deposited in periods of high-order sea-level fall.

Geraldine Ford Field History

Geraldine Ford field is located 2 mi south of the Texas–New Mexico state line in Reeves and Culberson Counties, Texas (fig. 1). As of May, 1994, there were 115 producer and 75 injector wells in the field (fig. 7). Cumulative production to date is 25.6 MMbbl. Oil gravity is 42° (API), and viscosity is 0.77 cp at 82° F and 1,380 psi. Reservoir pressure is 1445 psi.

Geraldine Ford field was discovered in 1956 from reservoirs in the upper Bell Canyon Formation (fig. 8). Three major rock types are present in the field—very fine-grained sandstone, laminated siltstone (laminite), and organic-rich siltstone (lutite) (Ruggiero, 1985, 1993). The sandstone facies is a silty, very fine-grained, moderately to well sorted subarkose (Williamson, 1978), and it forms the reservoir. Porosity ranges between 20 and 24 percent, and permeability from 0.01 to 300 md. Most sandstone appears massive, but Ruggiero (1985) reported that wet, polished core faces show thin horizontal laminations or planar cross-lamination. The laminite facies consists of parallel-laminated siltstone with alternating laminae (0.2 to 2 mm thick) of organics and silt (Ruggiero, 1985, 1993). Porosity ranges between 18 and 19 percent, and permeability from 0.01 to 4 md. The laminated siltstone forms the seal of the stratigraphic trap. Lutite is a dark, fissile, organic-rich siltstone containing little detrital clay (Ruggiero, 1985, 1993), and it also contributes to the seal.

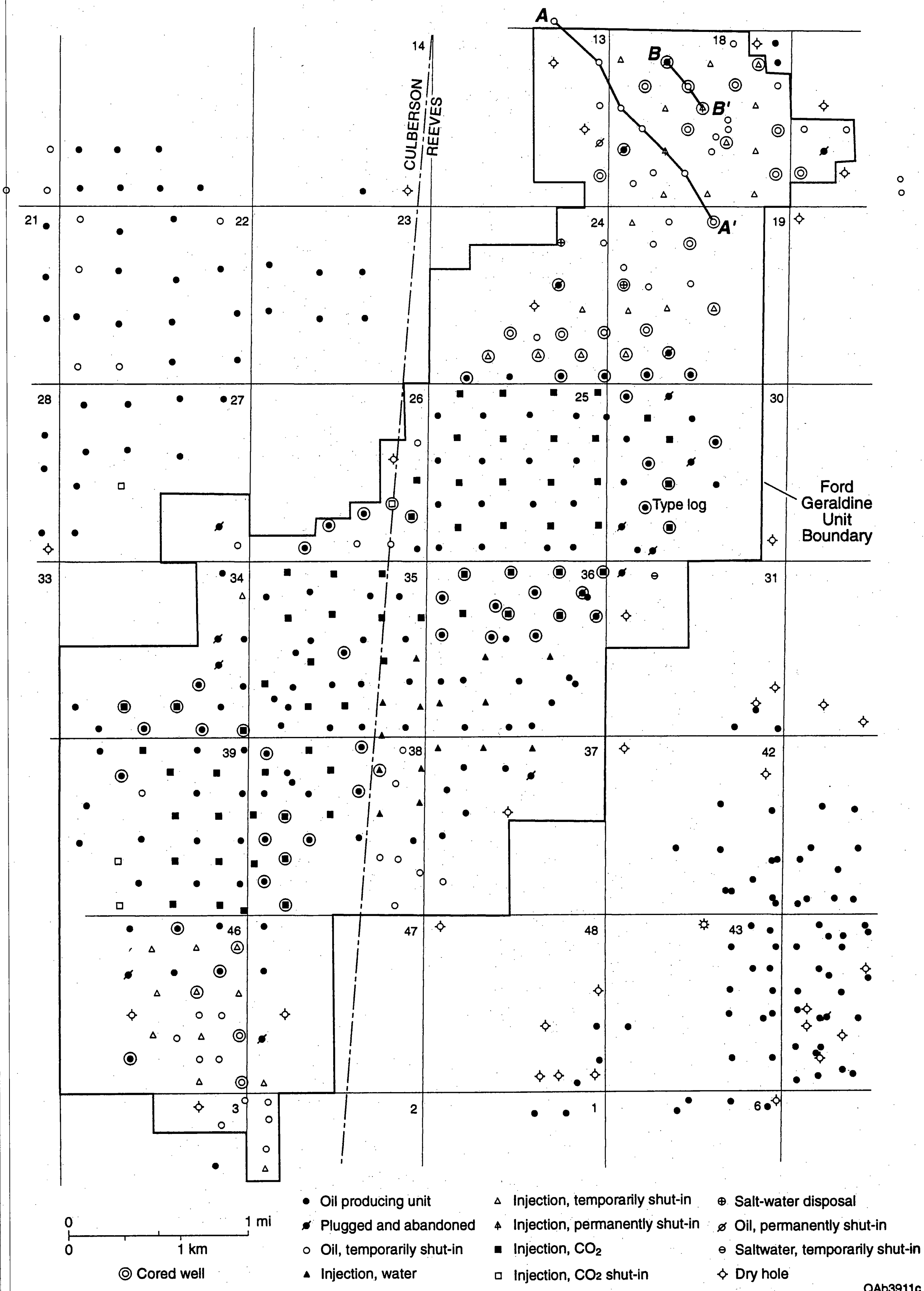


Figure 7. Status of wells in the Ford Geraldine unit and distribution of core control. Type log is shown in figure 8, cross section A-A' in figure 17, and cross section B-B' in figure 18.

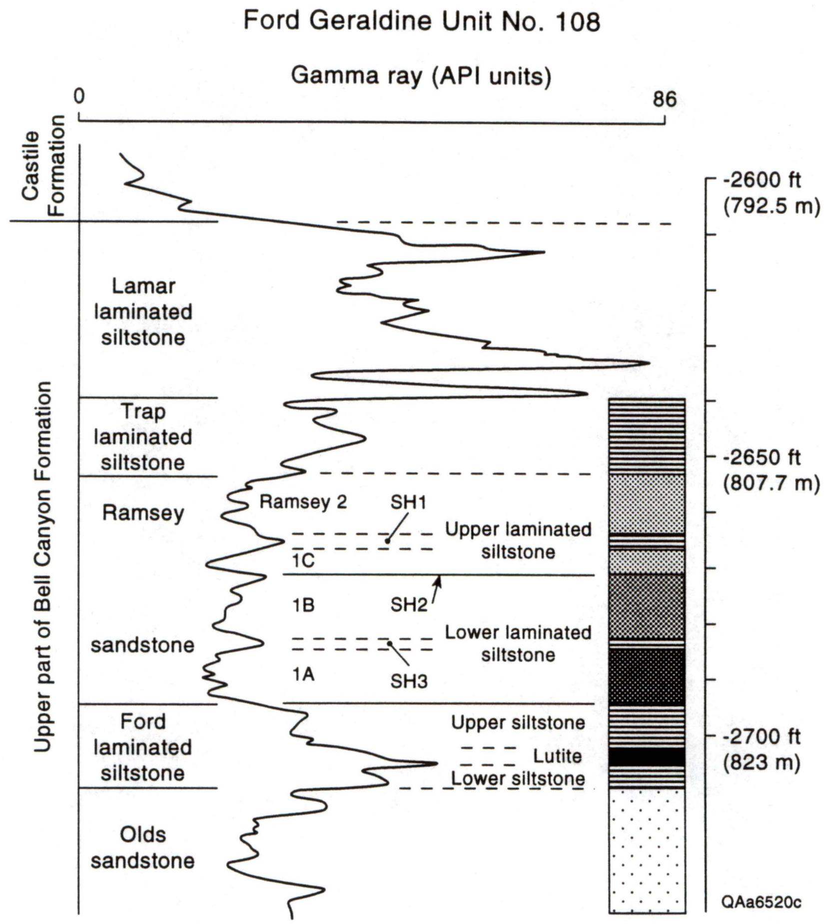


Figure 8. Type log from the Ford Geraldine unit well No. 108 (modified from Ruggiero, 1985). Well location is shown in figure 7.

By 1958 most of the field had been developed on a 20-acre spacing, and reservoir pressure had declined to bubble point (1383 psi), resulting in a sharp increase in gas-oil ratio and water production (Ruggiero, 1985, 1993). Reduced pressures initially aided high production rates as dissolved gases within the oil came out of solution but also produced local gas caps within compartments in the reservoir. By 1968, reservoir pressure had dropped to 300 to 500 psi. The field was unitized (into the Ford Geraldine unit) for secondary development after primary cumulative production of 13.2 MMbbl, for a primary recovery efficiency of 13 percent.

Secondary development was initiated in 1969, with reservoir pressure increased to nearly 1400 psi for a planned five-stage waterflood (Ruggiero, 1985, 1993). Flooding was completed in the southern part of the field, but the Stage 5 area (fig. 9), which is a possible demonstration area for this project, was never waterflooded. Secondary recovery of 2,875 bopd peaked in 1975. By 1981, recovery rates dropped to 569 bopd, and water cuts had risen to 95 percent of production. An additional 6.8 MMbbl of oil was produced after unitization, but only 3.5 MMbbl was attributed to the waterflood, significantly less than predicted from reservoir simulation. By the end of secondary development, recovery efficiency had increased to only 20 percent.

Tertiary development was initiated in the southern part of the field in 1981, but the northern part of the field still has not been CO_2 flooded. Effective reservoir sweep was reduced by early CO_2 breakthrough. Injected CO_2 ponded near the structural axis of the field, with CO_2 ineffective at mobilizing oil from more heterogeneous strata along the flanks (Ruggiero, 1985, 1993). To alleviate early CO_2 breakthrough, production rates were balanced and reservoir pressures were maintained above 900 psi, the minimum pressure needed for miscibility. As of 1994, cumulative tertiary production has been 5.5 million barrels and recovery efficiency is 26 percent.

Ford West Field History

Ford West field, an updip extension of Geraldine Ford field, is located 3 mi south of the Texas–New Mexico state line in Culberson County, Texas (fig. 1, 10). Ford West was discovered in 1976, and it produces oil and gas from the upper part of the Cherry Canyon and lowermost Bell

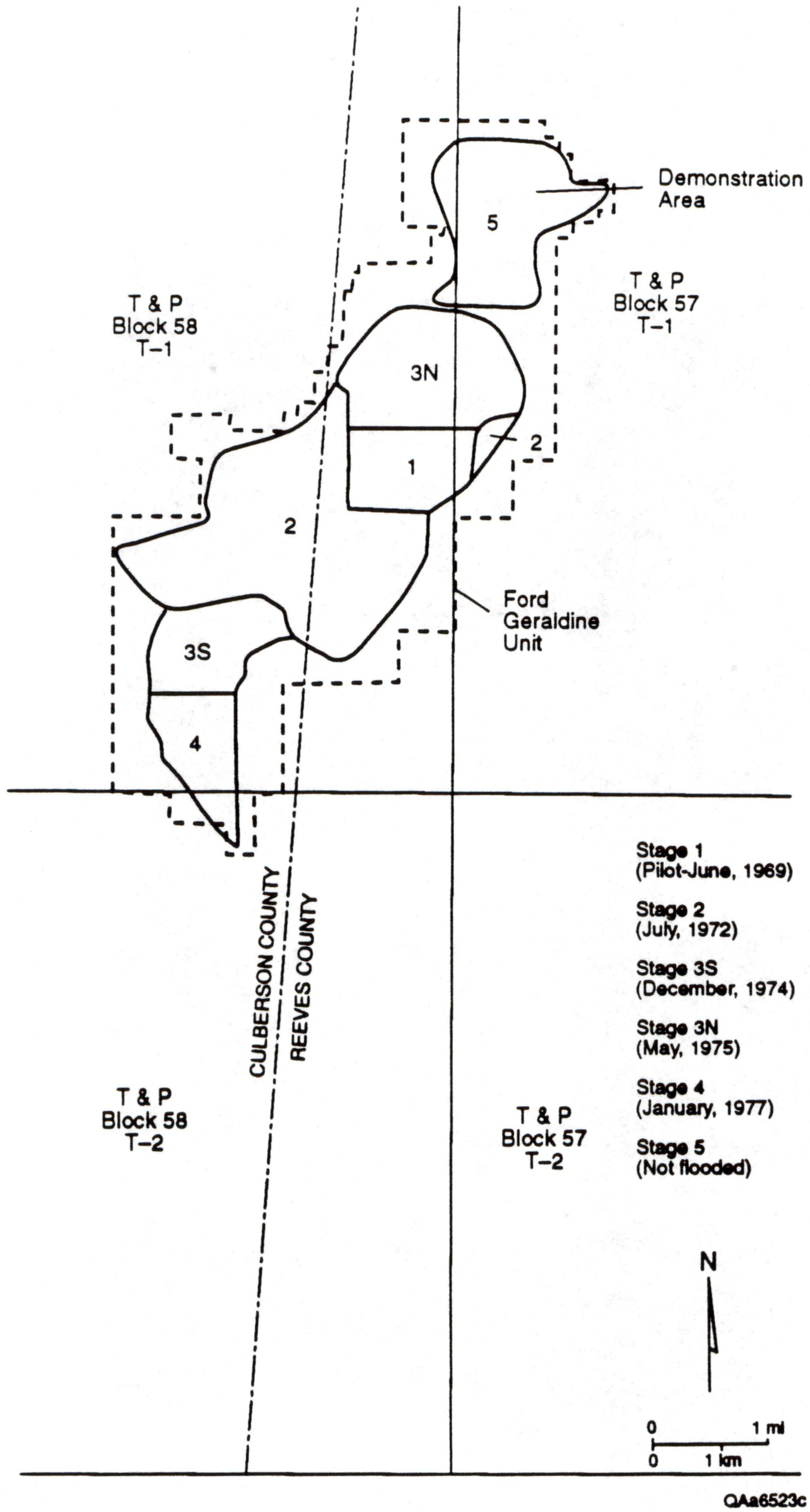


Figure 9. Waterflooding of the Ford Geraldine unit began in 1969 and took place in stages until 1981 (from Ruggiero, 1985). Flooding of the Stage 5 area, which is a possible demonstration area for this project, was never carried out.

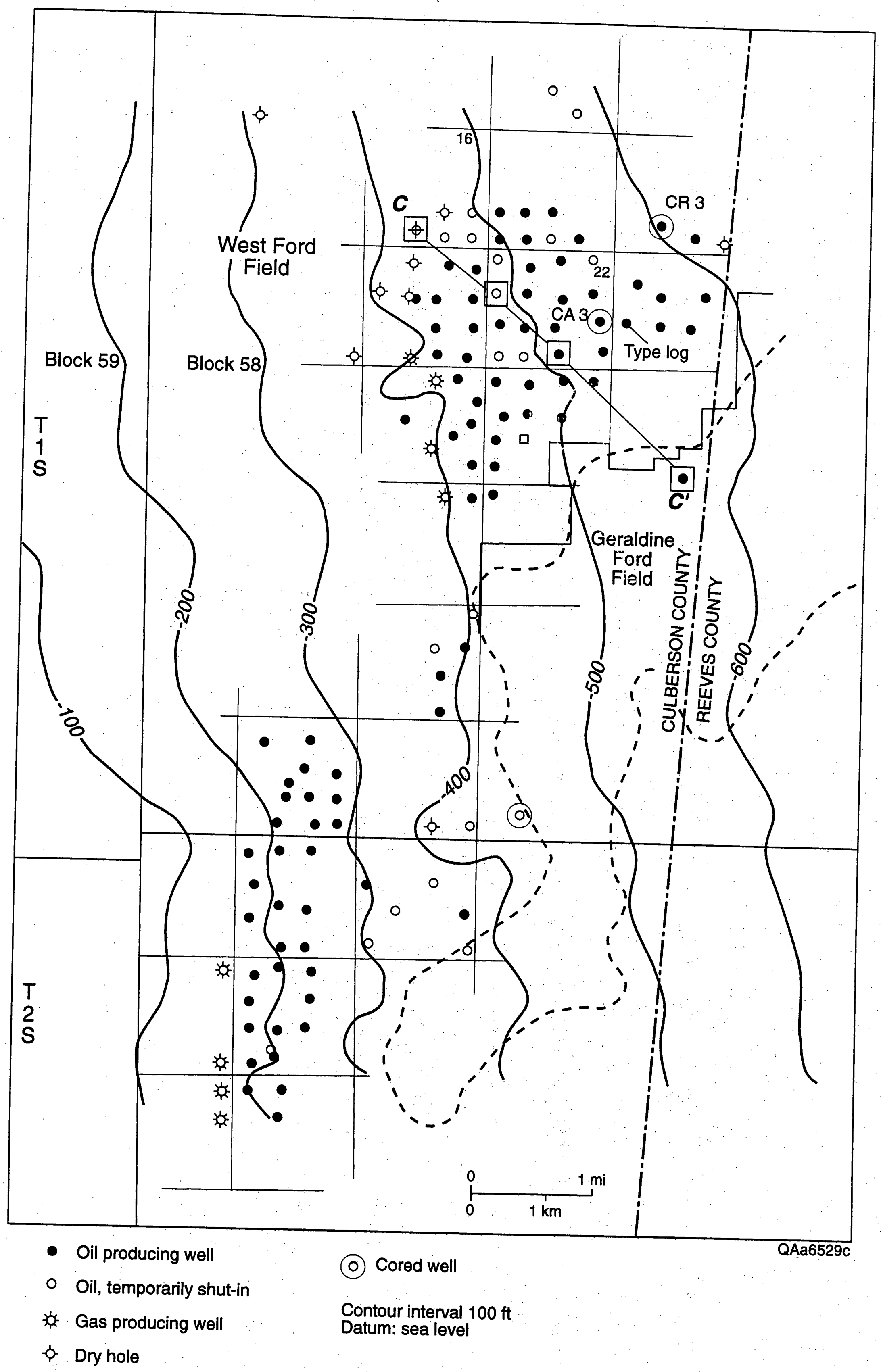


Figure 10. Location map of Ford West field, which produces from the upper Cherry Canyon Formation and lowermost Bell Canyon Formation, Delaware Mountain Group (modified from Linn, 1985). Four cores are available from Ford West field. Cross section C-C' is shown in figure 13, and the type log is shown in figure 11.

Canyon Formations (3,535 to 3,595 ft) (figs. 11, 12). The field is on primary production and consists of 65 wells drilled on a 40-acre spacing, including four cored wells. Core analysis data from 14 wells are available. As of May, 1994, there are 11 producer wells on the Conoco leases in sections 16 and 22 (fig. 10); original oil in place on the two leases was 15.8 MMbbl. By December, 1993, sections 16 and 22, the part of the field that is the focus of this study, had produced 727,614 barrels of oil. Oil gravity is 41° (API) and viscosity of 0.77 cp at 82°F and 1380 psi. Reservoir pressure is 300 psi. Despite high initial water cuts, the field is on primary production and has a hydrodynamic drive (Linn, 1985).

The field produces from two principal reservoir zones (figs. 11, 13). The lower sandstone reservoir in the uppermost part of the Cherry Canyon Formation (i.e., B2 zone of Linn, 1985) exhibits more variable reservoir properties than does the overlying sandstone reservoir in the lower part of the Bell Canyon Formation (i.e., B1 zone of Linn, 1985). As is the case in Geraldine Ford field, the highest initial production occurs along the field axis, where net sandstones are thickest.

GEOPHYSICAL CHARACTERIZATION OF GERALDINE FORD AND WEST FORD FIELDS

In the past few years, the use of 3-D reflection seismic data has become a key component of reservoir characterization. A key objective for the first year of this project was designing, acquiring, and processing 3-D seismic data from a 36-square mile area that covered the Ford Geraldine Unit, West Ford field, and the non-productive area between the two fields (fig. 14).

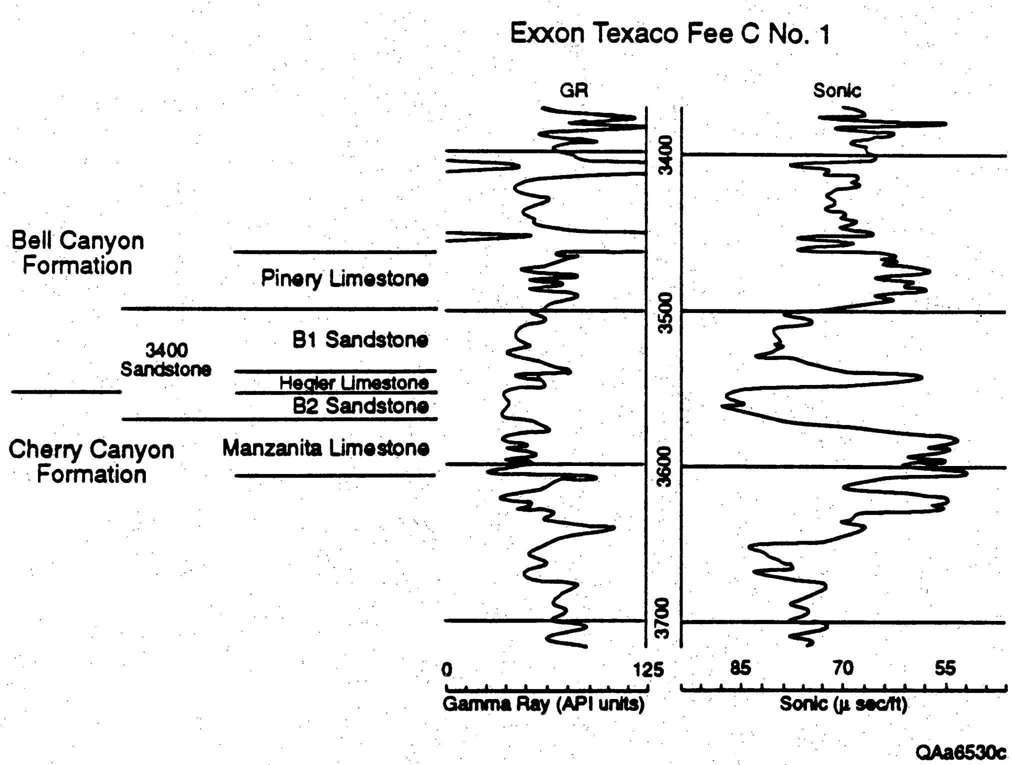


Figure 11. Type log for Ford West field from the Exxon Texaco Fee C No. 1 (from Linn, 1985). Well location shown in figure 10.

