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APPLICATION OF ADVANCED RESERVOIR CHARACTERIZATION, SIMULATION, AND PRODUCTION OPTIMIZATION STRATEGIES TO MAXIMIZE RECOVERY IN SLOPE 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 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 oil more economically through geologically based field development. The project is focused on East Ford field, a Delaware Mountain Group field that produces from the upper Bell Canyon Formation (Ramsey sandstone). The field, discovered in 1960, is operated by Orla Petco, Inc., as the East Ford unit. A CO_2 flood is being conducted in the unit, and this flood is the Phase 2 demonstration for the project.

Reservoir characterization was conducted using logs and pressure and production information from the East Ford unit, supplemented by Bell Canyon outcrop data and information from nearby Geraldine Ford field. Characterization was enhanced this year by recovery of a core from the Ramsey reservoir interval in the EFU 41R well. Ramsey sandstones are interpreted as having been deposited in a basin-floor setting in a channel-levee system with attached lobes. Overbank splays are interpreted as being the main area of sand storage outside of the channels. Porosity and permeability of the reservoir sandstones are controlled by calcite cement that can be concentrated in layers ranging from 5 to 40 cm in thickness. These laterally extensive calcite-cemented layers form significant vertical permeability baffles in some areas of the reservoir.

CO_2 injection in the East Ford unit began in July 1995. As a result of the CO_2 flood, production from the East Ford unit has increased from 30 bbl/d at the end of primary production to more than 170 bbl/d in 2000. The unit has produced 152,526 bbl of oil from the start of tertiary recovery through 2000, and essentially all production can be attributed to the enhanced oil recovery project.

Oil recovery has been improved by the CO_2 flood, but not as much as had been expected. Geologic heterogeneities caused by both depositional and diagenetic processes are apparently influencing reservoir displacement operations in the East Ford unit. The unit appears to be divided into three areas of better interwell communication; communication between wells in different areas is restricted. The areas may result from facies changes, subtle structural or bathymetric controls on

deposition, or variations in sediment-transport direction. Modification of the existing east-west alignment of injectors and producers may overcome the problem of apparently restricted communication between splay sandstones and channel sandstones at the north end of the field. Pressure response in the central area of the field has been slow, suggesting that communication is restricted between the producing wells in this area and the injector wells that are located in the north and south areas of the field. Adding an injector well in the central area may overcome this problem. The south area of the field is responding well to the existing north-south line of injectors. Recovery might be improved in this area by bringing on additional producers, which could be accomplished by overcoming mechanical problems with some of the shut-in wells.

INTRODUCTION

This report summarizes the results of research conducted this year for the DOE Class III project "Application of Advanced Reservoir Characterization, Simulation, and Production Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs, West Texas (Delaware Basin)." The objective of the project has been to demonstrate that detailed reservoir characterization of clastic reservoirs in basinal sandstones of the Delaware Mountain Group in West Texas and New Mexico is a cost-effective way to recover oil more economically by geologically based field development. Because current production from Delaware Mountain Group reservoirs averages less than 20 percent of the original 1.8 billion barrels (Bbbl) of oil in place, a clear opportunity for improving recovery exists.

Phase 1 of the project, reservoir characterization of the East Ford unit (figs. 1, 2), was completed last year (Dutton and others, 1999b, 1999c, 2000b). Reservoir characterization focused on the Ramsey sandstone, the youngest sandstone in the Delaware Mountain Group (fig. 3) and the main producing interval in the East Ford unit. Earlier in the project, reservoir characterization was conducted on the Ford Geraldine unit (Dutton and others, 1996, 1997a, b, 1998), which is immediately adjacent to the East Ford unit and produces from a branch of the same Ramsey sandstone channel (fig. 4).

The Phase 2 demonstration for the project is a CO_2 flood being conducted in the East Ford unit. Assessment of the effectiveness of the CO_2 flood to improve recovery in a mature Ramsey sandstone field was the focus of the project this year. The goal of Phase 2 is to apply the knowledge gained from the reservoir characterization to increase recovery from the CO_2 flood.

Orla Petco, the operator of the East Ford unit, began the CO_2 flood in the Ramsey sandstone in July 1995. Orla Petco has made available to the project all the injection and production data generated since the flood was initiated, providing an excellent opportunity to evaluate the success of the flood and compare the results with predictions made on the basis of the reservoir characterization. The CO_2 flood at East Ford field reached the response phase in December 1997, so evaluation of the flood results could begin as soon as Phase 2 started.

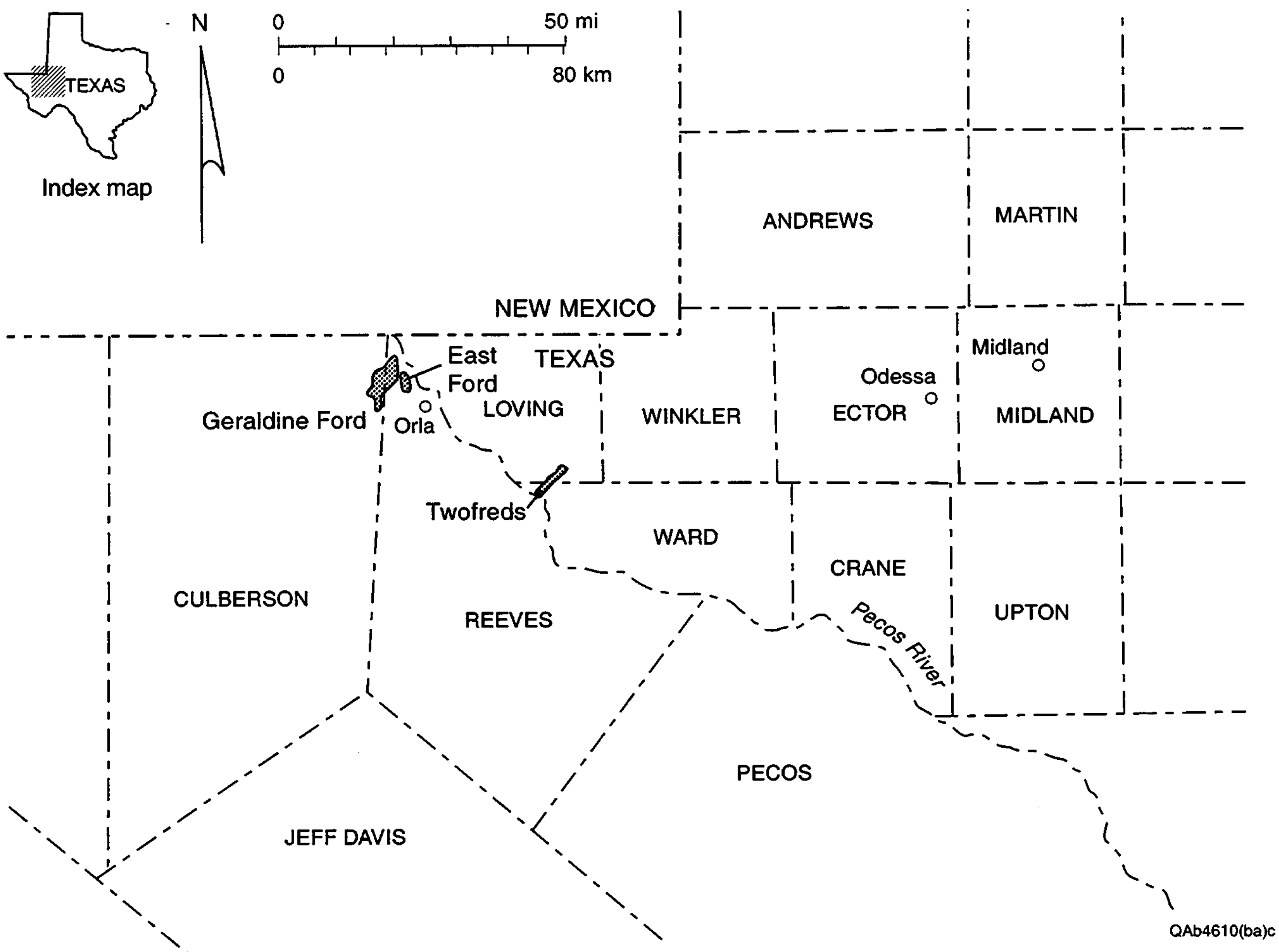


Figure 1. Location of East Ford, Geraldine Ford, and Twofreds fields in West Texas.

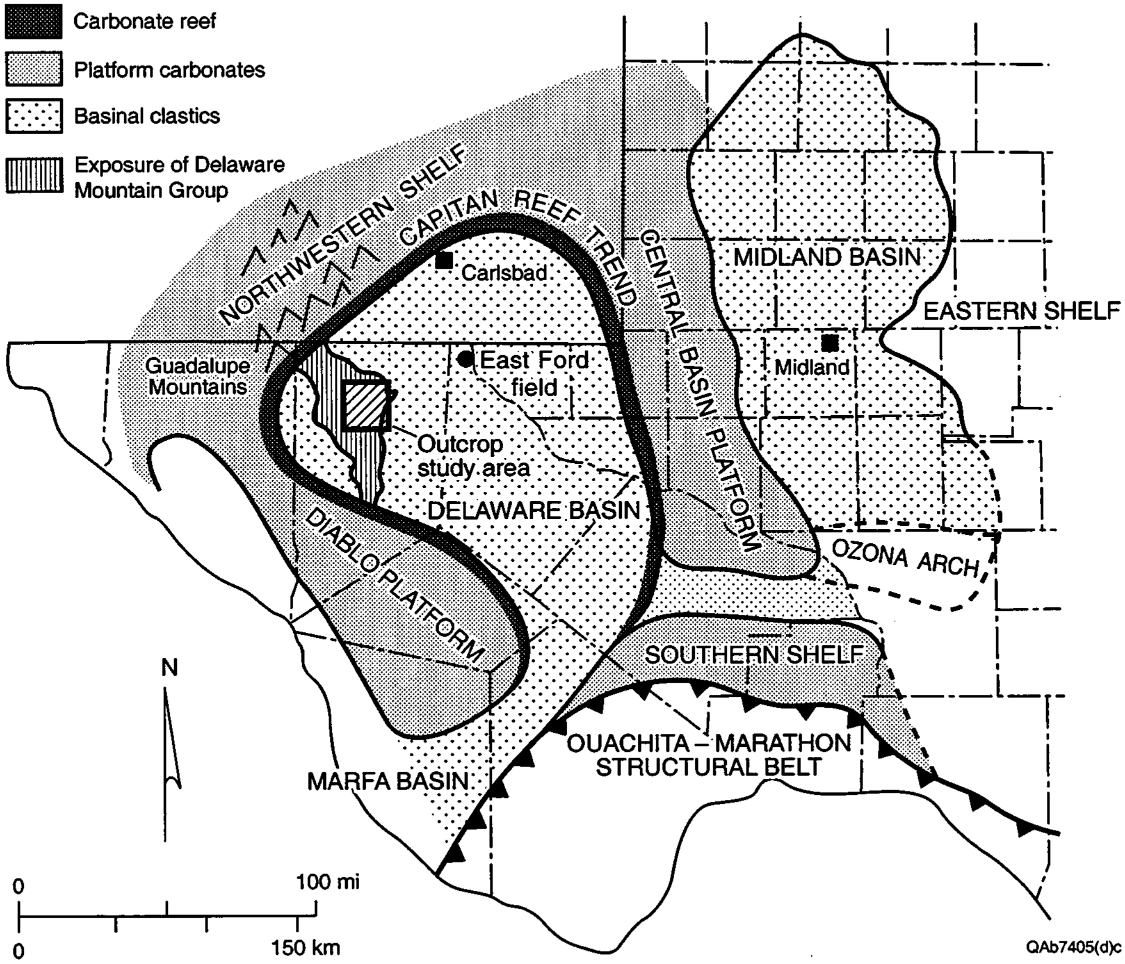


Figure 2. Map showing location of the Delaware Basin and paleogeographic setting during the Late Permian. Present-day exposures of the Delaware Mountain Group and locations of the outcrop study area and East Ford field are superimposed onto the paleogeographic map. Modified from Silver and Todd (1969).

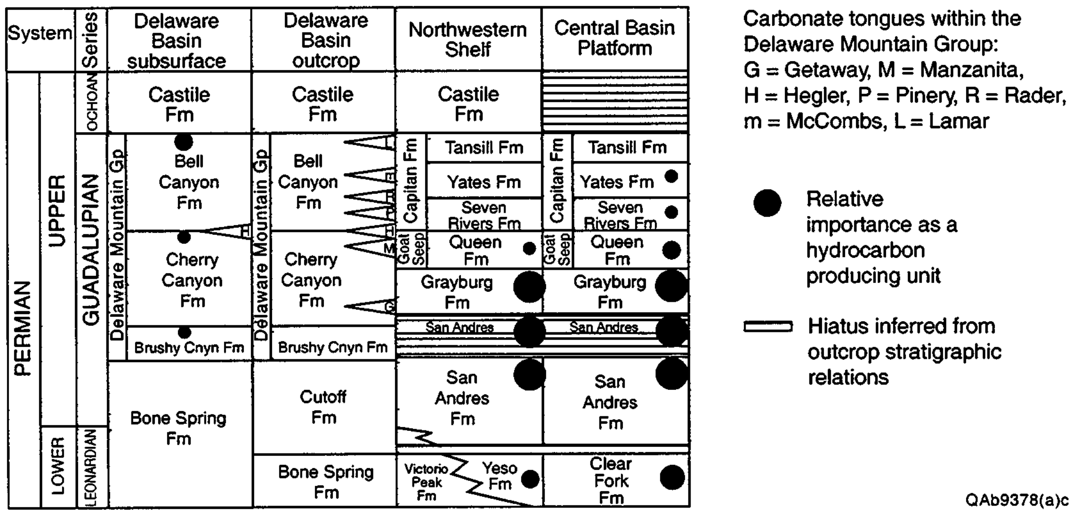


Figure 3. Stratigraphic nomenclature of the Delaware Mountain Group in the Delaware Basin subsurface and outcrop areas and time-equivalent formations on the surrounding shelves. Modified from Galloway and others (1983); Ross and Ross (1987); Kerans and Fitchen (1995).

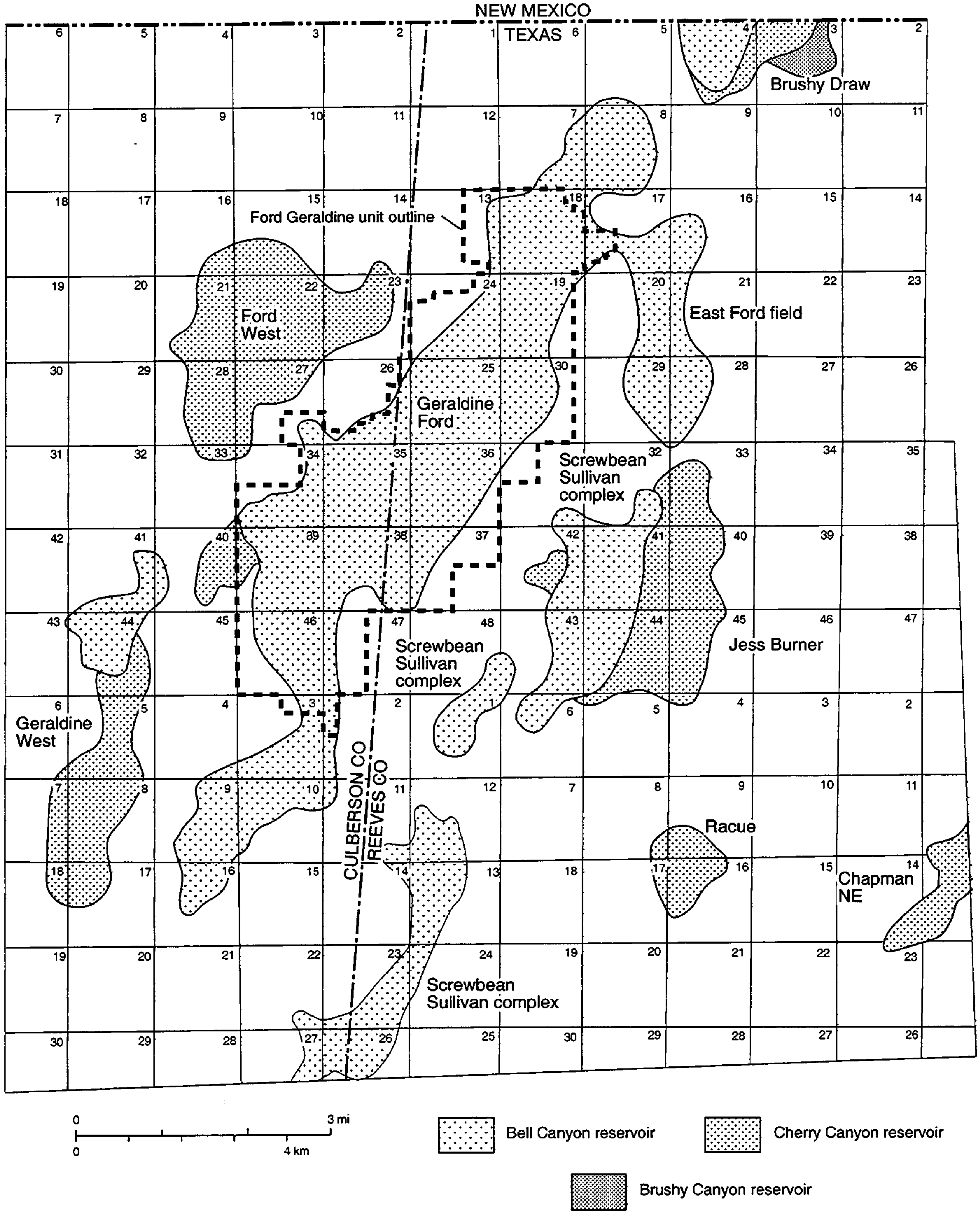


Figure 4. Detailed location map of the East Ford and Ford Geraldine units and other, nearby Bell, Cherry, and Brushy Canyon reservoirs.

General Information

The north end of the East Ford unit is located 2.5 mi south of the Texas-New Mexico state line in Reeves County, Texas, ~10 mi north of the town of Orla (fig. 1). The unit, which was discovered in 1960, is in Railroad Commission of Texas District 8. The Railroad Commission field name is Ford, East (Delaware Sand). The field was unitized and is operated by Orla Petco, Inc., as the East Ford unit (fig. 5).

Project Description

The goal of this study is to demonstrate that reservoir characterization can optimize EOR (CO_2 flood) projects in slope and basin clastic reservoirs of the Delaware Mountain Group. The project objective is to increase production and prevent premature abandonment of reservoirs in mature fields in the Delaware Basin of West Texas and New Mexico.

Project objectives are divided into two main phases. The original objectives of the reservoir-characterization phase of the project were (1) to gain a detailed understanding of the architecture and heterogeneity of two representative fields of the Delaware Mountain Group, Geraldine Ford and Ford West, which produce from the Bell Canyon and Cherry Canyon Formations (fig. 3), respectively; (2) to choose a demonstration area in one of the fields; and (3) to simulate a CO_2 flood in the demonstration area (Dutton and others, 1997a, b, 1998). After completion of the study of Geraldine Ford and Ford West fields, the original industry partner decided not to continue.

A new industry partner, Orla Petco, Inc., is now participating in the project, and the reservoir-characterization phase was expanded to include the East Ford unit. This additional reservoir characterization provided an excellent opportunity to test the transferability of the geologic model and log-interpretation methods developed during reservoir characterization of the Ford Geraldine unit to another field in the Delaware sandstone play. The East Ford unit underwent primary recovery through June 1995. As a result of serious producibility problems—particularly high water production without a water drive—primary recovery efficiency at the East Ford unit was less than

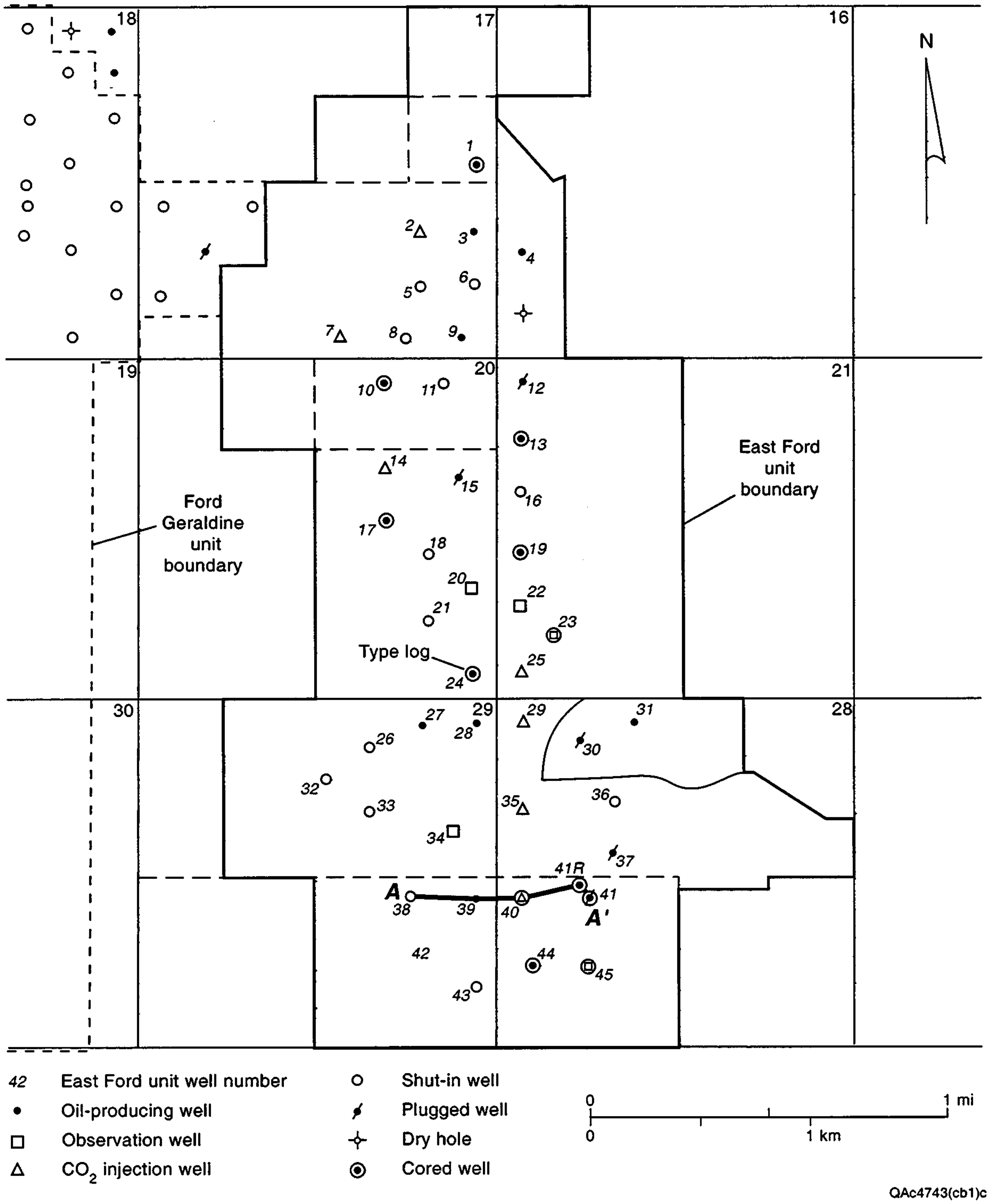


Figure 5. Status of wells in the East Ford unit. Type log shown in figure 6. Cross section A–A′ shown in figure 24.

