

Application of Advanced Reservoir Characterization, Simulation, and Production
Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs,
West Texas (Delaware Basin)

Annual Report

by

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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 a higher percentage of the original oil in place through geologically based field development. This year the project focused on reservoir characterization of the East Ford unit, a representative 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; it contained an estimated 19.8 million barrels (MMbbl) of original oil in place.

Petrophysical characterization of the East Ford unit was accomplished by integrating core and log data and quantifying petrophysical properties from wireline logs. Most methods of petrophysical analysis that had been developed during an earlier study of the Ford Geraldine unit were successfully transferred to the East Ford unit. The approach that was used to interpret water saturation from resistivity logs, however, had to be modified because in some East Ford wells the log-calculated water saturation was too high and inconsistent with observations made during the actual production. Log-porosity to core-porosity transforms and core-porosity to core-permeability transforms were derived for the East Ford reservoir. The petrophysical data were used to map porosity, permeability, net pay, water saturation, mobile-oil saturation, and other reservoir properties.

Subsurface mapping, study of Bell Canyon sandstones in outcrop, and descriptions of Ramsey sandstone cores from the adjacent Ford Geraldine unit indicate that reservoir sandstones at the East Ford unit were deposited in a deep-water channel-levee and lobe system. Ramsey sandstone channels at the East Ford unit, 1,000 to 1,500 ft wide and 15 to 30 ft thick, are flanked by levee deposits. Lobe facies were deposited at the mouths of channels. The best leases in the field produce from what are interpreted to be channel facies in the Ramsey 1 and 2 sandstones near the center of the unit. The thickest part of the Ramsey 2 channel occurs somewhat to the

west of the Ramsey 1 channel, suggesting that the Ramsey 2 sandstone was deposited in the topographic low to the west of the thick Ramsey 1 sandstone.

To estimate the tertiary recovery potential, we applied the results of fluid-flow simulations of a CO₂ flood in the Ramsey sandstone to the East Ford unit. The area simulated was the north end of the Ford Geraldine unit, which is similar to the East Ford unit, both in terms of reservoir thickness and in the separation of the Ramsey sandstone into two parts by the SH1 siltstone. Independent estimates of potential tertiary recovery from the East Ford unit were made on the basis of the results of the CO₂ flood performed in the south part of the Ford Geraldine unit. Both methods of estimating tertiary recovery in the East Ford unit indicate that a minimum of 10 percent of ROIP, or 1.69 MMbbl, is recoverable through CO₂ flood, and as much as 30 percent, or 5 MMbbl, could be recovered.

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. Many of these mature fields are nearing the end of primary production and are in danger of abandonment unless effective, economic methods of enhanced oil recovery can be implemented. The goal of this project is to demonstrate that reservoir characterization, using outcrop characterization, subsurface field studies, and other techniques, integrated with reservoir simulation, can optimize enhanced oil recovery (EOR) projects in Delaware Mountain Group reservoirs.

The original objectives of the reservoir-characterization phase of the project were to (1) provide a detailed explanation 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, respectively; (2) choose a demonstration area in

one of the fields; and (3) simulate a CO₂ flood in the demonstration area. Results indicated that 1 to 3 MMbbl of remaining oil in place in the demonstration area could be produced by CO₂ injection (Dutton and others, 1997a, b, 1998b). 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, which will include a Phase 2 field demonstration in the East Ford unit. The reservoir-characterization phase of the project has been expanded to include the East Ford unit, which is immediately adjacent to the Ford Geraldine unit and produces from a branch of the same Ramsey sandstone channel. Work performed on the project this year focused on two main topics: (1) geologic and petrophysical characterization of the East Ford unit and (2) applying the results of simulation of a CO₂ flood in the Ramsey sandstone to the East Ford unit. Reservoir characterization of the East Ford unit provided an excellent opportunity to test the transferability of the geologic model and log-interpretation methods developed during characterization of the Ford Geraldine unit to another field in the Delaware sandstone play.

Bell Canyon sandstones exposed in outcrop 25 mi west of the East Ford unit are analogs of slope and basin clastic reservoirs in the Ramsey sandstone, Delaware Basin. The depositional model developed from characterization of Bell Canyon outcrops and from the earlier study of the Ford Geraldine unit guided correlations of the Ramsey reservoir in the East Ford unit. Ramsey sandstones at the East Ford unit 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 channel-levee system with attached lobes. Channel facies, approximately 1,000 to 1,500 ft wide and 15 to 30 ft deep, are characterized by blocky log patterns. Levee facies occur as a sediment wedge along the margins of the channels that formed by overbanking of low-density turbidity currents. Log response of levee deposits is serrated. Lobe facies, deposited by unconfined, high-density turbidity currents, occur in broad sheets at the mouths of channels. Some lobe deposits show an upward-coarsening log pattern, but many have a blocky log response.

Reservoir characterization this year also focused on applying the petrophysical techniques developed during the study of the Geraldine Ford unit to the mapping of reservoir properties in the East Ford unit. Petrophysical characterization of the East Ford unit was accomplished by integrating core and log data and quantifying petrophysical properties from wireline logs; the result was a set of maps of porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties across the unit. The approach used to interpret water saturation from resistivity logs in the Ford Geraldine unit had to be modified because the log-calculated water saturation in some East Ford wells was too high and inconsistent with the actual production. The maps of average porosity, average permeability, and net pay of the Ramsey sandstone in the East Ford unit exhibit a strong north-south trend that follows the positions of the Ramsey 1 and 2 sandstone channels.

Compositional simulation of a CO₂ flood in a quarter five-spot pattern in the Ramsey sandstone indicates that 10 to 30 percent of remaining oil in place in the East Ford unit, or 1.7 to 5 MMbbl, is recoverable through CO₂ flood. This estimate agrees well with the estimate that is based on production results from the south part of the Ford Geraldine unit. Secondary and tertiary development in the Ford Geraldine unit recovered 17.8 percent of the remaining oil in place after primary development. A CO₂ flood in the East Ford unit might therefore be expected to recover an additional 18 percent of the 16.9 MMbbl of remaining oil in place, or 3 MMbbl. This may be a conservative figure because the East Ford unit, rather than undergo an ineffective secondary waterflood, went directly from primary production to a CO₂.