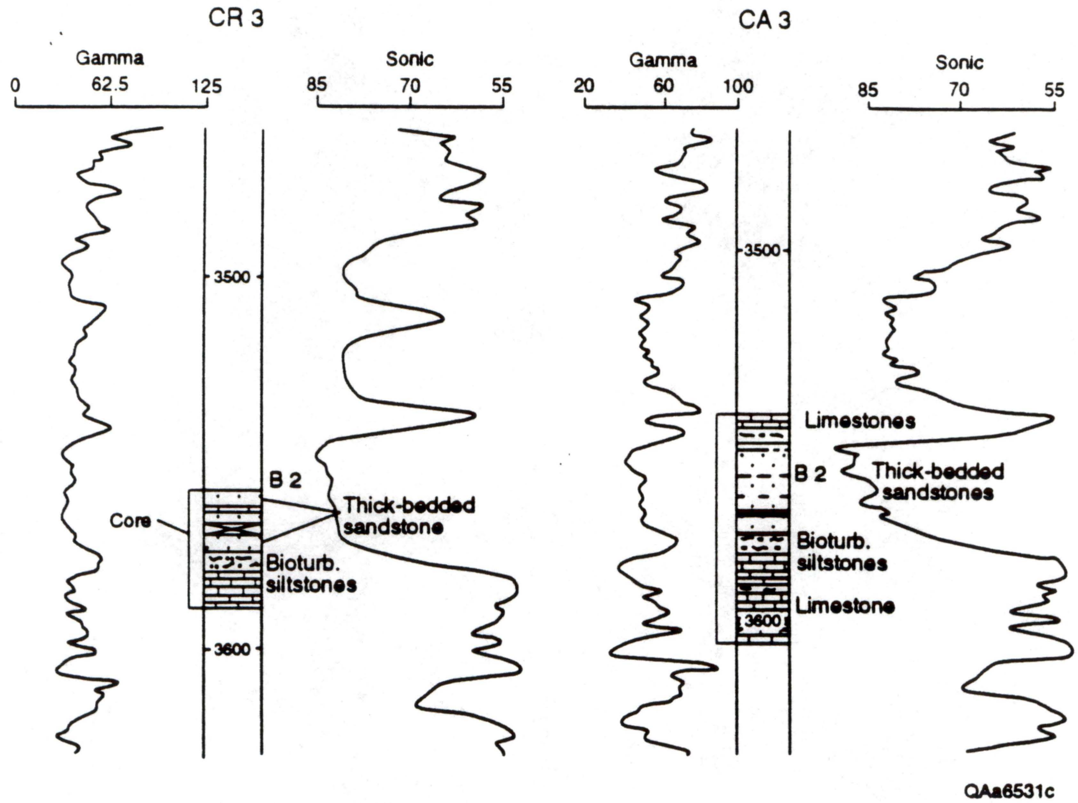


Figure 12. Core descriptions and log responses of the producing Cherry Canyon interval in Ford West field (from Linn, 1985). Location of wells shown in figure 18.

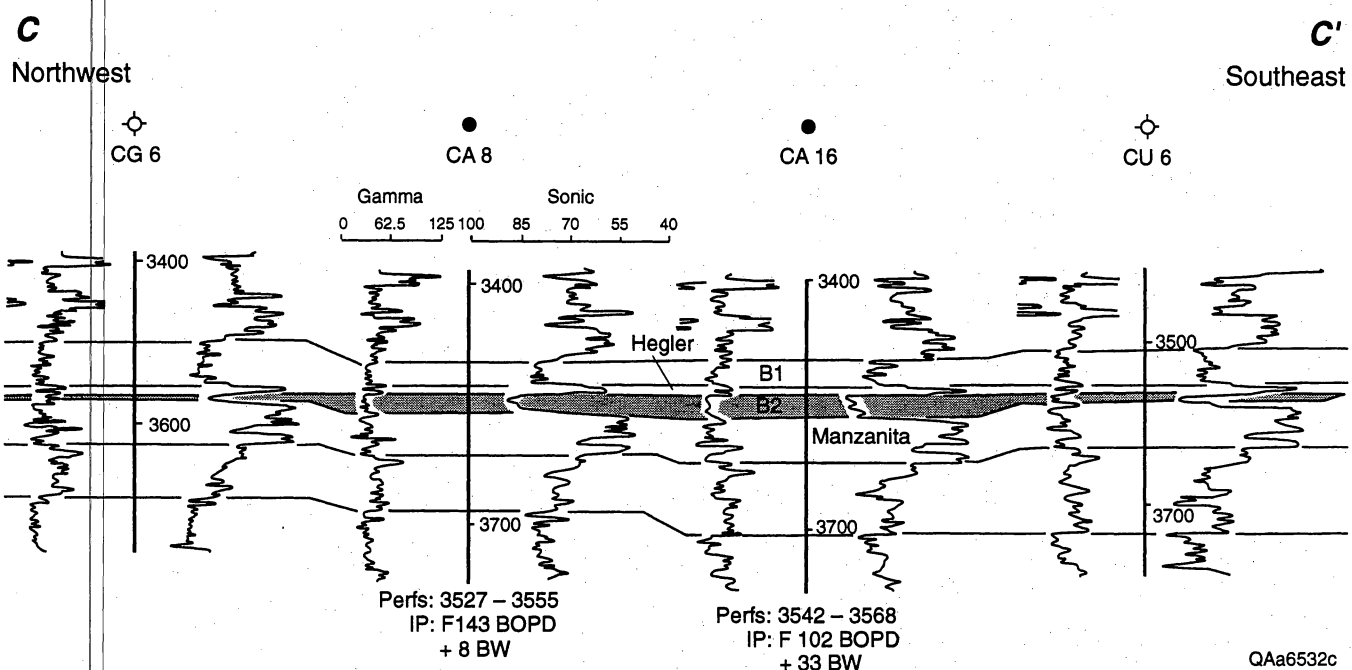


Figure 13. Strike cross section C-C' of the upper Cherry Canyon interval in Ford West field, which is a potential project demonstration area (from Linn, 1985). Location of cross section shown in figure 10.

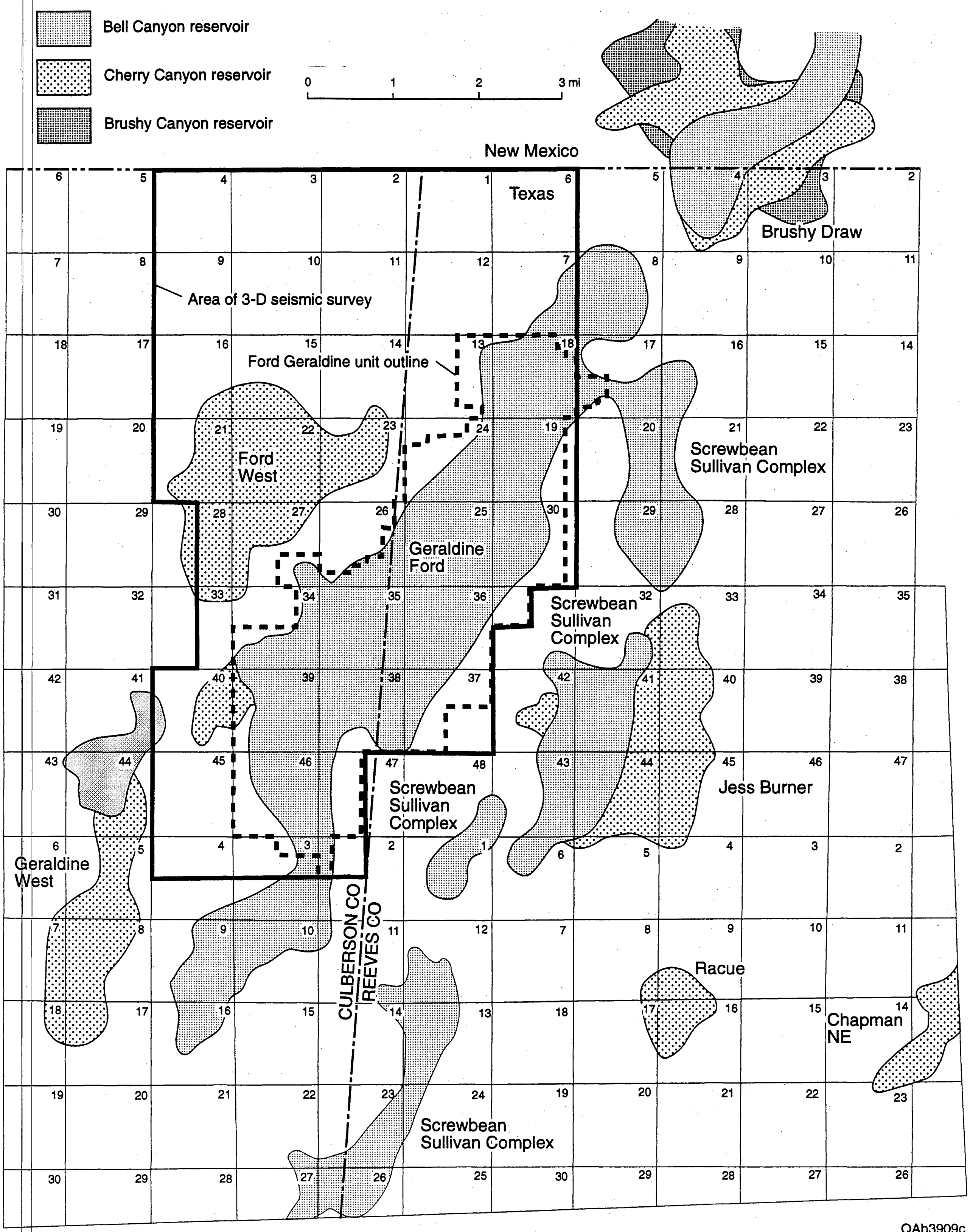


Figure 14. Outline of the area in which the 3-D seismic survey was acquired. Also shown are the locations of Ford Geraldine Unit, West Ford field, and other nearby Bell and Cherry Canyon reservoirs.

Design

The 3-D seismic survey was designed with the following parameters:

Area	36 square miles
Bin Size	110 ft × 110 ft
Spread	8 lines × 96 channels/line (768 channels live)
Receiver line spacing	1100 ft
Receiver flags	220 ft
Receiver arrays	24 geophones/linear array
Array dimension	220 ft inline, 100 ft crossline
Source line spacing	880 ft
Source flags	220 ft
Source arrays	4 vibs × 8 sweeps (Actually used 5 vibs)
Sweep	8-60 Hz/12 sec long
Sample rate	2 millisecs
Listen time	4 secs

Acquisition

Acquisition of the 3-D seismic was completed on July 26, 1995. All equipment and trash were removed at that time. The only unexpected problem that occurred in the acquisition phase was the permitting fees. Conoco's original estimate was between \$2,000 and \$3,000 per square mile for permitting fees, based on previous work in similar areas within the Permian Basin. The major landowner originally requested \$10,000 a square mile. It took a great deal of time and effort to settle at \$5,000 per square mile. It would have been a benefit to Conoco to have taken over dealings with the permits from the start instead of having a contractor deal with the landowner.

Processing

Processing was done at Ponca City Research (PCR), a division of Conoco, Inc., and one processor and two technicians worked on the project full time. There were no problems in this stage, and the processors kept the Conoco geologist informed and involved all the way through the processing phase. PCR had 100 percent of the surface elevation survey available at the time of seismic field acquisition. The total amount of field data received by PCR included 232 reels, 5,373 source positions, and 4,483,596 traces. The geometry was verified and trace editing was completed in 3 weeks. The total number of bad traces edited was very low, three tenths of one percent. A subset of the data was used to test deconvolution parameters. Testing of single-trace, source-consistent, and surface-consistent deconvolutions yielded comparable results. Deconvolution of the entire survey followed, and progress was made optimizing statics program parameters.

The signal-to-noise ratio of all first breaks was good over the project area. Total number of traces requiring editing was very low, 13,026 out of 4,483,596 traces, which is indicative of good geophone plants and field recording practices. The shot profiles exhibited poor reflection quality or no recovery on the western edge of the survey, with generally fair signal-to-noise ratios for the rest of the survey. Brute stacks were produced on several control lines selected on a one mile grid. Initial stacking velocities derived from the control lines varied significantly. Surface-consistent residual statics were determined and removed, and new final stacking velocities derived. The final stacking velocities varied little vertically or laterally over the survey. Residual statics were found to range from +25 to -25 milliseconds, with the average of the absolute value equal to about 3 milliseconds. Removal of the residual statics significantly improved the stack of the control lines, but the areas of reduced fold (below 50 fold) displayed weaker reflection strength.

The record quality of near-offset stacks out to 10,000 ft was comparable to far-offset stacks from 10,000 ft to 20,000 ft below 1.2 seconds. The final mute applied after normal move out was approximately linear and muted the 20,000 ft offset data at 1.5 seconds. Migration of the data volume improved the signal-to-noise ratio of the data, and filter tests revealed reflection energy of 50-60 hertz down to 1.5 seconds.

In summary, the data processing sequence was as follows:

1. Verify geometry using first-breaks prediction based on offset and trace edits.
2. Plot X-Ys to verify source and receiver locations.
3. Construct mathematical transformation for surveyed X-Ys to grid bin coordinate system and apply this transform to bin headers.
4. Test mute and deconvolution parameters.
5. Shift to floating datum.
6. Perform the first-pass velocity analysis using semblance panels and whole-line constant-velocity stacks.
7. Make the normal move-out correction using final datum and brute stack.
8. Interactively determine ground-position-oriented surface-consistent residual statics.
9. Make final-pass velocity analysis.
10. Make final stack.
11. Perform migration velocity tests and filter tests.
12. Do final migration with zero phase filter, using C4w.

Interpretation

The processed seismic data were loaded and quality checked on a work station using Landmark SeisWorks™ software. Preliminary attempts at generating synthetics with wells in the survey were made. Synthetic generation of wells from the Ford West Field (Cherry Canyon) were created and attempts were made to tie the synthetics with the seismic. The results were somewhat disappointing due to the lack of complete acoustic logs. The majority of the well logs in the area that have acoustic and/or density logs were not logged throughout the entire section. Attempts to generate synthetics will continue, and the possibility of running a VSP is being investigated.

Coherence Technology Company processed the 3-D volume. The high signal-to-noise ratio of the data allowed the processors to use three different processing strings to get three different "looks" from the data. The coherence "cube" (coherency processing) is expected to help with the stratigraphic interpretation of the survey. Interpretation of the seismic data will continue in the coming year.

RESERVOIR CHARACTERIZATION OF GERALDINE FORD FIELD

In addition to using 3-D seismic data, the project is also characterizing heterogeneity of Geraldine Ford and West Ford fields using subsurface logs and cores. Work to date has concentrated on the larger field, Geraldine Ford. The field consists of 340 wells, and cores from 85 wells (fig. 7) are now available for detailed geologic, petrographic, and petrophysical description. These 85 cores include 27 that were studied by Ruggiero (1985) and 58 additional cores that were shipped from Conoco to the Bureau's Core Research Center this year. Core-analysis data from 171 wells were entered into a computer data base.

Gamma-ray curves of the reservoir interval between the top of the Lamar and the top of the Olds (fig. 8) from 305 wells in Geraldine Ford field were digitized. Sonic logs were digitized if they were available (82 wells), otherwise neutron logs (97 wells), microlaterologs (13 wells), laterologs (4 wells), or density logs (3 wells) were digitized. For many of these old wells, only gamma-ray logs were run. Because the old gamma-ray logs were run by many different companies at different scales and sensitivities, they have been normalized to API units using modern logs from the field to develop normalization equations in the following form:

API units = m (old units) + b, where the slope and y-intercept are calculated for each log individually.

The tops shown in figure 8 have been correlated on all logs in Geraldine Ford field. The log curves, elevation datum, total depth, latitude and longitude, and tops have been entered into the Landmark software OpenWorks™. Core-analysis, perforation, and production data will also be added to OpenWorks™. All the subsurface log and core data that have been assembled into the data base this year are being used to evaluate reservoir heterogeneity caused by depositional processes and post-depositional diagenesis.

Characterization of Depositional Heterogeneity

Vertical Heterogeneity

Cyclic changes in sea level were an important cause of vertical heterogeneity in Geraldine Ford field. Gardner's work (in press) in Screwbean field recognized cycles in the upper Bell Canyon deposits that reflect changes in sea level, and he correlated those cycles to Geraldine Ford field (fig. 15). The reservoir interval at Geraldine Ford is correlative with Gardner's D and E high-order cycles near the top of the Bell Canyon Formation (Gardner, in press). The sealing facies above the Ramsey sandstone (upper unit E and unit F) is interpreted as being a particularly effective trap because it was deposited at a time of sea-level rise at all three scales of cyclicity (fig. 6). The Ramsey sandstone reservoirs were deposited during periods of sea-level fall (base-level fall) in the high-order D and E cycles (figs. 6, 15). Laterally continuous organic-rich siltstones such as SH1 (fig. 8), which were deposited during periods of sea-level rise (base-level rise) in the high-order D and E cycles, are probably barriers to vertical fluid flow within the reservoir.

Lateral Heterogeneity

Bell Canyon sandstones in Geraldine Ford Field were interpreted by Ruggiero (1985, 1993) as having been deposited in a submarine-fan channel that funneled bottom-hugging saline density currents into the basin from breaks in the shelf margin. In this model a channel about 2 miles wide and 40 ft deep was cut prior to deposition of the Olds sandstone (fig. 8). The sandstones that filled the channel form the reservoir at Geraldine Ford field. Following the model of Harms (1974) and Harms and Williamson (1988), Ruggiero concluded that saline-density currents laden with fine-grained sandstone swept off the shelf and flowed down slope, confined within the channel. Each depositional episode deposited a sandstone 1–5 ft thick, and the major correlative units at Geraldine

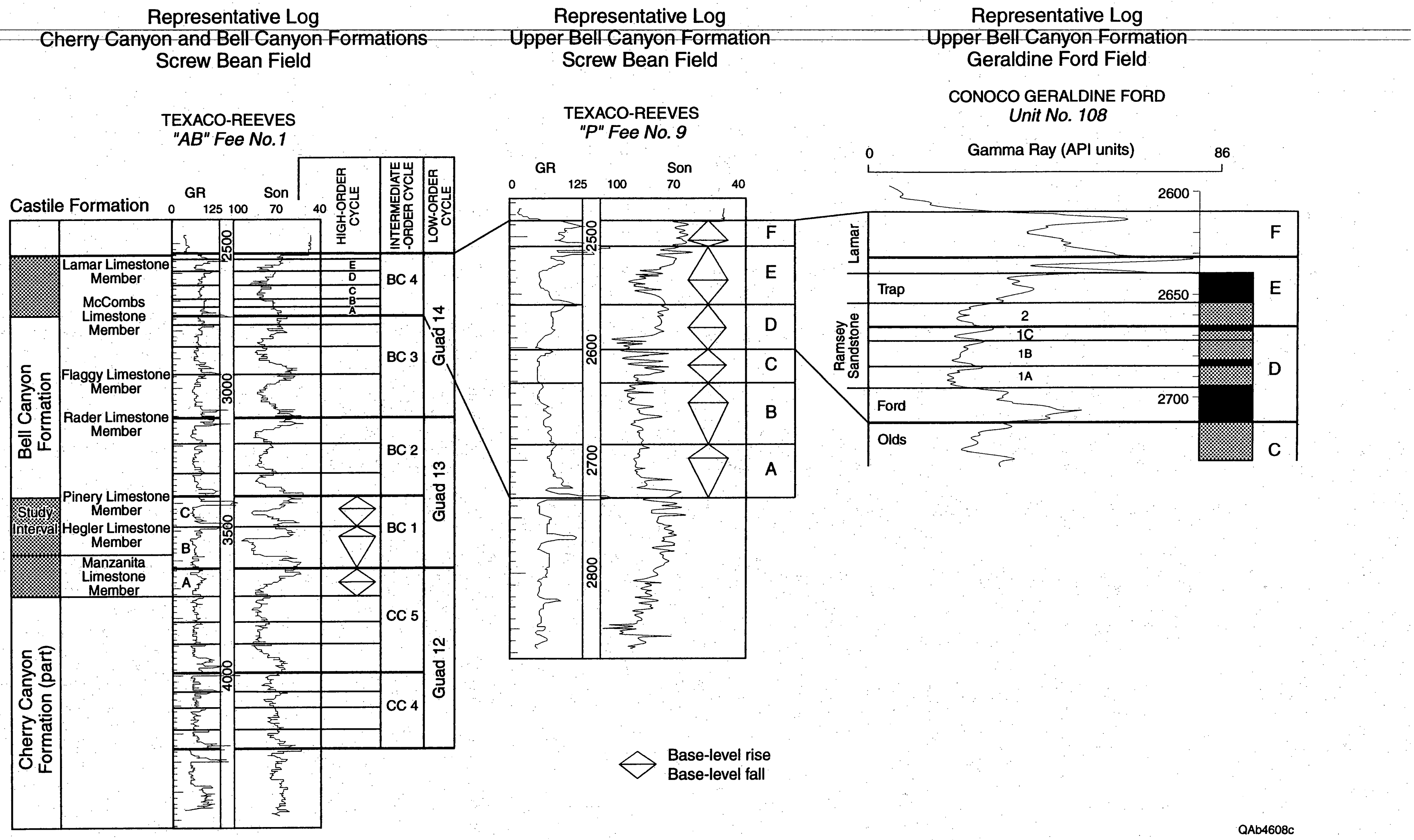


Figure 15. Diagram showing core description and representative log signature of high-order cycles in the Bell Canyon and Cherry Canyon Formations and the stratigraphic hierarchy of intermediate- and high-order cycles (modified from Gardner, in press).