15 percent. Unless methodologies and technologies to overcome these producibility problems could be applied, much of the remaining oil in the East Ford unit would not be recovered.

Reservoir characterization of the East Ford unit built upon the earlier, integrated reservoir-characterization study of the Ford Geraldine unit (Dutton and others, 1996, 1997a, b, 1998) and the work of Ruggiero (1985). Both units produce from the most prolific horizon in the Bell Canyon Formation, and the reservoir-characterization studies of these units provide insights that are applicable to other slope and basin clastic fields in the Delaware Basin. The technologies used for reservoir characterization of the East Ford unit included (1) subsurface log, core, and petrophysical study; (2) high-resolution sequence stratigraphy; (3) mapping of nearby outcrop reservoir analogs; and (4) analysis of production history.

Currently in Phase 2 the knowledge gained during reservoir characterization is being applied to increase recovery from the CO_2 flood in the East Ford unit. Comparisons are being made between production from the unit during the CO_2 flood and the geologic model developed during Phase 1. This comparison will provide an important opportunity to test the accuracy of reservoir-characterization studies as tools in resource preservation of mature fields. In addition, the results of the CO_2 flood are being used to refine and improve the geologic model of the East Ford unit. Through technology transfer, the knowledge gained in the study of the East Ford and Ford Geraldine units can be applied to increase production from the more than 350 other Delaware Mountain Group reservoirs in West Texas and New Mexico, which together contain more than 1.5 Bbbl of remaining oil.

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 less than 20 percent since production began in the 1920's, and, therefore, a substantial amount of the original oil in place remains unproduced. Many of these mature fields are nearing the end of primary or secondary production and are in danger of abandonment unless effective, economic methods of enhanced oil recovery (EOR) can be implemented. The goal of this project is to demonstrate that reservoir characterization, using outcrop characterization, subsurface field studies, and other techniques can optimize EOR projects in Delaware Mountain Group reservoirs.

Reservoir characterization of East Ford field (Phase 1) was completed last year, and the project moved into the implementation phase (Phase 2). The CO_2 flood being conducted in the East Ford unit is the Phase 2 demonstration for the project. The objectives of the implementation phase of the project are to (1) apply the knowledge gained from reservoir characterization to increase recovery from a demonstration area and (2) demonstrate that economically significant, unrecovered oil can be recovered by a CO_2 flood. The project this year was mainly focused on (1) evaluating the possible effect of geologic heterogeneities on the response to the CO_2 flood and (2) using the reservoir characterization to suggest ways the flood pattern could be modified to increase recovery.

Ramsey sandstones at East Ford field are interpreted as having been deposited by sandy high- and low-density turbidity currents that carried a narrow range of sediment size, mostly very fine sand to coarse silt. The sands were deposited in a basin-floor setting by a system of leveed channels having attached lobes and overbank splays. Individual channel-levee and lobe complexes stack in a compensatory fashion and are separated by laterally continuous, laminated siltstones. Until this year, no cores from East Ford field were available for viewing, so facies were interpreted on the basis of sandstone thickness and log response, augmented by analysis of the response to CO_2 injection. Acquisition of core this year from the EFU 41R well allowed the depositional and diagenetic features of Ramsey sandstones at the south end of the field to be characterized. Most Ramsey 1 and 2 sandstones are very fine grained and massive. The most common sedimentary structures are features related to dewatering—dish structures, flame structures, and convolute bedding. The Ramsey 2 sandstone in this location is interpreted as having been deposited in a broad lobe, and the Ramsey 1 sandstone in a lobe or splay. The presence of massive sandstones and sandstones with fluid-escape structures in the EFU 41R core is consistent with this interpretation.

Porosity in the sandstones in the EFU 41R core ranges from 4.5 to 24.6 percent and permeability to air from 0.01 to 78 md. Siltstones have porosity ranging from 14.1 to 17.3 percent and permeability from 0.2 to 4.1 md. Zones of low porosity and permeability in the sandstones occur within highly calcite cemented intervals that are 2 to 16 inches thick. Four tightly cemented calcite layers occur in the lower part of the Ramsey 1 sandstone, where they are spaced about 3 ft apart. The Ramsey 2 sandstone contains one cemented layer that is 14 inches thick.

Sonic and neutron logs from the EFU 41R well showed a gas effect in the lower 8 to 10 ft of the Ramsey 1 sandstone, in the same interval in which the calcite-cemented layers occur. No gas effect was seen above the uppermost calcite layer. When the well was first completed, it produced a high volume of high-concentration CO_2 (>90 percent) for a period of time. Production and temperature logs confirmed the gas effect by indicating that inflow to the well bore was all occurring essentially in the bottom 10 ft of the Ramsey 1 sandstone. CO_2 from the nearby injector well EFU 40 was apparently trapped in the bottom part of the Ramsey 1 sandstone, below the low-permeability, calcite-cemented layers. This trapping suggests that one or more of the calcite layers are laterally continuous between wells 40 and 41R, causing vertical compartmentalization in the Ramsey 1 sandstone.

Calcite-cemented sandstone layers are not as abundant in most of the East Ford unit as they are in the area around EFU 41R. Maps of the percentage of calcite-cement sandstone in the Ramsey 1 and 2 intervals show variations across the field. In general, the percentage of calcite-cemented sandstone is lower in the Ramsey 1 than in the Ramsey 2 sandstone. In both sandstones, the areas having the lowest percentage of calcite-cemented sandstone (<10 percent) occur where the sandstone is thickest, in what is interpreted to be the channel facies. Areas having high percentages of calcite-cemented sandstone (>20 percent) occur along the margins of the sandstones, in levee, overbank, and lobe deposits.

Oil recovery has been improved by the CO_2 flood of the East Ford unit, but not as much as had been expected. Analysis of the results of the flood suggests that geologic heterogeneities affect reservoir displacement operations. CO_2 injector wells in splay sandstones apparently have poor communication with wells in channel sandstones, perhaps because communication is restricted through levee deposits. The field also appears to be divided into three areas of better interwell communication; communication between wells in different areas is restricted. The areas may result from facies changes, subtle structural or bathymetric controls on deposition, or variations in sediment-transport direction.

Modification of the existing east-west alignment of injectors and producers may overcome the problem of apparently restricted communication between splay sandstones and channel sandstones at the north end of the field. Converting EFU 6 to an injector that would be in a north-south orientation with the existing producers might improve recovery from the thick Ramsey 2 channel sandstones in this north area. Pressure response in the central area of the unit has been slow, suggesting that communication is restricted between the producing wells in this area and the injector wells that are located in the north and south areas of the field. Adding an injector well in this area, such as EFU 20, and making EFU 18, 21, and 22 producers may improve production from this apparently isolated area. The south area of the field is responding well to the existing north-south line of injectors. Recovery might be improved in this area by bringing on additional producers, such as EFU 34 and 36, which could be accomplished by overcoming mechanical problems with some of the shut-in wells.

FIELD-DEVELOPMENT HISTORY

East Ford field was discovered in 1960 from reservoirs in the upper Bell Canyon Formation. The main producing interval, the Ramsey sandstone, is divided into two sandstones (Ramsey 1 and 2) that are separated by a 1- to 3-ft-thick laminated siltstone (SH1) (fig. 6). The field was originally developed on 20-acre spacing at the north end, then drilled on 40-acre spacing throughout the rest of the field (fig. 5). Currently 15 producer and 7 injector wells are in the field (fig. 5). Approximately half of the East Ford wells are open-hole completions. The open-hole wells, most drilled by cable tools, initially only penetrated 10 to 15 ft into the Ramsey 2 sandstone. Some were later deepened into the Ramsey 1 sandstone. Cased-hole wells were generally perforated only in the Ramsey 2 sandstone because it was assumed that fracture stimulation would open communication between the Ramsey 1 and 2 sandstones across the SH1 siltstone (fig. 6).

Wells in East Ford field were stimulated with a small fracture treatment of 1,000 gal of lease oil and 1,500 lb of sand. Many wells were restimulated between 1970 and 1987 with 3,000 gal of lease oil and 4,500 lb of sand. The restimulations were marginally successful in increasing production, possibly by opening communication between the Ramsey 1 and 2 sandstones in some wells. Several wells were initially completed in the Olds sandstone (fig. 6). Production from the Olds and Ramsey sandstones was commingled.

Oil gravity in East Ford field is 43° (API), and viscosity is 0.775 cp at reservoir temperature. Average current reservoir pressure is 850 psi. An oil-water contact occurs at an elevation of 88 ft above sea level.

Primary recovery in East Ford field began in October 1960 and continued until June 1995. A total of 45 wells were drilled for primary production. Oil production peaked at 965 bbl of oil per day (bopd) in May 1966. Cumulative production by the end of primary recovery in June 1995 was 3,209,655 bbl. An estimated 10 percent of the total production, or 320,966 bbl, was from the Olds sandstone (W. A. Flanders, Transpetco Engineering, written communication, 1994). The estimated 2,888,690 bbl produced from the Ramsey sandstone represents 15.7 percent of the 18.4 MMbbl of OOIP (Dutton and others, 1999c).

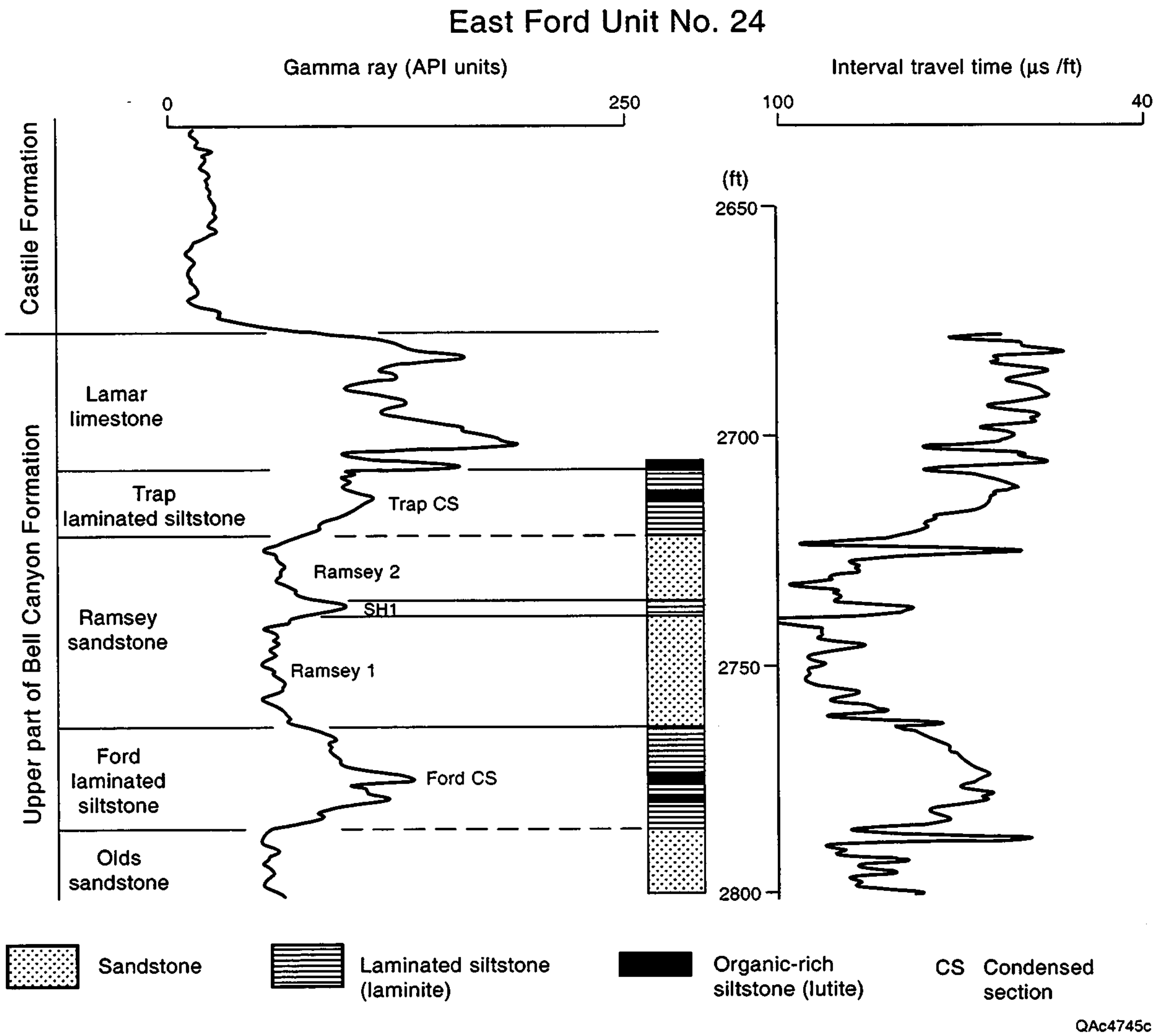


Figure 6. Typical log from East Ford Unit Well No. 24. Well location shown in figure 5.

The East Ford unit did not undergo secondary recovery by waterflooding. In Ramsey sandstone reservoirs in other fields, waterflooding has not been very successful. By the end of secondary development in the Ford Geraldine unit (figs. 1, 4), waterflooding added only an estimated 4.5 percent of the OOIP to the total recovery (Pittaway and Rosato, 1991). Low secondary recovery is not unique to the Ford Geraldine unit; secondary recovery from Twofreds field (fig. 1) was only 4 percent (Kirkpatrick and others, 1985; Flanders and DePauw, 1993).

Tertiary recovery in the East Ford unit by CO_2 injection began in July 1995. The first response was observed in April 1996 in well EFU No. 28, and major production response in the unit began in December 1997 (fig. 7). As a result of the CO_2 flood, production from the East Ford unit increased from 30 bbl/d at the end of primary production to more than 170 bbl/d in 2000. The unit has produced 152,526 bbl of oil from the start of tertiary recovery through 2000, and total production in 2000 was 62,190 bbl.

Production during 1994, the last full year of primary production, was 9,734 bbl. The primary production decline rate, calculated by using an exponential least-squares fit of the production data from April 1991 through September 1994, was 10.1 percent (from Application for an EOR Positive Production Response Certification for the East Ford Unit, form H-13, filed by Orla Petco, Inc., with the Railroad Commission of Texas, March 1998; application was approved in June 1998). At that rate of decline, the economic limit of the field would have been reached within the next few years if the CO_2 flood had not started. Essentially all the production since the start of the CO_2 flood—152,526 bbl through December 2000—can thus be attributed to the EOR project (fig. 7).

RAMSEY SANDSTONE DEPOSITIONAL MODEL

Investigation of Bell Canyon sandstones in outcrop (Barton, 1997; Barton and Dutton, 1999) and subsurface characterization of Geraldine Ford field (Dutton and others, 1999a)—studies that were conducted earlier in the project—formed the basis for the depositional model developed for East Ford field. Ramsey sandstones at East Ford field are interpreted as having been deposited by

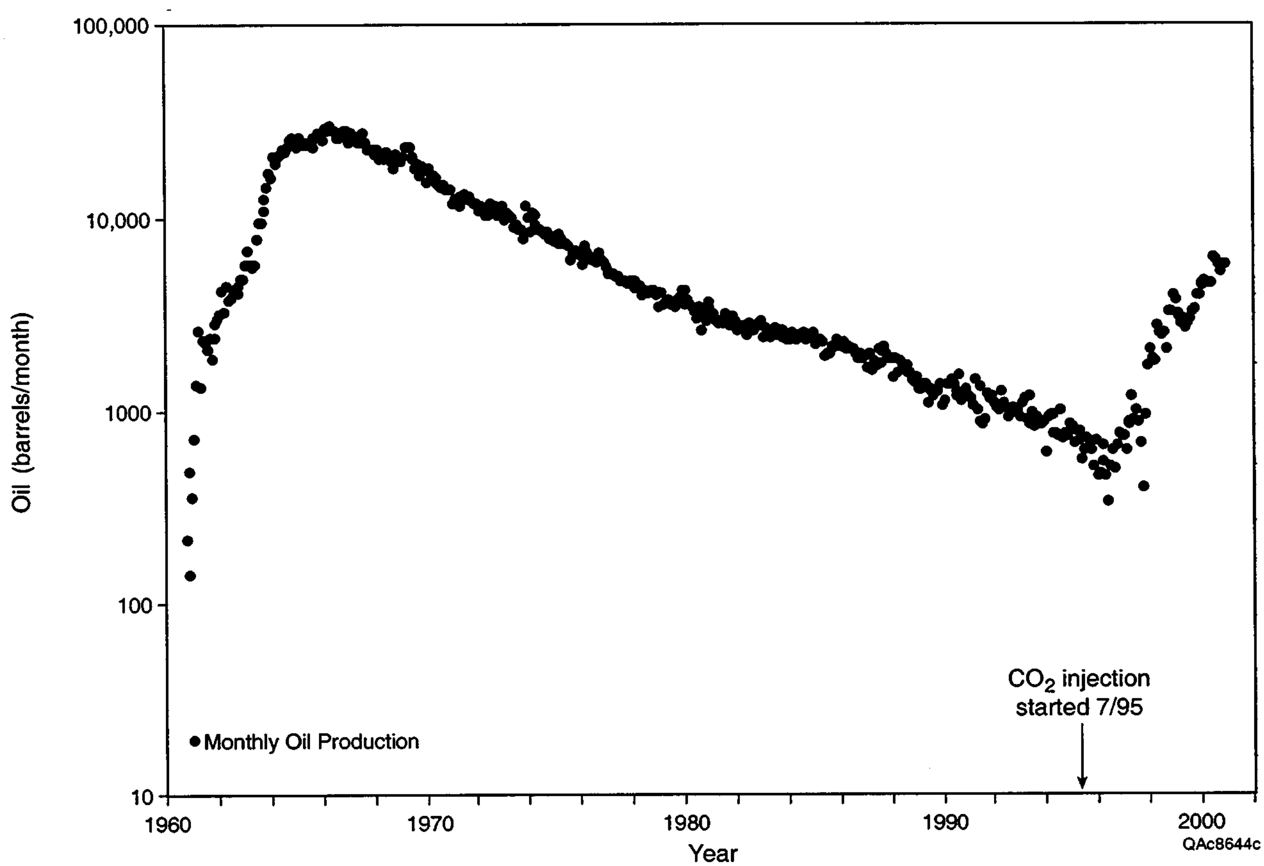


Figure 7. Plot of monthly oil production from the East Ford unit since the field was discovered in 1960. The field was on primary production until a CO_2 flood was begun in July 1995.

sandy high- and low-density turbidity currents that carried a narrow range of sediment size, mostly very fine sand to coarse silt. The sands were deposited in a basin-floor setting by a system of leveed channels having attached lobes and overbank splays (figs. 8, 9). Individual channel-levee and lobe complexes stack in a compensatory fashion and are separated by laterally continuous, laminated siltstones. These siltstones are interpreted to have been deposited by the settling of marine organic matter and airborne silt during periods when coarser particles were prevented from entering the basin.

Lobe sandstones, as much as 25 ft thick and 2 mi wide, are composed of massive sandstones having dewatering features such as dish and flame structures. Lobe deposits, which display a broad, tabular geometry, were deposited by unconfined flow at the mouths of channels (fig. 9b). In a prograding system, lobe facies would have been deposited first and then overlain and partly eroded by the channel-levee-overbank-splay system.

Channels are largely filled with massive and cross-stratified sandstone. Channels mapped in outcrop range from 10 to 60 ft in thickness, most 20 to 40 ft thick. Channel widths are 300 to 3,000 ft, giving aspect ratios of 10 to 100. In updip areas, channel positions remained relatively fixed. As a result, individual channels are highly amalgamated and form a body that has dimensions larger than those of any single channel (Barton and Dutton, 1999). Downdip the spacing of the channels expands. The expansion reflects migration of the channel laterally during the initial stages of channelization (fig. 9c) and channel avulsion or bifurcation, or both, during later stages (fig. 9d).

Flanking the channels on both sides are wedges composed of thinly bedded sandstone and siltstone that are interpreted to be levees. The width of levee deposits mapped in outcrop varies. Many levee deposits are about 500 ft wide, but some are as wide as 0.5 mi (Barton, 1997). The levees thin away rapidly from the channel, decreasing in thickness from 20 to 3 ft over the distance of a few hundred feet to 0.5 mi (Barton and Dutton, 1999). Sandstone-bed thickness and sandstone content (net:gross) also decrease in a similar fashion. Near the channel margin, sandstone beds

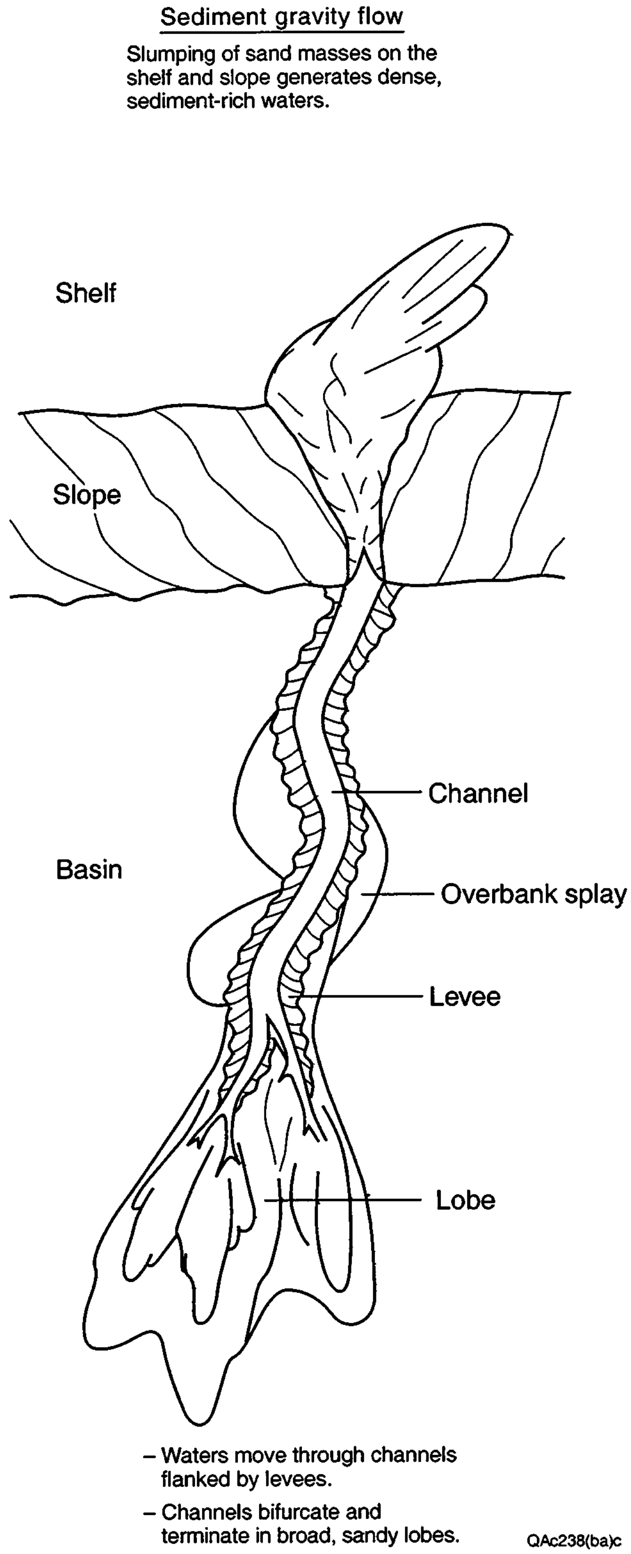


Figure 8. Depositional model proposed for the Ramsey sandstone in the East Ford unit. From Barton (1997); modified from Galloway and Hobday (1996).