INTRODUCTION

This report summarizes the results of reservoir characterization conducted during the fourth year of 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 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 original oil in place by geologically based field development. Current production from Delaware Mountain Group reservoirs is only 14 percent of an original 1.8 Bbbl of oil in place, which provides a clear opportunity for improved recovery.

The focus of reservoir characterization this year was the East Ford unit, located in Reeves County, Texas (figs. 1, 2). The main reservoir in the East Ford unit is the Ramsey sandstone in the upper Bell Canyon Formation (fig. 3). Earlier reservoir-characterization work focused on the Ford Geraldine unit (Dutton and others, 1996, 1997a, b, 1998b), which is immediately adjacent to the East Ford unit and produces from a branch of the same Ramsey sandstone channel (fig. 4). Abundant subsurface data were available from the Geraldine Ford unit for reservoir characterization, including cores from 83 wells, core analyses from 152 wells, and 3-D seismic over the entire unit. In contrast, the smaller, subsurface data base from the East Ford unit is more typical of most Delaware sandstone fields. Reservoir characterization of the East Ford unit has provided an excellent opportunity to test the transferability of the reservoir model and the methodology developed during reservoir characterization of the Ford Geraldine unit to another Ramsey sandstone field.

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, approximately 10 miles 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 (table 1).

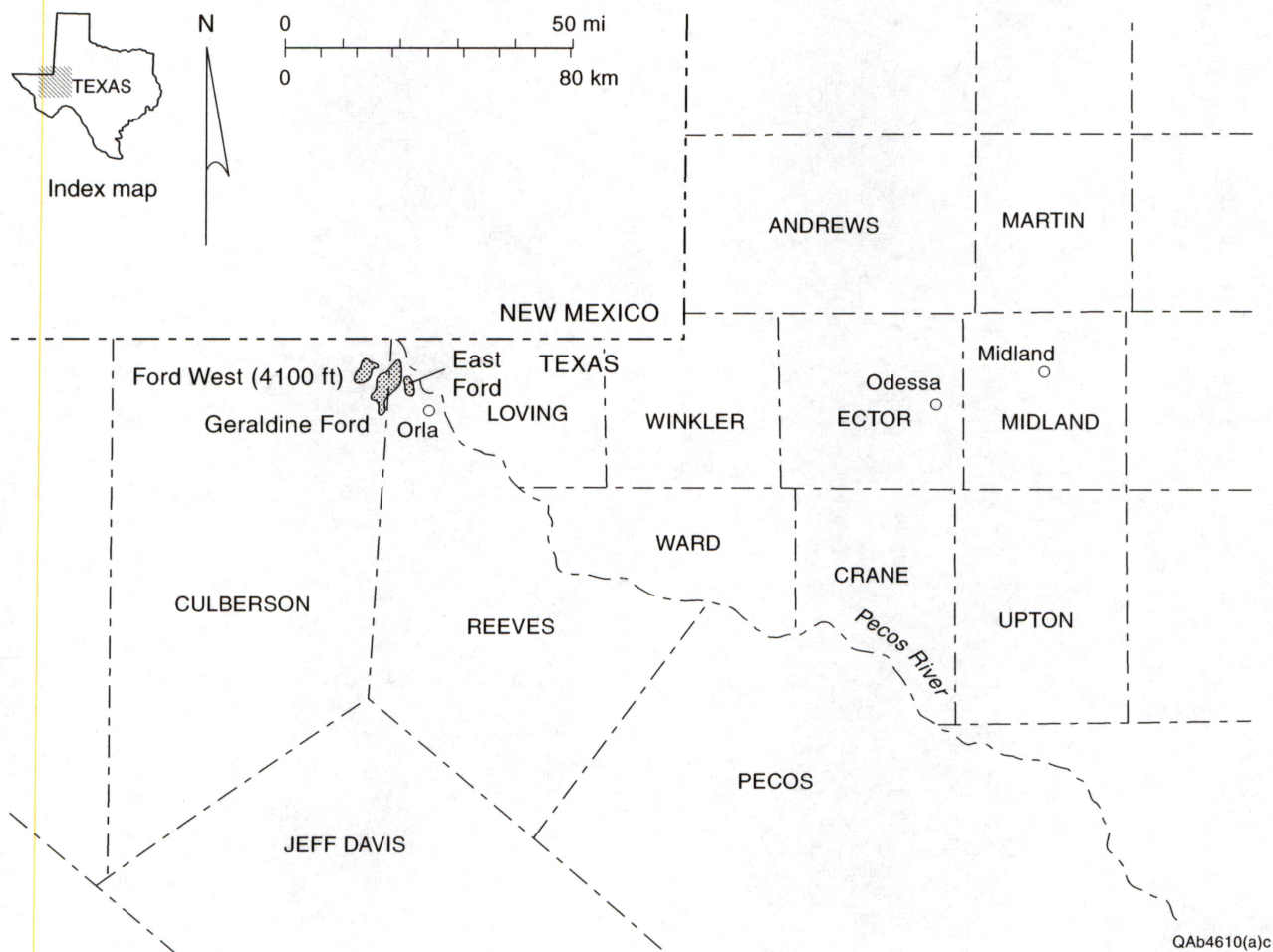


Figure 1. Location of East Ford and Geraldine Ford fields in Reeves and Culberson Counties, Texas.