Ford field, named the Ramsey 2, 1C, 1B, and 1A (fig. 8), are formed of aggregates of these thin sandstone beds. Ruggiero interpreted the major correlative units as being laterally continuous across the entire channel (Ruggiero, 1985, 1993). He concluded that the bottom-hugging saline-density currents had enough volume to fill the entire channel in a sheet-like fashion from margin to margin (fig. 16). This interpretation of the depositional processes is of particular importance to the model for reservoir architecture in Geraldine Ford field, because it suggests a high degree of lateral continuity within sandstones (fig. 17).

Correlations in Geraldine Ford field done for this study suggest that lateral sandstone continuity is not as great as interpreted by Ruggiero (1985, 1993). A detailed cross section from the northern end of the field (fig. 18) shows a high degree of lateral, as well as vertical, sandstone heterogeneity, suggesting that numerous untapped compartments may exist. Comparison of the depth of perforated intervals in each well to the exact positions of reservoir and nonreservoir beds in light of this more heterogeneous picture of the reservoir will be the next step in locating untapped resources in the field.

The recognition of a greater amount of lateral heterogeneity within these Bell Canyon sandstones, as well as recent work on nearby Screwbean field by Gardner (1992, in press), suggest that the Geraldine Ford sandstones were deposited by a different process than saline-density currents. Gardner (1992, in press) interpreted the Bell Canyon sandstones in both Screwbean and Geraldine Ford fields as deposits of an eolian-derived turbidite system (fig. 19). This model was first proposed for sandstones of the Delaware Mountain Group by Fischer and Sarnthein (1988). In this depositional model, fine sand was transported from source areas in the ancestral Rockies by migration of eolian ergs, and silt and clay were transported as dust by the wind (Fischer and Sarnthein, 1988). Clay was carried by the wind beyond the Delaware Basin, thus accounting for the lack of clay-sized sediment in the Delaware Mountain Group deposits. Silt-sized dust was deposited in the basin by fallout from the wind and settling through the water column, forming topography-mantling laminated siltstones. During lowstands of sea level, dune sands were driven across the exposed shelf to the shelf edge, where they fed unstable, shallow-

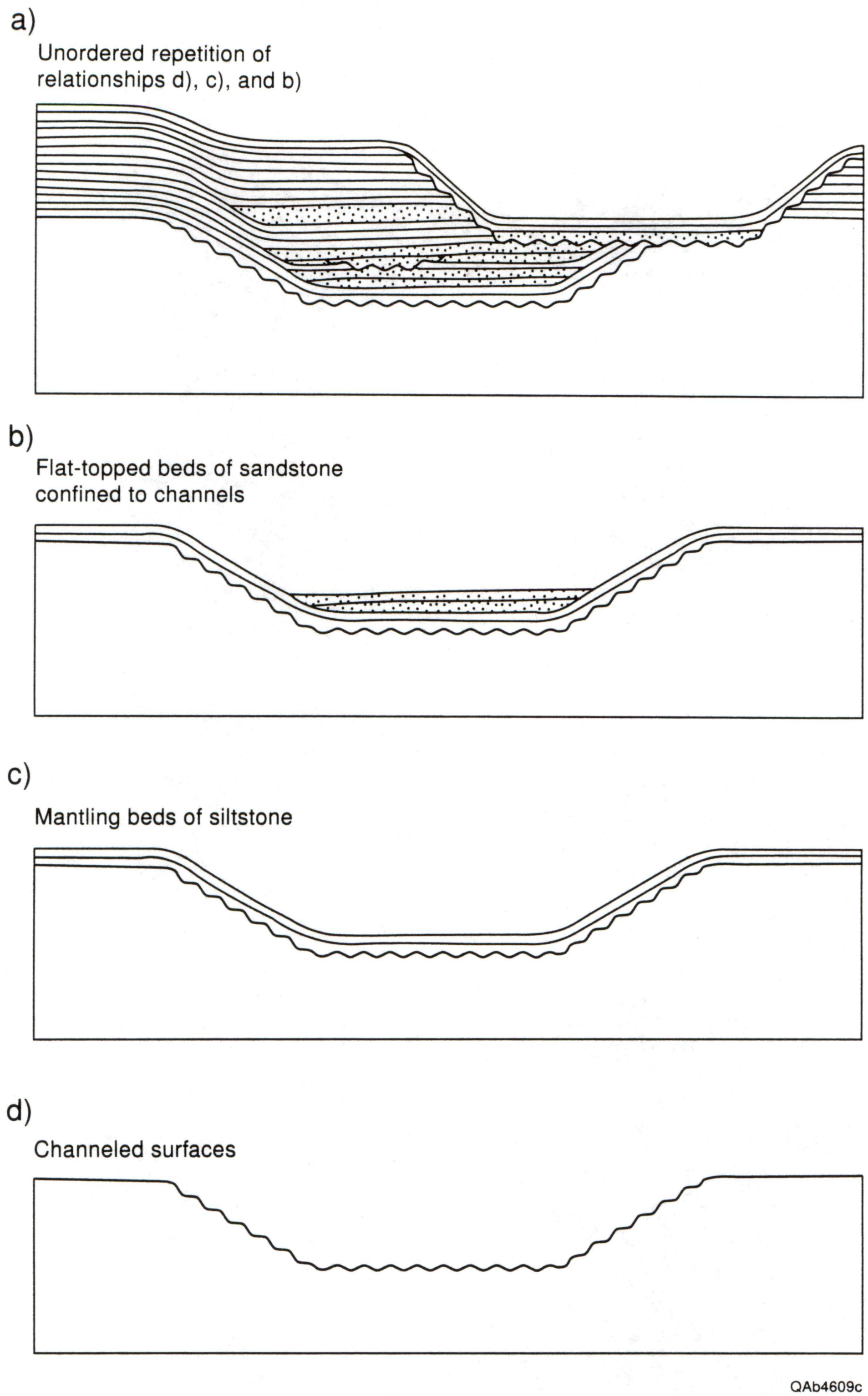


Figure 16. Interpreted sequence of events during deposition of Delaware Mountain Group sediments by saline-density currents (modified from Harms, 1974). In this model, channels (d) were scoured by strong currents of dense water flowing basinward under less dense, deep water. Deposition of silt (c) occurred by settling from intermediate density water flowing basinward into density-stratified, deep water. The final stage of the sequence (b) was deposition within preexisting channels of sand tractionally carried by thin, upper-to-lower flow regime currents of dense, low turbidity water flowing basinward under less dense, deep water.

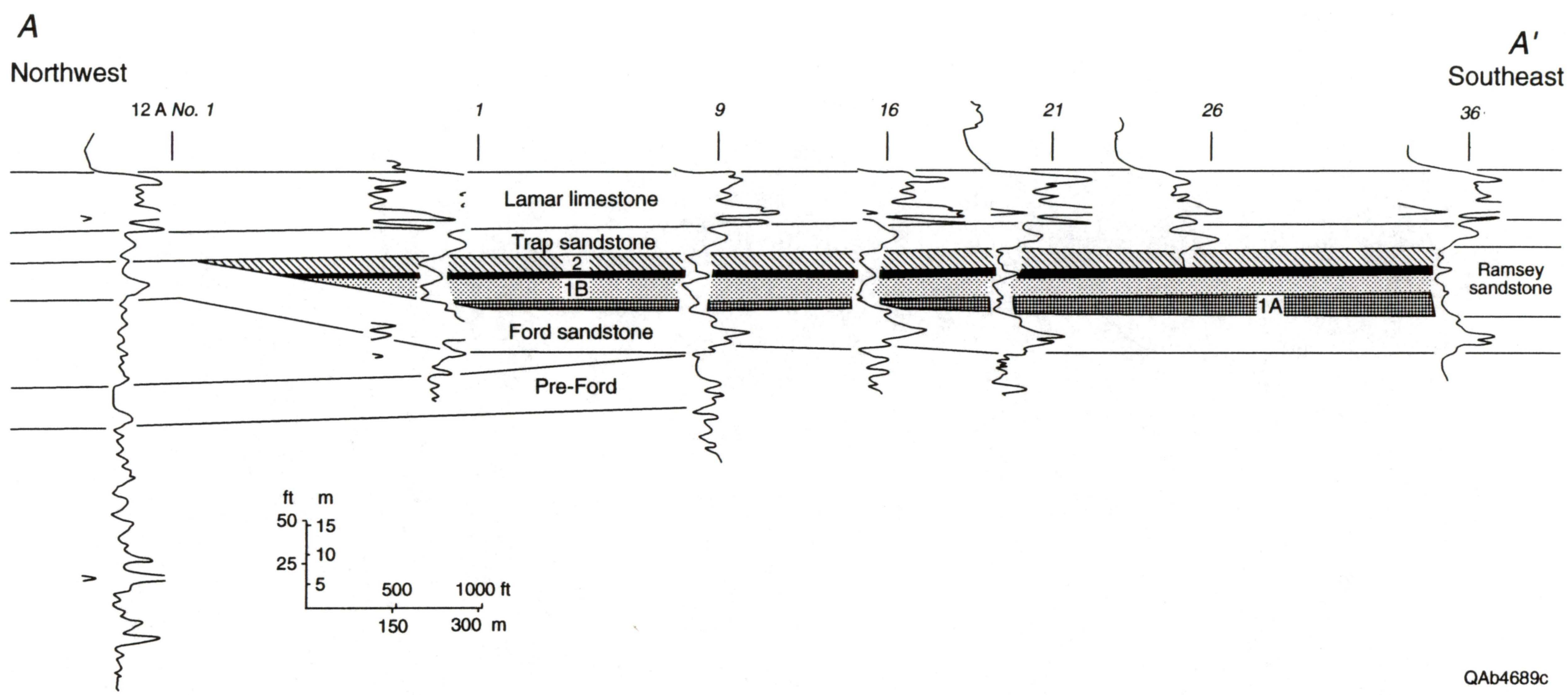


Figure 17. Strike cross section A-A' of the upper Bell Canyon interval in the northern part of Ford Geraldine unit (modified from Ruggiero, 1985). In the depositional model proposed by Ruggiero (1985, 1993), bottom-hugging saline-density currents had enough volume to fill the entire channel in a sheet-like fashion from margin to margin. Location of cross section shown in figure 7.

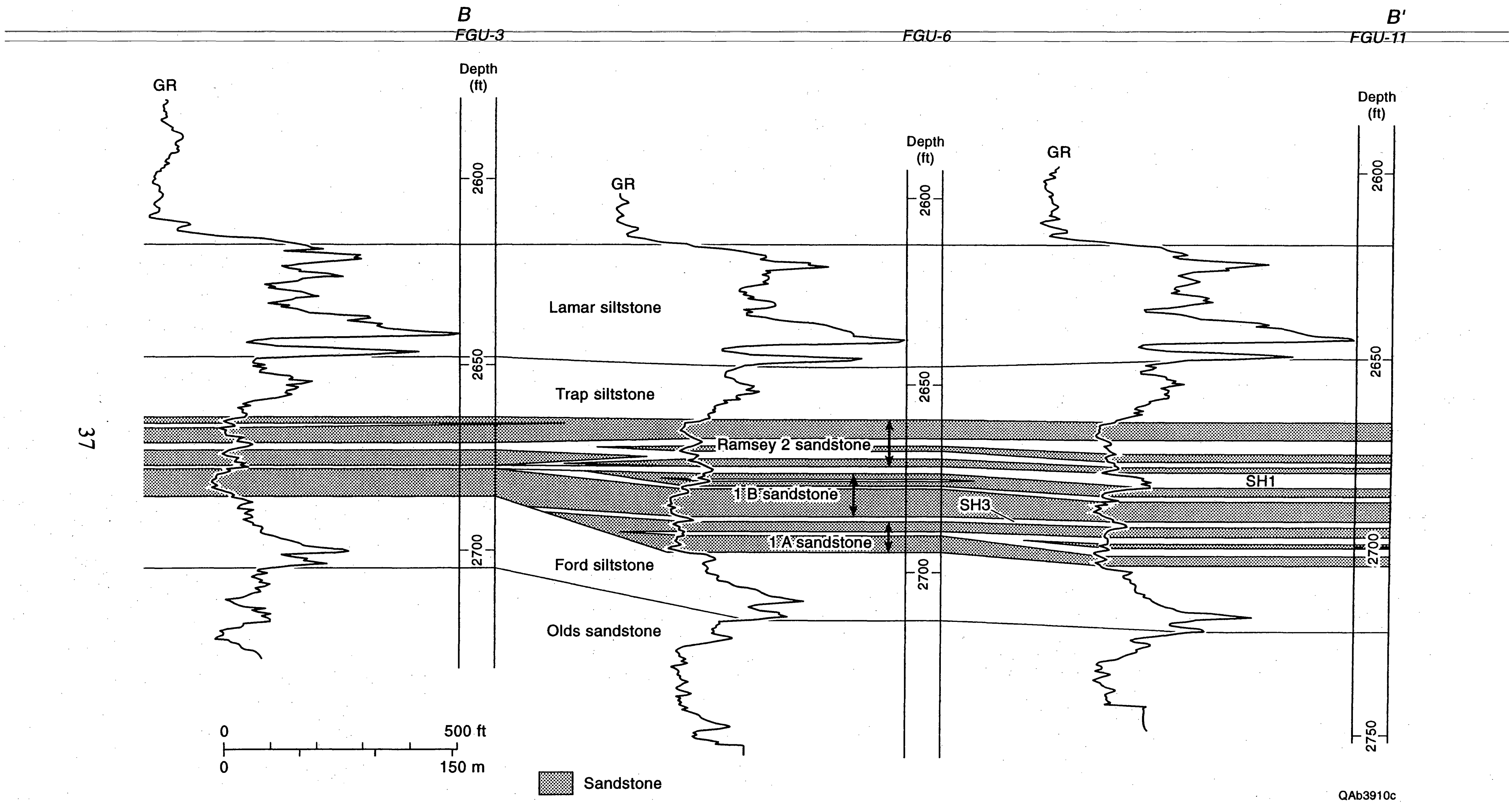


Figure 18. Strike cross section B-B' in the northern part of Ford Geraldine unit. Detailed correlations suggest greater lateral and vertical heterogeneity within major correlative sandstones than would be predicted by the saline-density-current depositional model.

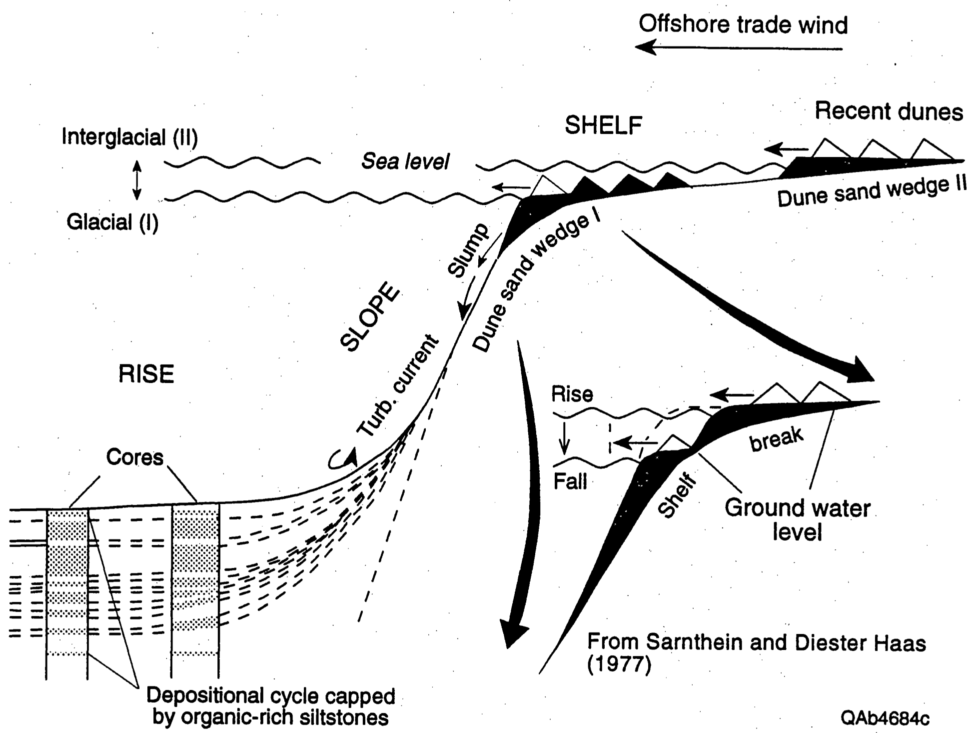


Figure 19. Eolian-derived turbidite model relates downslope transport of eolian sands to periods of sea-level fall (from Sarnthein and Diester Haas, 1977). During periods of sea-level rise, most sediment accumulates on the shelf.

water sand wedges (fig. 20). Slumping of the sand wedges gave rise to turbidity currents that carved channels and filled them with well sorted sandstone. During periods of sea-level rise, the dunes were transgressed and reworked in a shallow-marine environment, and sand was stored on the shelf.

The following observations support the interpretation of an eolian-derived turbidite system for Delaware Mountain Group deposition (Gardner, 1992; Kerans and Fitchen, 1996; Gardner and Sonnenfeld, 1996; Gardner, in press): (1) a high proportion of massive, ungraded bedding in the sandstones, (2) high textural maturity and uniform grain size, (3) abundant burrowed intervals, precluding a stratified and anoxic water column, (4) multiple truncation surfaces within "channel" sandstones, indicating many amalgamated depositional events and not simple channel fill, (5) absence of detrital mudstone, and (6) karst surfaces indicating exposure of the shelf during deposition of the Brushy Canyon Formation, precluding development of a hypersaline lagoon as a source of saline-density flows.