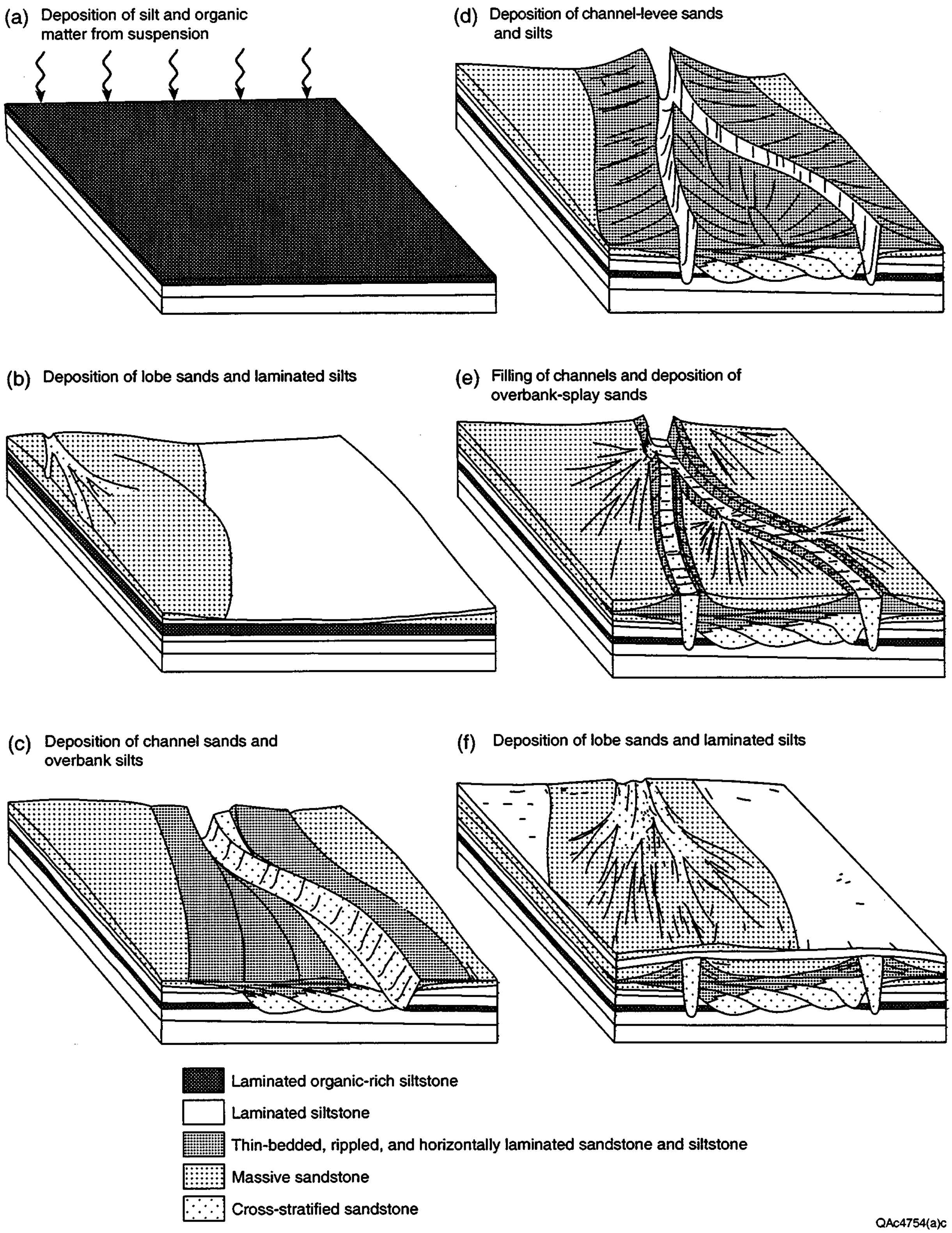


Figure 9. Depositional model proposed for the Bell Canyon sandstone, showing deposition in submarine channels with levees, overbank splays, and attached lobes. From Barton and Dutton (1999). The model was developed from outcrop study of a high-order cycle in the upper Bell Canyon Formation.

in the levees are several feet thick, whereas several hundred feet away they are several inches to a foot thick. Sandstone content decreases from about 70 percent near the channel margin to less than 10 percent where the levees pinch out. Levee deposits form a volumetrically small component of the system, about 10 percent, but are important in a reservoir because they form the topography that defines the geometry and connectivity of overbank splays (M. Barton, personal communication, 1999).

The levee deposits are onlapped by massive sandstones that display a broad, tabular to irregular geometry. The massive sandstones are 3 to 25 ft thick and as much as 3,000 ft wide (Barton, 1997). These massive sandstones are interpreted as overbank splays that filled topographically low interchannel areas (fig. 9e). Volumetrically they contain much of the sandstone in the system. The somewhat irregular geometry of the overbank splays is related to the underlying topography. Stratigraphic relationships suggest that the splays formed during the final stages of channel filling (Barton and Dutton, 1999).

The Ramsey sandstone in the East Ford unit is divided into lower and upper sandstones, named the Ramsey 1 and Ramsey 2, respectively. The older, Ramsey 1 sandstone is thickest on the east side of the unit (fig. 10). It pinches out along the west and south margins of the unit and reaches a maximum thickness of more than 25 ft along an elongate, north-south trend. The younger sandstone in the Ramsey cycle, the Ramsey 2 (fig. 11), is thickest along a north-south trend that is shifted to the west of the underlying Ramsey 1 sandstone. The offset of the Ramsey 2 sandstone trend suggests that the younger sandstone was deposited in the adjacent topographic depression created by deposition of the preceding Ramsey 1 sandstone, an example of compensational stacking. The Ramsey 2 sandstone is thinner than the Ramsey 1, having a maximum thickness of 24 ft at the north end and 10 ft at the south end (fig. 11).

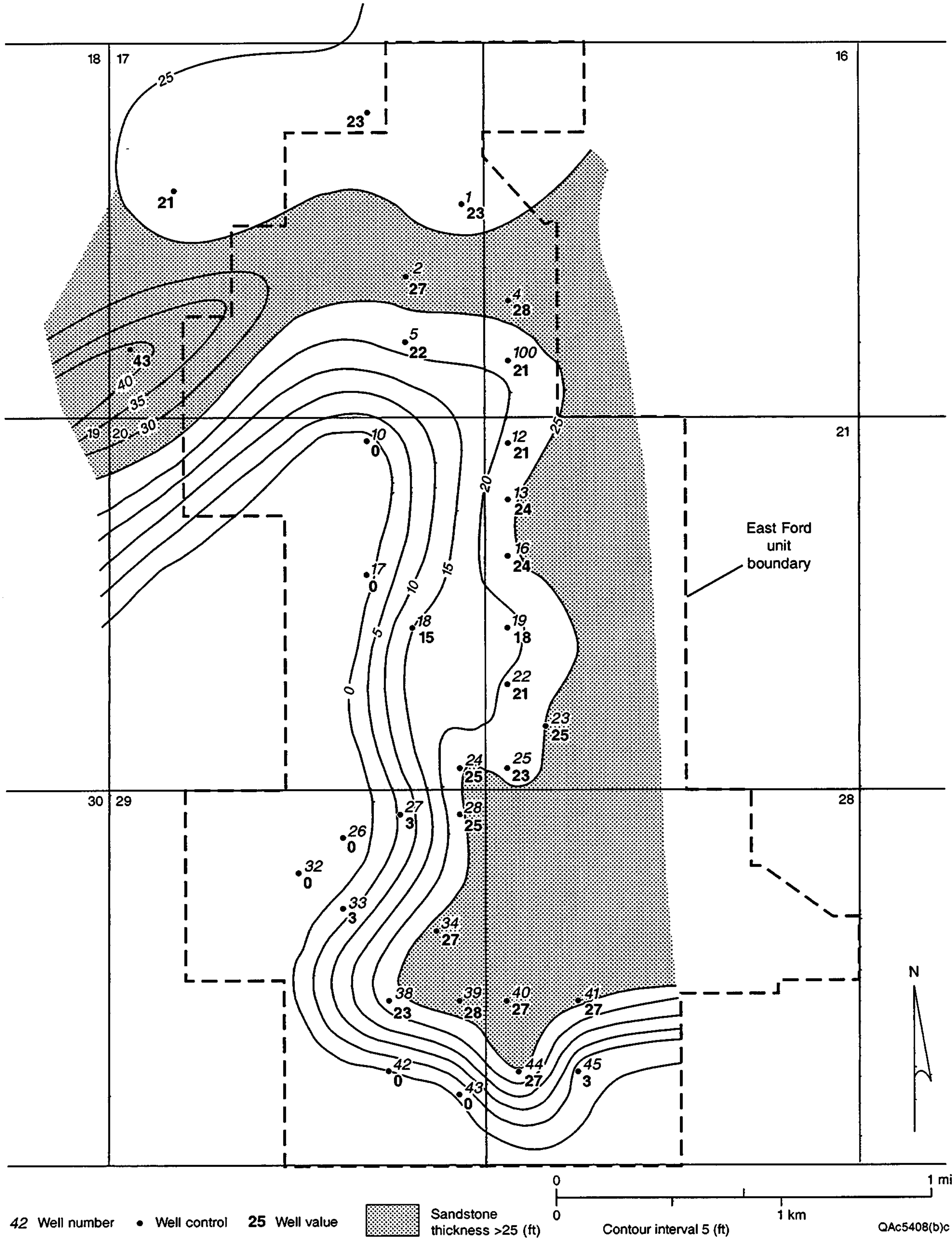


Figure 10. Isopach map of the Ramsey 1 sandstone, which is thickest along a north-south, elongate trend on the east side of the East Ford unit.

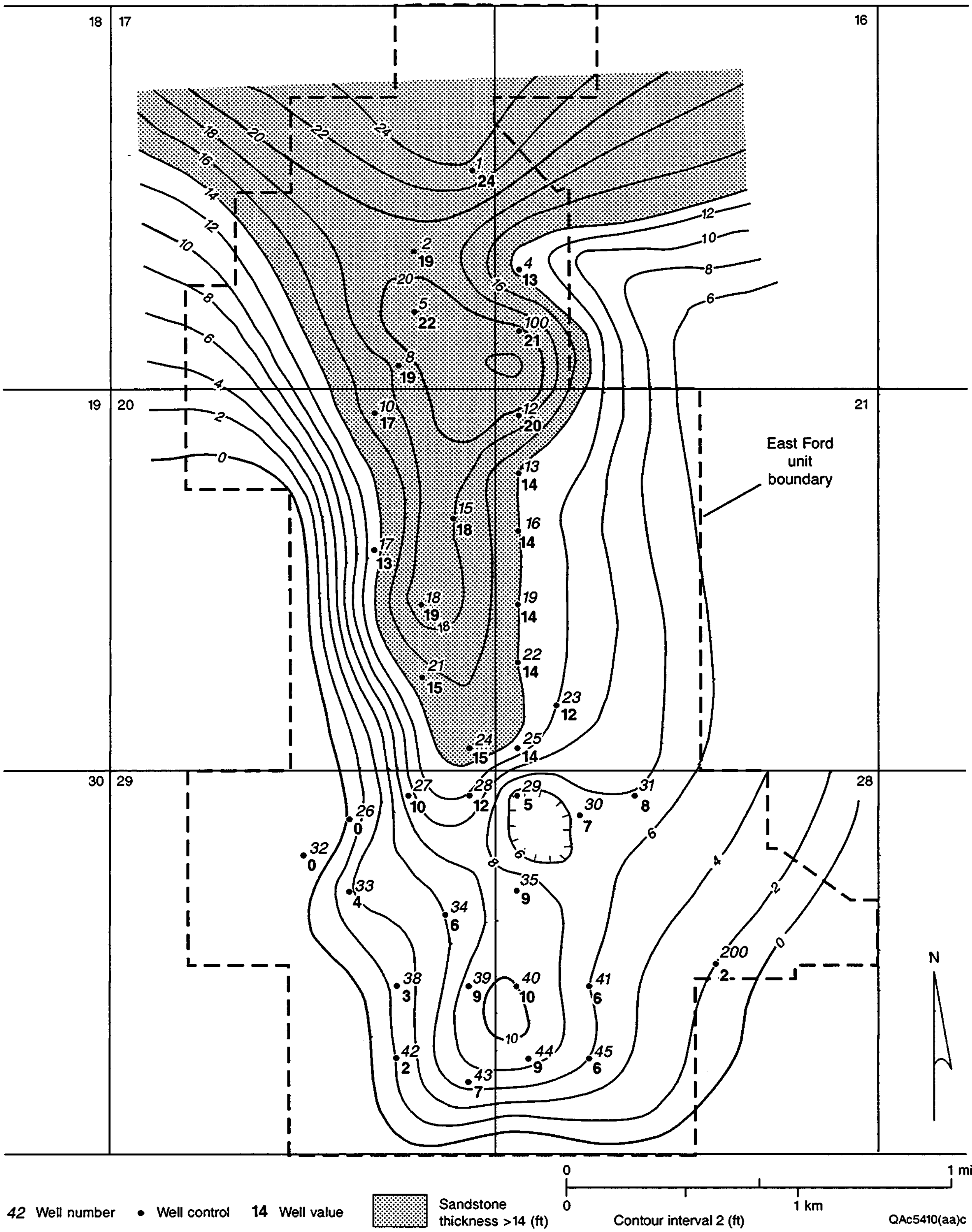


Figure 11. Isopach map of the Ramsey 2 sandstone. The thickest Ramsey 2 sandstone is shifted to the west of the Ramsey 1 sandstone, and the offset of the two sandstones bodies are an example of compensational stacking.

EAST FORD UNIT 41R WELL

As part of the ongoing CO_2 flood of the East Ford unit, a new well was drilled this year. The well, called the East Ford Unit No. 41R (EFU 41R), is located 100 ft northwest of well 41 (fig. 5). Well 41 was replaced because its casing parted during a workover to repair a casing leak. The well was spudded on May 24, 2000, and reached a TD of 2,900 ft on June 1, 2000. A total of 54 ft of core was cut from 2,734 to 2,788 ft. A complete suite of modern logs was taken in the EFU 41R well—gamma ray, sonic, neutron, density, deep laterolog, shallow laterolog, and microlaterolog. Acquisition of the core and log data has allowed us to refine the depositional and diagenetic model of the Ramsey sandstone in the East Ford unit.

The EFU 41R well has been put on pump. Average production now is 5 to 10 bopd, 50 bbl of water, and 85 Mcf of gas. When the well was first completed, it produced a high volume (750 Mcf/d) of high-concentration (>90 percent) CO_2. To control excess gas production, the adjacent well, EFU 40, was converted to water injection. The gas-alternating-water (GAW) cycle was apparently successful because gas production was reduced. The EFU 40 well has been returned to CO_2 injection.

Until this year, no cores from the East Ford unit were available for viewing, so facies were interpreted on the basis of sandstone thickness and log response, augmented by analysis of the response to CO_2 injection. Acquisition of core this year from the EFU 41R well at the south end of the field (fig. 5) allowed us to refine the East Ford depositional model. Depositional and diagenetic features of Ramsey sandstones were characterized in the core.

The cored interval extends from the bottom few feet of the Trap siltstone, through the Ramsey 2 sandstone, SH1 siltstone, Ramsey 1 sandstone, and into the upper few feet of the Ford siltstone (fig. 12). Figures 13 through 16 show the complete Ramsey sandstone interval of the core, photographed in regular light and ultraviolet (UV) light. Porosity and permeability were analyzed on core plugs taken every foot. Steady-state air permeability was measured on core plugs confined in a Hassler rubber sleeve. Permeability was also measured directly on the slabbed core by using an unsteady-state pulse-decay method. This technique allowed determination of detailed permeability variations across the core surface.

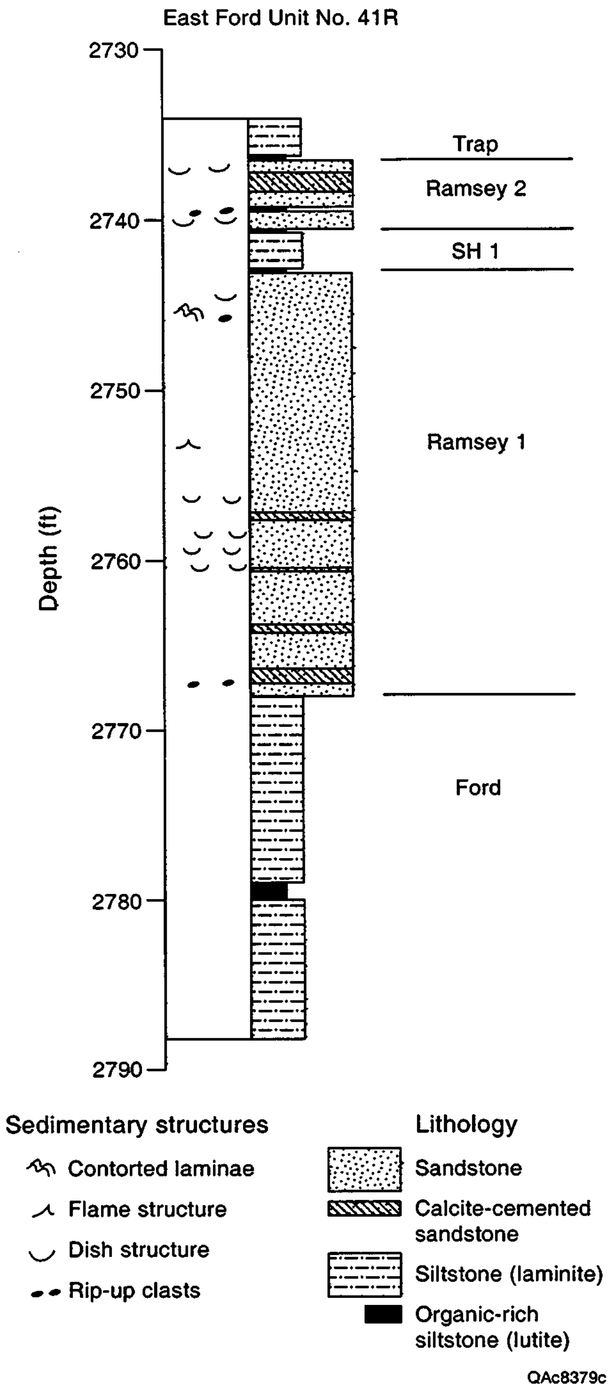


Figure 12. Description of core from East Ford unit well No. 41R (EFU 41R). From Dutton and Flanders (2001).

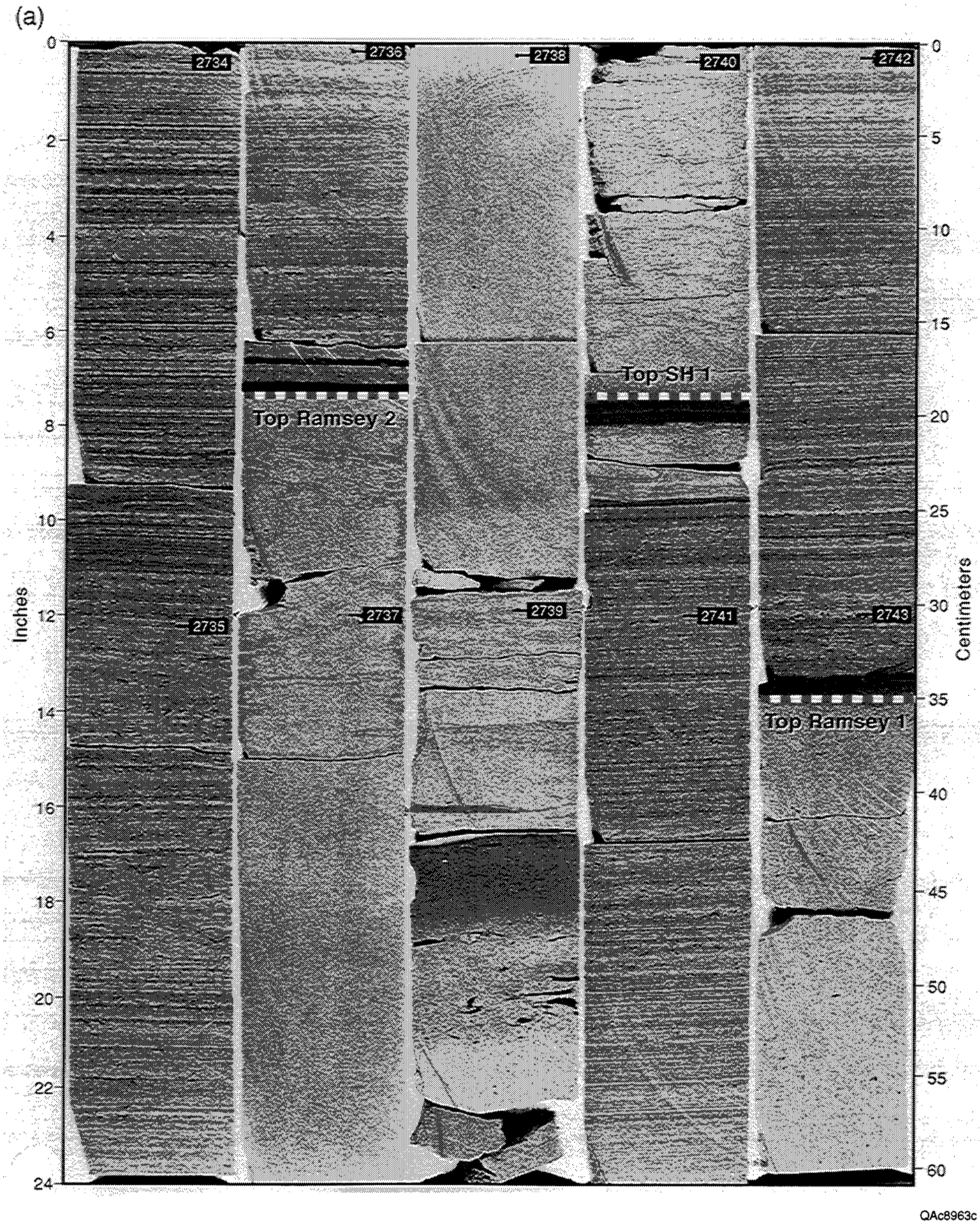


Figure 13. Photograph of core from the EFU 41R well, from a depth of 2,734 to 2,744 ft. (a) Natural-light photograph and (b) ultraviolet-light photograph. Dark intervals in the ultraviolet-light photograph are calcite-cemented layers.