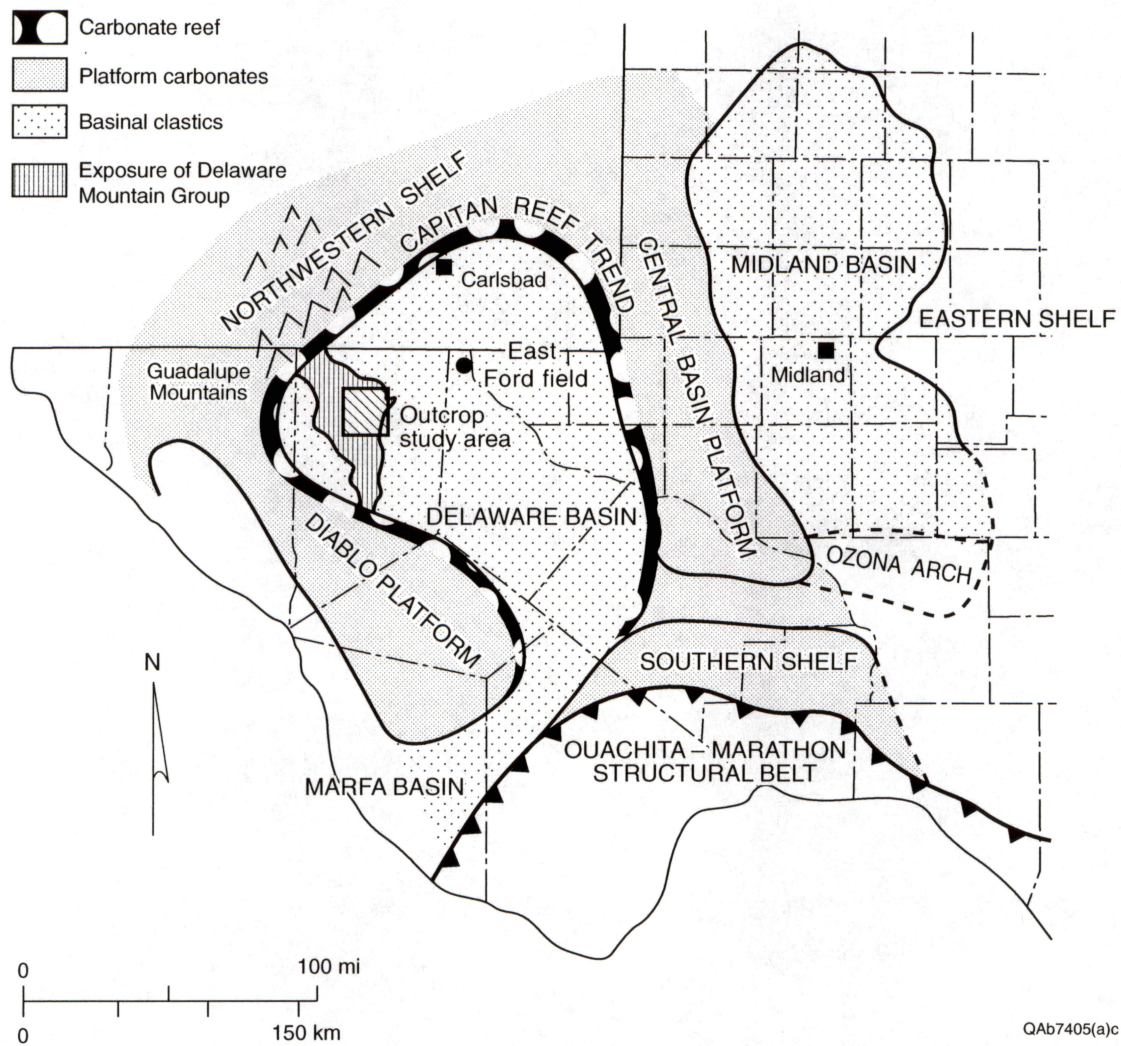


Figure 2. Map showing location of the Delaware Basin and paleogeographic setting during the Late Permian. Present-day exposures of the Delaware Mountain Group and the locations of the outcrop study area and East Ford field are superimposed onto the paleogeographic map. Modified from Silver and Todd (1969).

System	Series	Delaware Basin subsurface	Delaware Basin outcrop	Northwest Shelf	Central Basin Platform
PERMIAN	OCHOAN	Castile Fm	Castile Fm	Castile Fm	
	GUADALUPIAN	Bell Canyon Fm	Bell Canyon Fm	Tansill Fm	Tansill Fm
				Yates Fm	Yates Fm
				Seven Rivers Fm	Seven Rivers Fm
		Cherry Canyon Fm	Cherry Canyon Fm	Queen Fm	Queen Fm
	LEONARDIAN	Brushy Cnyn Fm	Brushy Cnyn Fm	Grayburg Fm	Grayburg Fm
				San Andres	San Andres
	LEONARDIAN	Bone Spring Fm	Cut Off Fm	San Andres Fm	San Andres Fm
			Bone Spring Fm	Victorio Peak Fm	Clear Fork Fm

Modified from Galloway and others (1983); Ross and Ross (1987)