Instead of filling a large channel, as suggested by the saline-density-current model, the Bell Canyon sandstones at Screwbean and Geraldine Ford field may have been deposited as compensation lobes on the basin floor (Gardner, in press). In this model, the confinement of the sandstones within a narrow geographic area is a result of reef topography on the highly aggradational carbonate platform. At the platform edge, reef topography focused sediment transport into lows and promoted point-source sediment dispersal, resulting in linear northeast-southwest oriented sandstone thicks in the basin (Williamson, 1978) (fig. 5). Gardner (in press) interpreted the internal arrangement and stacking patterns of the Screwbean and Geraldine Ford sandstones as compensation lobes that formed by individual beds being deposited in an adjacent topographic depression created by deposition of the immediately preceding bed (Mutti and Normark, 1987) (fig. 21). The amount of channelization in these distal deposits is uncertain (M. H. Gardner, personal communication, 1996), but the numerous cores available from Geraldine Ford field should provide insight into this question in the next year of the project. The reservoir facies may represent submarine channel deposits encased within lower permeability lobe

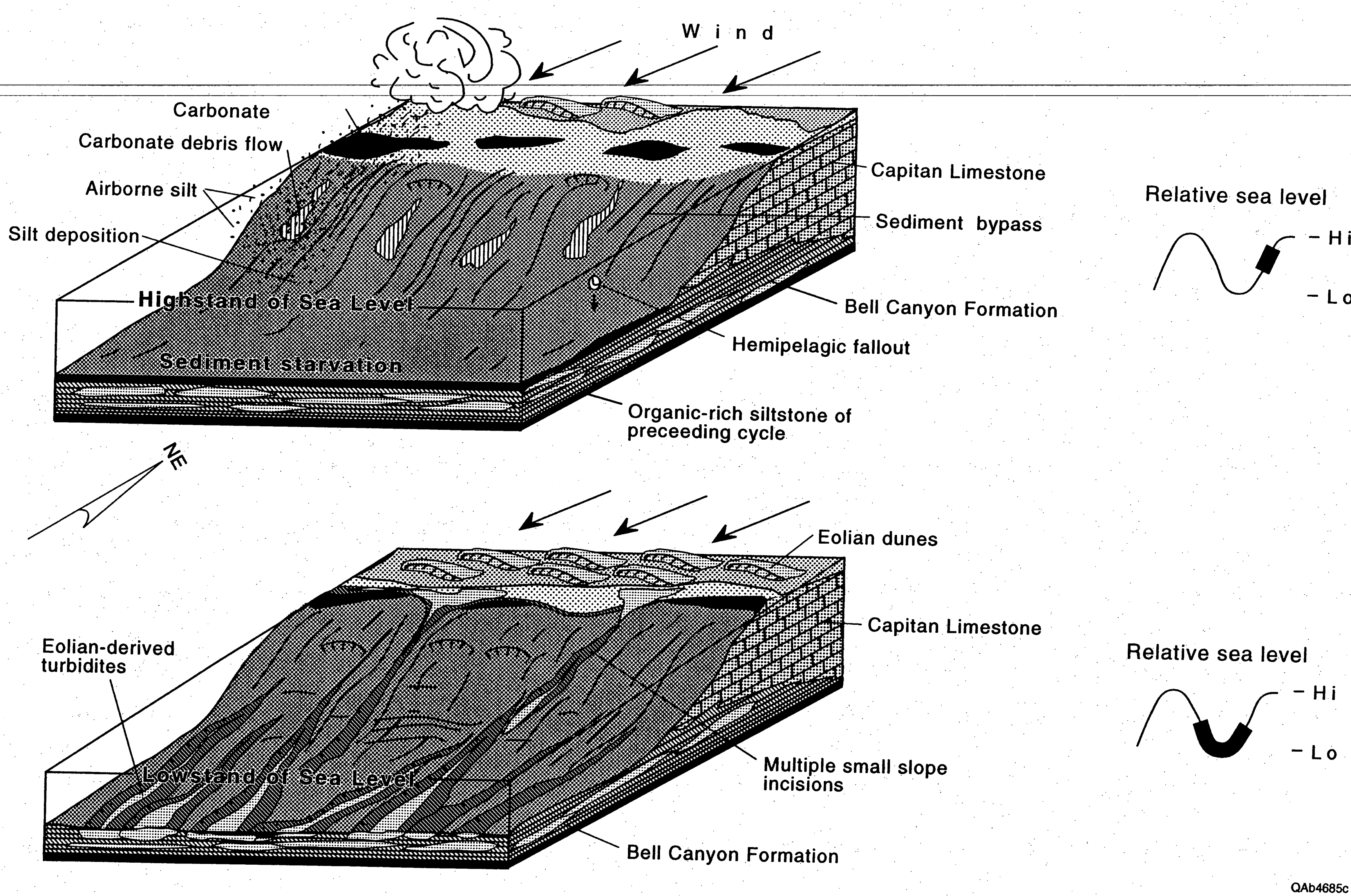


Figure 20. Diagram showing eolian-derived turbidite model for the Delaware Basin (from Gardner, 1992). Relative sea-level fall (lower block) produces dune progradation and slope incision, resulting in downslope transport of eolian-derived sands. Subsequent sea-level rise (upper block) results in transgression over platform dunes.

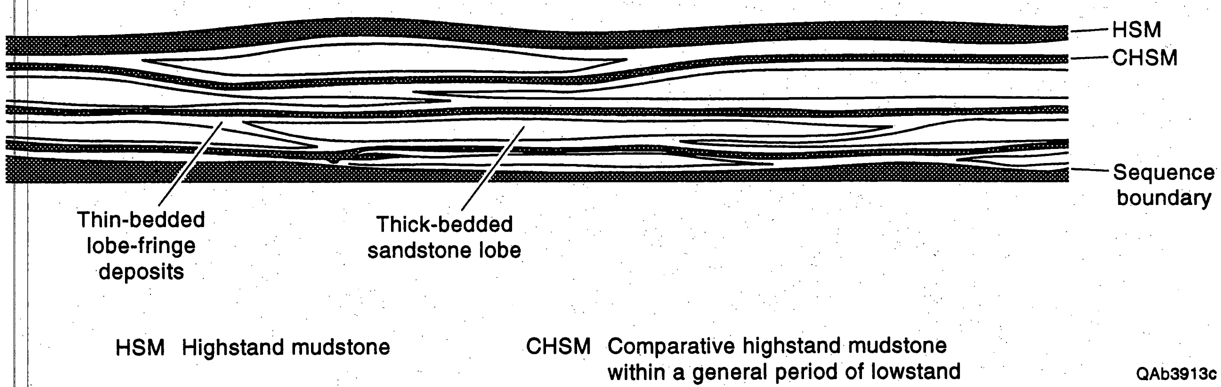


Figure 21. Schematic cross section of turbidite geometries that illustrates the development of compensation cycles, as individual beds are deposited in the adjacent topographic depressions created by deposition of preceding beds (from Mutti, 1985). No scale implied.

deposits, or, alternatively, the reservoirs may be thick-bedded sandstone lobes and the nonreservoir facies are interbedded thin-bedded lobe-fringe deposits (fig. 21).

All of the models that have been proposed for the deposition of the Geraldine Ford sandstones will be evaluated in the coming year as reservoir characterization continues. Distinguishing among these models will be important for the successful completion of the pilot project, because the various depositional models give very different predictions for sand-body continuity and dimensions.

Characterization of Diagenetic Heterogeneity

One of the common reasons for poor recovery efficiency is heterogeneous development of permeability within reservoir sandstone bodies. The spatial distribution of low and high permeability within the sandstone units has implications for recovery strategies. Figure 22 shows hypothetical examples of some possible patterns of permeability development. High permeability zones may serve to capture most of the flow, and oil in other parts of the reservoir will be bypassed. Figure 22a shows an example of stratigraphic control on permeability, similar to that documented by Williamson (1978) in the Bell Canyon in the El Mar Field, where laterally continuous zones of high permeability occur at the top of sandstone beds. If subtle changes in grain size, mineralogy, or sorting influence diagenesis, facies control on permeability, as shown in figure 22b, might be expected. Very local influences, such as cementation of nodules (fig. 22c), will produce a small-scale random pattern of low permeability that may reduce the efficiency of secondary recovery. Other complex diagenetic patterns such as one related to a present or paleo-oil water contact (fig. 22d) may result from combinations of several patterns of permeability development.

Identifying the causes of enhanced and diminished permeability, mapping the distribution of permeability, and interpreting the origin of the observed relationships are the principle approaches used in identifying the diagenetic influences on hydrocarbon recovery. In the first year of this study, we completed the initial phases of each of these steps. In the following section, we describe

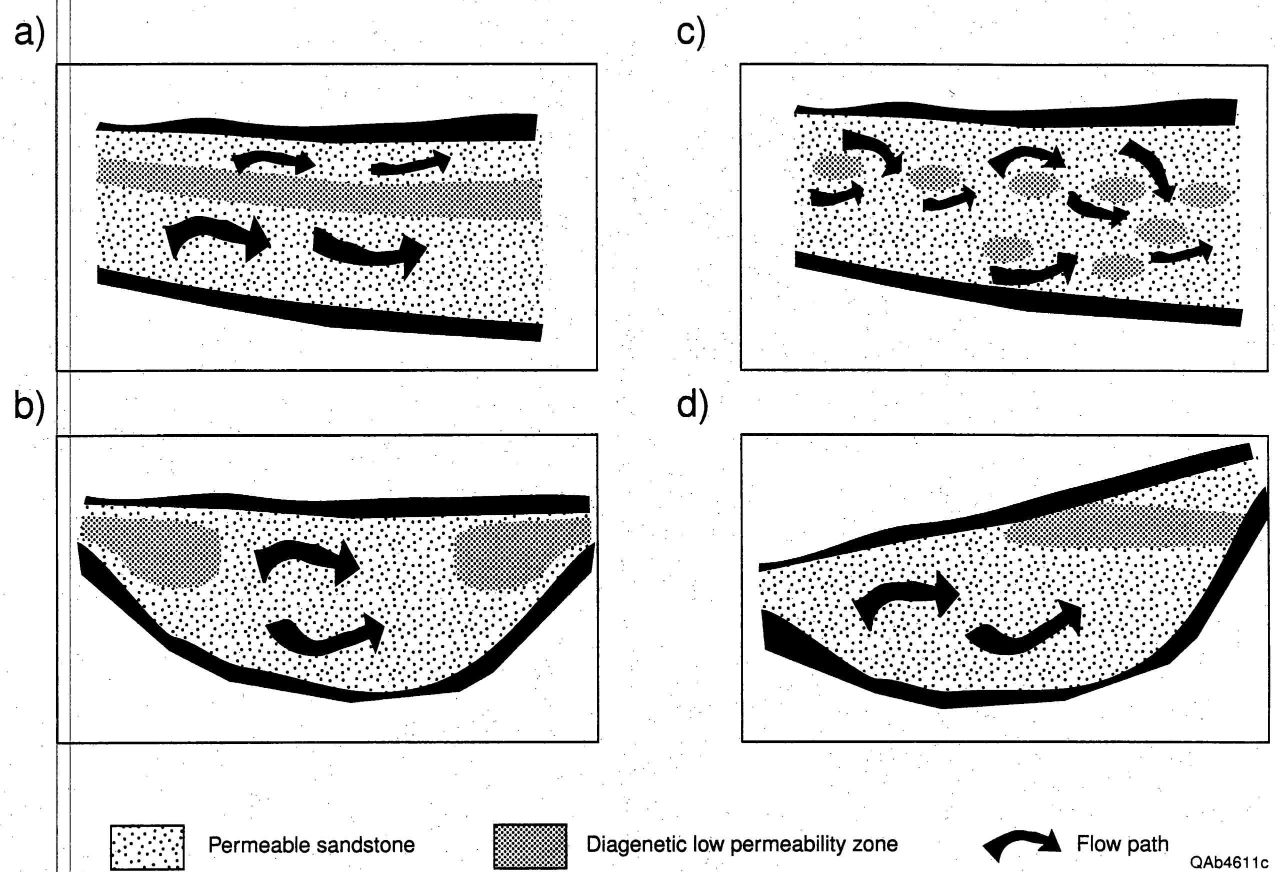


Figure 22. Conceptual diagram showing a variety of permeability distributions. See the discussion in the text.

the methods used, the observations made, present preliminary interpretations, and outline some of the possible future activities that may improve interpretation of diagenetic features.

Methods

The two methods that have been used during this phase of the study to examine the petrophysical characteristics of the Ramsey sandstones are (1) scanning electron microscope (SEM) imaging and (2) core analysis evaluation. A JEOL T-300 SEM was used to examine, qualitatively describe, and photograph the grains, cements, and pore structure of about 20 representative samples from the Ramsey 1A, 1B, and 2 sandstones in the FGU 60 core (fig. 23). This core was selected because lithologic, gamma-ray, and neutron logs are all available, allowing samples to be characterized as typical of high- or low-porosity intervals. Qualitative compositional analysis using a Tracor energy dispersive system (EDS) aided in mineral identification.

Core analyses (permeability, porosity, water saturation, and oil saturation) from nearly 8,000 samples from 120 cores throughout the FGU were entered in a spreadsheet. Records were photocopied from Conoco's files. Most appear to have been analyzed during the initial field development. The approximate stratigraphic position of each sample was determined by depth-correcting permeability against the stratigraphic picks made using gamma-ray logs. The top of the high permeability interval was matched to the top of the Ramsey 2 sandstone, and relatively low permeability was matched to the SH1 laminite (fig. 8).

Petrography of the Ramsey Sandstones

The major components in the Ramsey sandstones identified during SEM examination are framework grains, cements, and pores (fig. 24). The petrography of the Ramsey sandstones was repetitive, with the same components identified in many samples varying subtly in abundance.

Quartz, K-feldspar, and plagioclase are the dominant framework grains, and inspection suggests that the composition of the Ramsey sandstones in FGU falls within the ranges determined

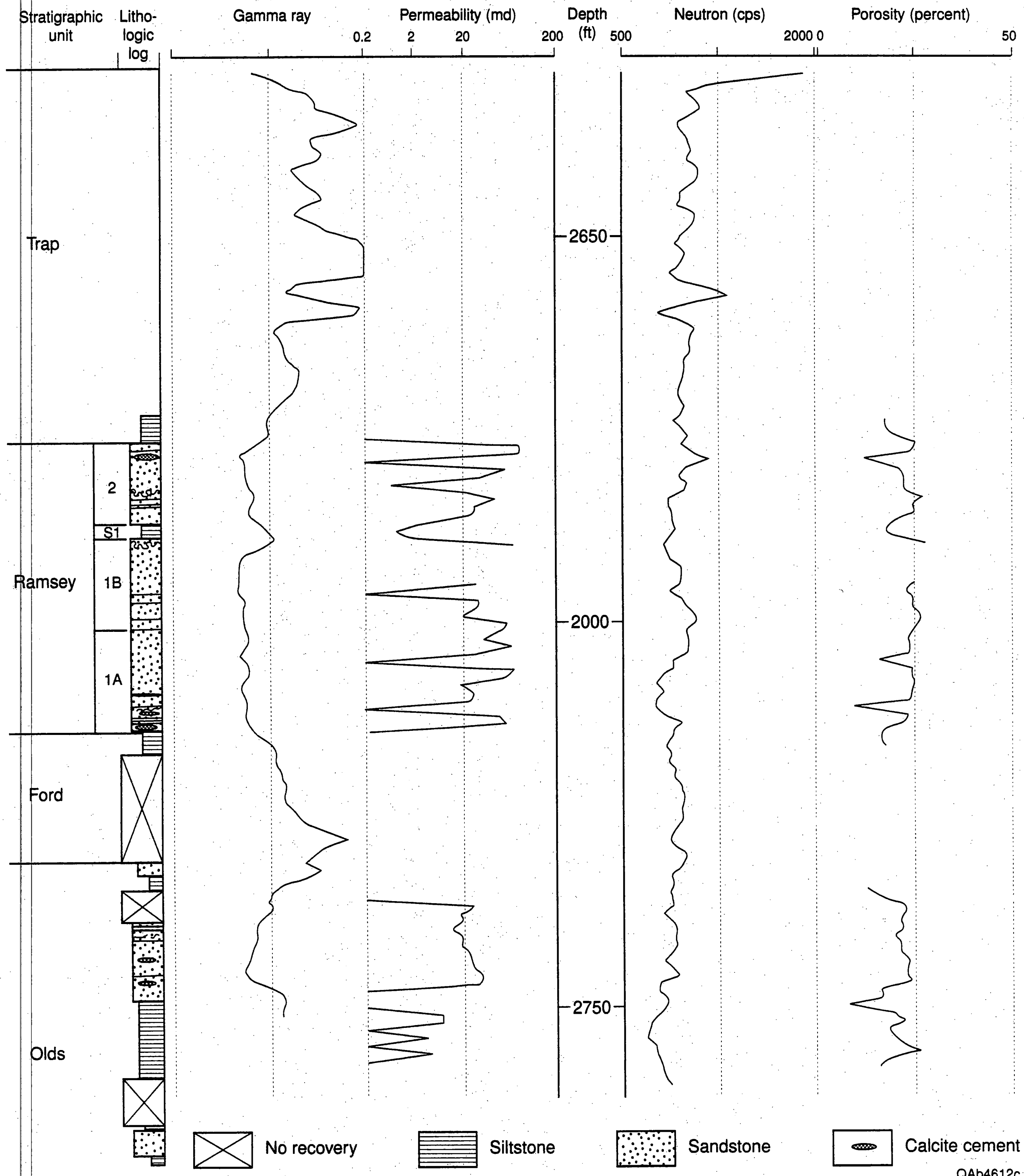
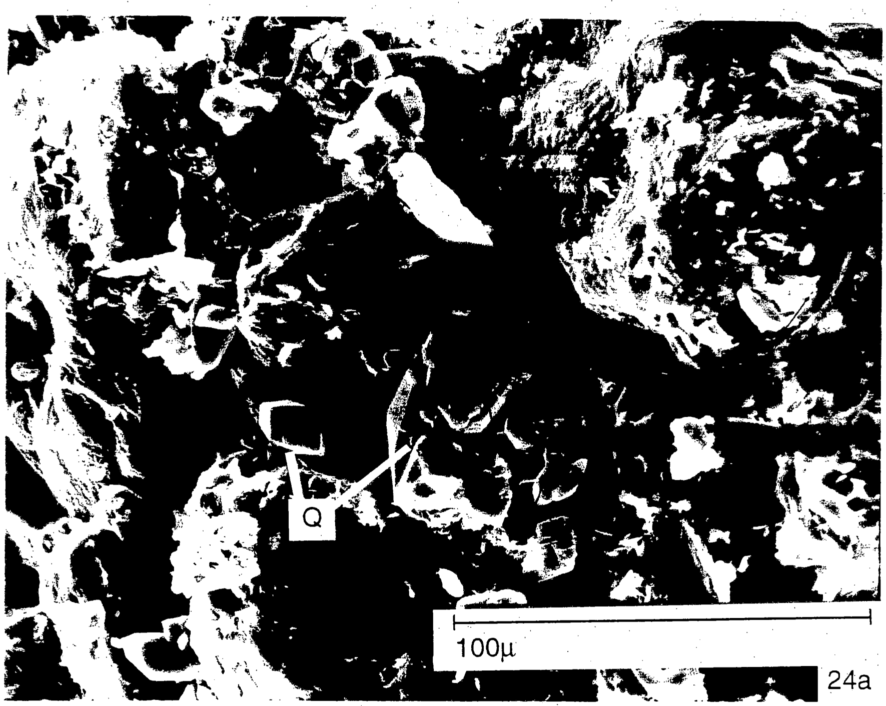


Figure 23. Data set from the FGU 60 borehole, with digitized traces from gamma-ray and neutron porosity logs, core log (modified from Ruggiero, 1985), and porosity and permeability determined from core analysis and depth corrected to match the wireline logs.



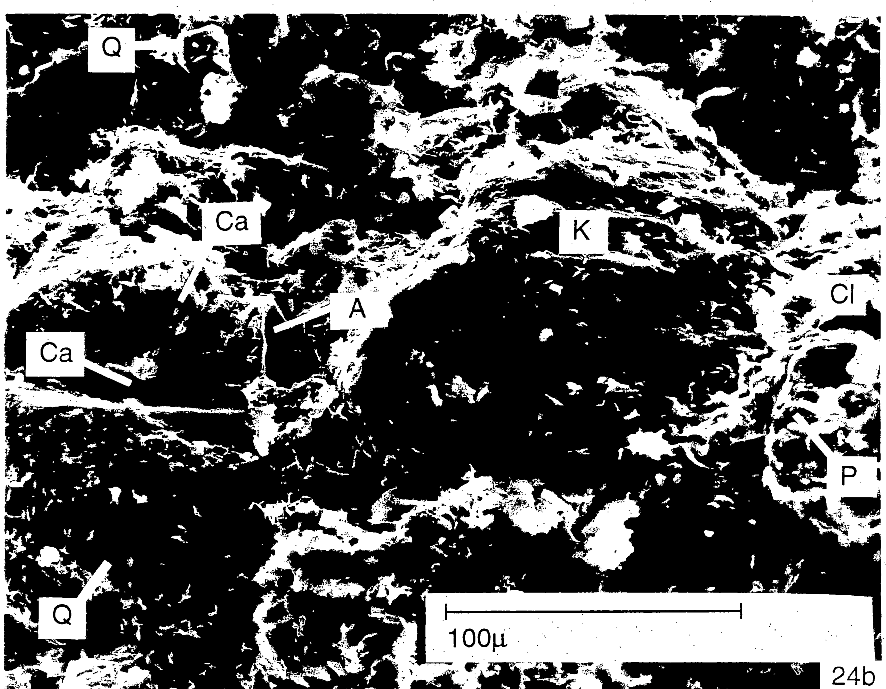


Figure 24. SEM images of typical framework grains and cements in the FGU 60 core. Mineralogy identified by EDS indicated Q = quartz; K =K-feldspar, P = plagioclase; Cl = clay (chlorite); Ca = calcite, A = anhydrite. (a) porous, quartz-cemented sandstone, 2700.2 feet. (b) Fairly porous sample from 2704 ft. (c) Better cemented area in the same chip.