(b)

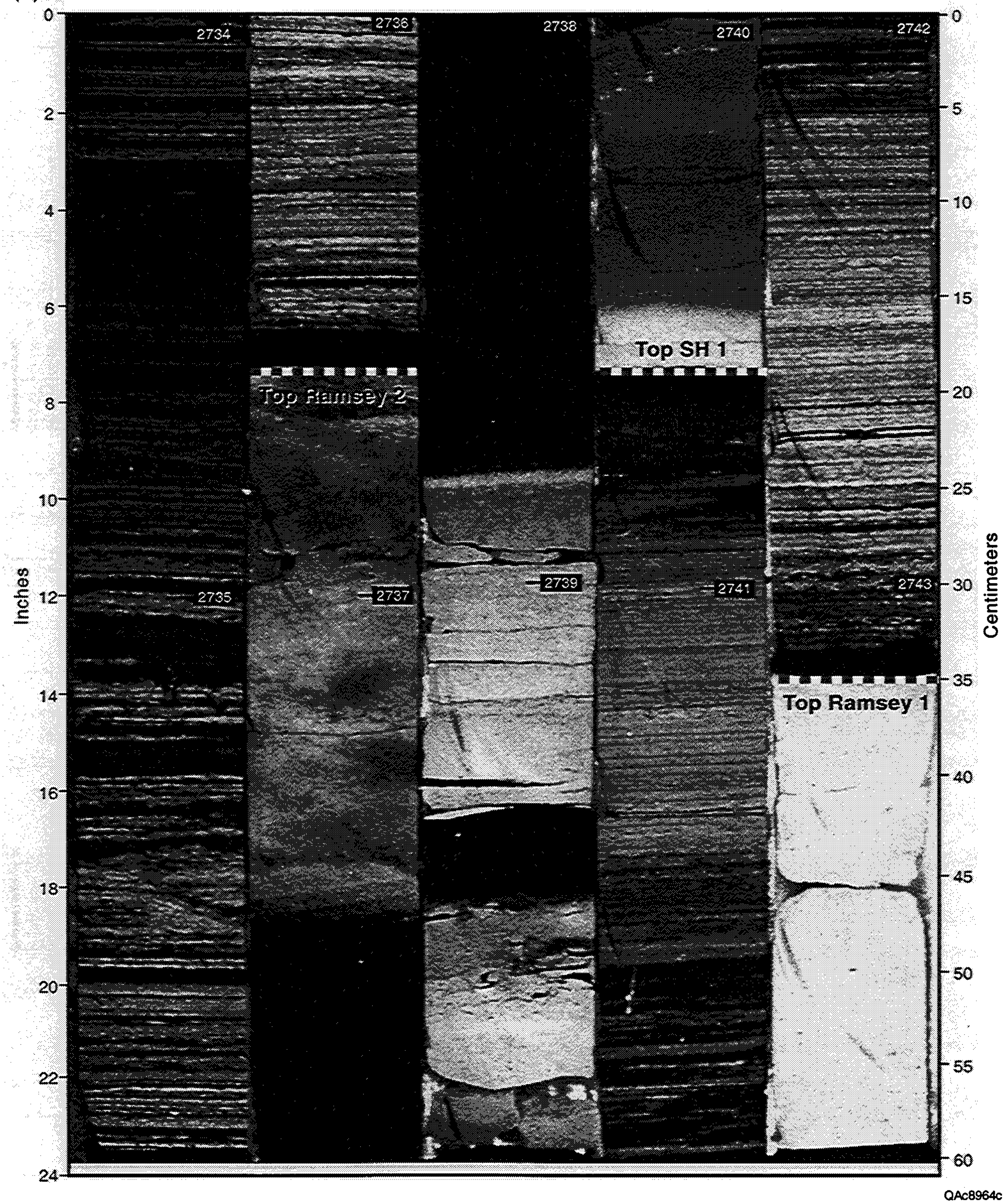


Figure 13. (cont.)

(a)

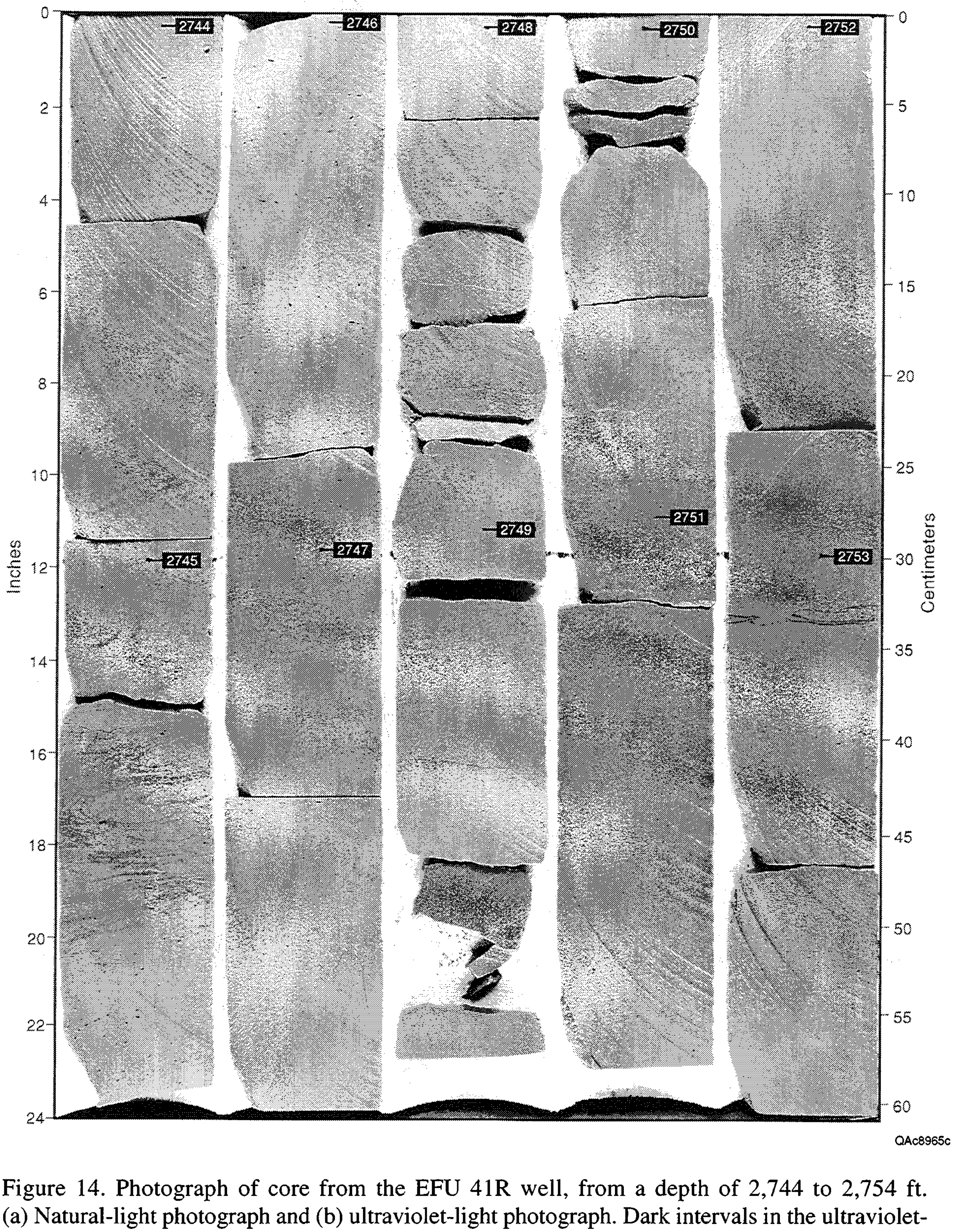


Figure 14. Photograph of core from the EFU 41R well, from a depth of 2,744 to 2,754 ft. (a) Natural-light photograph and (b) ultraviolet-light photograph. Dark intervals in the ultraviolet-light photograph are calcite-cemented layers.

(b)

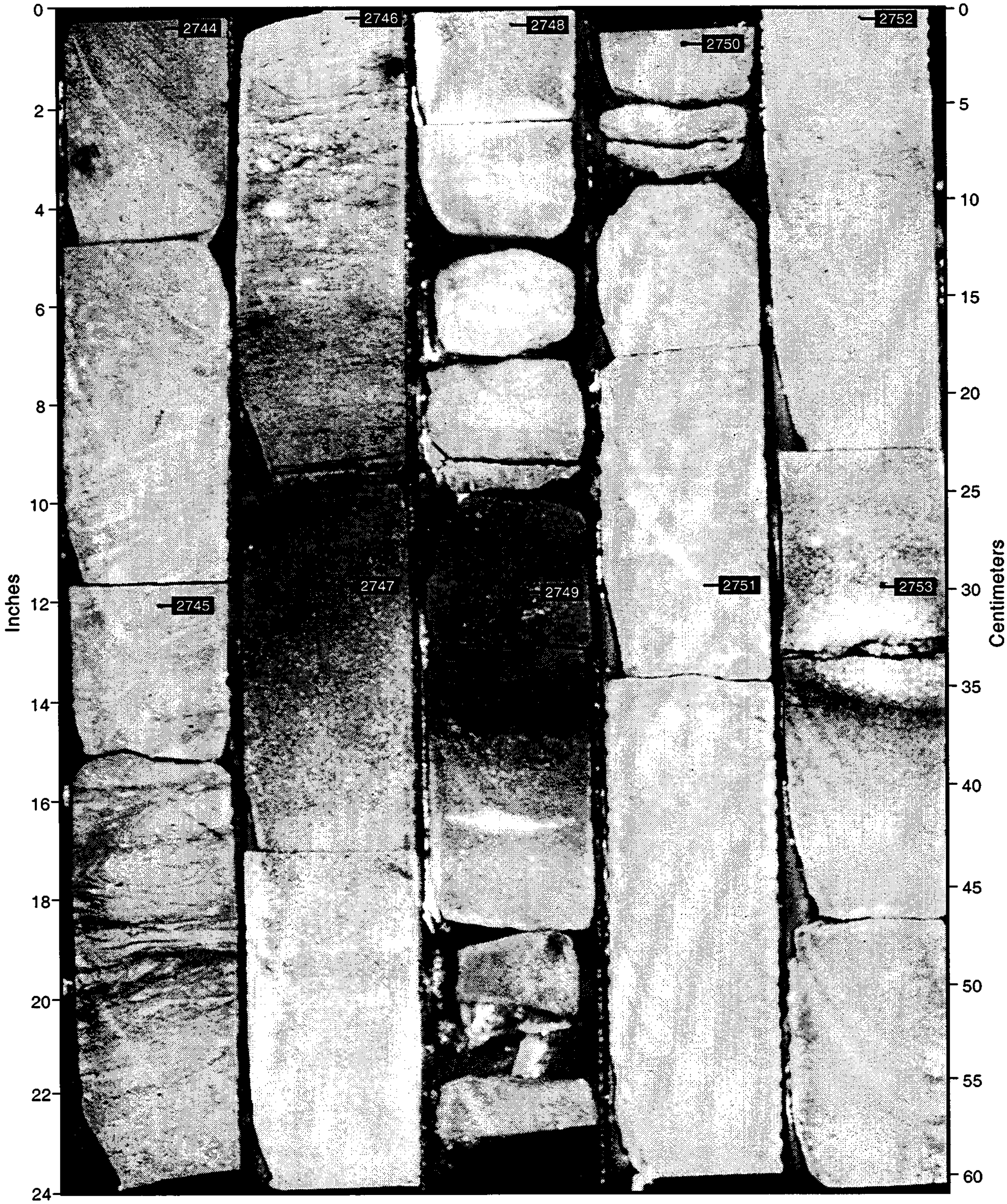
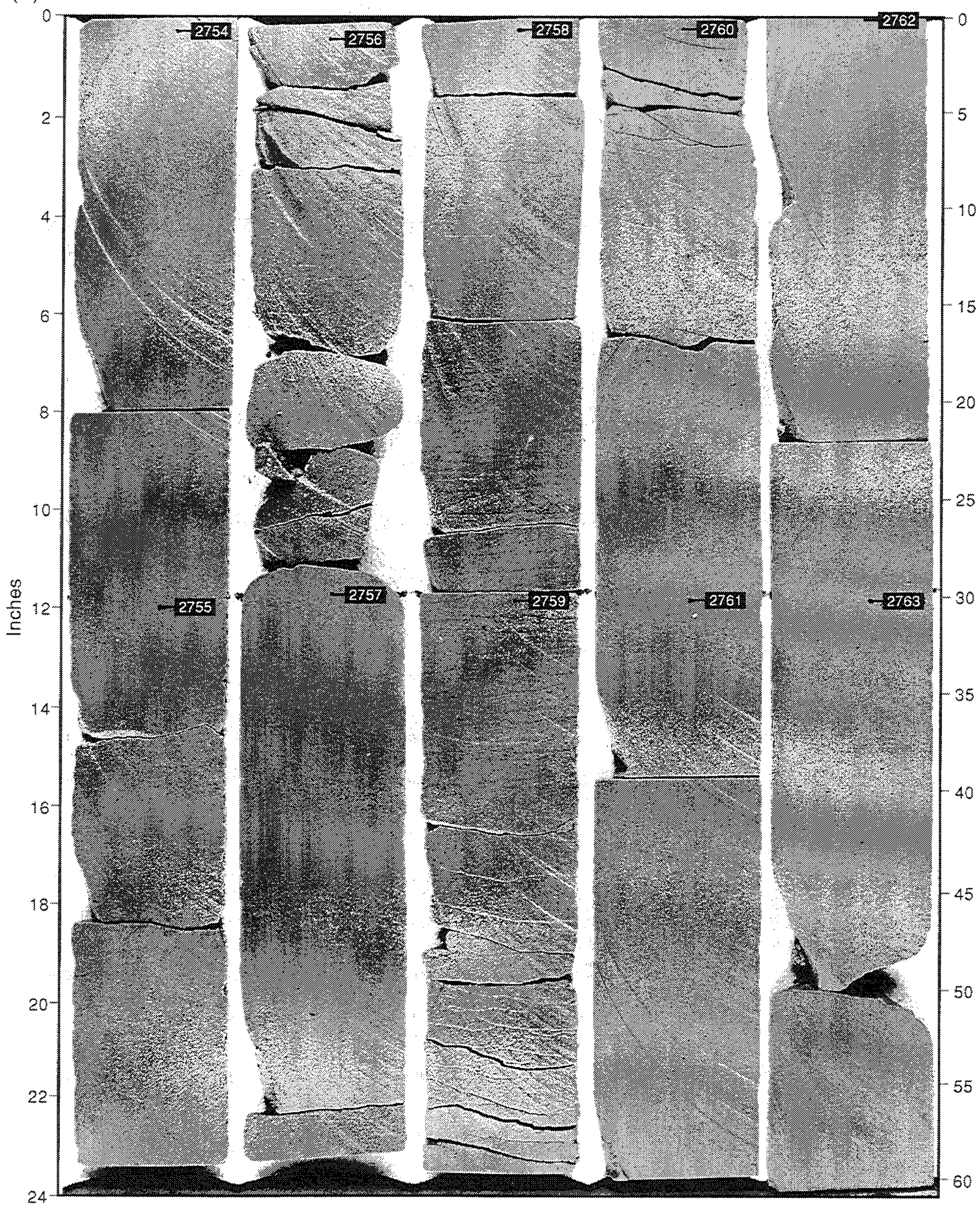


Figure 14. (cont.)

(a)



QAc8380(a)c

Figure 15. Photograph of core from the EFU 41R well, from a depth of 2,754 to 2,764 ft. (a) Natural-light photograph and (b) ultraviolet-light photograph. Dark intervals in the ultraviolet-light photograph are calcite-cemented layers. From Dutton and Flanders (2001).

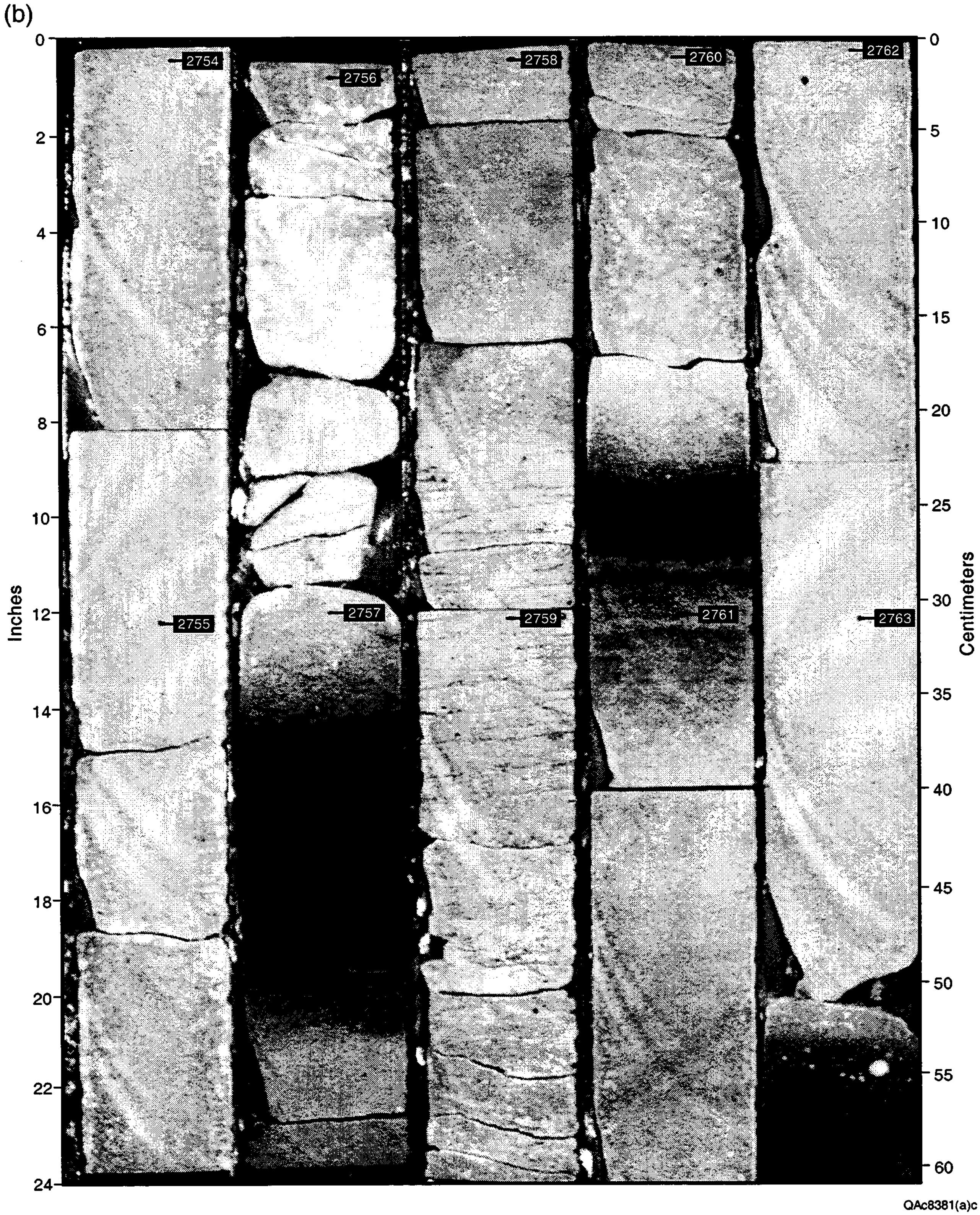


Figure 15. (cont.)

(a)

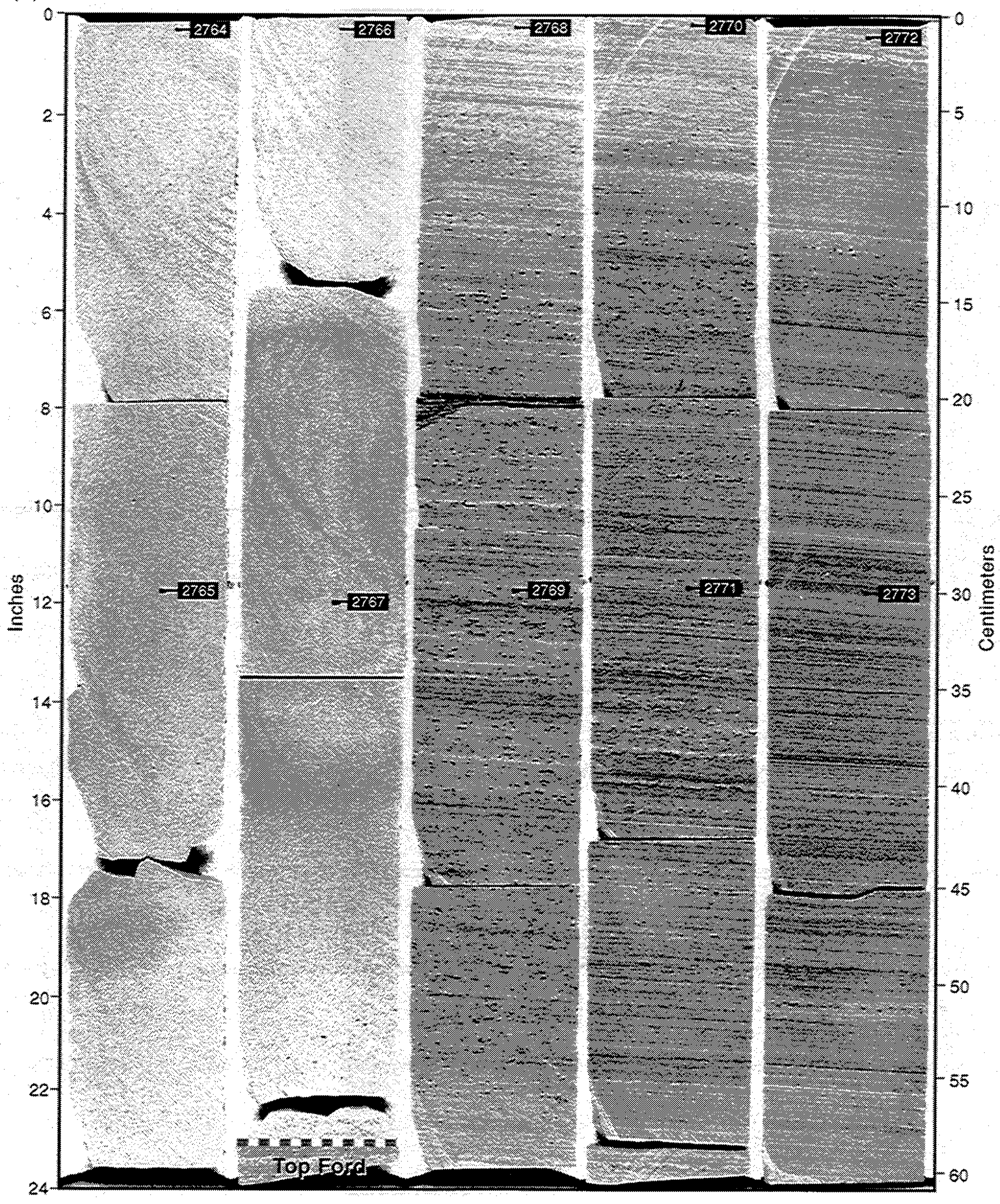


Figure 16. Photograph of core from the EFU 41R well, from a depth of 2,764 to 2,774 ft. (a) Natural-light photograph and (b) ultraviolet-light photograph. Dark intervals in the ultraviolet-light photograph are calcite-cemented layers.