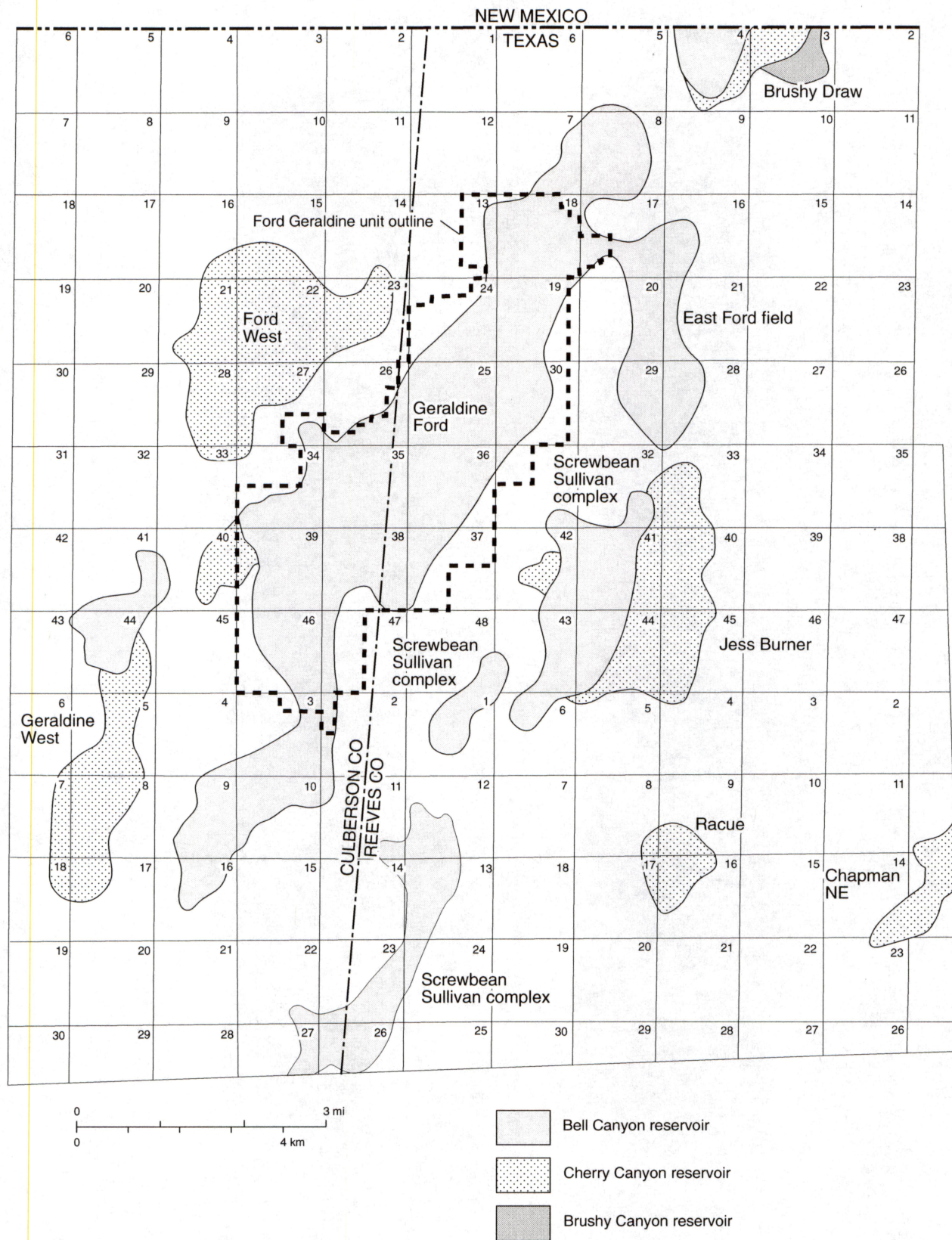
Carbonate tongues within the Delaware Mountain Gp: G = Getaway, M = Manzanita, H = Hegler, P = Pinery, R = Rader, m = McCombs, L = Lamar

● Relative importance as a hydrocarbon producing unit; based on Galloway and others (1983)

≡≡≡ Hiatus inferred from outcrop stratigraphic relations

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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.



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

Table 1. General information about the East Ford unit.

Field Name	East Ford
Unit Name	East Ford
Reservoir Name	Ramsey sandstone
State	Texas
County	Reeves
Formation	Bell Canyon
Railroad Commission District of Texas	8
Field Discovery Date	October 1960
Current Operator	Orla Petco, Inc.
Project Team Members	Bureau of Economic Geology The University of Texas at Austin University Station, Box X Austin, TX 78713-8924 Orla Petco, Inc. 1 Marienfeld Place, Suite 525 Midland, TX 79701
Technical Contact	Dr. Shirley P. Dutton Bureau of Economic Geology The University of Texas at Austin University Station, Box X Austin, TX 78713-8924 (512) 471-0329
Primary Drive Mechanism	Solution gas drive with limited water encroachment
Estimated primary recovery factor for Ramsey sandstone	14.6% (Assuming 10% of total production was from Olds sandstone)
No secondary recovery undertaken	
Date of first production	October 29, 1960

Table 1 (cont).

Number of wells drilled in field
45

Well patterns
20-acre spacing at north end, 40-acre spacing in the rest of the field

Number of wells penetrating reservoir
45

Total completions to date in field
45

Total current completions
17

Total current producers
10

Total current injection wells
7

Number of flowing wells
None

Project location
Within Reeves County, Texas, T&P Block 57, T-1, parts of sections 16, 17, 20, 21, 28, and 29
(see fig. 5).

Project Description

The goal of this study is to demonstrate that reservoir characterization can optimize enhanced oil recovery (CO₂ 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.

The project objective is divided into two main phases. Original objectives of the reservoir-characterization phase of the project were to (1) provide a detailed explanation 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, respectively; (2) choose a demonstration area in one of the fields; and (3) simulate a CO₂ flood in the demonstration area. Results indicated that 10 to 30 percent (1 to 3 MMbbl) of remaining oil in place in the demonstration area could be produced by CO₂ injection (Dutton and others, 1997a, b, 1998b). 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 has been expanded to include the East Ford unit. This additional reservoir characterization provides 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 low reservoir energy and inadequate reservoir characterization—primary recovery efficiency at the East Ford unit was less than 15 percent. Unless methodologies and technologies to overcome these producibility problems are applied, much of the remaining oil in the East Ford unit will 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, 1998b).

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.

Estimated recovery from the Phase II demonstration, a CO₂ flood in the East Ford unit, was also assessed. This assessment included (1) evaluating the results of the CO₂ flood conducted in the south part of the Ford Geraldine unit and (2) applying the results of simulation of a CO₂ flood of the north end of Ford Geraldine unit (Dutton and others, 1997a, b, 1998b) to the East Ford unit.

Phase II will apply the knowledge gained from the reservoir characterization to increase recovery from the East Ford unit through an enhanced-recovery program (CO₂ flood). Detailed comparison will be made between production from the East Ford unit during the CO₂ flood with the predictions that were made during Phase I on the basis of simulations. This comparison will provide an important opportunity to test the accuracy of reservoir-characterization and flow-simulation studies as predictive tools in resource preservation of mature fields. 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 100 other Delaware Mountain Group reservoirs in West Texas and New Mexico, which together contain 1,558 MMbbl of remaining oil.