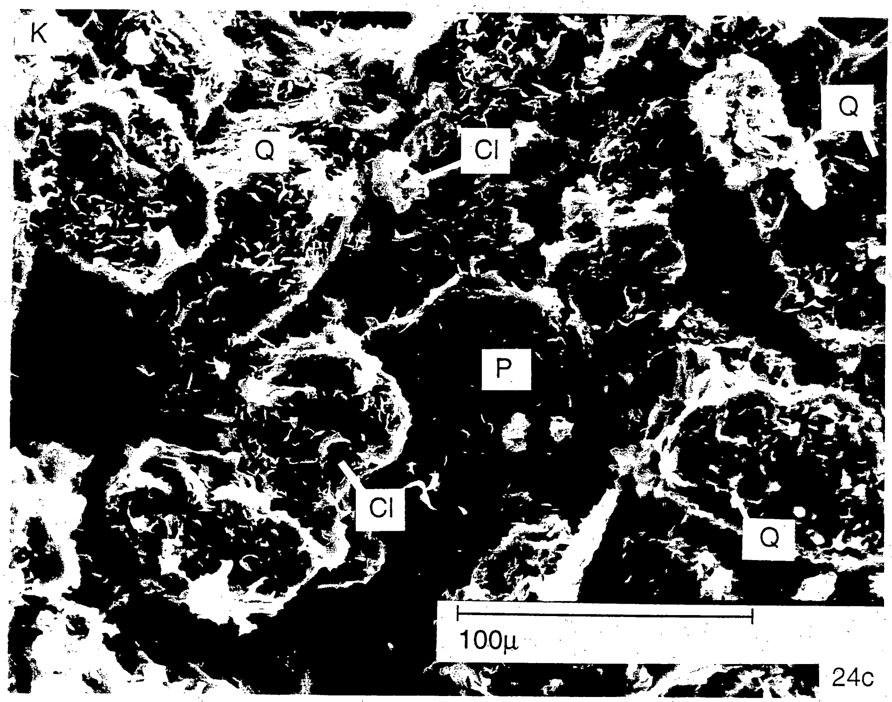


Figure 24 (cont.).

for other Bell Canyon sandstones (table 1). Quartz occurs as well-rounded grains with a rough surface texture (fig. 25a). K-feldspar is similar to quartz in SEM images and was identified by EDS spectrum, cleavage visible on fractured surfaces (fig. 25b), or where crystal facies on feldspar overgrowths are visible. Microcline, which is reported as a common framework grain (Williamson, 1978), is indistinguishable from orthoclase in SEM image. Plagioclase has been partly vacuolized and sericitized (fig. 25c and d). Rock fragments that make up a few percent of petrographically described sandstones (table 1) were not easily identified in SEM images, although micas suggest that metamorphic rock fragments are present.

Diagenetic phases imaged (fig. 24) include abundant authigenic clay throughout the Ramsey sandstones, locally abundant calcite cement, pervasive but volumetrically minor authigenic quartz and feldspar overgrowths, and local anhydrite cement.

Two end-member clay textures are recognized in SEM images—rosettes and aggregates. Well formed rosettes of clay flakes as much as 10 microns across cover grain surfaces (fig. 26a) and bridge between some grains. Clay aggregates underlie rosettes in some samples (fig. 25a). Many other grains have no aggregate coats beneath rosettes (figs. 25c and 27c).

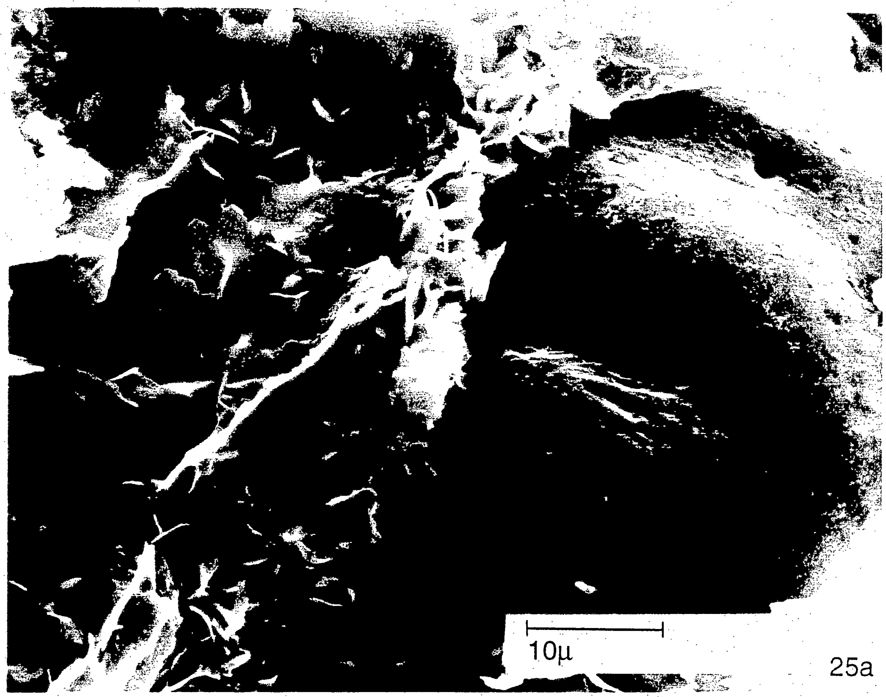
The appearance of the authigenic clay is similar to authigenic chlorite and associated mixed-layer clays identified elsewhere in the Bell Canyon Formation (Williamson, 1979; Hays, 1992; Walling, 1992). The qualitative clay composition determined using EDS (fig. 28) contains Mg, Fe, Al, and Si, a plausible composition for chlorite. SEM data are not sufficient to test the statement of Hays (1992) that aggregates are more finely crystalline and more abundant. The EDS analysis of Hays (1992) indicated that rosettes are more iron-rich than aggregates. This relationship was not reproduced in this study; minor iron peaks were produced from a number of grain surfaces not only from clay rosettes.

Quantitative analysis of other Bell Canyon sandstones gave average estimates of 3 percent clay (Williamson, 1978) and 13 volume percent (8 weight percent) clay (Hays, 1992); FGU sandstones probably fall within this range. Authigenic clays rim grains, increasing the roughness

Table 1. Composition of Bell Canyon sandstones based on thin section point count data.

	Williamson (1978) El Mar Field	Hays (1992) Waha Field
Quartz	52 (44-58)	34
Feldspar	14.6 (11-19) [75% orthoclase]	23 [10% orthoclase]
Rock fragments	6.0 (4-10) [low-rank metamorphics, carbonates]	2.5 [volcanic rock fragments, 15% carbonate]
Calcite	8 (tr-24)	6 (tr-29)
Clay	3 (tr-10)	8
Quartz and feldspar	0.9 (0 -3)	0.3 -0.9
Anhydrite/Gypsum	0	2
Halite		0.7 (0-10)
Dolomite		3
Ti-oxides		0.5
Porosity (point count)	15.0	19

( ) = range of values



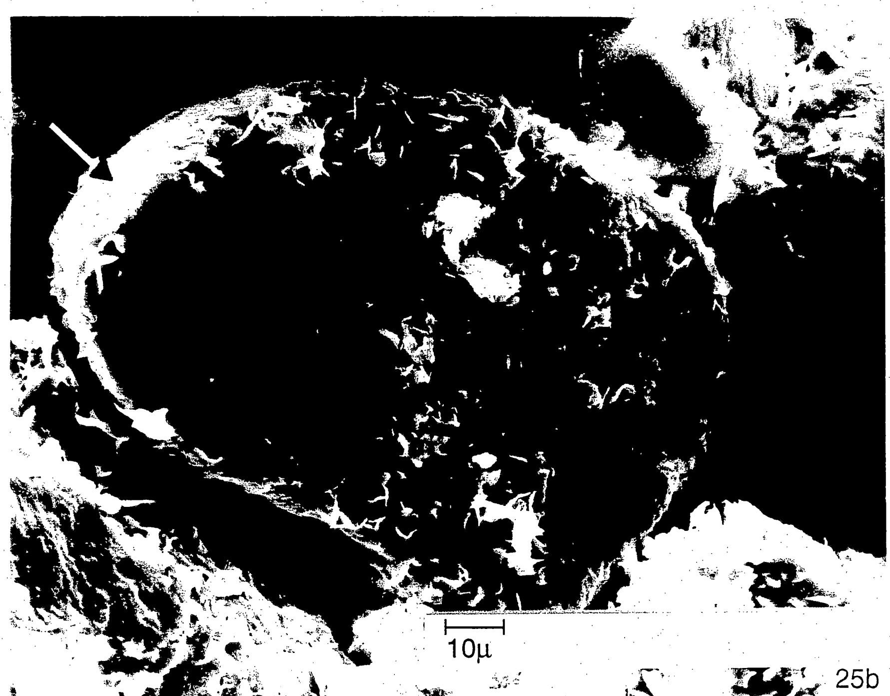
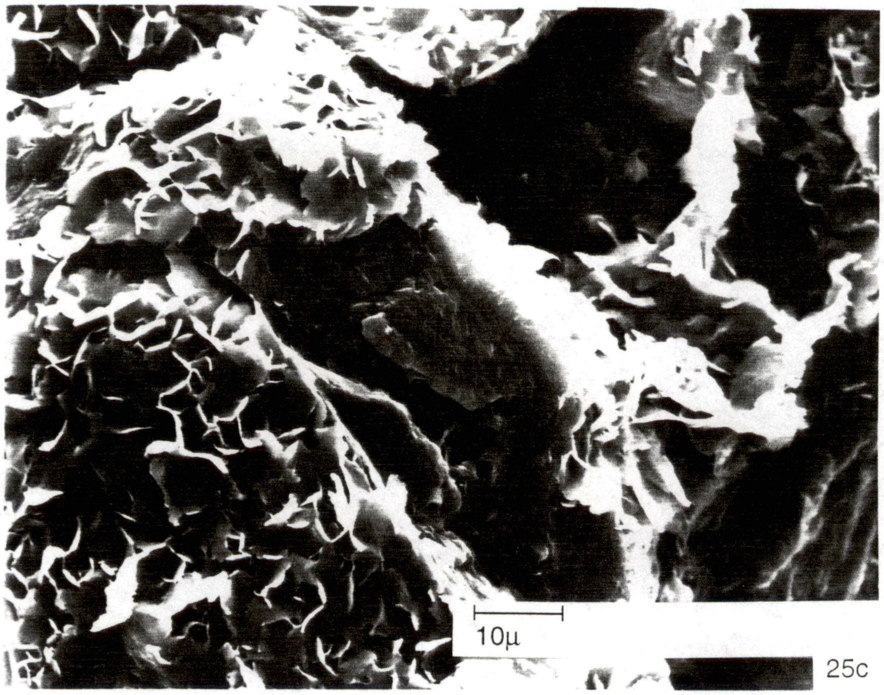


Figure 25. Typical framework grains in the FGU 60 core. (a) Surface of well rounded quartz grain visible where amalgamated clay and clay rosettes have spalled off. Depth 2708 ft. (b) K-feldspar was identified by K and Al peaks in EDS analysis. Depth 2704 ft. Slightly more euhedral shape and faint trace of cleavage (arrow) suggest mineralogy. (c) Plagioclase feldspar (Na identified in EDS analysis) is partly vacuolized and coated with clay rosettes. Depth 2710 ft. (d) Vacuolized feldspar within the base of the Trap siltstone. Depth 2675 ft.



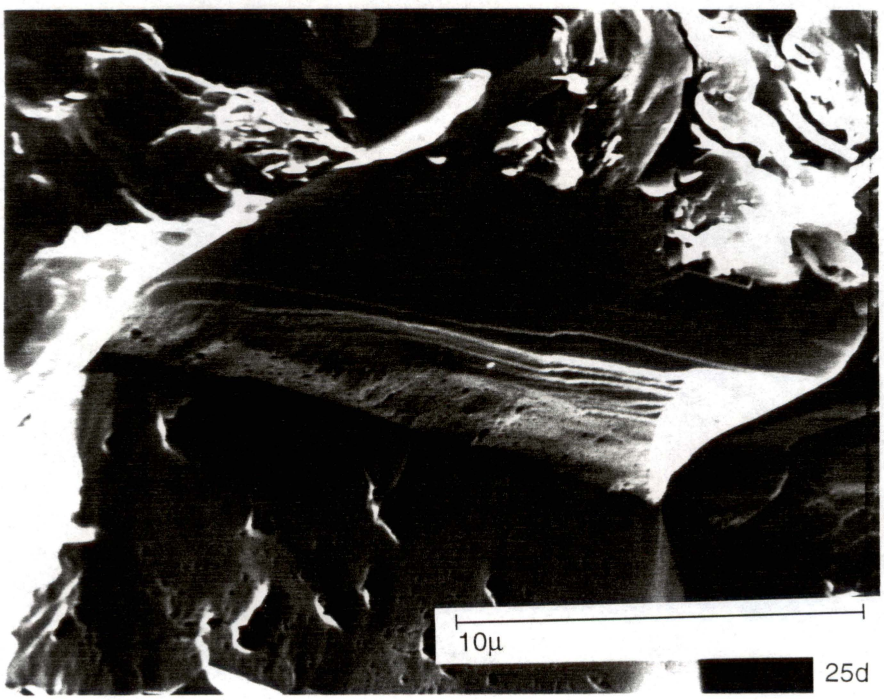
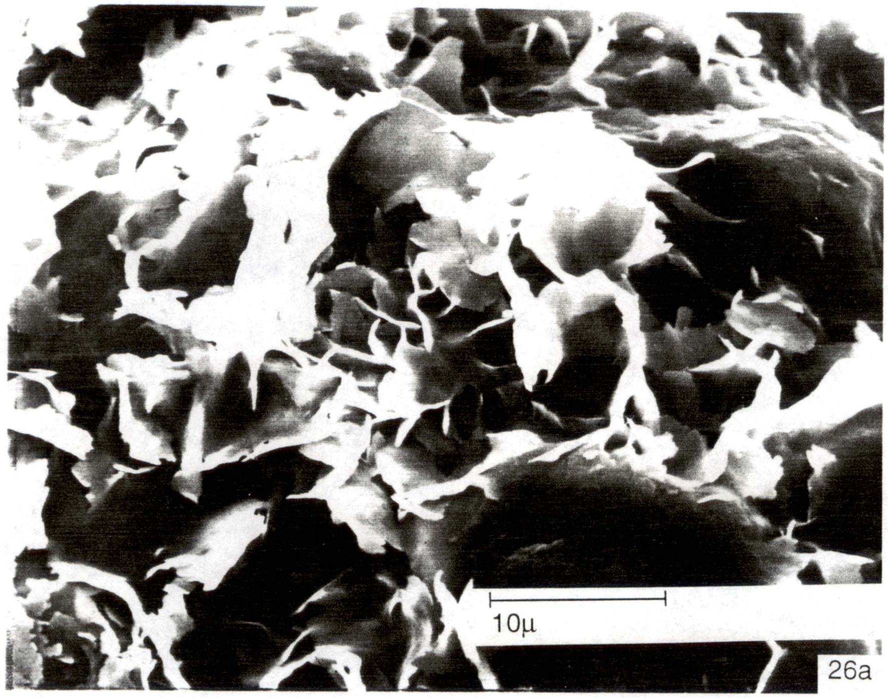


Figure 25 (cont.).



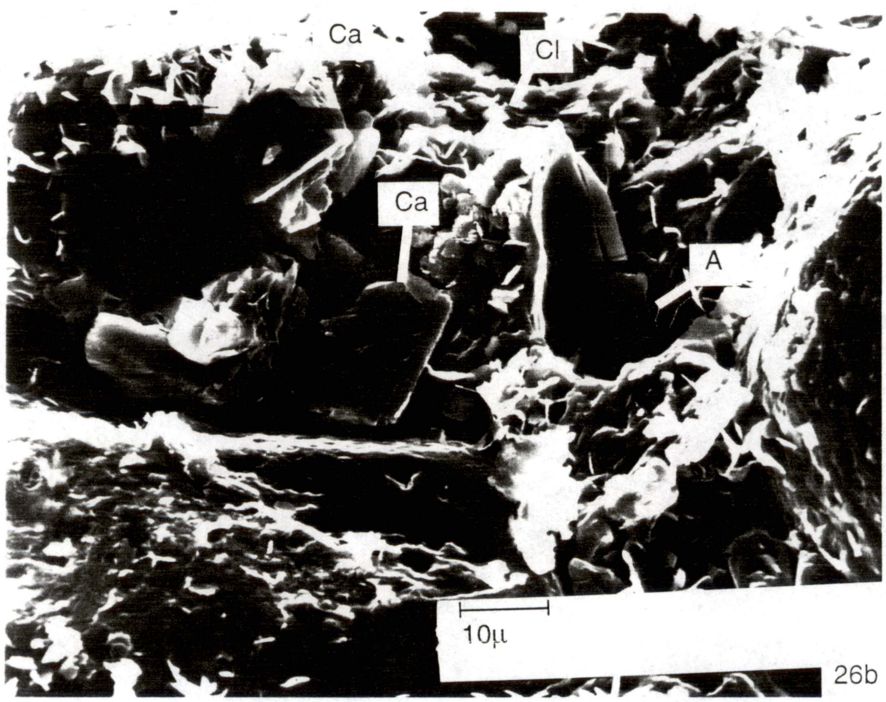
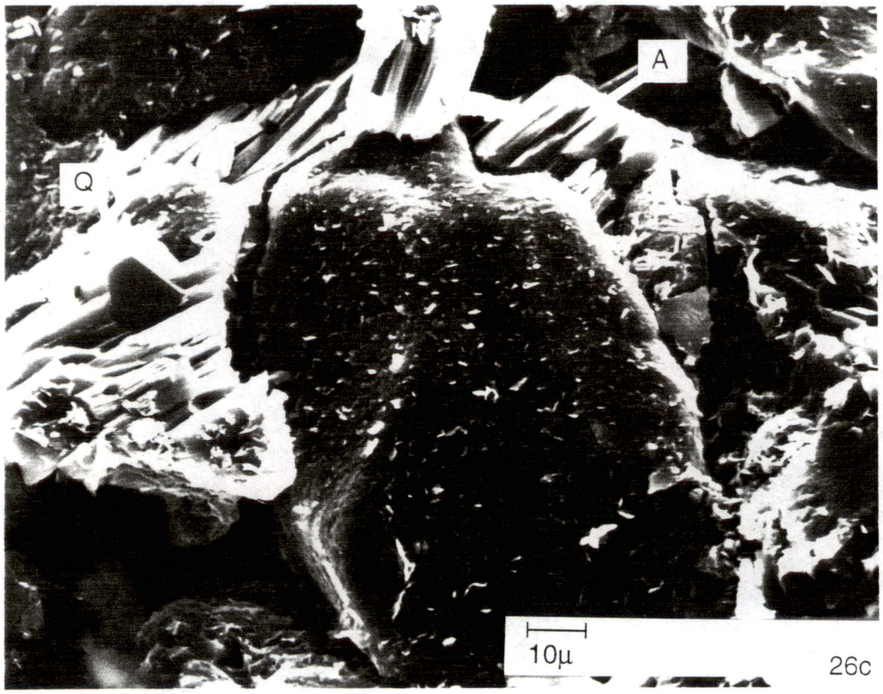
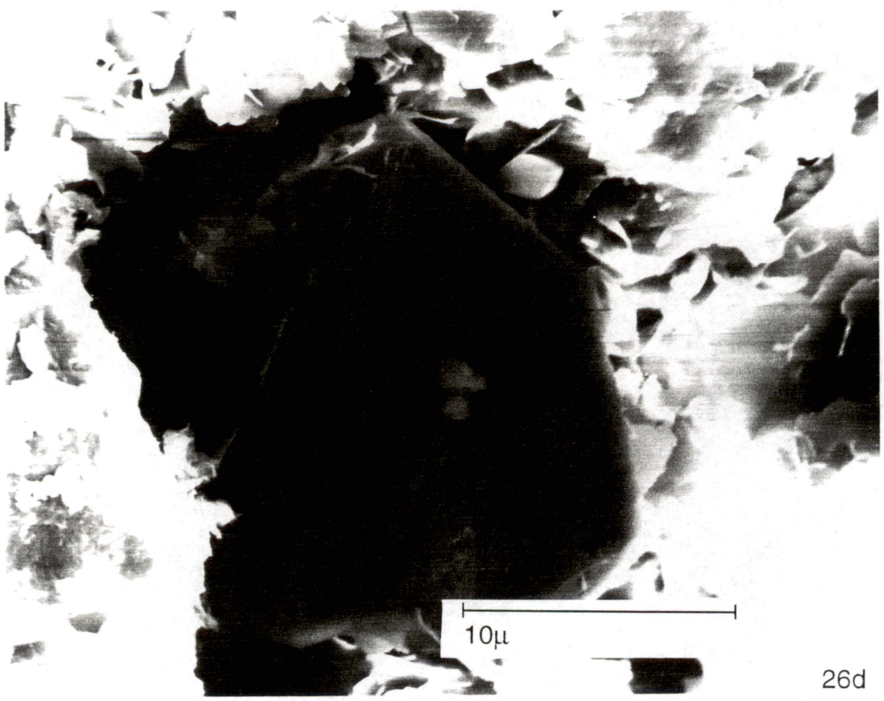


Figure 26. Typical diagenetic minerals in Ramsey sandstones in FGU 60 core. (a) Typical authigenic clay rosettes tentatively identified as chlorite based on similar morphology and occurrence to chlorite identified in other Bell Canyon sandstones (Williamson, 1979; Hays, 1992, Walling, 1992). Depth 2708 ft. (b) Authigenic clay (Cl), calcite (Ca) and anhydrite (A). Detail of fig. 24b, depth 2704 ft. (c) Anhydrite cement (A) near the top of Ramsey 2 sand cements a clay-coated quartz grain and overgrows euhedral quartz (Q). Depth 2677.3. (d) Slightly corroded euhedral carbonate crystal, EDS suggests that this may be siderite. Depth 2702.2 ft.