(b)

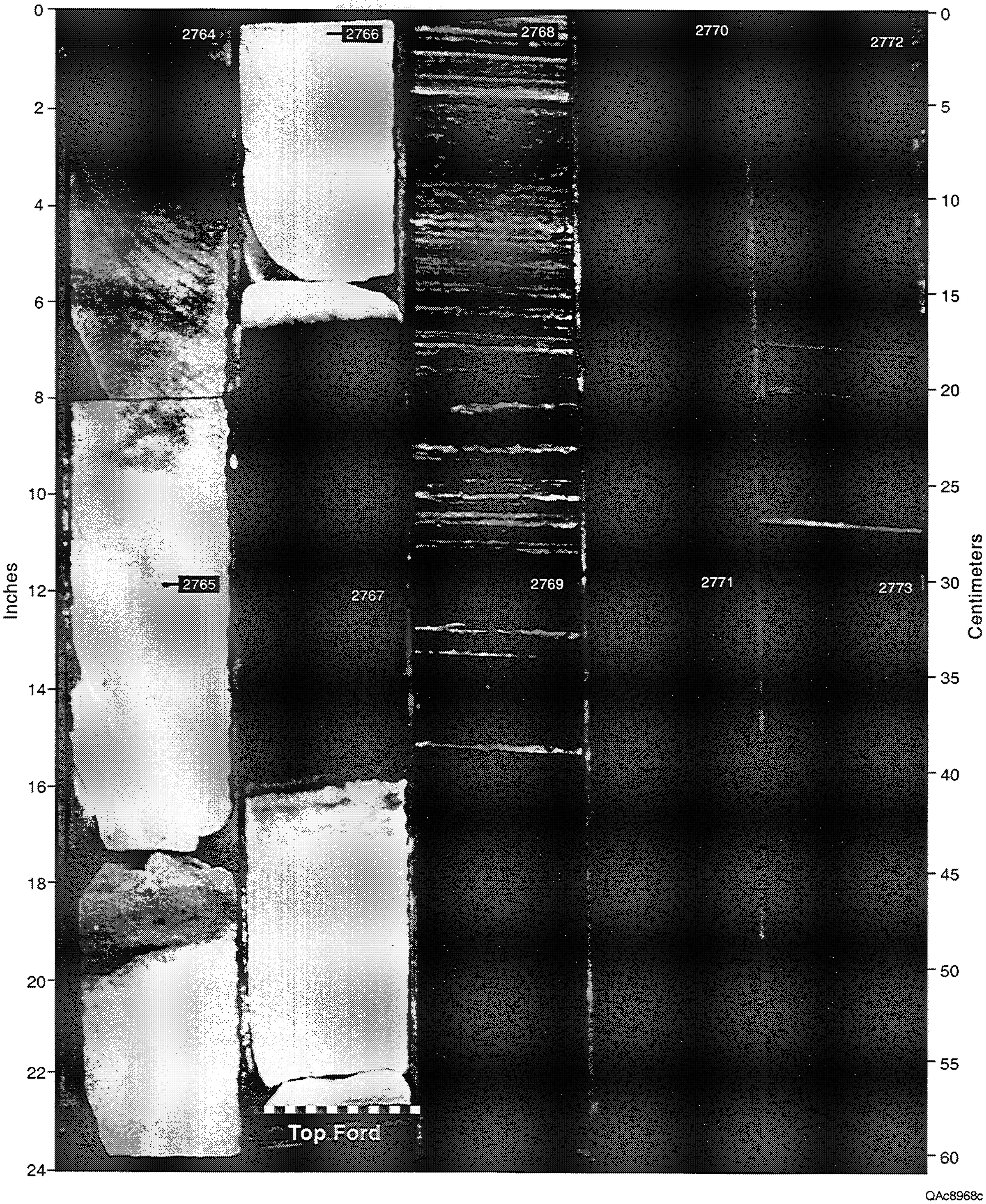


Figure 16. (cont.)

Depositional Features

Description of sedimentary features of the core shows that the Ramsey 1 and 2 sandstones are very fine grained; many intervals of the sandstone are massive. The most common sedimentary structures are features related to dewatering—dish structures, flame structures, and convolute bedding (fig. 12). Many of the sedimentary structures show up better in UV light than in natural light. In UV light, low-porosity zones are dark because they have no oil-filled porosity, whereas porous sandstones have a bright-yellow fluorescence because of the oil saturation. As a result, slight differences in porosity highlight the sedimentary structures in UV light.

Dish structures are particularly abundant in the EFU 41R core; a good example occurs in the core between 2,759 and 2,760 ft (fig. 15). Dish structures form in thick, massive sandstones as fluid escapes during initial compaction (Walker, 1992). They consist of thin, dark, less permeable layers (probably containing more organic matter) and paler, cleaner layers; escaping fluid has broken through the darker layers and curved them upward. These features develop in massive sandstones at the base of turbidity-current deposits, as described by Walker (1992). In a turbidity current, all the sand is supported above the bed by fluid turbulence. As flow decelerates, the turbulence becomes too weak to support the coarser grains, which gradually settle toward the base of the flow. For awhile they continue to be transported as a layer of dispersed, colliding grains. When the flow slows down more, the layer stops moving ("freezes"). The loosely packed bed compacts to form a massive sandstone without sedimentary structures. In thicker beds, escape of fluid during compaction causes vertical fluid-escape pillars and dish structures to form (Walker, 1992). Similar fluid-escape features were observed in Bell Canyon outcrops in both lobe and overbank-splay sandstones (Barton and Dutton, 1999). The EFU 41R well is located near the south end of East Ford field. The Ramsey 2 sandstone in this location is interpreted as having been deposited in a broad lobe, and the Ramsey 1 sandstone in a lobe or splay. The presence of massive sandstones and sandstones with fluid-escape structures in the EFU 41R core is consistent with this interpretation.

Diagenetic Features

The composition of Ramsey sandstones in the EFU 41R core was determined by point counts of 25 thin sections made from samples representing a range of permeability to quantify the petrographic characteristics of grain size, detrital mineralogy, authigenic cements, and porosity. The chips used to make the thin sections were end trims off core-analysis plugs so that petrographic parameters could be compared with porosity and permeability. Composition was determined by point counts (200 points) of thin sections stained for potassium feldspar and carbonates.

Ramsey sandstones in the EFU 41R well are well-sorted, very fine grained arkoses having an average composition of $Q_{67}F_{26}R_{7}$. Plagioclase and potassium feldspar are approximately equal in abundance. The most common lithic grains are metamorphic, plutonic, and carbonate rock fragments. Cements and replacive minerals constitute between 1 and 31 percent of the sandstone volume, calcite and chlorite being the most abundant. Calcite cement has an average volume of 7 percent and ranges from 0 to 30 percent. Most of the calcite fills intergranular pores, but an average of 1 percent calcite cement occurs within secondary pores. Chlorite (average = 1 percent) forms rims around detrital grains, extending into pores and pore throats. Primary porosity averages 19 percent and secondary porosity, 2 percent.

Core-plug porosity in Ramsey sandstones in the EFU 41R core ranges from 4.5 to 24.6 percent, and permeability to air from 0.01 to 78 md (fig. 17). Siltstones have porosity ranging from 14.1 to 17.3 percent and permeability from 0.2 to 4.1 md (fig. 17).

Zones of low porosity and permeability in the sandstones occur within highly calcite cemented intervals (Dutton and Flanders, 2001). The cemented zones appear black in ultraviolet light because they have no oil-filled porosity (figs. 13b, 15b, 16b). The rest of the Ramsey sandstones have a bright-yellow fluorescence in ultraviolet light because of the oil saturation. The calcite-cemented layers are 2 to 16 inches thick. Four tightly cemented calcite layers occur in the lower part of the Ramsey 1 sandstone, where they are spaced about 3 ft apart (fig. 12). The Ramsey 2 sandstone contains one cemented layer that is 14 inches thick (fig. 12).

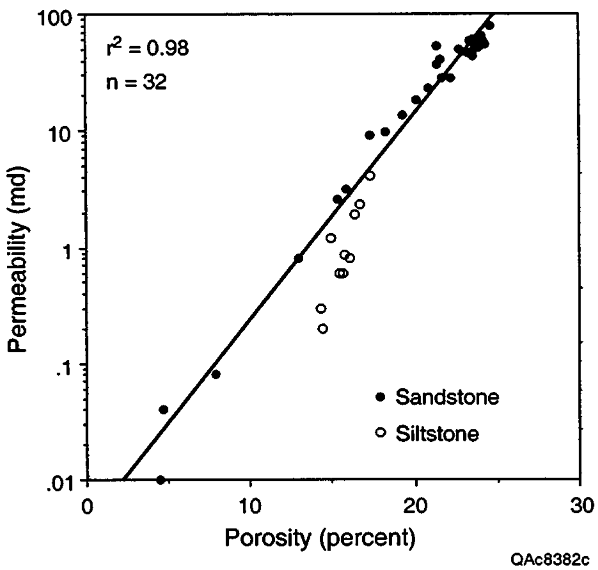


Figure 17. Plot of porosity versus permeability from core-analysis data from the EFU 41R well. From Dutton and Flanders (2001). Regression line calculated from sandstone data only.

A statistically significant relationship exists between the volume of calcite cement and permeability (fig. 18). In these sandstones, which have little variation in grain size and contain no detrital clay, volume of calcite cement is the dominant control on porosity and permeability (Dutton and Flanders, 2001). In samples having more than 10 percent calcite cement, geometric mean permeability is 0.4 md and average porosity is 11.5 percent. Sandstones having less than 10 percent calcite cement have a geometric mean permeability of 40 md and an average porosity of 22.5 percent.

Detailed permeability measurements were taken on the slabbed core face at ~1-inch intervals above, within, and below the 5-inch-thick cemented zone at 2,757 ft (fig. 15b) using a device that measures permeability by an unsteady-state pulse-decay method. (The correlation coefficient comparing 39 steady-state permeability measurements made on core plugs confined in a Hassler rubber sleeve with unsteady-state permeability measured directly on the core plugs is 0.99). The lowest permeability, and presumably the highest volume of calcite cement, occurs from 2,757.5 to 2,757.6 ft (fig. 19). Permeability increases slightly in the 2 inches above and below this depth (fig. 19), but the absence of oil fluorescence in the entire 5-inch-thick zone (fig. 15b) suggests that porosity is occluded by calcite cement. Moderate fluorescence in 1-inch-wide zones above and below the completely cemented layer (fig. 15b) suggests that there is a thin transition zone in which porosity is somewhat, but not completely, reduced by calcite cement.

Logs from EFU No. 41R Well

A complete suite of modern logs was taken in the EFU 41R well—gamma ray, sonic, neutron, density, deep laterolog, shallow laterolog, and microlaterolog. Having the three laterologs made it possible to calculate true formation resistivity (R_t) by three different methods, using (1) the deep laterolog and shallow laterolog (Asquith, 1980), (2) the deep laterolog and the microlaterolog (Hilchie, 1979), and (3) all three laterologs together and determining R_t from a "Tornado Chart" (Asquith and Gibson, 1982; Schlumberger, 1989). Water saturation was then calculated for the Ramsey 1, Ramsey 2, and Olds sandstones according to the modified Archie Equation developed

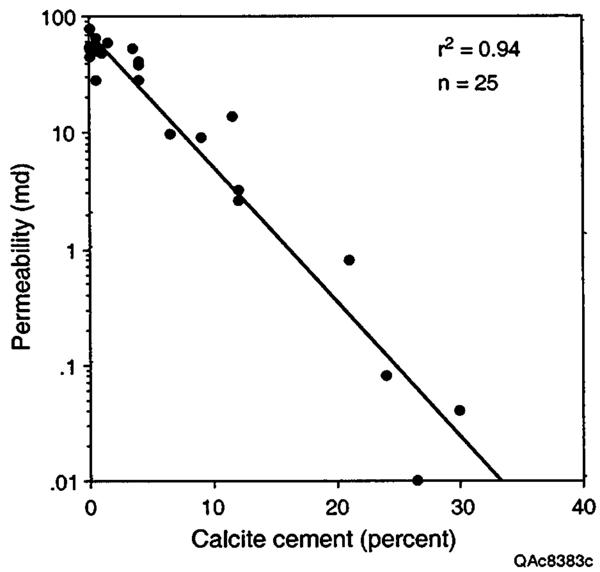


Figure 18. Plot showing that calcite-cement volume is the main control on permeability in Ramsey sandstones from the EFU 41R well. From Dutton and Flanders (2001).

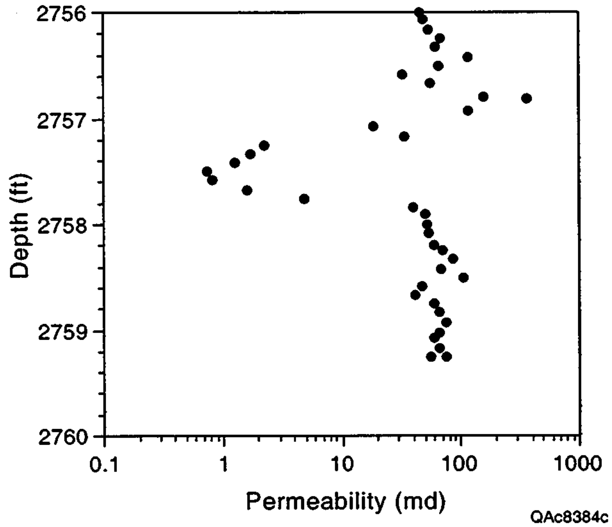


Figure 19. Plot of permeability versus depth across a calcite-cemented layer in the EFU-41R well. From Dutton and Flanders (2001). Permeability was measured at 1-inch intervals directly on the slabbed core face using a device that measures permeability by an unsteady-state pulse-decay method. Permeability has been corrected from air permeability to liquid Klinkenburg permeability.

for Bell Canyon sandstones in the Ford Geraldine area (Asquith and others, 1997; Dutton and others, 1999a):

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90}$$

where

ϕ = porosity

R_w = formation water resistivity at formation temperature

R_t = true formation resistivity

S_w = water saturation.

Water saturation calculated from the Tornado Chart averages 53 percent in the Ramsey 1 and 2 sandstones and 52 percent in the Olds sandstone. This method, which uses all three laterologs, is probably the most accurate. The Hilchie (1979) and Asquith (1980) methods were designed for situations in which modern logs are not available. If the method of Hilchie (1979) is used, water saturation in the Ramsey 1 averages 56 percent, the Ramsey 2 averages 49 percent, and the Olds averages 53 percent. Water saturation calculated by the Asquith (1980) method averages 54 percent in the Ramsey 1, 58 percent in the Ramsey 2, and 53 percent in the Olds sandstone.

GEOLOGIC HETEROGENEITY IN EAST FORD UNIT

Heterogeneities within reservoir sandstones, whether formed by depositional processes or by postdepositional diagenesis, have the potential to influence recovery. In many cases these heterogeneities do not have a major influence on primary recovery, but they can have a significant impact on EOR processes, including a CO_2 flood. Some of the most important causes of heterogeneity in the Ramsey sandstone reservoirs in the East Ford unit are the presence of siltstone beds, variations in net:gross sandstone, and calcite-cemented sandstone layers. Logs, core-analysis data, and cores from the EFU 41R well were used to assess and map heterogeneities in the East Ford unit.

Siltstones

Siltstones cause important depositional heterogeneity within Bell Canyon reservoirs because of the grain size and permeability contrast between sandstone and siltstone facies. Because of the low permeability of siltstones, limited cross-flow of fluids will occur between sandstones separated by siltstones. The depositional model provides a way to predict the distribution of siltstones in Bell Canyon deposits. Siltstones occur as (1) widespread sheets that bound high-order depositional cycles; (2) a concentration of rounded siltstone clasts and, rarely, a drape of massive, organic-rich siltstone along the base of channels; (3) beds interbedded with thin sandstones within the levee deposits that flank both sides of channels and gradually thin and taper away from the channel; and (4) overlying erosion surfaces associated with channel avulsion (Dutton and others, 2000a, b). All of these siltstone beds have the potential to disrupt displacement operations in Delaware sandstone reservoirs. For example, cross-flow of fluids may be limited between a well in an overbank-splay deposit and a well in a channel deposit, not only because of interbedded siltstones in the levee, but also because of a siltstone-pebble lag or thin siltstone drape along the base of the channel (Dutton and others, 2000a, b).

In the East Ford unit, a major geologic heterogeneity is caused by the 1- to 3-ft-thick laminated siltstone (SH1 siltstone [fig. 6]) that divides the Ramsey reservoir into the Ramsey 1 and Ramsey 2 sandstones throughout the field. The SH1 siltstone represents a break in sandstone deposition within the Ramsey interval, when laminated siltstone was deposited over a widespread area. Cross-flow of fluids between the Ramsey 1 and 2 sandstones will be limited because of the SH1 siltstone. Because CO_2 that is injected only into the Ramsey 2 sandstone interval probably will not penetrate the Ramsey 1 sandstone, both injector and producer wells should be perforated above and below the SH1 siltstone.

Net:Gross Sandstone

Another source of heterogeneity in the East Ford unit is variation in reservoir quality between wells. One way to quantify heterogeneity in the Ramsey 1 and 2 sandstones is by mapping the ratio of net:gross sandstone. In the East Ford unit, net pay of an interval was calculated as the number of feet of sandstone having porosity ≥17.5 percent, volume of clay (V_{cl}) ≤15 percent, and water saturation <60 percent (Dutton and others, 1999c). Gross sandstone is simply the total thickness of the interval. Because the goal of the Ramsey 1 and 2 net:gross sandstone maps was to show the ratio of clean sandstone to total sandstone, net sandstone was mapped as sandstone having porosity ≥17.5 percent and V_{cl} ≤15 percent, no matter what the water saturation. Clean sandstones on the east side of the field have high water saturation because they are in a structurally lower position, not because of poorer reservoir quality.

The map of net:gross sandstone for the Ramsey 1 interval (fig. 20) shows high net:gross values (> 90 percent) at the east side of the field, along the inferred trend of the Ramsey 1 channel. The Ramsey 1 channel is interpreted to make a sharp meander east of well EFU 19 because both sandstone thickness (fig. 10) and net:gross values (fig. 20) are lower in EFU 19 than in EFU 16 and 22. Net:gross values decline toward the west side of the field, in the areas that are interpreted to be levee and overbank deposits. Good-quality reservoir sandstone was deposited within the levee and overbank deposits, but these facies also contain interbedded siltstones and silty sandstones and thus have lower net:gross values. High net:gross values at the south end of the field (wells EFU 38, 39, 40, and 41) are interpreted to occur in the center of the lobe facies and decrease toward the margins of the lobe (fig. 20).

The Ramsey 2 sandstone has net:gross sandstone values (fig. 21) somewhat lower than those of the Ramsey 1 sandstone, although few wells have sonic logs where the Ramsey sandstone is thickest and might be expected to have the highest net:gross values. In the center of the field, thick Ramsey 2 sandstone in wells EFU 5, 15, and 18 (fig. 21) are interpreted to follow the channel trend. These wells do not have sonic logs, so net:gross sandstone could not be calculated.

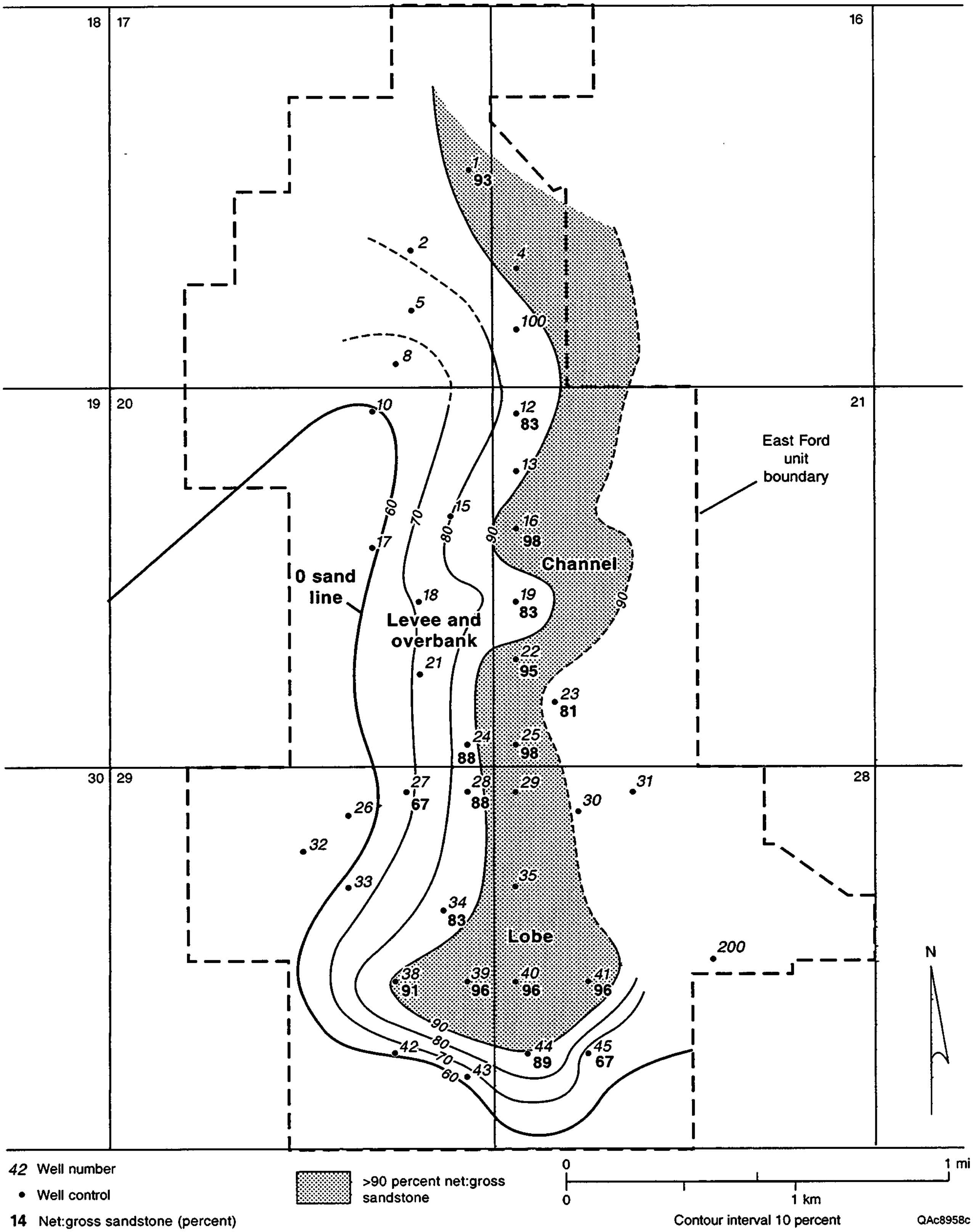


Figure 20. Isopach map of percentage of net/gross sandstone in the Ramsey 1 interval. Net sandstone was determined from sonic and gamma-ray logs as the number of feet of sandstone having volume of clay ≤ 15 percent and porosity ≥ 17.5 percent.