Summary of Field History

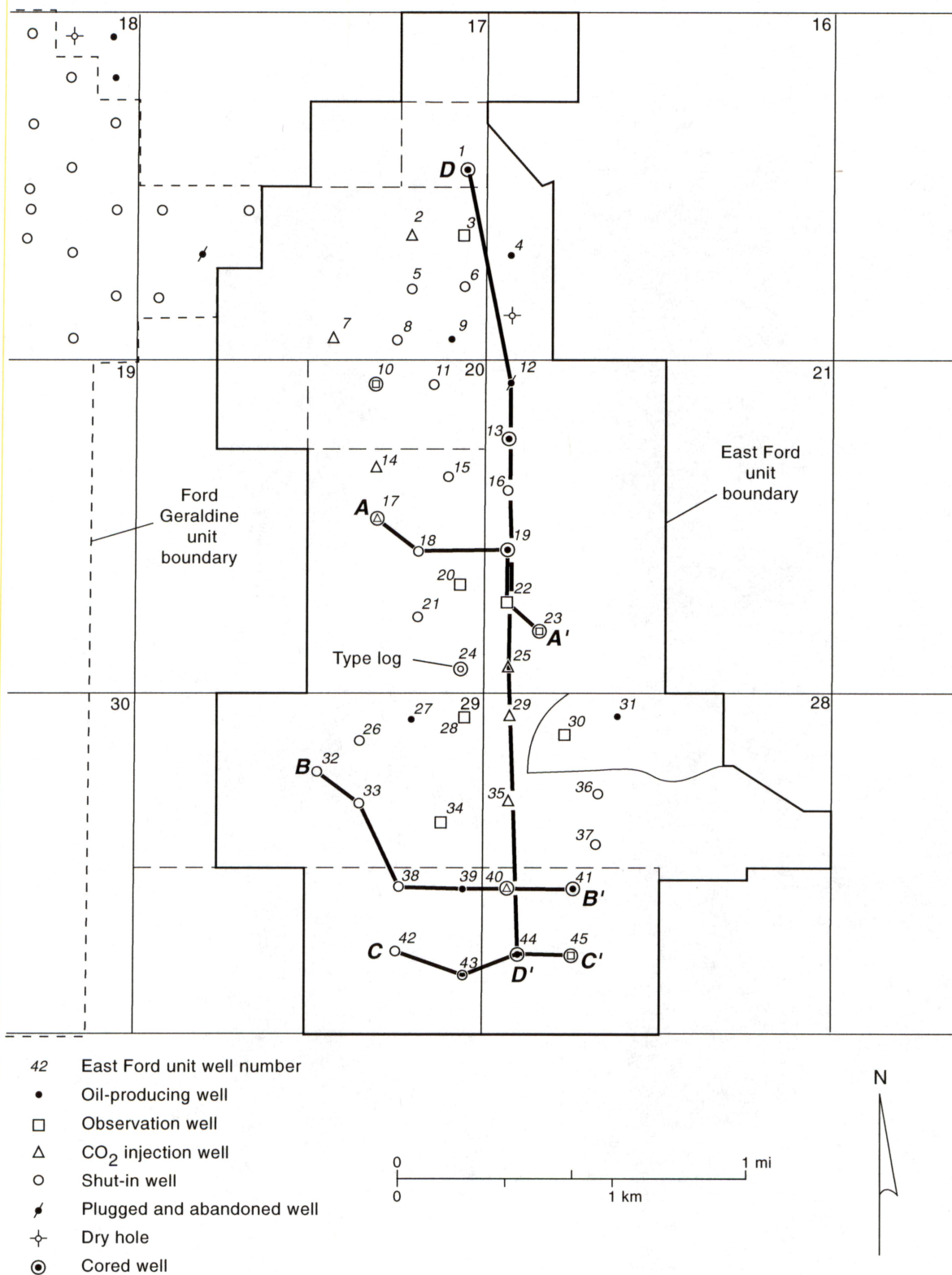
East Ford field was discovered in 1960 from reservoirs in the upper Bell Canyon Formation (fig. 3). The field was originally developed on 20-acre spacing at the north end then drilled on

40-acre spacing throughout the rest of the field (fig. 5). There are currently 44 usable well bores in the field, including 10 producer and 7 injector wells (fig. 5; table 1). Approximately half of the East Ford wells are open-hole completions. Most wells were initially stimulated by a small fracture treatment of 1,000 gallons of lease oil and 1,000 to 1,500 pounds of 20/40 sand (W. A. Flanders, Transpetco Engineering, written communication, 1994). About 5 yr after completion, many of the wells were restimulated by larger fracture treatments, typically 3,000 to 5,000 gallons of lease oil and 4,000 to 7,500 pounds of 10/20 sand. Most wells were initially completed in the Ramsey sandstone, then as Ramsey production declined, some wells were deepened and completed in the Olds sandstone (fig. 6). Production from the Olds and Ramsey sandstones was commingled.

The East Ford unit contained an estimated 19.8 million barrels (MMbbl) of original oil in place in the Ramsey sandstone (W. A. Flanders, Transpetco Engineering, written communication, 1994). 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 3,209,591 bbl. Of this, 90 percent, or 2,888,632 bbl, was estimated to have been produced from the Ramsey sandstone (W. A. Flanders, Transpetco Engineering, written communication, 1994). Recovery from the Ramsey sandstone represents 14.6 percent of the original Ramsey oil in place. Oil gravity 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.