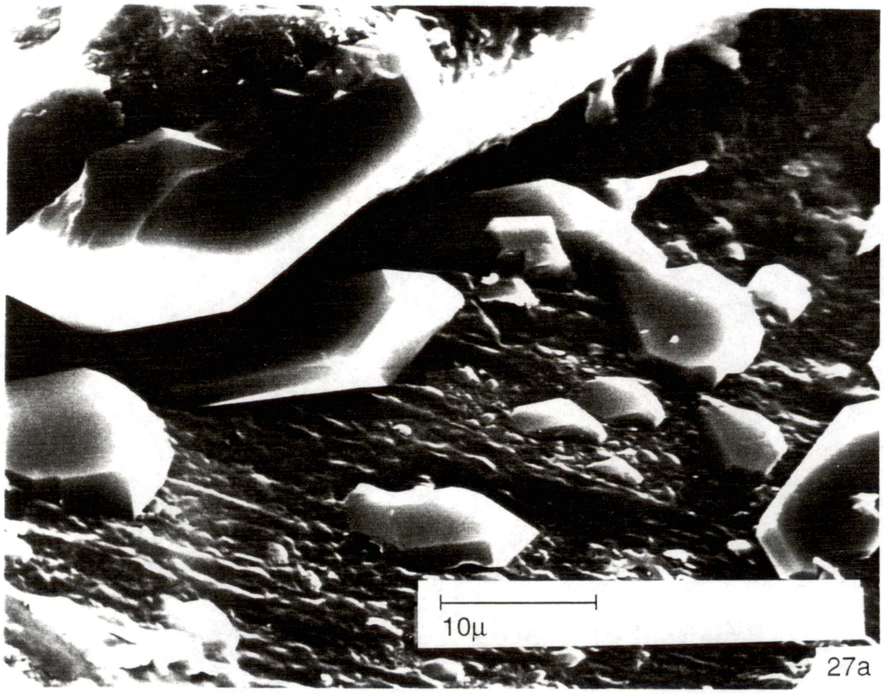


26c



26d

Figure 26 (cont.).



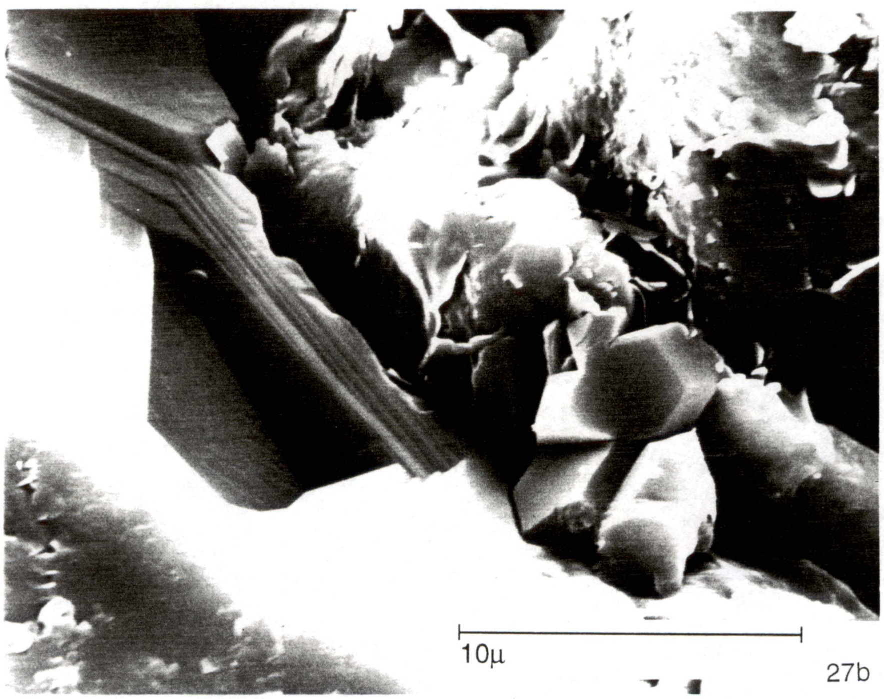


Figure 27. Typical diagenetic minerals in Ramsey sandstones in FGU 60 core. (a) Euhedral quartz overgrowth on a detrital quartz grain. Depth 2704 ft. (b) Euhedral quartz intergrown with authigenic clay rosettes. Depth 2700.2 ft. (c) Authigenic feldspar intergrown with clay rosettes. Depth 2704 ft.

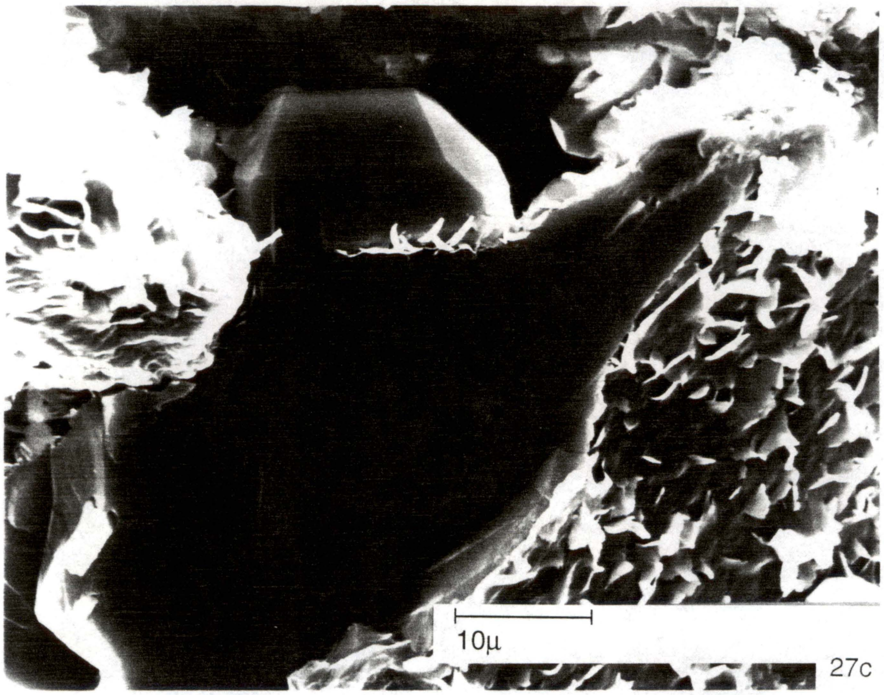


Figure 27 (cont.).

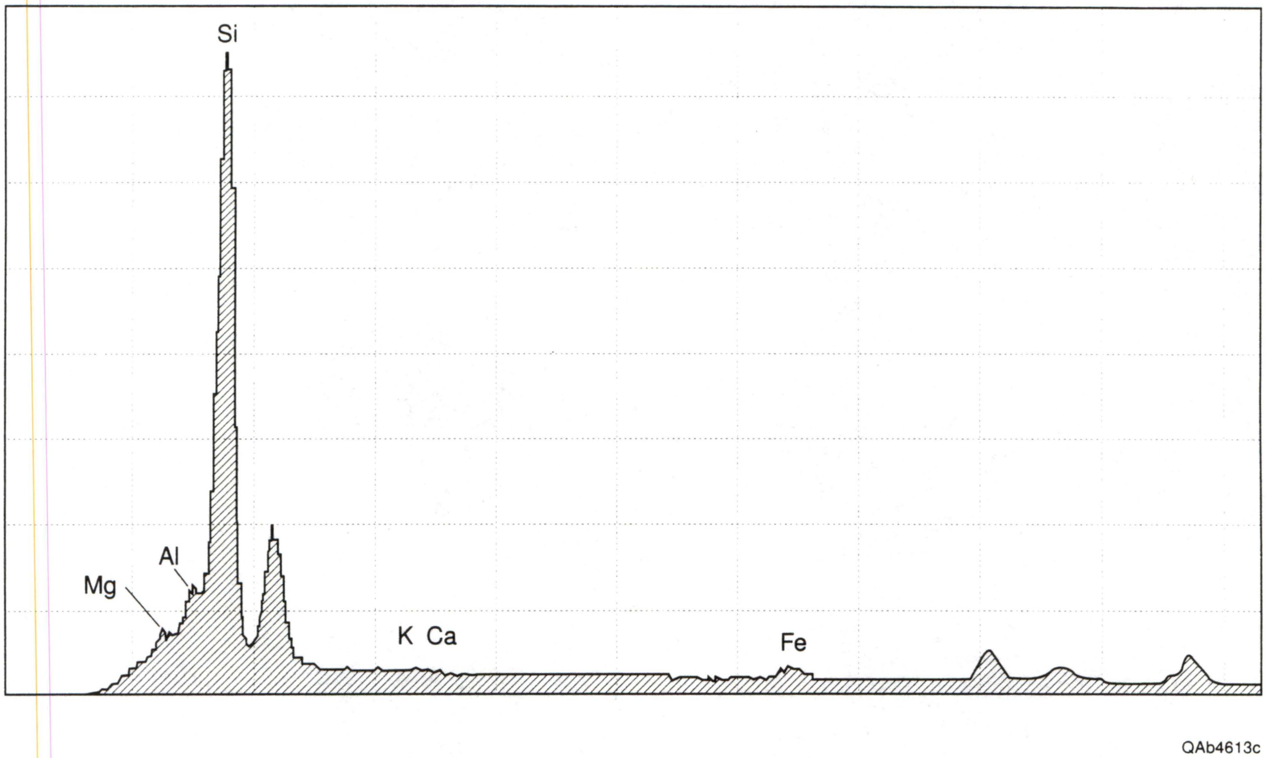


Figure 28. EDS spectrum of typical authigenic clay, showing Mg, Al, Si and minor Fe peaks. This analysis does not show quantitative elemental abundance.

of the surfaces, and a few flakes bridge pores between grains, however clay does not completely fill pore throats.

Calcite is the other important authigenic mineral; it is abundant in a few samples and insignificant in other samples, as shown by the range in table 1. In core, dense calcite cement occurs in nodules (fig. 23) (Ruggiero, 1985). Williamson (1978) and Hays (1992) noted relationships between limestone beds or abundant carbonate rock fragments and abundant calcite cement, suggesting that calcite cement is remobilized from these sources. Calcite cement has an inconspicuous appearance on fractured surfaces in SEM (fig. 24b) and a complex relationship with clay, appearing to both include and be overgrown by clay flakes. Many calcite crystals are euhedral, but crystal facies appear to have been somewhat corroded (fig. 26b). Hays (1992) emphasized calcite dissolution as a major event in the creation and preservation of porous, friable sandstones. Examination of FGU samples neither supports nor discounts this interpretation in this field.

Minor amounts of anhydrite were imaged in several samples (fig. 26b and 26c). Anhydrite appears to have been corroded at grain boundaries and along fractures. Relationships such as those shown in figure 26c suggest that anhydrite has overgrown and therefore post-dates authigenic clay on quartz grains and euhedral quartz. The relationships are less clear in other samples (fig. 26b) where clay that appears on the surface of anhydrite may post-date anhydrite precipitation or may be an insoluble residue left after part of the anhydrite has dissolved.

Euhedral quartz occurs in most samples; volumes quantified in other fields of less than 1 percent (table 1) are reasonable estimates of the volume of authigenic quartz in FGU sandstones. Quartz occurs as small crystals on quartz grain surfaces (fig. 27a), as isolated euhedral crystals, and as syntaxial overgrowths on detrital quartz grains (fig. 27b). Quartz generally appears to have overgrown and included authigenic clay. Feldspar overgrowths (both K-feldspar and Na-plagioclase) are common but volumetrically minor (fig. 27c).

Reconnaissance description of representative chips using the SEM failed to identify any prominent vertical trends or unique petrographic aspects that could be correlated with porous and less porous intervals within the Ramsey sandstone units in the FGU 60 core. The samples all contain authigenic clay and quartz, and variation in calcite content from one area of a chip to another (compare figure 24b and 24c) appeared to be as important as variation among samples. Additional more quantitative description is required to match clay and calcite abundance with permeability relationships. The framework grain composition and diagenetic history of the Ramsey sandstone in this field is generally similar to that described for other Bell Canyon sandstones (Williamson, 1978; Hays, 1992; Walling, 1992).

Petrophysics of the Ramsey Sandstones

The distribution of porosity and permeability from core-analysis data was subdivided by stratigraphic unit and examined vertically through the reservoir internal in histograms and cross plots to identify relationships among porosity, permeability, and stratigraphic setting. This initial examination used only stratigraphic data; no observations were made about the petrography of the samples.

The Ramsey 1A, 1B, 1C, and 2 sandstone units have remarkably similar porosity and permeability characteristics. Porosity ranges from 2 to 30 percent and is strongly skewed, with modal values of 22 percent (fig. 29). Permeability distributions are similarly skewed from the expected log-normal distribution, with modal values of about 32 md (fig. 30).

Permeability and porosity from core analysis varies systematically with position in each Ramsey sandstone unit, with highest values as well as the highest average permeability at the top of the unit and lowest average immediately below (fig. 31). Ramsey 2 (fig. 31a) and to some extent Ramsey 1C (fig. 31b) sandstones have an increase in permeability toward the base of the unit as well as the top. The pattern is different in the Ramsey 1A sandstone, which has lower average and more variable permeability toward the base (fig. 31d). A plot normalizing stratigraphic thickness to 1 produced a more systematic plot than using depth below the top of the unit (fig. 32). A three-dimensional display of the data may be helpful in further interpreting permeability distribution with depth. Porosity has similar relationships (fig. 33) with depth as does

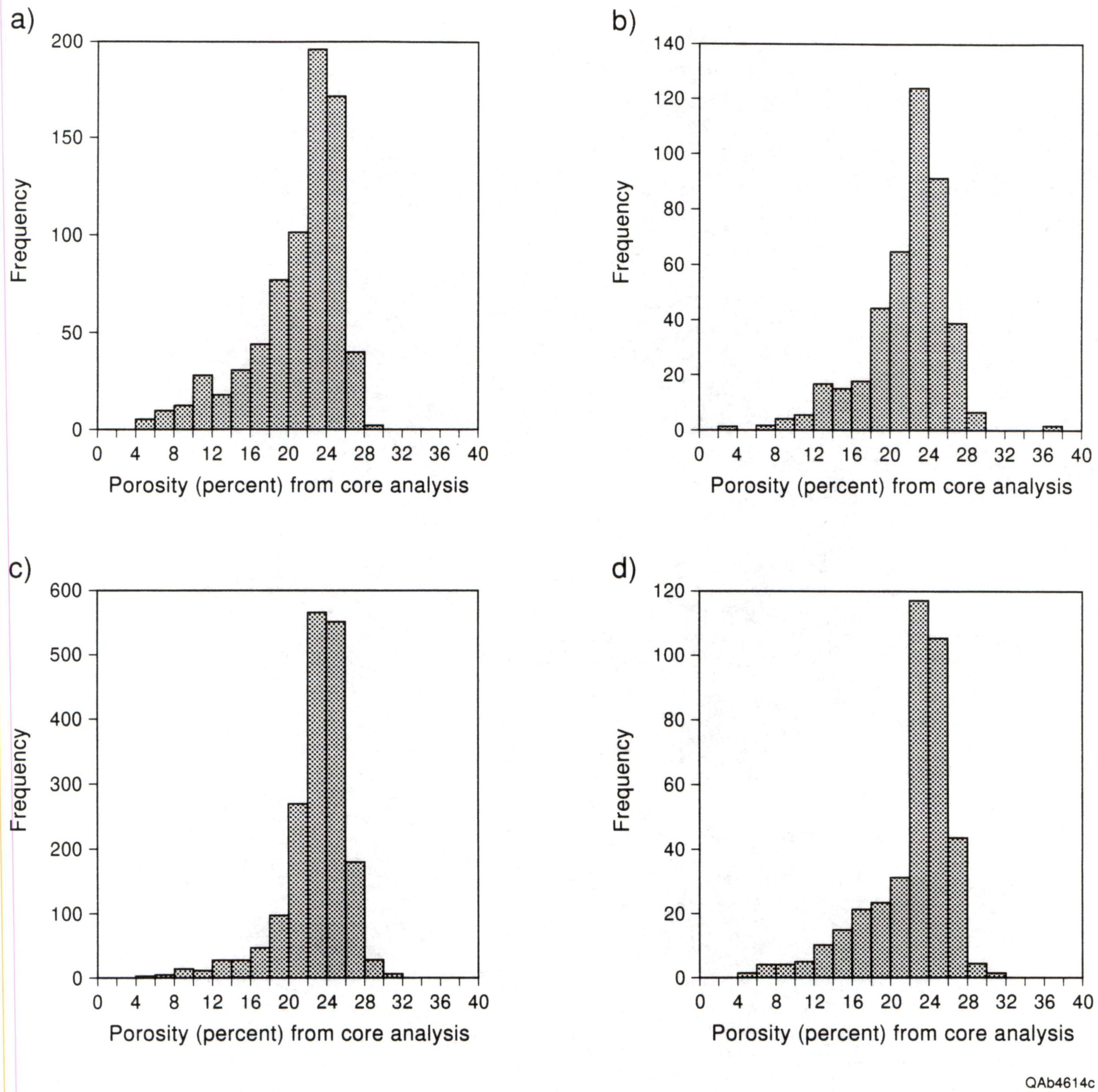


Figure 29. Histograms showing distributions of porosity from core analysis of Ramsey sandstones in FGU. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

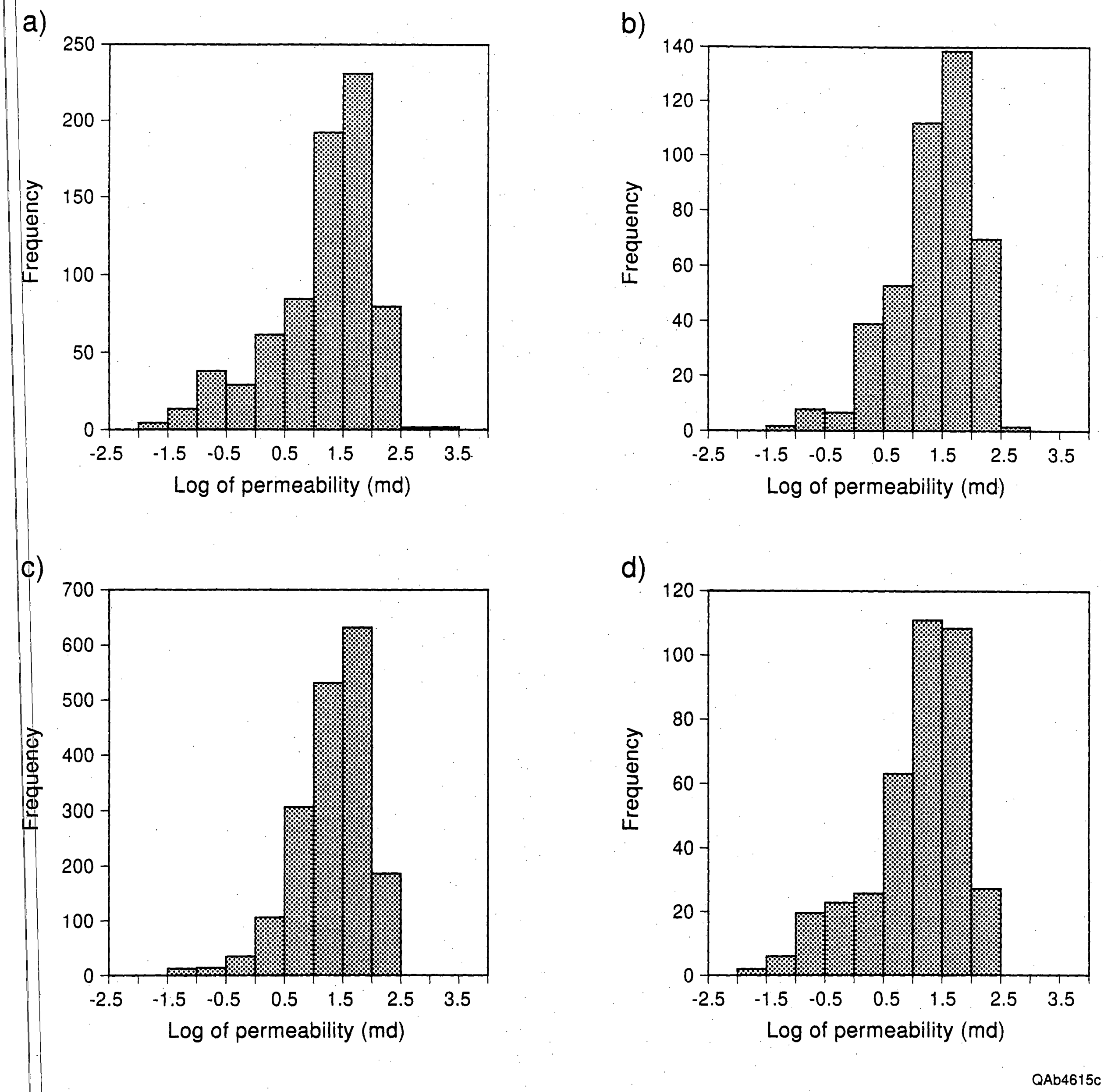


Figure 30. Histograms showing distributions of permeability from core analysis of Ramsey sandstones in FGU. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