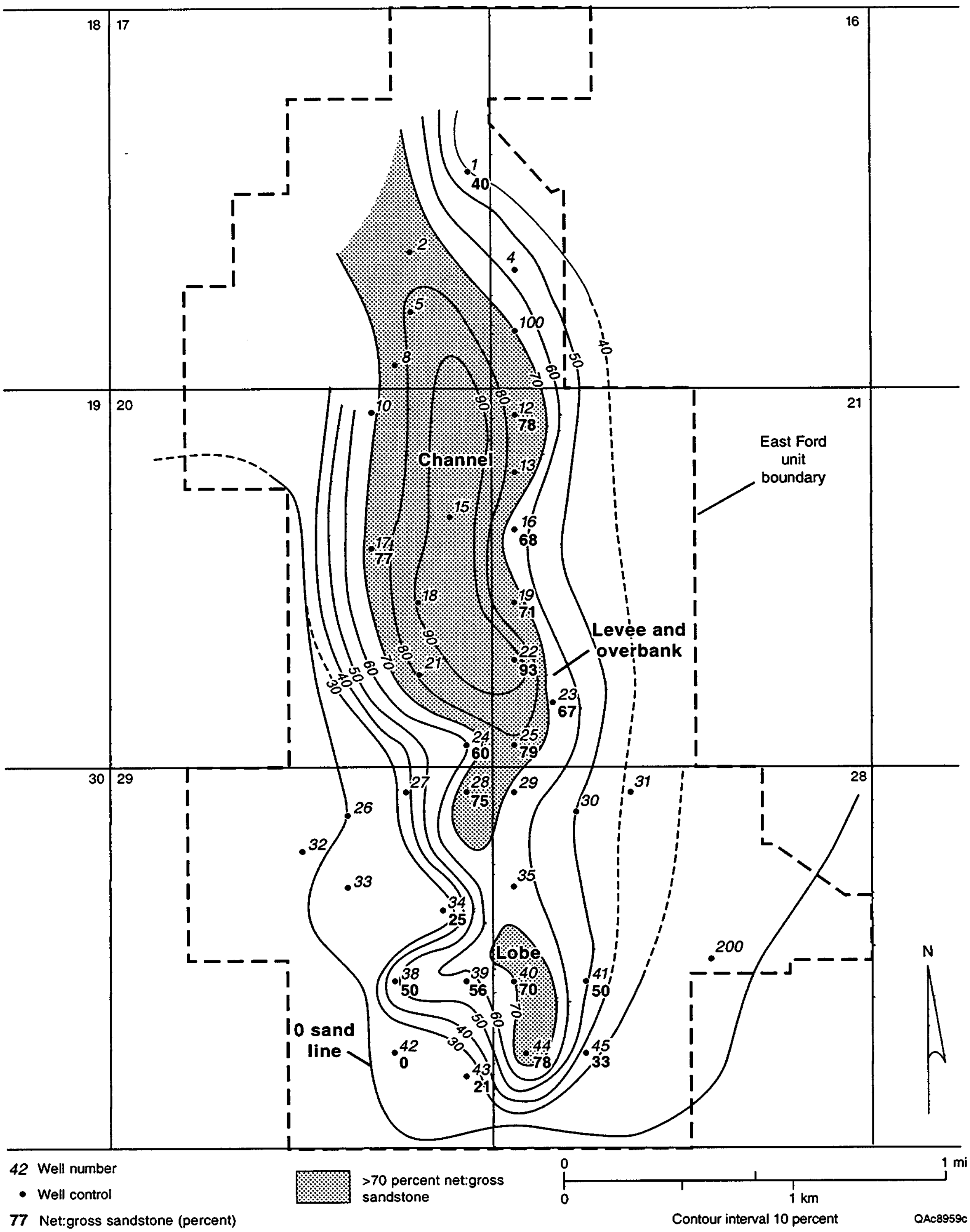


Figure 21. Isopach map of percentage of net/gross sandstone in the Ramsey 2 interval. Net sandstone was determined from sonic and gamma-ray logs as the number of feet of sandstone having volume of clay ≤ 15 percent and porosity ≥ 17.5 percent.

The highest values (>70 percent) of net:gross sandstone occur adjacent to the inferred channel and, to a lesser extent, in the lobe (fig. 21). The Ramsey 2 sandstone may have less clean sandstone than does the Ramsey 1 because it was deposited during a time of rising sea level, when less clastic input and back-stepping of the thickest sand deposits occurred toward the shelf margin (Dutton and others, 1999a). The Ramsey 2 sandstones also contain higher percentages of calcite-cemented sandstone (see Correlation of Calcite-Cemented Layers, p. 46). As a result of these differences, Ramsey 1 sandstones have higher average permeability than do Ramsey 2 sandstones, 46 versus 34 md, respectively (Dutton and others, 1999c).

Net:gross maps of both Ramsey 1 and 2 intervals provide an indication of geologic heterogeneity in the East Ford unit. The channel- and central-lobe deposits are the most homogeneous, consisting mostly of clean, porous sandstone, whereas the levee, overbank, and lobe-margin deposits are more heterogeneous. In general, better communication would be expected between wells within the areas of high net:gross sandstone and poorer communication in areas of low net: gross sandstone or between areas of high and low net:gross sandstone.

Diagenetic Heterogeneity

Diagenetic heterogeneities, particularly the layers of tightly calcite cemented sandstone, also appear to affect the East Ford CO_2 flood. Plots of permeability versus depth show numerous spikes of high and low permeability in Ramsey 1 and 2 sandstones (Dutton and others, 1999c). Petrographic analysis of samples from the EFU 41R well demonstrated that the low-permeability zones correspond to calcite-cemented layers (Dutton and Flanders, 2001). The three low-permeability zones at the base of the Ramsey 1 interval (fig. 22) occur in sandstones having an average volume of 20 percent calcite cement. The fourth cement layer, observed in the core at a depth of 2,763.8 to 2,764.0 ft (fig. 15b), was not sampled by the core-analysis plugs. The zones of slightly lower permeability at 2747.2, 2749.1, and 2753.3 ft (fig. 22) are caused by smaller volumes of calcite cement, averaging 9 percent of the whole-rock volume. The low-permeability zone in the Ramsey 2 sandstone (fig. 22) is caused by calcite cement that fills 27 percent of the whole-rock volume.

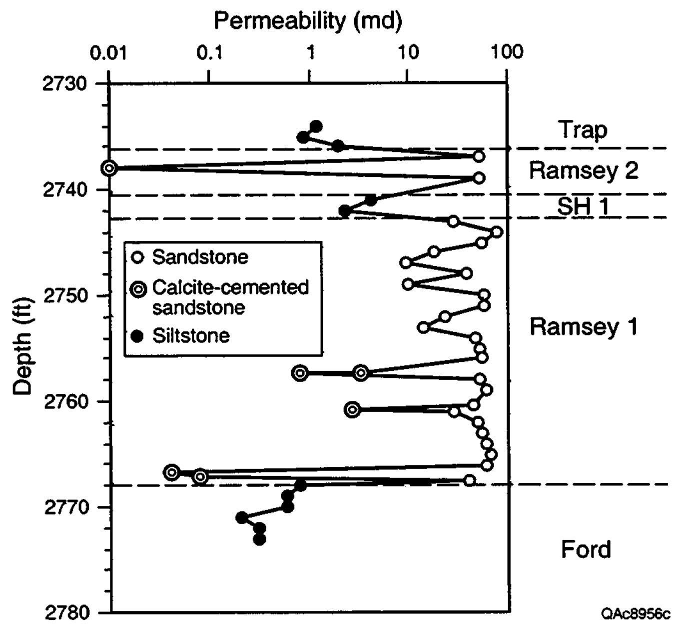


Figure 22. Plot of permeability versus depth in the EFU 41R well. Steady-state air permeability was measured on core plugs confined in a Hassler rubber sleeve.

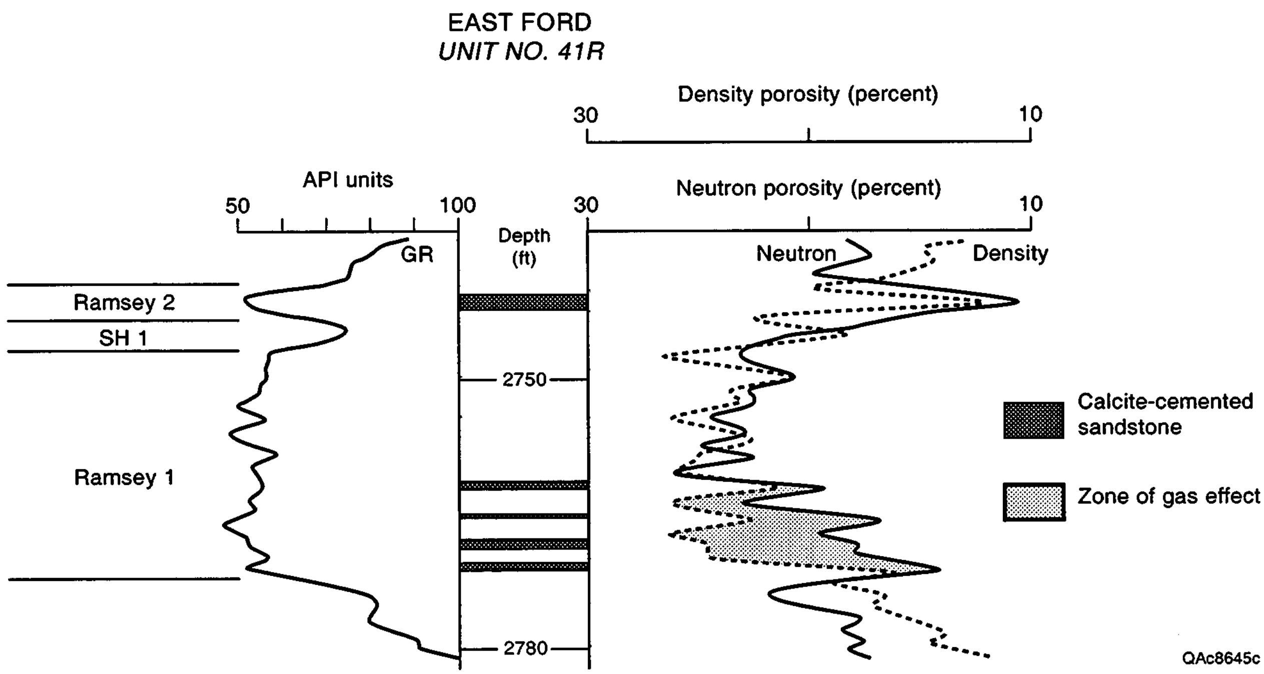


Figure 23. Gamma-ray, neutron, and density logs from the EFU 41R well. The neutron log shows a gas effect in the lower Ramsey 1 sandstone below the uppermost calcite-cemented layer.

Gas Effect in EFU 41R Well

Sonic and neutron logs from the EFU 41R well showed a gas effect in the lower 8 to 10 ft of the Ramsey 1 sandstone, in the same interval in which the calcite-cemented layers occur (fig. 23). No gas effect was seen above the uppermost calcite layer. When the well was first completed, it produced a high volume (750 Mcf/d) of high-concentration CO_2 (>90 percent). Production and temperature logs confirmed the gas effect by indicating that inflow to the well bore was all occurring essentially in the bottom 10 ft of the Ramsey 1 sandstone. CO_2 from the nearby injector well EFU 40 (fig. 5) was apparently trapped in the bottom part of the Ramsey 1 sandstone, below the low-permeability, calcite-cemented layers. This trapping suggests that one or more of the calcite layers are laterally continuous between wells 40 and 41R, causing vertical compartmentalization in the Ramsey 1 sandstone.

CO_2 was injected in the EFU 40 well above and below the calcite-cemented layers, but the previous producing wells, EFU 39 and 41, had no perforations in the Ramsey 1 sandstone below the calcite layers. The CO_2 that was produced in the EFU 41R well probably represents banked-up energy that gave a first flush of CO_2 when the well was completed. To control excess gas production, EFU 40 was converted to water injection. The gas-alternating-water (GAW) cycle was apparently successful because gas production was reduced, and the EFU 40 well has been returned to CO_2 injection. Current production suggests that the displacement bank has not reached the EFU 41R well yet. The well has been put on pump and produces 5 to 10 bopd, 50 bbl of water, and 85 Mcf of gas.

Correlation of Calcite-Cemented Layers

Spikes on the EFU 41R sonic log in the lower part of the Ramsey 1 sandstone appear to correlate to those on the EFU 40 and EFU 41 sonic logs (fig. 24), further evidence suggesting lateral continuity of the cement layers. Because the distance between well EFU 40 and wells EFU 41 and 41R is about 1,000 ft, the four calcite layers observed in the EFU 41R core are inter-

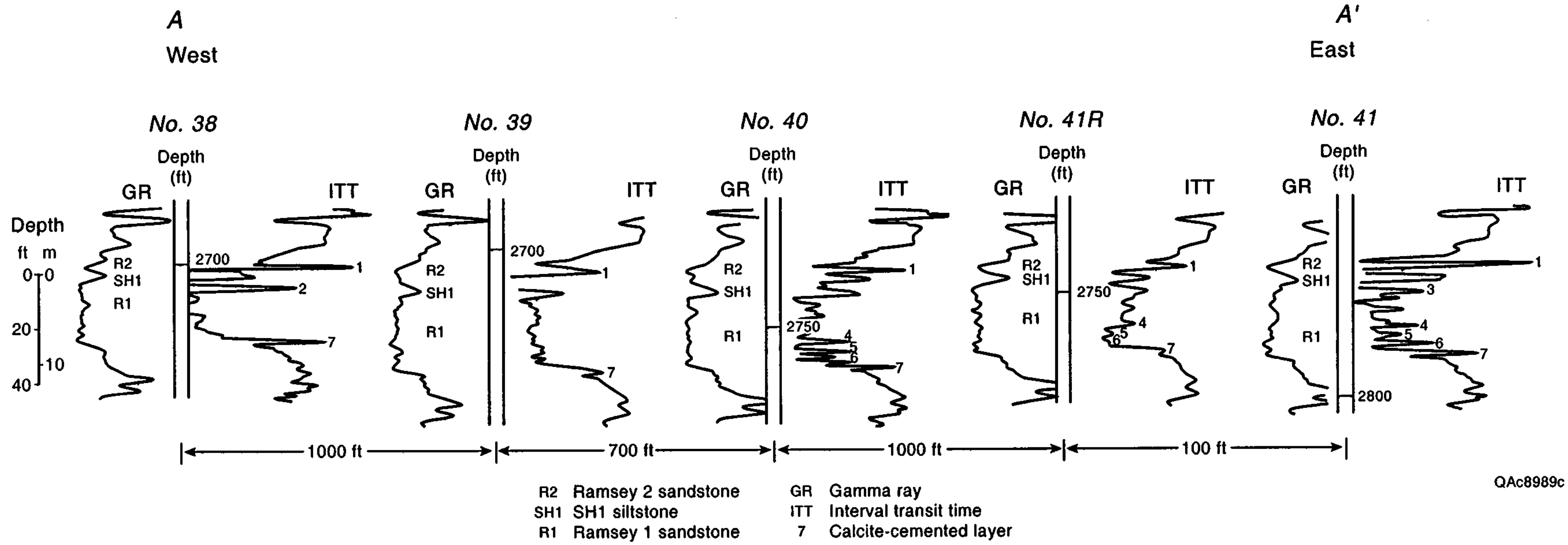


Figure 24. Cross section A–A′ of south end of the East Ford unit. Four calcite-cemented layers in the lower Ramsey 1 sandstone can be correlated in the EFU 40, 41, and 41R wells. The layer at the base of the Ramsey 1 sandstone and another near the top of the Ramsey 2 sandstone occur in all five wells. Location of cross section shown in Figure 5.

preted as having a lateral extent of at least that distance. Most of these layers did not extend to wells EFU 39 and 38 (fig. 24), which contain fewer calcite-cemented layers in the Ramsey 1 sandstone. However, the cemented zones at the base of the Ramsey 1 sandstone and near the top of the Ramsey 2 sandstone both appear to be continuous across the south part of the unit (fig. 24).

Calcite-cemented layers were identified throughout the East Ford unit by using core-analysis data and sonic and resistivity logs to identify cemented intervals. The cemented thicknesses are probably overestimated because cemented zones appear thicker on the logs than they really are (see fig. 23, for example). Wells EFU 24 and 28 contain several calcite-cemented layers in the bottom of the Ramsey 1 sandstone that appear to correlate between the two wells, a distance of ~735 ft. In addition, a 1- to 2-ft-thick calcite-cemented zone was observed in most wells just below the top of the Ramsey 2 sandstone and just above the base of the Ramsey 1 sandstone. In most wells, including EFU 41R, these layers are not at the very top or bottom of the sandstone, but about 6 inches from the contact with the siltstone (figs. 13b, 16b).

Maps of the percentage of calcite-cemented sandstone in the Ramsey 1 and Ramsey 2 intervals (figs. 25, 26, respectively) show variations across the field. In general, the percentage of calcite-cemented sandstone is lower in the Ramsey 1 than in the Ramsey 2 sandstone. In both sandstones, the areas having the lowest percentage of calcite-cemented sandstone (<10 percent) occur where the sandstone is thickest, in what is interpreted to be the channel facies. Areas having high percentages of calcite-cemented sandstone (>20 percent) occur along the margins of the sandstones, in levee, overbank, and lobe deposits.

In a study of turbidite reservoirs in Upanema field in the Potiguar Basin, Brazil, Moraes and Surdam (1993) observed carbonate cement (calcite and dolomite) in both channel and lobes facies. Carbonate-cemented layers in channel sandstones were dispersed and of short lateral extent, whereas in the lobe facies carbonate layers were more numerous and laterally extensive (fig. 27). They interpreted the carbonate cement to be associated with shaly zones between turbidite depositional packages. Because shaly zones were more likely to be deposited and preserved in the lobe facies than in the channel facies, carbonate-cemented layers are longer and more abundant in

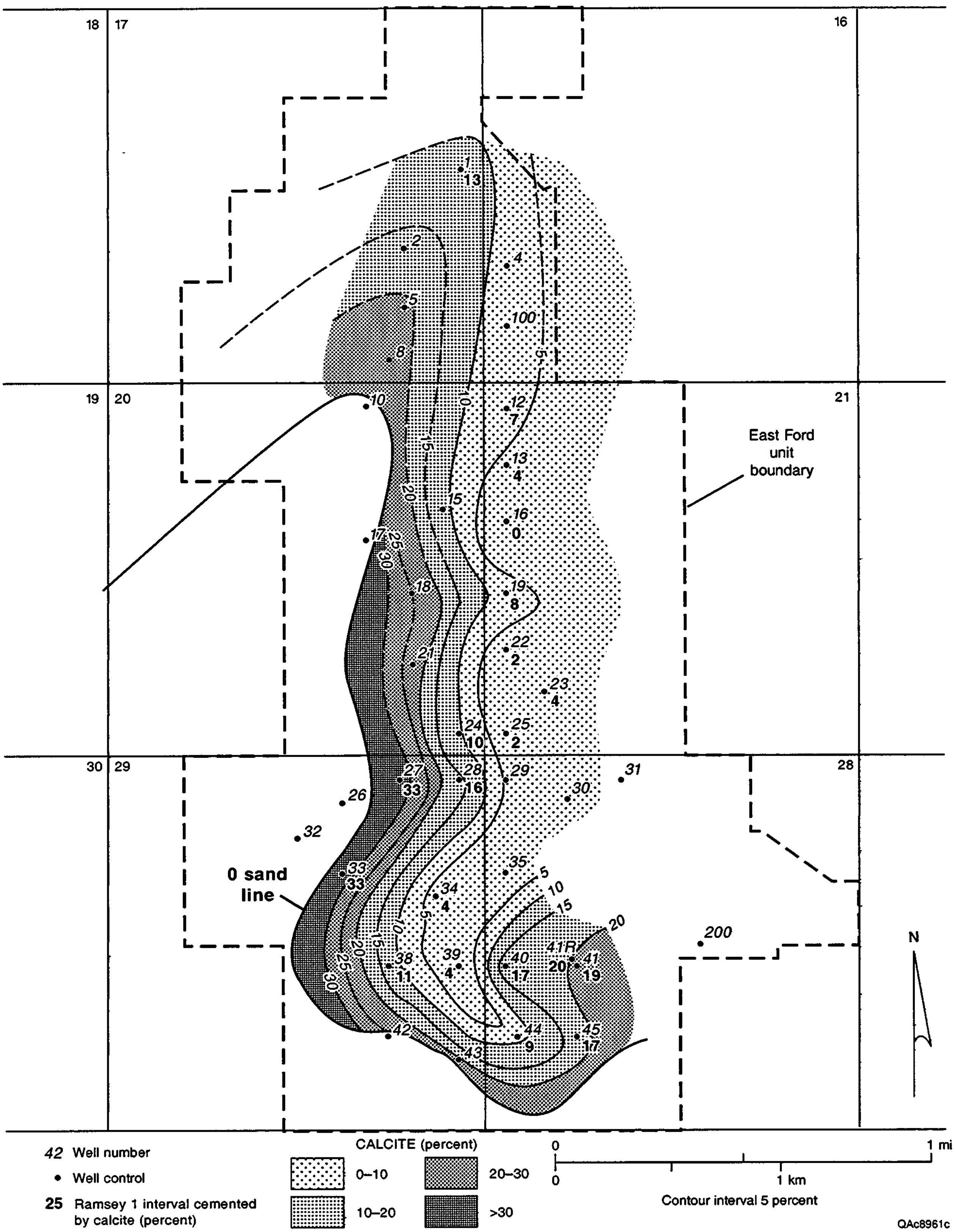


Figure 25. Map of percentage of the Ramsey 1 sandstone that is cemented by calcite.

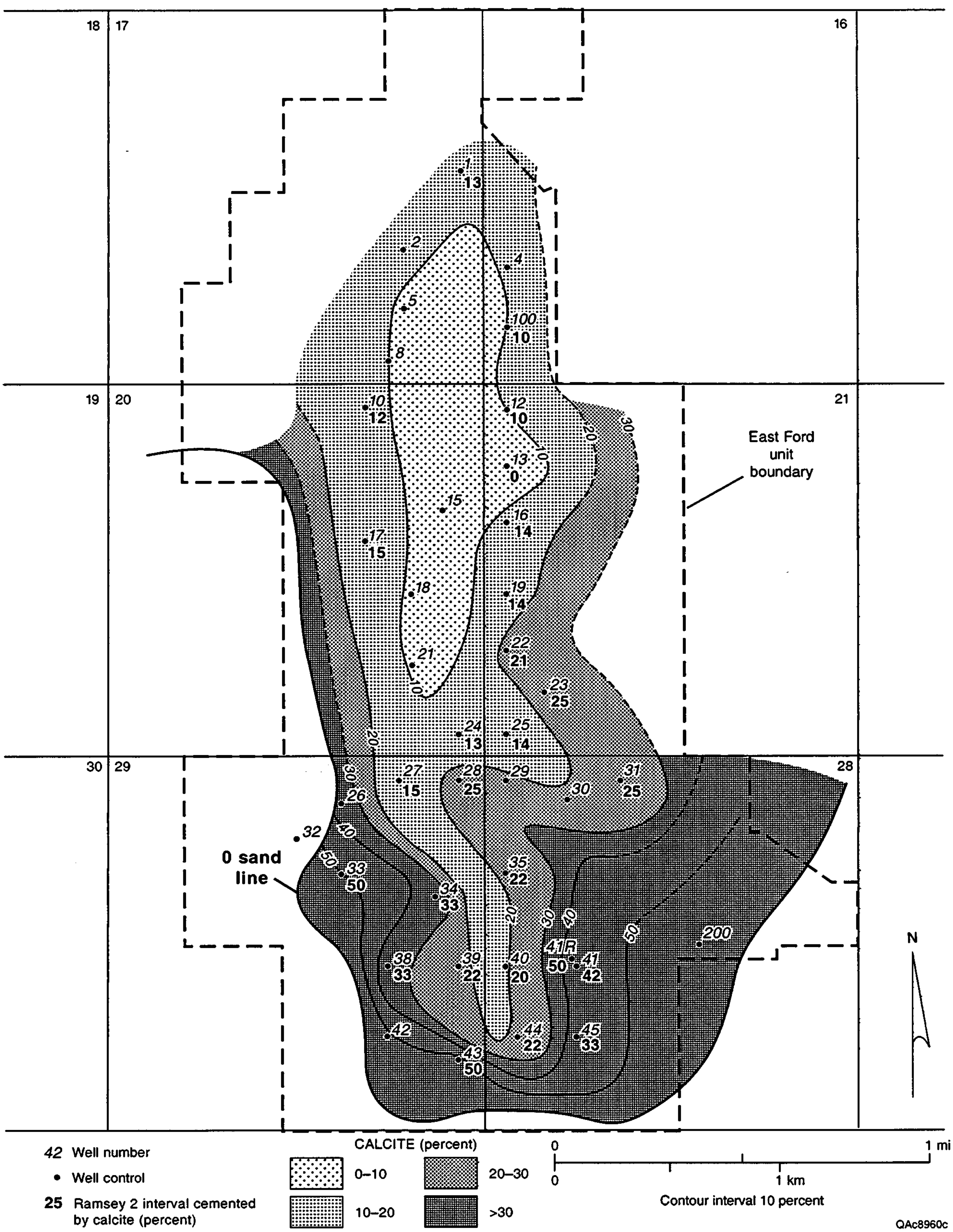


Figure 26. Map of percentage of the Ramsey 2 sandstone that is cemented by calcite.