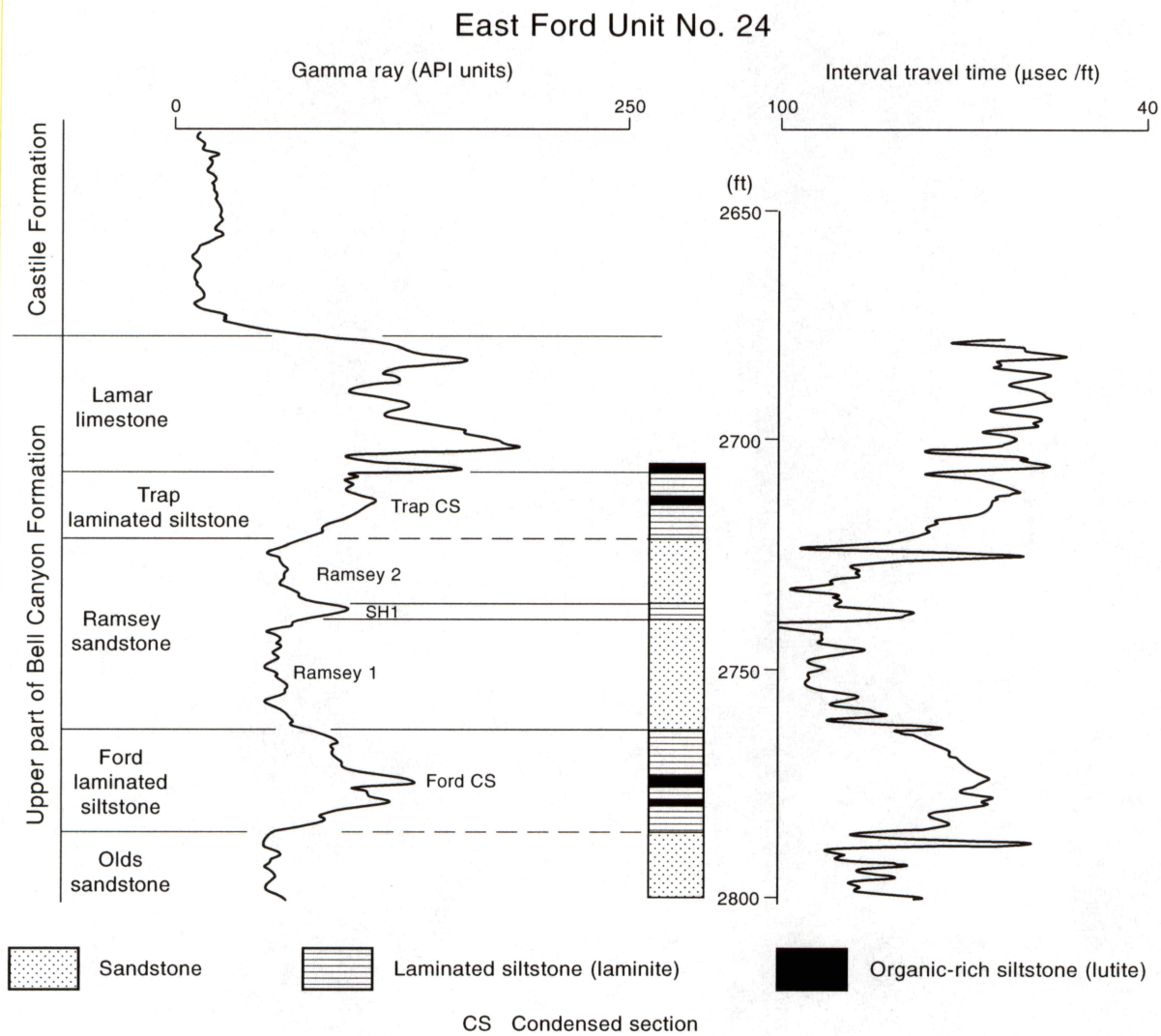
PETROPHYSICAL CHARACTERIZATION METHODS

Petrophysical characterization of the East Ford unit was accomplished by integrating core and log data and quantifying petrophysical properties from wireline logs (fig. 7); the goal was a set of maps of porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties across the unit. Petrophysical analysis of the Ramsey sandstone at the East Ford unit is complicated by the incomplete nature of the logging suites. A review of



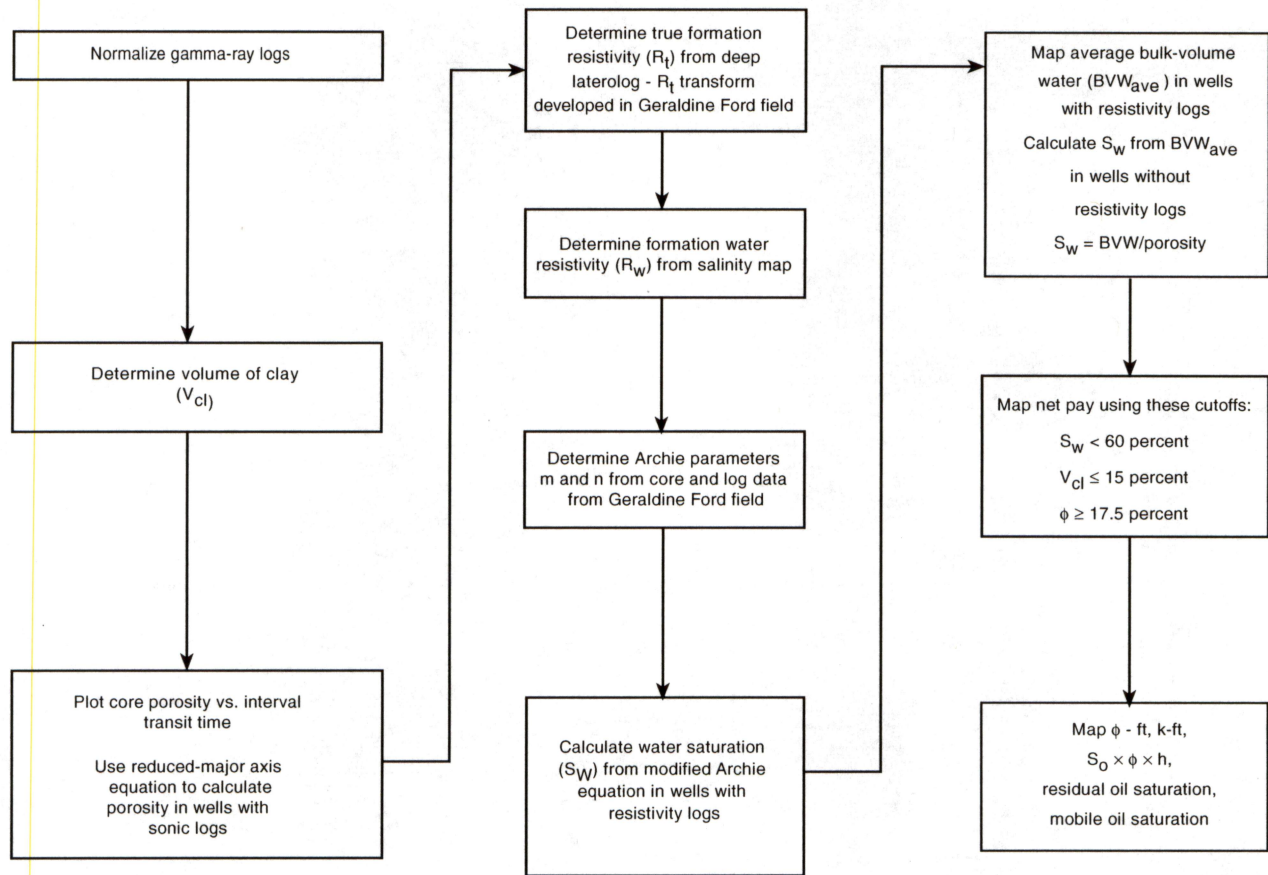
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Figure 5. Status of wells in the East Ford unit. Type log shown in figure 6, cross section A–A' in figure 40, cross section B–B' in figure 41, cross section C–C' in figure 42, and cross section D–D' in figure 43.