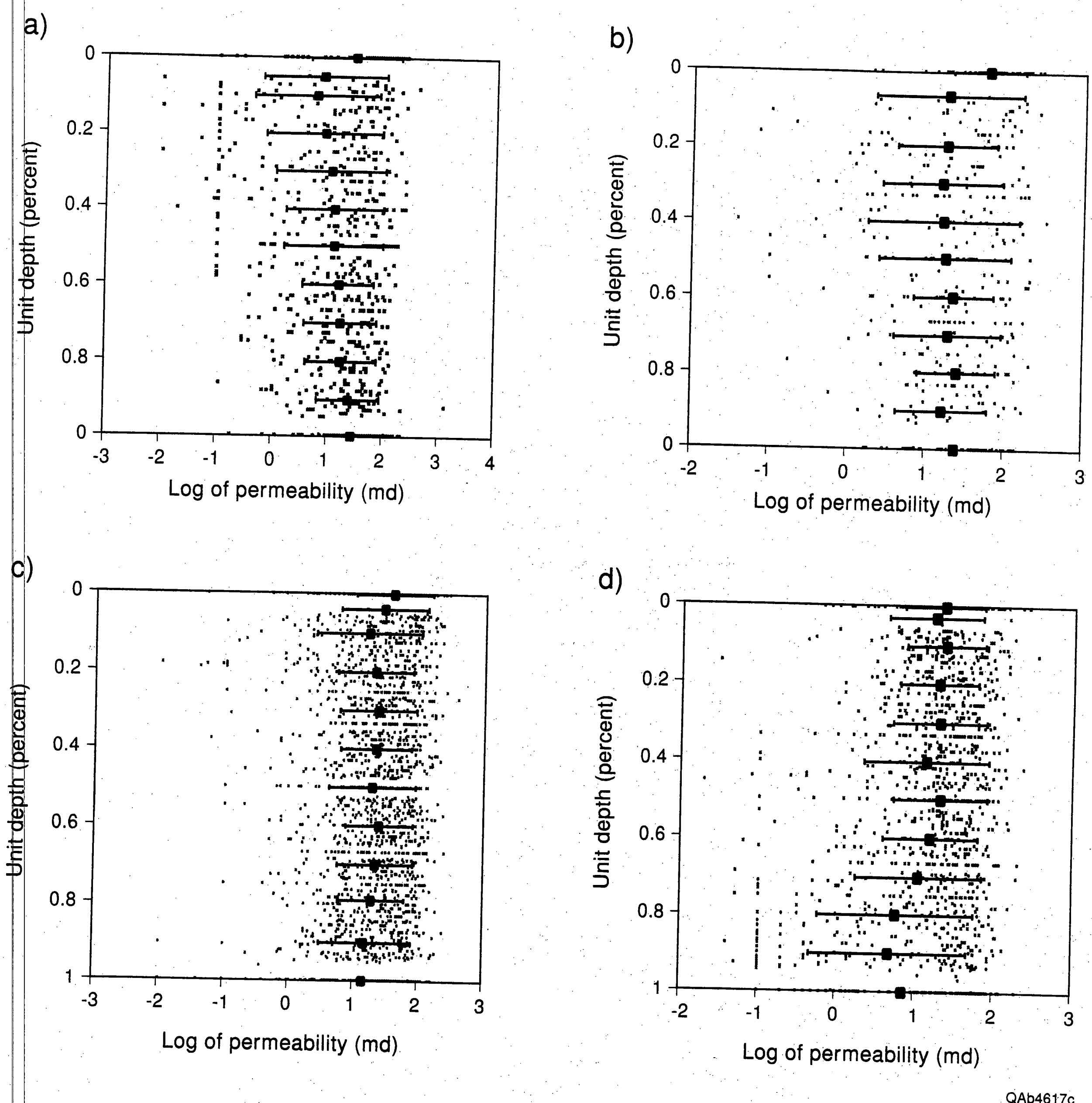


Figure 31. Plots of permeability from core analysis versus relative position in each Ramsey sandstone. Depths were normalized to give each stratigraphic interval a thickness of one. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

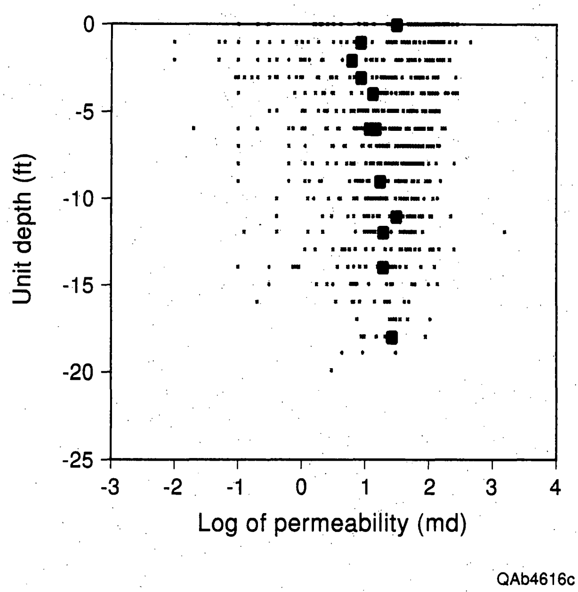


Figure 32. Plot of permeability from core analysis versus depth in the Ramsey 2 sandstone, showing more scatter in the lower part of the plot than the normalized plots shown in figure 31.

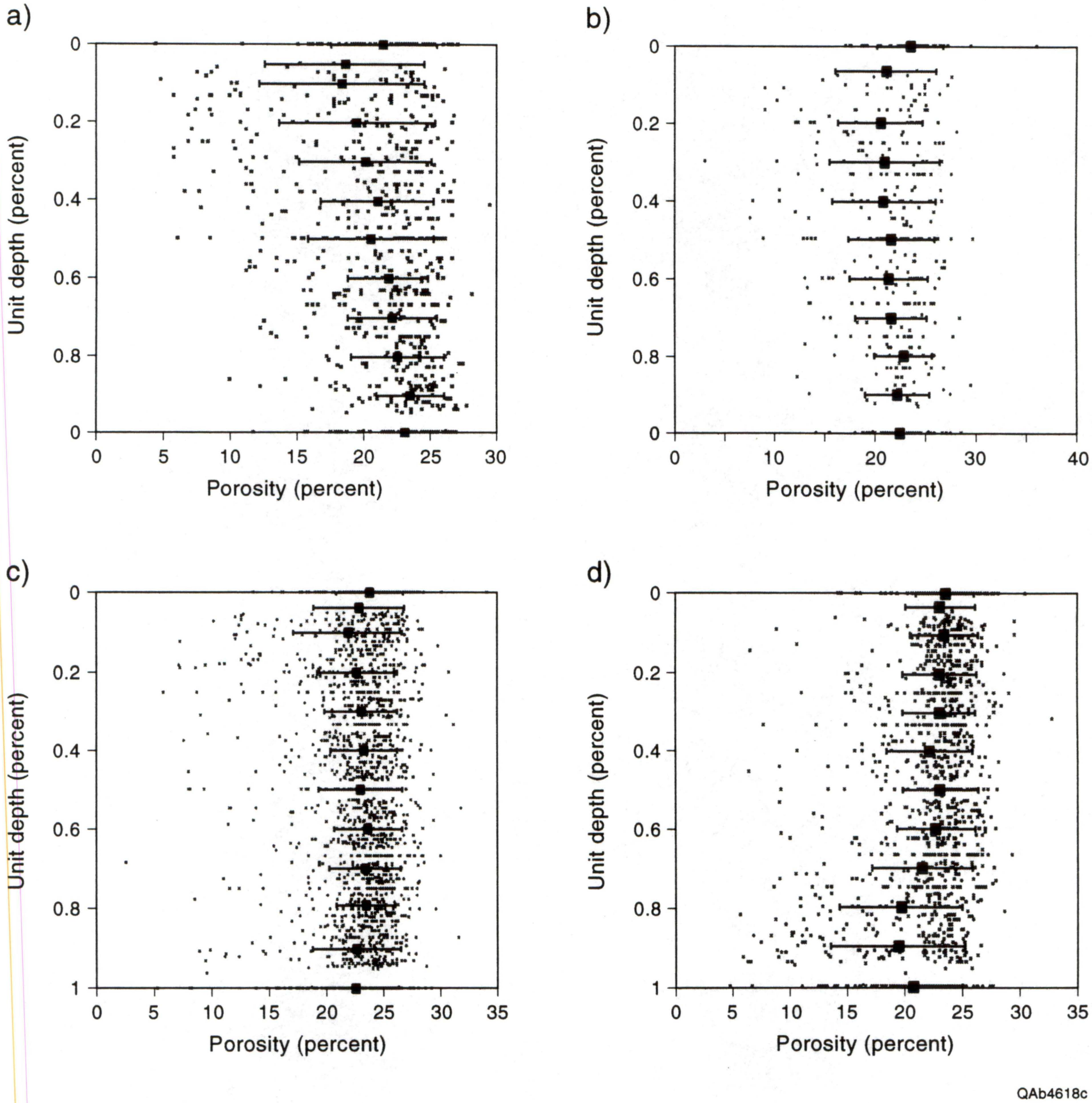


Figure 33. Plots of porosity from core analysis versus relative position in each Ramsey sandstone. Depths were normalized to give each stratigraphic interval a thickness of one. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

permeability, but oil and water saturation do not show significant variation with depth (figs. 34 and 35).

Porosity plotted versus the log of permeability (fig. 36) produces a moderately strong trend. This relationship might be predicted for a sandstone with petrographic characteristics like the Ramsey, where sorting is good and cementation and grain leaching are minor. Both petrographic and cross-plot relationships suggest that intergranular flow dominates and is not complicated by large variations in pore structure. However, four orders of magnitude variation in permeability are worthy of additional examination. Petrographic data on individual samples might show distinct permeability trends depending on the abundance of authigenic phases. Williamson (1978) documented the effect of abundant authigenic clay in decreasing permeability in the El Mar field.

In Ramsey 2 and 1C sandstones (fig. 36a and 36b), the samples at the top of the unit have slightly higher than average permeability relative to porosity, which might indicate permeability enhancement as a result of leaching. The low values may correspond to calcite cementation commonly observed near the top of some units. These relationships are not evident in the 1B and 1C sandstones (fig. 36c and 36d). Better constraint on the petrographic characteristics of samples with these permeability distributions are needed to further interpret these data.

Porosity (fig. 37) and permeability (fig. 38) data from core analyses were also compiled for the low permeability units within the FGU. All of the units show a spread of values, from samples that have very low porosity and permeability to others that are similar to reservoir rocks. The continuity and thickness of the low permeability units are important in the function of these units as flow barriers on top of and within the reservoir. Vertical permeability may also be lower than the measured horizontal permeability in these fine grained rocks.

Preliminary Interpretations

The sandstones in the Ford Geraldine reservoir are unusually homogeneous, therefore subtle, possibly diagenetically influenced permeability variations may define the flow patterns in the reservoir. Much of the field has old logs with poor vertical resolution and limited porosity data.

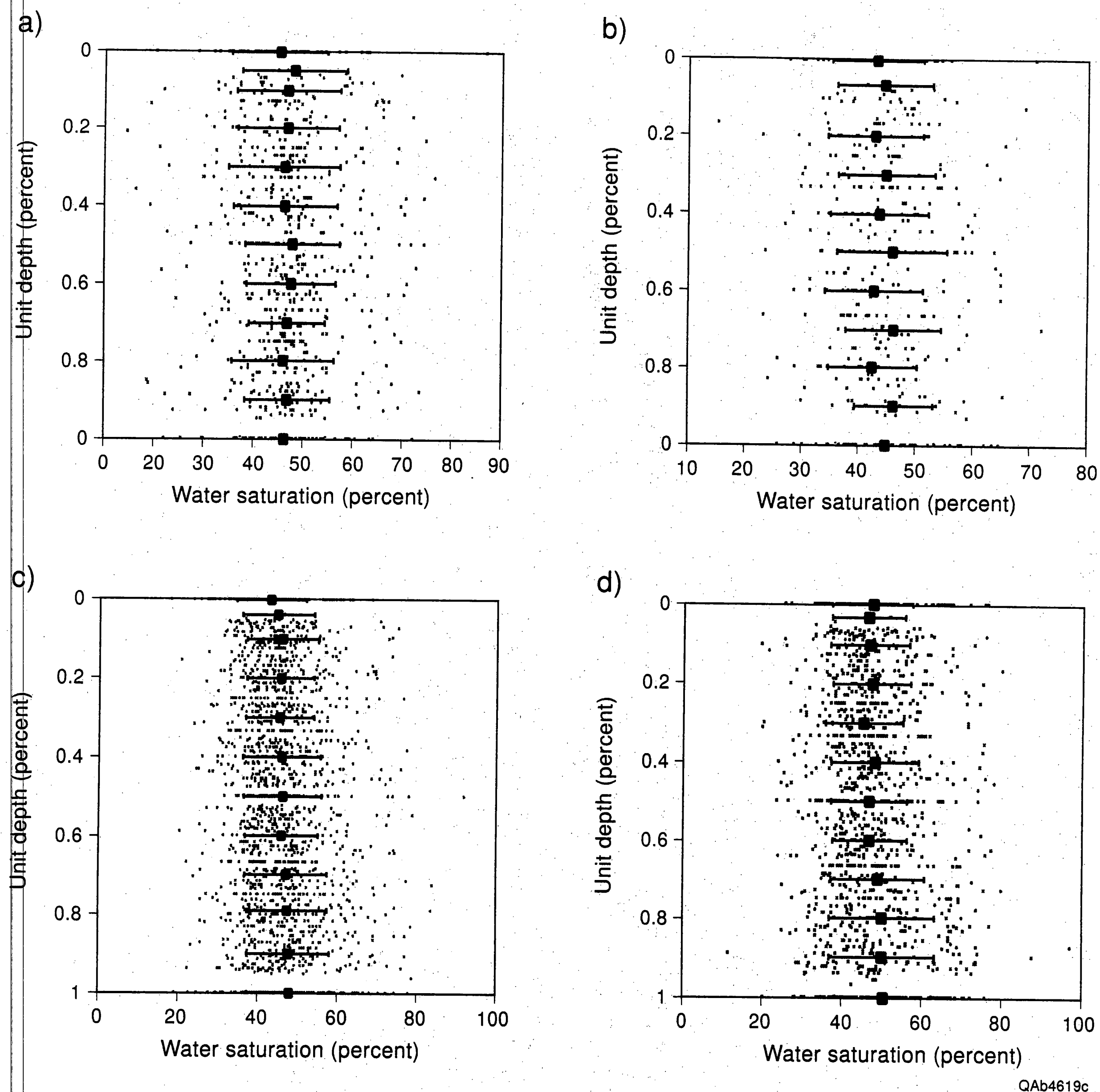


Figure 34. Plots of water saturation from core analysis versus relative position in each Ramsey sandstone. Depths were normalized to give each stratigraphic interval a thickness of one. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A.

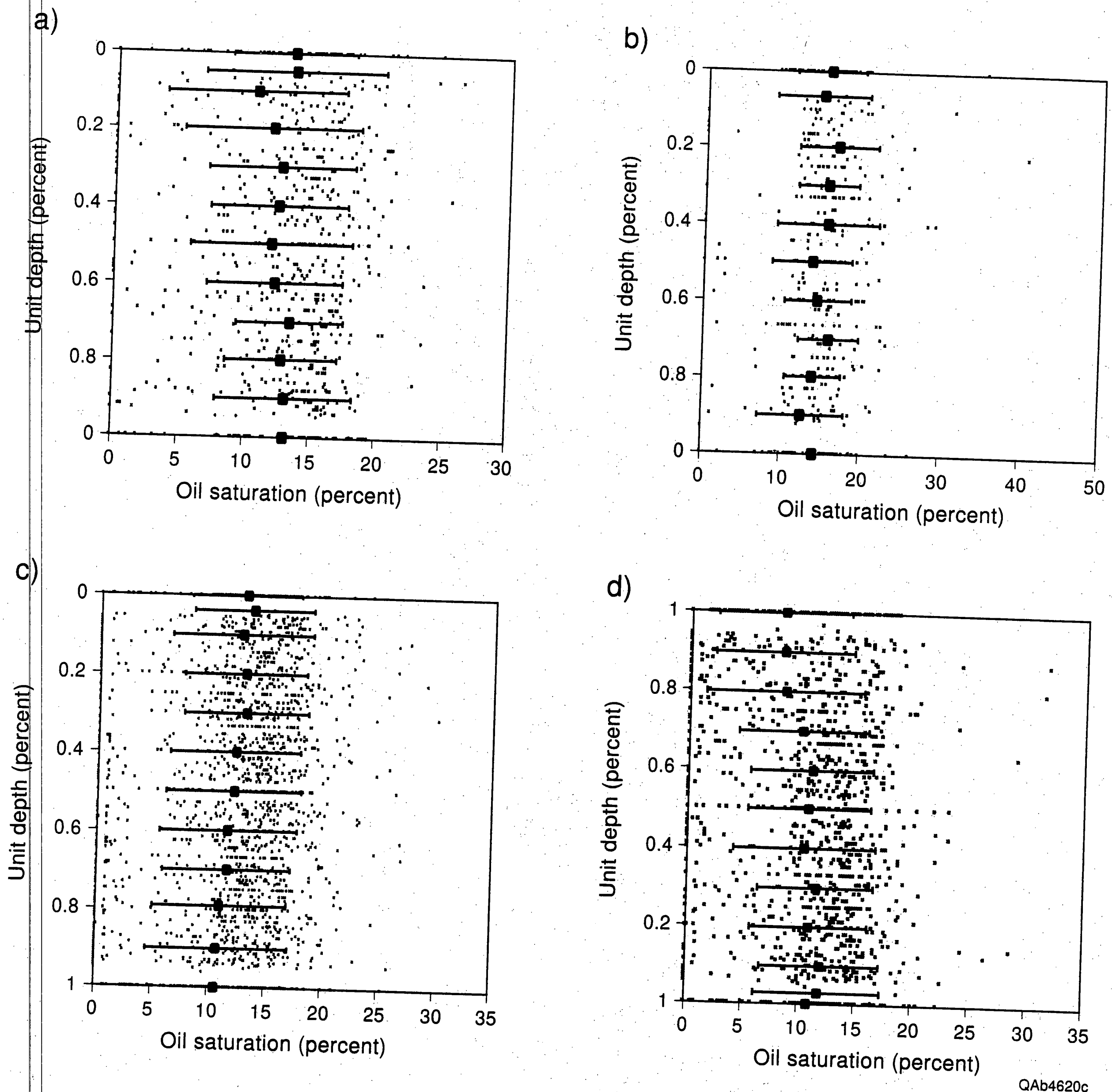


Figure 35. Plots of oil saturation from core analysis versus relative position in each Ramsey sandstone. Depths were normalized to give each stratigraphic interval a thickness of one. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone. (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

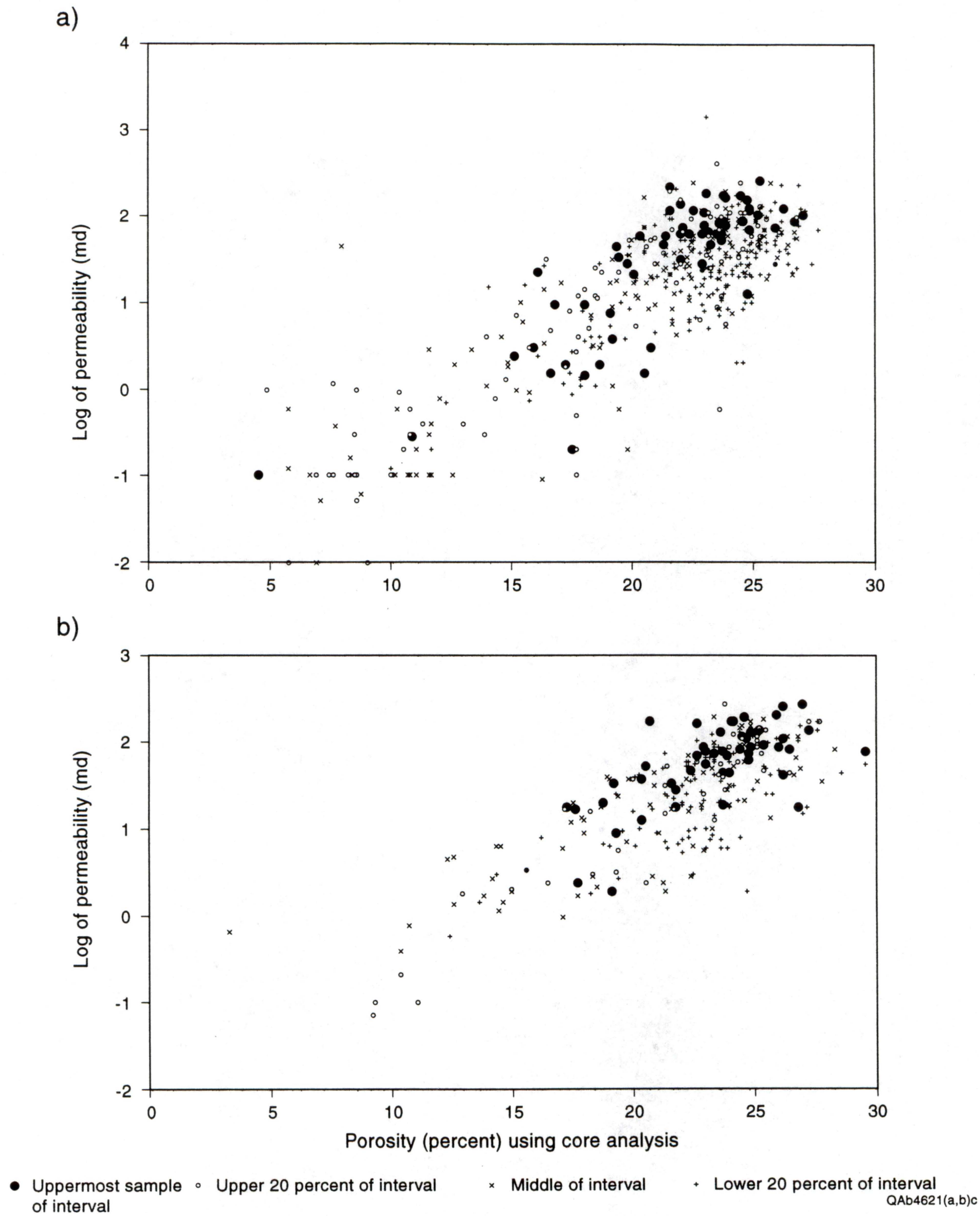


Figure 36. Plots of porosity versus the log of the permeability from core analysis. Symbols show the relative position of the sample in each Ramsey sandstone. (a) Ramsey 2 sandstone. (b) Ramsey 1C sandstone.