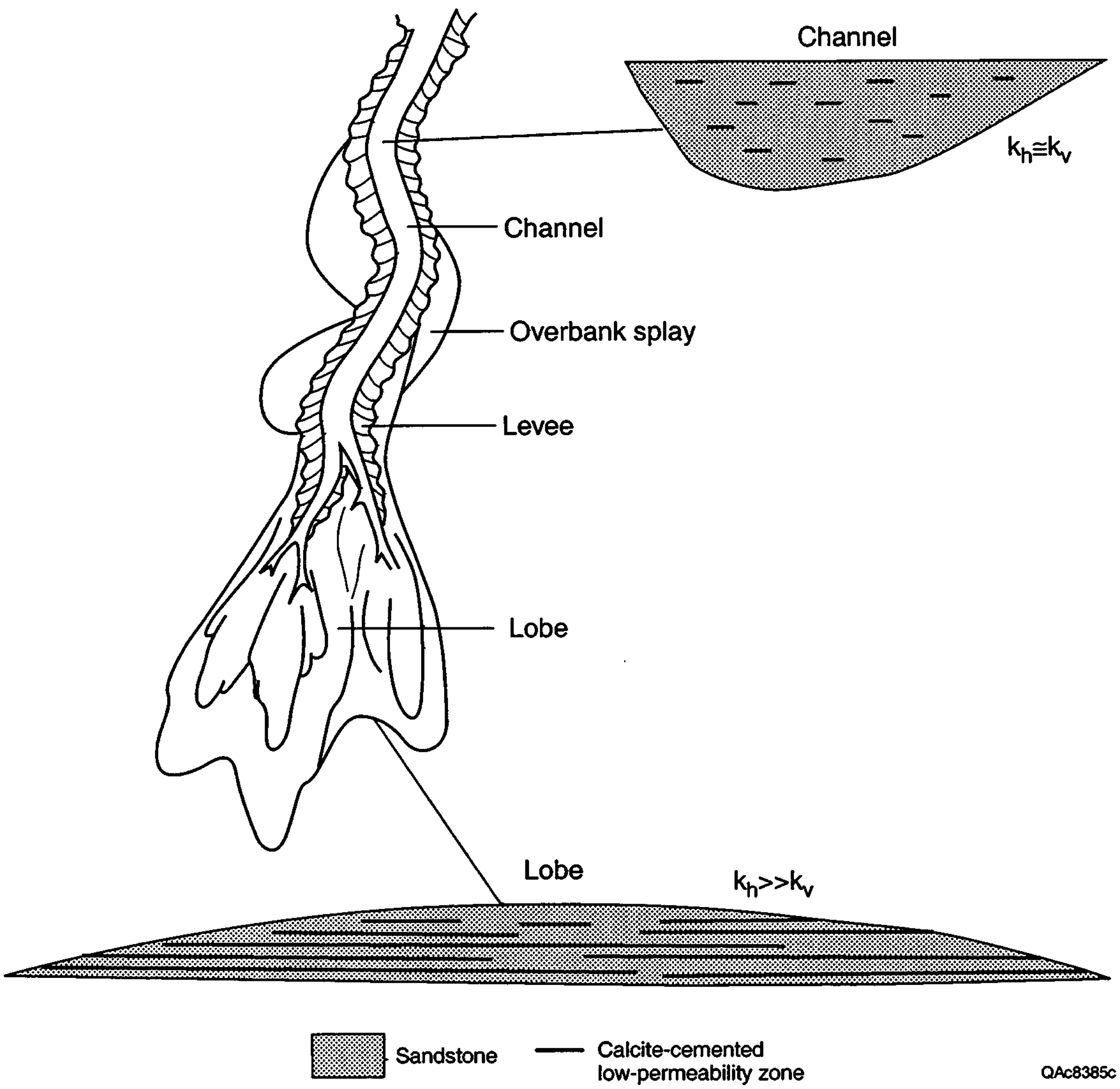


Figure 27. Interpretive model of possible calcite-cement distribution in turbidite sandstones in the East Ford unit. Model of calcite-cement distribution in channel and lobe sandstones and inferred horizontal (k_h) and vertical (k_v) permeability relationship from Moraes and Surdam (1993), superimposed on turbidite depositional model after Galloway and Hobday (1996) and Barton (1997).

lobe deposits (fig. 27). Moraes and Surdam (1993) noted that the laterally extensive calcite-cemented layers can form significant vertical permeability baffles in a reservoir.

The model that Moraes and Surdam (1993) developed for calcite cementation in lobe sandstones may explain the apparent lateral continuity of calcite layers in sandstones at the south end of East Ford field. The calcite layers may be associated with pulses of turbidite deposition, although the uniform grain size in East Ford sandstones makes it difficult to differentiate turbidite packages. The source of calcium carbonate that forms the cement is probably dissolution and reprecipitation of detrital carbonate rock fragments and fossils that occur in both the sandstones and siltstones. The common occurrence of calcite cement near the sandstone-siltstone contacts would be explained if some of the calcite had been derived from the siltstones.

Chlorite Cement

Chlorite cement is the second most abundant authigenic mineral in Ramsey sandstones in the EFU 41R core. Chlorite has an average volume of 1 percent and ranges from 0 to 3 percent. Forming rims around detrital grains and extending into pores and pore throats, it can thus have a greater effect on permeability in these very fine grained sandstones than its volume alone might indicate.

Authigenic chlorite has been identified in many other Delaware sandstone reservoirs. In El Mar field in Loving County, chlorite and mixed-layer illite-smectite compose a maximum of 10 percent of the bulk rock volume (Williamson, 1978). Authigenic clays compose 1 to 10 percent of the bulk rock volume of Delaware sandstones in Waha field, southeast Reeves County; the most abundant clays are chlorite and an interlayered chlorite/expandable clay (Hays and Tieh, 1992; Walling and others, 1992). Clay minerals make up 5 to 6 weight percent of the Delaware sandstone samples in Twofreds field (fig. 1). The clays are mainly mixed-layer chlorite/smectite (76 to 91 percent), with lesser amounts of illite/mica (9 to 24 percent) (W. A. Flanders, Transpetco Engineering, written communication, 1994). The mixed-layer chlorite contains ~30 to 35 percent expandable interlayers.

CO_2 FLOOD OF EAST FORD UNIT

The CO_2 flood of the East Ford unit began in July 1995 with 8 injectors and 10 producers. In the north part of the unit the injectors were positioned on the west side, but to the south the injectors were located centrally (fig. 28a). The number of active wells in the unit was minimized to reduce costs. The unit currently has 7 injectors and 15 producers (fig. 5).

Average bottom-hole pressure in the unit at the start of the project was 723 psi, whereas minimum miscibility pressure is 900 psi. Somewhat higher pressure occurred around wells 7, 12, 36, and 37 (fig. 28a). The low pressure in the East Ford unit at the start of the CO_2 flood, combined with the low reservoir temperature of 83°F, meant that CO_2 would exist as both vapor and liquid phases under these conditions (fig. 29). Response to CO_2 injection in the field may have been delayed as a result. At these low temperatures and pressures, liquid CO_2 can occur on both the injection side as well as the production side. For comparison, CO_2 injected in the Ford Geraldine unit was entirely in the vapor phase at the temperature and pressure conditions in that unit (fig. 29). The higher pressure in the Ford Geraldine unit resulted from repressuring by a waterflood prior to CO_2 flooding.

The production rate in April 2000 in the East Ford unit was 155 bopd, 290 barrels of water per day (bwpd), and 1.15 MMcf/d (fig. 30). Cumulative production through April 2000 was 95,000 stock tank barrels of oil, 370,000 bbl of water, and 664 MMcf of gas. Most of the produced gas and water are reinjected. Injection rates in April 2000 were 4,900 Mcf/d of purchased CO_2, 950 Mcf/d of recycled CO_2, and 460 bwpd (fig. 31). In order to repressure the reservoir, additional water for injection is being taken from a nearby operator. Cumulative injection through April 2000 was 7,440 MMcf of purchased CO_2, 514 MMcf of recycled CO_2, and 390,000 bbl of water. The unit has produced 152,526 bbl of oil from the start of tertiary recovery through December 2000, and total production in 2000 was 62,190 bbl.

The CO_2 flood has increased production from the East Ford unit substantially (fig. 7), but several production abnormalities have been observed: (1) low pressure in the center of the field, (2) low production rates, (3) severe reduction in transmissibility indicated by a bottom-hole

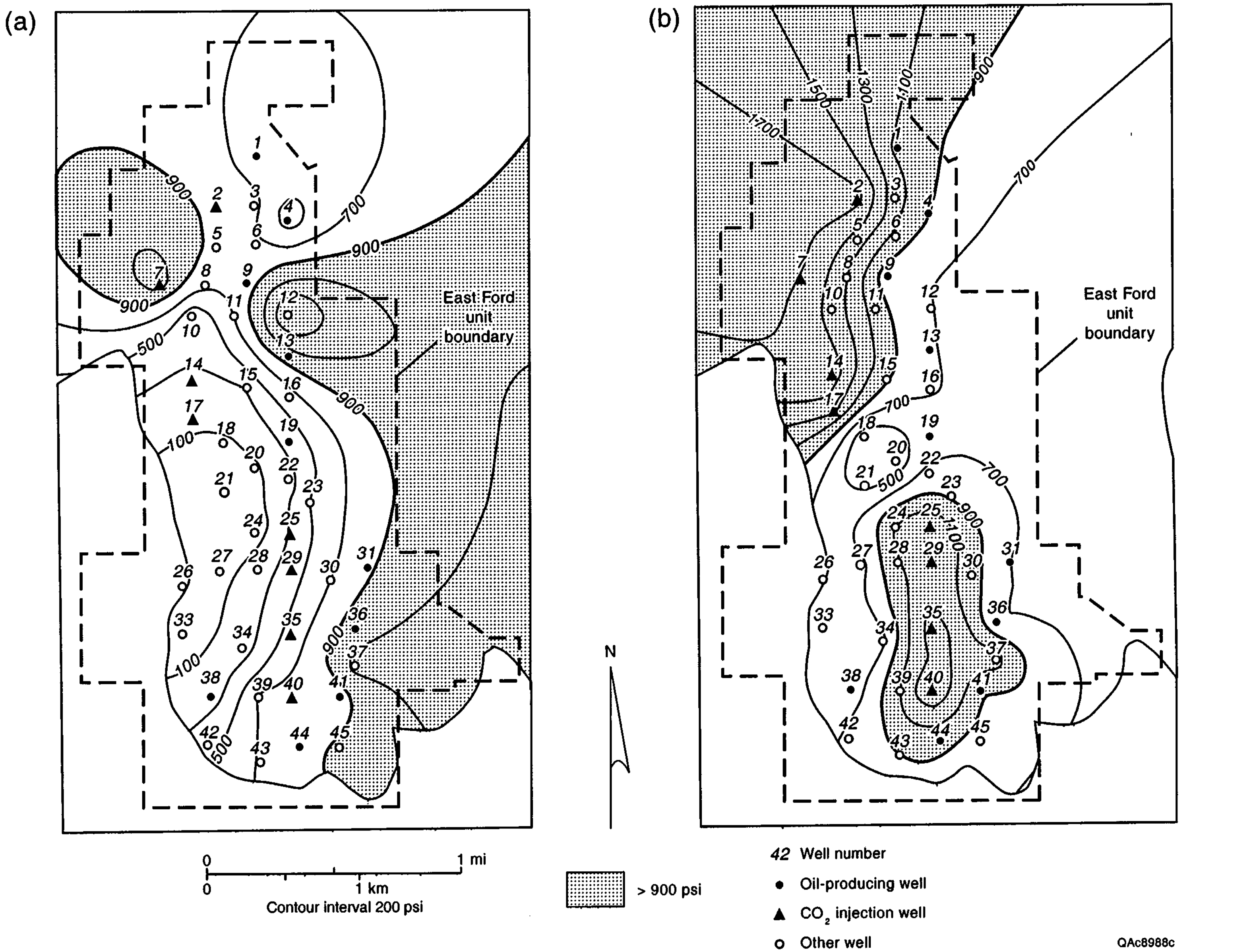


Figure 28. Bottom-hole pressure in the East Ford unit in (a) July 1995 and (b) January 1999. Miscibility pressure is 900 psi.

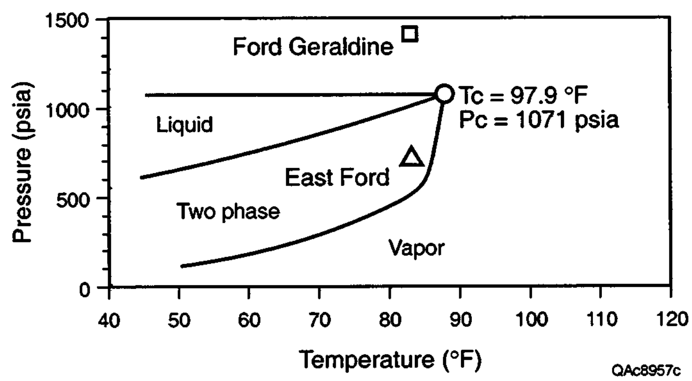


Figure 29. Pressure-temperature phase diagram for CO_2 showing conditions in the East Ford and Ford Geraldine units at the beginning of CO_2 injection.

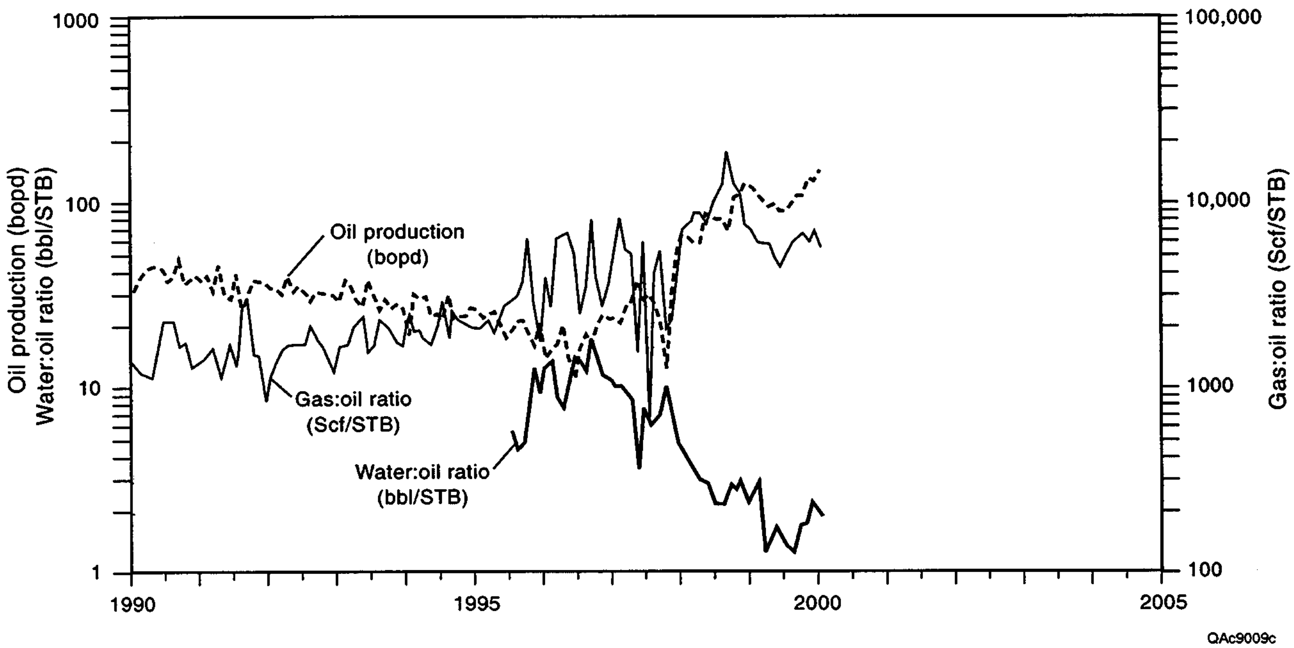


Figure 30. Plot of oil production, water:oil ratio (WOR), and gas:oil ratio (GOR) in the East Ford unit since 1990.

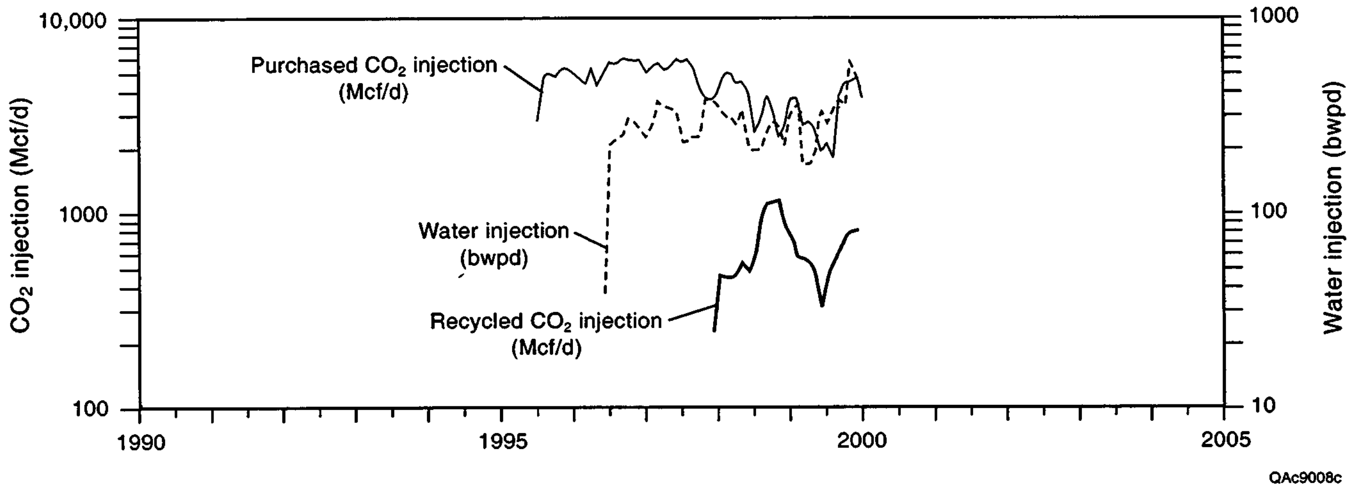


Figure 31. Plot of gas and water injection in the East Ford unit since 1995.

pressure-buildup test, and (4) low gas production rates in key wells. Some of these abnormalities may be caused by mechanical problems, but others may result from the effect of geologic heterogeneity in the field.

Although pressure at the north and south ends of the field has increased during CO_2 injection, low pressure has persisted in the center of the field (fig. 28b). The pressure data were collected in wells used as observation wells (fig. 5); injection wells were shut in for 48 h, and the decline in pressure was observed. The pressure distribution suggests that communication is poor between wells in the center of the field (EFU 18, 19, 20, and 21) and the nearest injectors (EFU 14 and 25) (figs. 5, 28b).

The production rate in some wells, including EFU 3 and 4 (fig. 5), is lower than would be expected from their initial potential. For example, well 4 made 106 bbl of liquids (oil + water) per day (blpd) during initial-potential tests (fig. 32), so the current production of about 20 blpd (fig. 33) is surprisingly low. In addition, gas production from EFU 4 has leveled off. Well EFU 3 has a similarly low production rate of 10 blpd (whereas it flowed 110 blpd during the initial-potential test) (fig. 32), and pressure in the well now is >1,200 psi. Gas production from EFU 3 is also low, even though the well is close to the injector EFU 2. A pressure-buildup test in EFU 3 indicates severe reduction in transmissibility ~65 ft from the well, which may be restricting production.

Influence of Geologic Heterogeneity on East Ford Production

Oil recovery has been improved by the CO_2 flood, but not as much as had been expected. Production abnormalities, such as those listed earlier, may indicate that geologic heterogeneities are affecting reservoir displacement operations. In many cases there seem to be restrictions between injector and producer wells that are causing production to be lower than expected, and these restrictions may be caused by depositional and diagenetic heterogeneities.

The East Ford unit appears to be divided into three areas of better interwell communication (fig. 34); communication between wells in different areas is restricted. The areas may result from facies changes, subtle structural or bathymetric controls on deposition, or variations in sediment

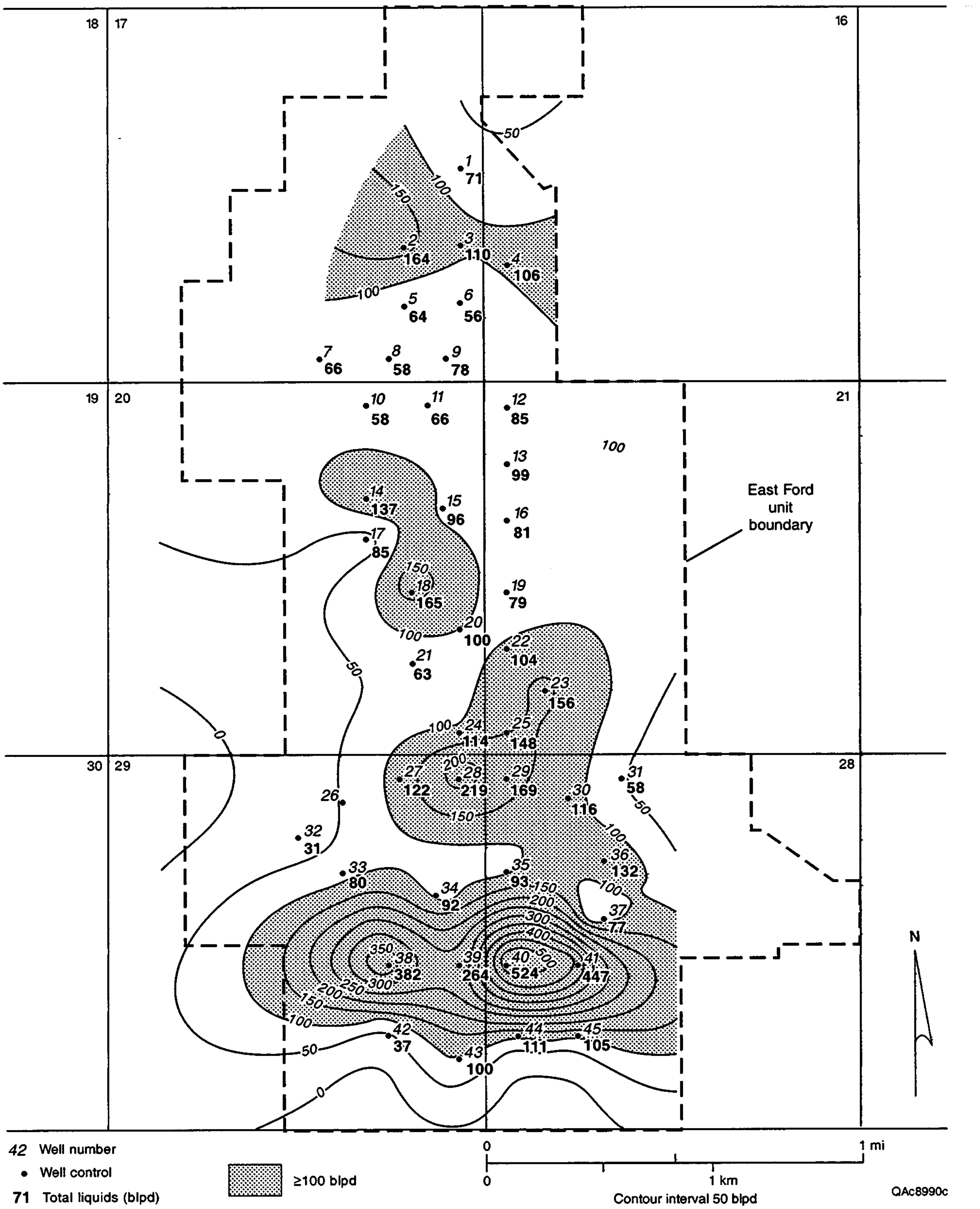


Figure 32. Map of total liquids (oil + water) produced from the Ramsey sandstone during initial-potential tests in wells of the East Ford unit.