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



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Figure 7. Flow chart of petrophysical analysis. Because most of the wells in the East Ford unit were drilled and logged in the early 1960's, special techniques had to be used to maximize the information that could be derived from the old logs.

available log suites from the 45 East Ford unit wells showed that 26 wells have porosity logs, not counting the 4 wells having only cased-hole neutron logs (fig. 8). The cased-hole neutron logs were not used for quantitative petrophysical analysis. Because interval-transit-time (ITT) logs were the most common, we analyzed logs for porosity using only the 23 ITT logs; 17 wells have both ITT and resistivity logs. Of the 45 wells in the unit, 26 penetrate the entire reservoir interval; 1 dry hole just east of the East Ford unit also penetrates the Ramsey interval.

Because the gamma-ray logs in the East Ford unit were run in the early 1960's by several different companies at different sensitivities, they cannot be directly compared, even though all but one of the logs were recorded in API units. All the gamma-ray logs were normalized by equations in the following form:

$$\text{Normalized GR value (API units)} = m \times (\text{old GR value}) + b.$$

High and low gamma-ray values were selected for each well, so that the normalizing transforms each had different slopes (m) and y-intercepts (b). An example of the procedure is as follows:

High gamma ray = 89.4 API units from three specific peaks in the Lamar interval

Low gamma ray = 50.4 API units from clean Ramsey sandstone, or 15.3 API units from

Castile evaporite (used where Ramsey sandstone was missing or silty)

Gamma-ray counts from high gamma zone in old log = (HIgr)

Gamma-ray counts from low gamma zone in old log = (LOWgr)

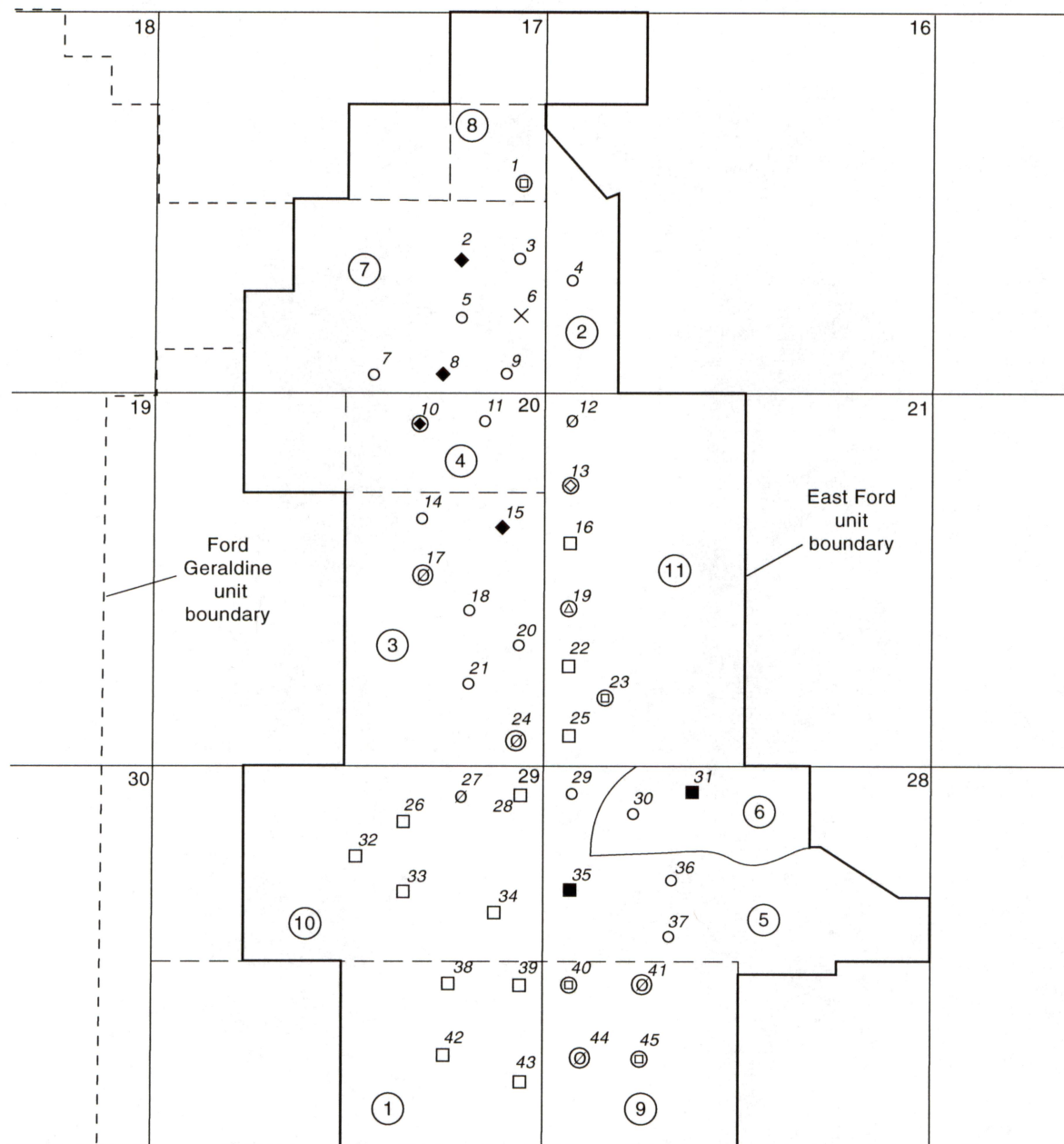
$$m = (89.4 - 50.4) / (\text{HIgr} - (\text{LOWgr}))$$

$$b = 50.4 - m \times \text{LOWgr}$$

$$\text{Normalized GR value (API units)} = m \times (\text{old GR value}) + b.$$

Porosity Transforms

One goal of the petrophysical analysis was to calculate porosity and permeability from ITT logs of wells having no core data. Data from the Ramsey interval in all cored wells were