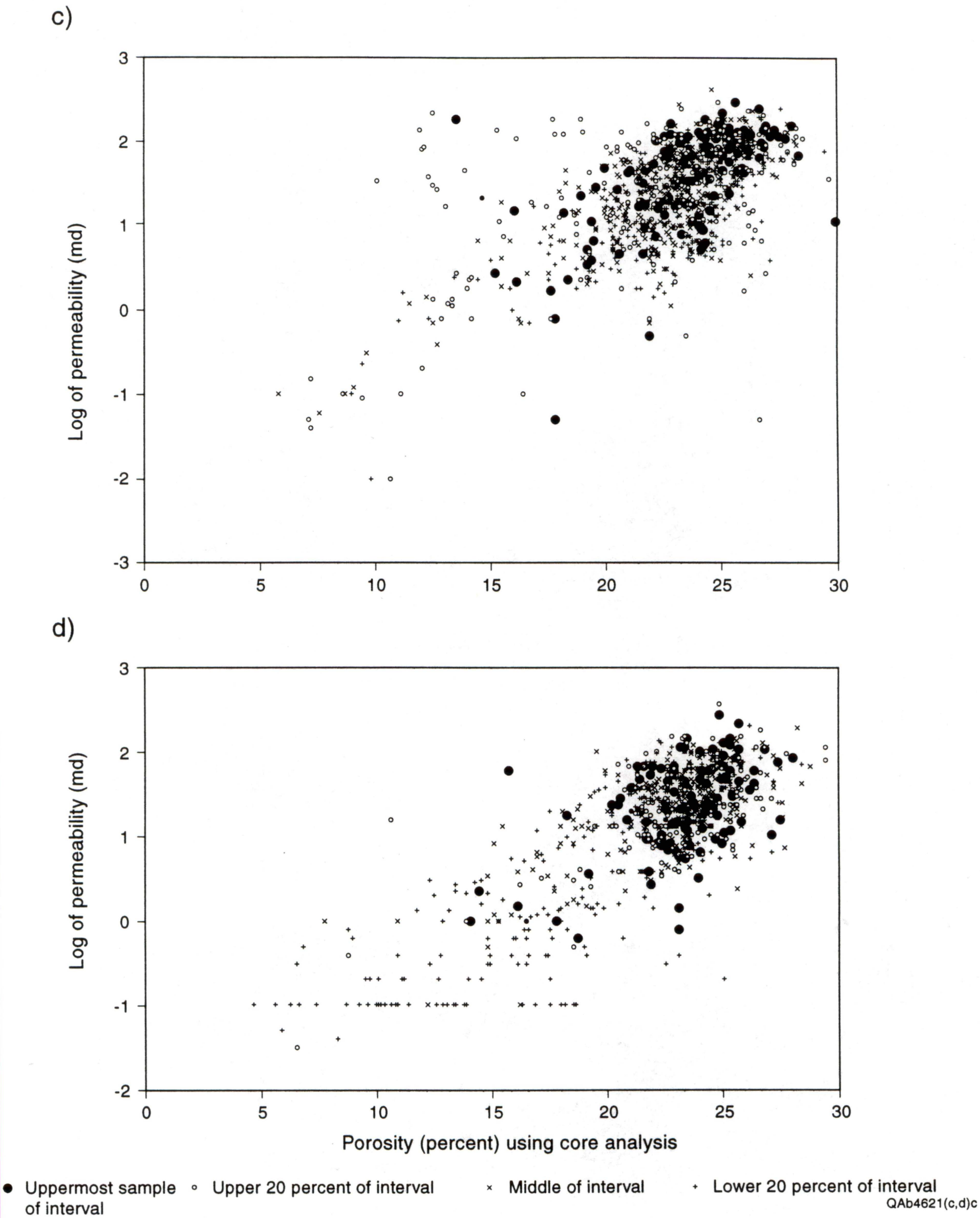


Figure 36. (cont.) (c) Ramsey 1B sandstone. (d) Ramsey 1A sandstone.

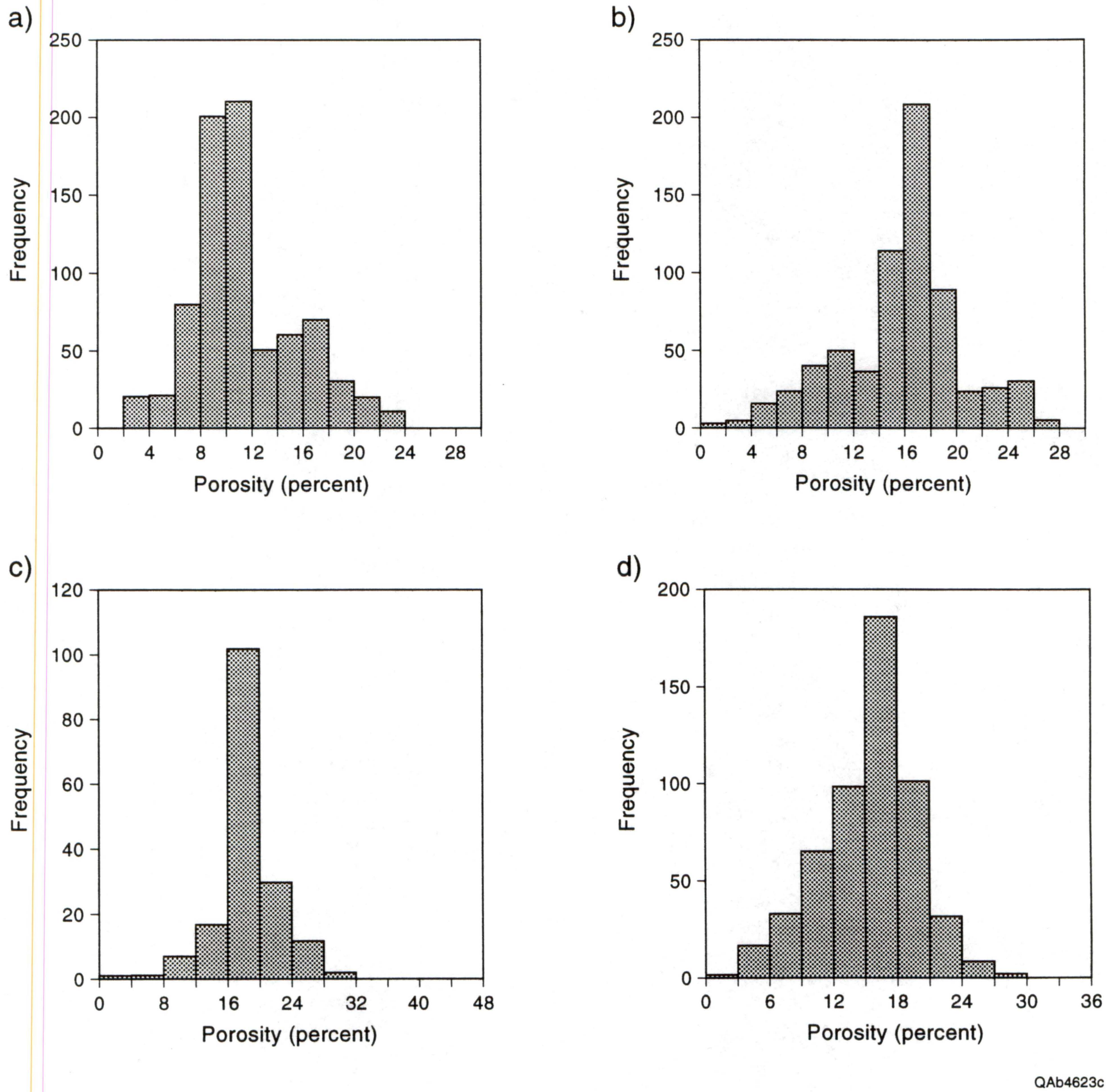


Figure 37. Histograms showing distributions of porosity from core analysis of low permeability units in FGU. (a) Lamar. (b) Trap. (c) Laminites S1, S2, and S3 within the Ramsey. (d) Ford.

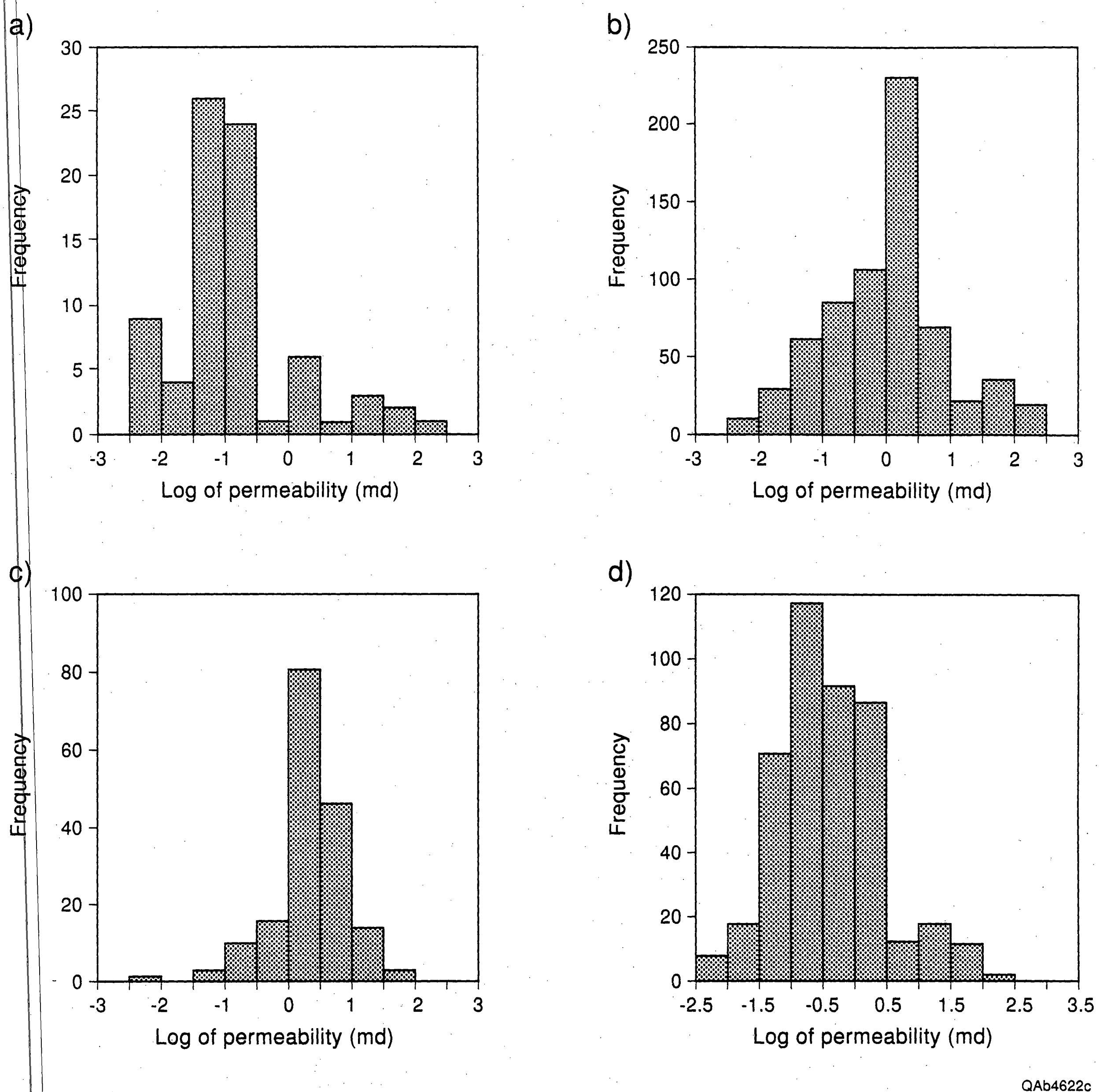


Figure 38. Histograms showing distributions of permeability from core analysis of low permeability units in FGU. (a) Lamar. (b) Trap. (c) Laminites S1, S2, and S3 within the Ramsey. (d) Ford.

However, the lack of modern log data is partly offset by a large set of permeability data from core analyses that may allow a fairly refined image of permeability distribution to be created.

Calcite and authigenic clay are the major minerals observed in Bell Canyon sandstones in FGU and in other fields (Williamson, 1978; Hays; 1992) that are expected to impact the permeability structure of the reservoir. Information about the genesis of these authigenic mineral is needed in order to correctly interpolate the permeability data. Many detailed observations and interpretations have been made about the diagenetic history of the Bell Canyon in previous studies (Williamson, 1978; Hays, 1992), and the present reconnaissance observations are not adequate to resolve questions and conflicts presented by these previous studies. However, some new hypotheses are offered with regard to unresolved issues of (1) source and mechanism for clay precipitation; and (2) calcite and anhydrite cementation and leaching.

Clay Precipitation

Clay is a minor component in the Delaware Basin and on the shelves around the basin. This is probably a result of the importance of eolian transport in moving siliciclastics from Ancestral Rockies source areas and across wide, arid, low-relief platforms before they were moved off the shelf into the basin. Most of the eolian sand and silt on the platform has prominent red clay coats (cutans) that are formed during episodes of dune and sand-sheet stability and incipient soil formation. The cutans are preserved when sand is remobilized and transported across the platform. The sand in the FGU and apparently elsewhere in the Delaware Mountain Group lacks these pervasive cutans. Instead, several weight-percent chlorite and mixed-layer clays are present as authigenic minerals. It is therefore suggested that the clay cutans present when the sand was on the shelf were recrystallized and served as the source for the authigenic clays.

The mechanism suggested to drive recrystallization of the clay is introduction of reactive brine sourced from the water mass that precipitated the overlying Castile and Salado Formations. Although the Lamar Formation probably served as a low-permeability barrier beneath the evaporites, prolonged ponding of very high density brine in the overlying water column eventually drove evaporite brine into the Bell Canyon sandstones and displaced less dense connate fluids. Sea water concentrated to halite precipitation has high Mg^{2+} activity. The role of such brine in recrystallizing dioctahedral clays to Mg-rich trioctahedral clays is well documented in Permian and other brine-pool environment (Bodine, 1985; Palmer; 1987), and extrapolation of this process to the shallow burial environment is a reasonable hypothesis.

One possible reaction (Bodine and Madsen, 1987; S. Fisher personal communication, 1988) is:

$$\underset{\text{(detrital Al-smectite)}}{1.25\ [Mg_{0.2}(Al_{1.6}Mg_{0.4})Si_4O_{10}(OH)_2]} + 4.25\ Mg^{+2} + 7H_2O = \underset{\text{(Mg-chlorite)}}{(Mg_5\ Al)\ (Si_3Al)O_{10}(OH)_8} + 8.5H^+ + 2SiO_2 \qquad (1)$$

This equation consumes Mg from brine to make detrital clay into Mg-chlorite, and as a byproduct also produces quartz. Euhedral and doubly-terminated quartz is a common minor phase in evaporite sections, possibly as a result of clay diagenesis. Petrographic relationships observed in FGU would permit coprecipitation of chlorite rosettes and authigenic quartz, and the volumes are reasonable. However, to further document the plausibility of this mechanism for clay formation, more information is needed about chlorite composition, because this process is not applicable to Fe-chlorite precipitation.

Calcite and Anhydrite Precipitation and Dissolution

The source of calcite cement is interpreted on the basis of its distribution to be dissolution and reprecipitation of carbonate grains (Williamson, 1978; Hays, 1992). Isotopic data presented by Hays suggest that calcite precipitated in the zone of biogenic reduction at cool (11°C) shallow-burial but deep basinal temperatures. The source of anhydrite is interpreted from distribution and sulfur-isotopic composition to be Castile brines (Hays, 1992). Corroded cement margins show that dissolution of both calcite and anhydrite followed their precipitation. From fabric criteria Hays (1992) interpreted that calcite dissolution was an important process in porosity preservation. However, the occurrence of calcite-cemented nodules in FGU cores does not fit directly with a dissolution model; additional petrographic observations are needed. Carbonate and/or anhydrite dissolution play a prominent role in porosity creation in Central Basin Platform carbonate reservoirs. A relationship may exist between the postulated leaching at FGU and somewhat similar leaching in the platform carbonates.

Core-analysis data provide additional information about the role of carbonate and anhydrite cement in the reservoir. The samples at the top of units, especially Ramsey 2 and 1C, have slightly higher permeability relative to porosity on a porosity versus permeability cross plot (fig. 35). This relationship might suggest permeability enhancement as a result of leaching. The skewed permeability distribution is tentatively interpreted as the result of combining more than one population with different permeability characteristics. Low values may correspond to calcite-cemented nodules commonly observed near the top of some units. Better constraint on the petrographic characteristics of samples with these permeability distributions are needed to further interpret these data.

Additional Work

Three-dimensional analysis of permeability structure on a stratigraphic and structural base will facilitate examination of the permeability structure both in cross section and map view. The continuity and geometry of the high permeability interval at the top of reservoir sandstones is of special interest. Williamson (1978) documented a thick high permeability interval in the El Mar field in the channel axis in one cross section. Testing the validity of a depositional or a diagenetic model of this interval would be useful in predicting reservoir production.

Additional petrographic observations should focus on the special problems of (1) genesis of the high permeability at the top of sandstones, (2) genesis of low permeability intervals, especially the low just below the top of the units. A continuous bed of low permeability may have more impact on reservoir production than abundant calcite-cemented nodules, although the effect of a decrease in transmissivity across a nodular zone within in a fairly homogeneous sandstone might be significant.

CONCLUSIONS

Much of the research effort during the first year of the project was focused on gathering and evaluating data needed for reservoir characterization. A 36 square mile 3-D seismic survey was designed, acquired, and processed, and interpretation has begun. Geophysical log and core data have been assembled, and core-analysis data from 171 wells were entered into spread sheets. Log curves were digitized, and old gamma-ray curves were normalized to API units. Important marker horizons in the reservoir interval and the nonproductive section above and below were correlated on all logs in Geraldine Ford field, and the data have been entered into a Landmark OpenWorks™ data base.

Initial reservoir characterization indicates that the productive Bell Canyon sandstones in Geraldine Ford field are more heterogeneous both vertically and laterally than previously recognized. A new depositional model has been proposed to explain the distribution, texture, and geometry of these sandstones—accumulation in compensation lobes in an eolian-derived turbidite system. This model interprets the reservoir interval at Geraldine Ford field as being composed of many small-scale sandstones that amalgamate into a 2-mi-wide submarine-lobe complex. Within the larger lobe complex, high-permeability reservoir sandstones are encased in low-permeability, nonreservoir sandstone and siltstone.

Permeability varies systematically with position in each Ramsey sandstone unit, with highest values as well as the highest average permeability at the top of each unit and lowest average immediately below. High permeability values at the top of the unit might indicate permeability enhancement as a result of leaching, and the low values may correspond to calcite cementation commonly observed near the top of some units.

In the coming year, this model will be tested and refined using the seismic, log, core, and outcrop data, in order to develop a better understanding of the depositional and diagenetic processes that formed and modified the reservoir sandstones. Outcrop studies will be particularly important to determining the size of sand bodies. Subsurface data indicate that the dimensions of reservoir sandstones are commonly smaller than the distances between wells, but their actual size cannot be determined from subsurface data alone. Outcrop investigations will provide critical information on sandstone dimensions that will be used in simulations of the reservoir in the demonstration area.

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