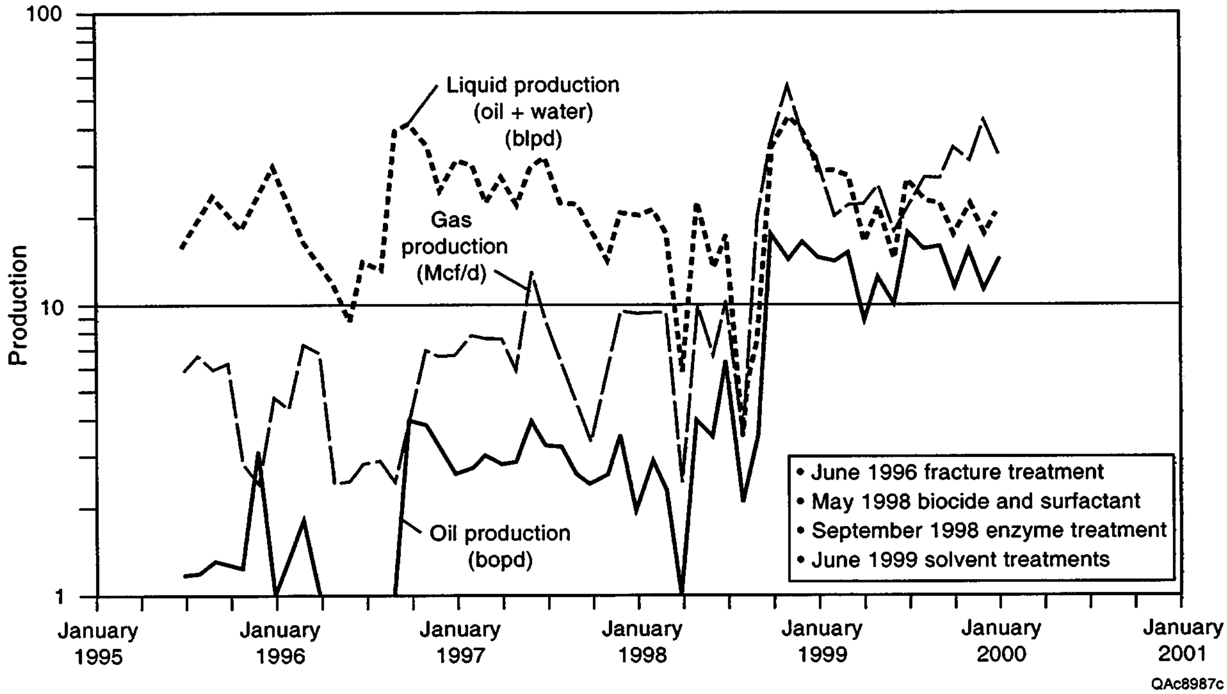


Figure 33. Plot of oil, water, and gas production from the EFU 4 well.

transport direction. The three areas are shown in figure 34, superimposed on an isopach map of the total Ramsey sandstone interval.

North Part of East Ford Unit

The area at the north end of the unit contains three injector wells located along the west side of the area (EFU 2, 7, and 14) and seven producers (EFU 1, 3, 4, 9, 10, 13, and 17) (fig. 34). In this part of the field, the Ramsey 2 sandstone is the main target (fig. 11). The Ramsey 1 sandstone is thin in EFU 7 and not present in EFU 10 (fig. 10). EFU 2 was deepened into the Ramsey 1 sandstone, but the bottom of the well filled in with sand and injection pressure went up, indicating that CO_2 is not going into the Ramsey 1 sandstone.

EFU 1 has responded well to the flood and is one of the better wells in the field, producing about 26 bopd in March 2000. The 40-percent net:gross sandstone value for the Ramsey 2 in this well (fig. 21) is surprisingly low and is based on gamma-ray log values that calculated 14.5 ft of sandstone (out of 24 ft gross sandstone) having V_{cl} >15 percent. Core-analysis data from this well showed that 18 ft of the Ramsey 2 sandstone has permeability >10 md and porosity >17.5 percent, so a net:gross sandstone value of 75 percent might be more accurate.

Production from EFU 4 is lower, about 15 bopd (fig. 33). One possible explanation for the lower production is that a barrier may restrict communication between this producing well and EFU 2. Initial geologic interpretations suggested the presence of a channel-levee boundary between wells 3 and 4 in the Ramsey 2 sandstone. To overcome this restriction, EFU 3 was brought into production. Production from EFU 3, however, dropped off quickly to about 5 bopd. EFU 3 was then shut in for a pressure-buildup test to be run. The test indicates a severe reduction in transmissibility ~ 65 ft away. The cause of this reduction in transmissibility near EFU 3 is currently being investigated.

EFU 10, which is interpreted to be in the same overbank-splay sandstone as injector EFU 7 (fig. 35), is a moderately good well, producing about 19 bopd in March 2000. EFU 9 is a poor well, even though it is located in the thickest part of the Ramsey 2 sandstone. The presence of a levee

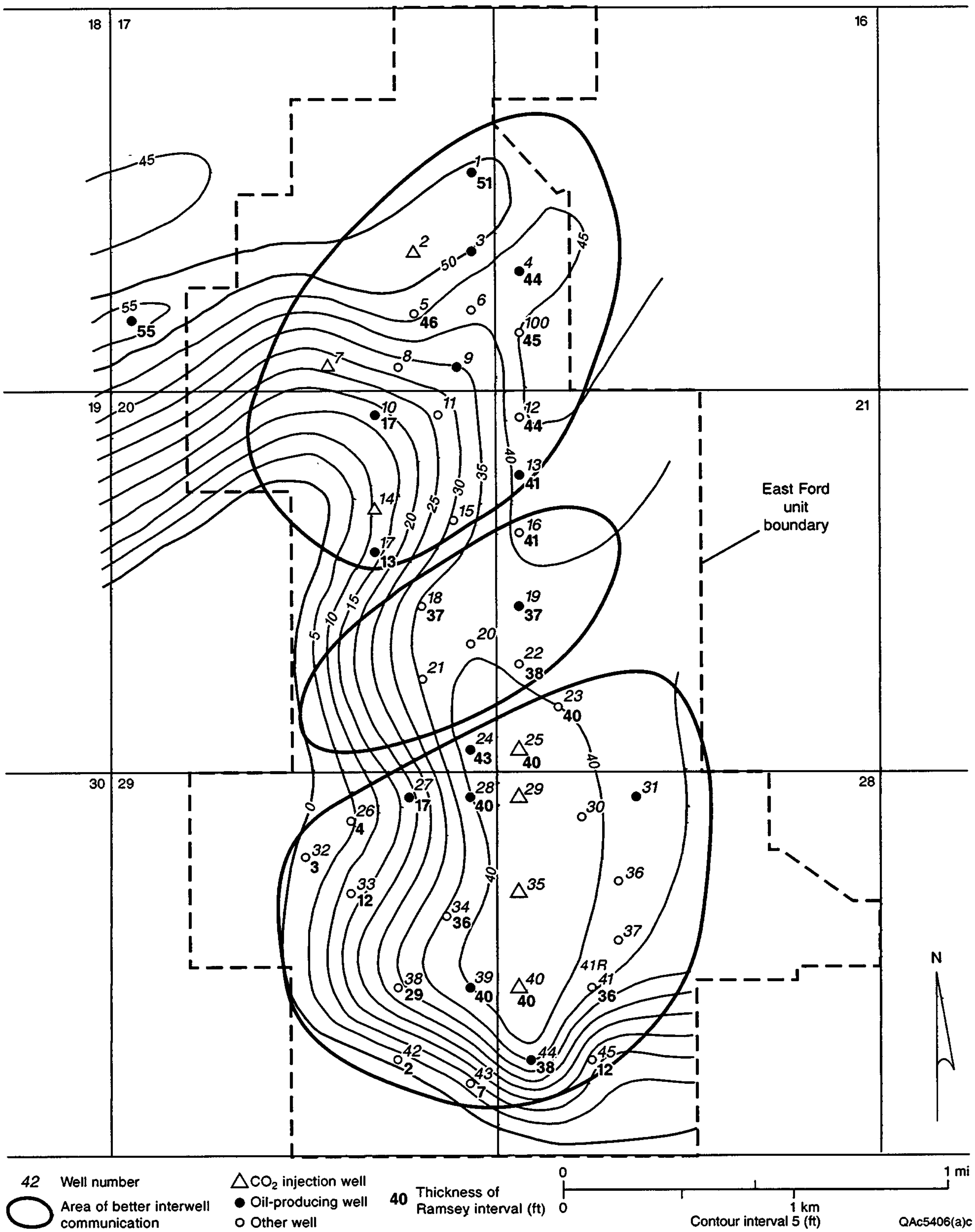


Figure 34. Outlines of the three areas of better interwell communication within the East Ford unit; communication between wells in different areas is restricted. The outlines are superimposed on a map of thickness of the total Ramsey sandstone interval, from the base of the Trap siltstone to the top of the Ford siltstone.

between injector well 7 and producer well 9 may explain the poor response of well 9. However, EFU 9 has a shallow casing leak and mechanical problems, so it may be replaced by EFU 8.

Wells 14 and 17 are interpreted as being in a different splay sandstone that is not in pressure communication with the splay to the north (fig. 35). Communication between wells in this southern splay and wells in the channel also appears to be restricted by levee deposits. Well 17 was converted from an injector to a producing well, and wells 14 and 17 apparently penetrate the same splay. The depositional model suggests that each separate splay sandstone, as well as the channel sandstone, must contain both injector and producer wells to be produced effectively.

Locating a new injector in a north-south orientation with the existing producers, following the channel trend, might improve recovery from the thick Ramsey 2 channel sandstones in this north area. EFU 6 could be converted into an injector and increase the response of EFU 9; both of these wells are in the thickest part of the Ramsey 2 sandstone channel.

Middle Part of East Ford Unit

Both Ramsey 1 and 2 sandstones are targets in this part of the unit. The pressure response in the middle part of the unit has been slow during the CO_2 flood (fig. 28b), suggesting that this area is in poor communication with injector EFU 14 (and EFU 17 when it was an injector) to the north and EFU 25 to the south. The south boundary of the central area is quite sharp and can be delineated easily by the high pressure in EFU 24, which is in the south part of the unit. The bottom-hole pressure in EFU 24 was 1,246 psi on June 14, 2000.

No injectors are located in this area, and well 19 is the only producer (fig. 34). EFU 19 is not responding to injection in EFU 14 or 25; production during March 2000 was only 4 bopd.

Communication between EFU 25 and 19 may be limited in the Ramsey 1 sandstone because the channel apparently makes a large bend to the east in this part of the field (fig. 36). The Ramsey 1 sandstone is thinner in EFU 19 (fig. 10), net:gross sandstone is lower than in the wells to the north and south (fig. 20), and the percentage of calcite-cemented sandstone is higher (fig. 25). All these factors may restrict communication between EFU 19 and 25.

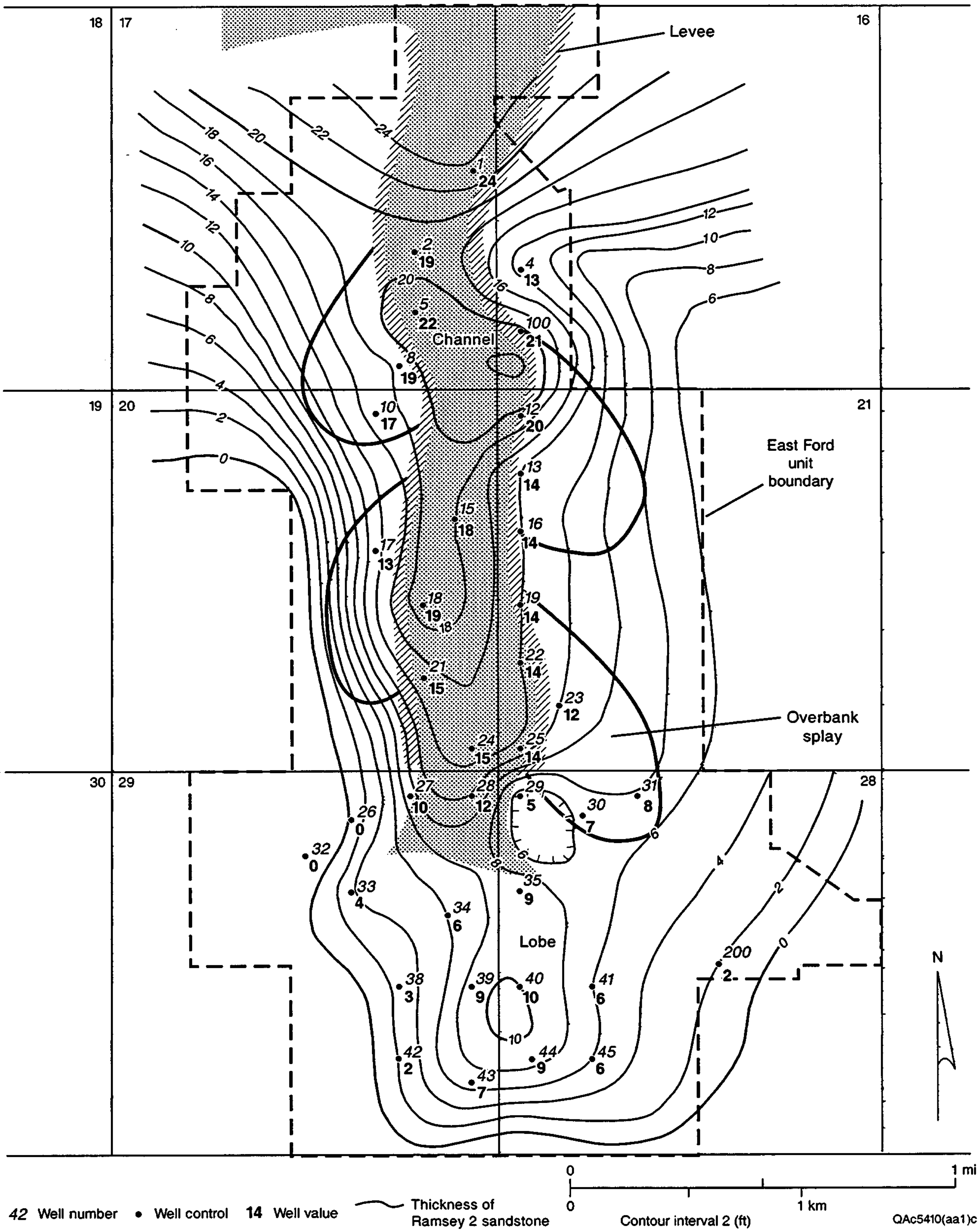


Figure 35. Isopach map of the Ramsey 2 sandstone in the East Ford unit, with interpreted facies distribution shown.

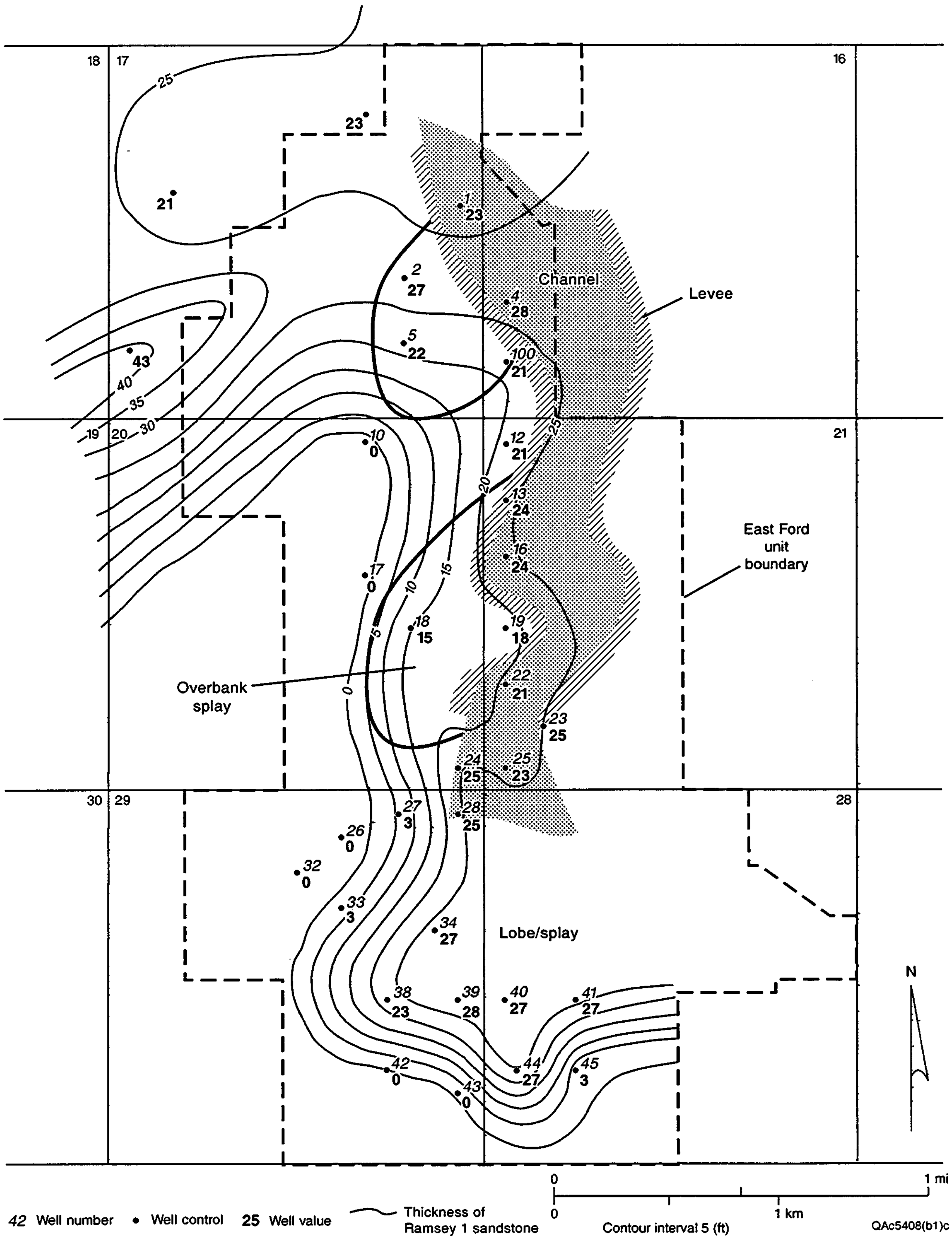


Figure 36. Isopach map of the Ramsey 1 sandstone in the East Ford unit, with interpreted facies distribution shown.

Adding an injector well to this area, such as EFU 20, and making EFU 18, 21, and 22 producers may improve production from this apparently isolated area. One approach would be first to inject water into the Ramsey 2 sandstone in EFU 20 and then to see whether the pressure increases in the surrounding wells. If it does, EFU 20 could be deepened into the Ramsey 1 sandstone and converted to a CO_2 injector.

South Part of East Ford Unit

The south area of the field is mostly in the lobe facies of the Ramsey 1 sandstone (fig. 36), but lobe deposits of the Ramsey 2 sandstone probably also contribute to production. This area is responding well to the existing north-south line of injectors EFU 25, 29, 35, and 40; current producers are EFU 24, 27, 28, 31, 39, 41R, and 44. Wells EFU 27, 28, and 31 are among the best wells in the field. Recovery in this area is interpreted to be good because the lobe sandstones are less laterally heterogeneous than are the channel-levee and splay sandstones to the north.

Recovery might be improved by bringing on additional producers; this could be accomplished by overcoming mechanical problems with some of the shut-in wells. EFU 31 was not responding well, so it was refractured. Production increased but then fell off quickly. It was determined that there was a problem with the pump, which has since been replaced, and production has improved. Well 36 is shut in because of a casing leak and could be brought on line as a producer when the leak is fixed. Well 34 needs to have injected water produced back, and EFU 39 needs to be fractured in the Ramsey 1 sandstone.

CONCLUSIONS

Research this year focused on evaluation and modification of the CO_2 flood to improve recovery. CO_2 injection in the East Ford unit began in July 1995, and production response was observed in December 1997. As a result of the CO_2 flood, production from the East Ford unit increased from 30 bbl/d at the end of primary production to more than 170 bbl/d in 2000. The unit has produced 152,526 bbl of oil from the start of tertiary recovery through 2000, and total production in 2000 was 62,190 bbl. Essentially all the production since the start of the CO_2 flood—152,526 bbl through December 2000—can be attributed to the EOR project.

Geologic heterogeneities appear to influence response to the CO_2 flood in the East Ford unit. The upper and lower Ramsey sandstones were deposited in a channel-levee system that terminated in broad lobes; overbank splays filled topographically low interchannel areas. CO_2 injector wells in splay sandstones apparently have poor communication with wells in channel sandstones, perhaps because communication is restricted through levee deposits. Diagenetic heterogeneity may also influence fluid-displacement operations by trapping CO_2 below low-permeability, calcite-cemented layers that can form significant vertical permeability baffles in a reservoir.

The East Ford unit appears to be divided into three areas of better interwell communication; communication between wells in different areas is restricted. The areas may result from facies changes, subtle structural or bathymetric controls on deposition, or variations in sediment transport direction. Modification of the existing east-west alignment of injectors and producers at the north end of the unit may overcome the problem of apparently restricted communication between splay sandstones and channel sandstones. Pressure response in the central area of the unit has been slow, suggesting that communication is restricted between the wells in this area and the injectors that are located in the north and south parts of the unit. Adding an injector in the central area may overcome this problem. The south area of the unit is responding well to the existing north-south line of injectors. Recovery might be improved in this area by bringing on additional producers; this could be accomplished by overcoming mechanical problems with some of the shut-in wells.

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