- 42 East Ford unit well number
- GR only
- ◇ GR-Ø_N (open hole)
- ◆ GR-Ø_N (cased hole)
- GR-ITT
- GR-ITT-LL
- △ GR-ITT-LL-MLL
- GR-DEN
- ⊙ Cored well
- × No logs
- ⑩ Tract number



0 1 mi
0 1 km

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Figure 8. Distribution of geophysical log suites available in the East Ford unit.

combined in a plot of core porosity versus core permeability in order to determine porosity cutoffs for pay zones and to determine a porosity-versus-permeability transform (fig. 9). The least-squares linear regression line relating core porosity and permeability is

$$\text{Permeability (md)} = 0.014 \times 10^{(0.144 \times \text{porosity})}.$$

On the basis of this equation, a porosity cutoff of 17.5 percent, corresponding to a permeability of 5 md, was selected for calculating net pay. A change in the slope of the permeability distribution occurs at 5 md, and sandstones having permeability of ≥ 5 md probably represent the floodable Ramsey sandstones. (See section on Permeability Distribution, p. 39).

Core-to-log correction factors were determined for each cored well, and core depths were shifted to log depths. A cross plot of ITT versus core porosity was constructed to determine the ITT-log to core-porosity transform (fig. 10). Several of the ITT logs had zones where the readings went off scale (>100 $\mu\text{sec/ft}$) because of hole washout, and these intervals were omitted from the plot of ITT versus porosity. The reduced-major-axis (RMA) equation relating ITT and core porosity was used to determine porosity in wells having ITT logs. The RMA equation is

$$\text{Porosity (percent)} = 0.533 (\text{ITT}) - 26.5.$$

Because so few ITT logs were available in the East Ford unit, logs from wells with hole washout were used in the petrophysical analysis. ITT values were extrapolated into the washed-out zones from depths where the Ramsey sandstone had good log response, and these extrapolated values were used to calculate porosity from the RMA equation.

Volume of Clay

Volume of clay is one of the parameters used to determine pay intervals in the Ramsey sandstone. To determine volume of clay (V_{cl}), the values for gamma-ray response in a clean sandstone (GR_{cl}) and in a shale (GR_{sh}) must be obtained. In the Delaware sandstones, determining an accurate value for GR_{sh} is difficult because of the absence of true shales. The gamma-ray response of organic-rich siltstones was substituted for GR_{sh} . In addition, the presence

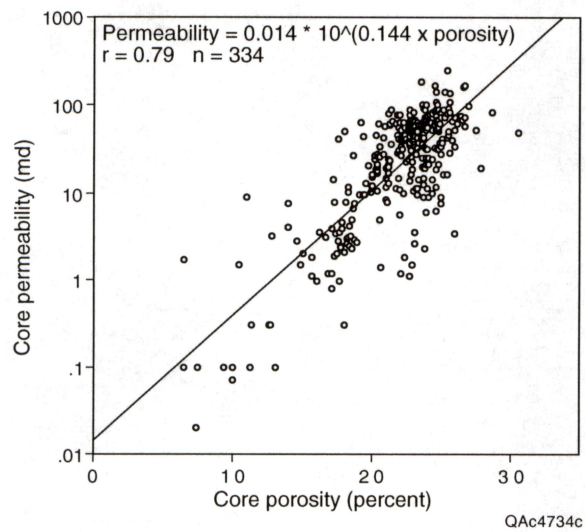


Figure 9. Cross plot of core porosity versus core permeability with porosity–permeability transform for the Ramsey sandstone in the East Ford unit, Reeves County, Texas.

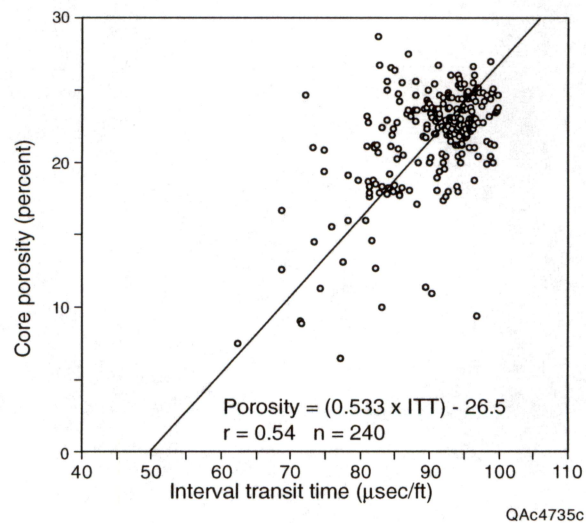


Figure 10. Cross plot of interval transit time (ITT) versus core porosity with porosity transform for the Ramsey sandstone in the East Ford unit.

of potassium feldspar in the sandstones can also affect the gamma-ray log response. Work on Brushy Canyon sandstones at Hat Mesa (Thomerson, 1992) and Red Tank (Green and others, 1996) fields in New Mexico, however, has demonstrated that the presence of potassium feldspar in both the sandstones and the adjacent siltstones appears to affect gamma-ray logs equally.

Figure 11 is a cross plot of interval transit time (ITT) versus normalized gamma-ray response (GR) from 16 wells in the East Ford unit. From this plot, a GR_{cl} value of 50 API and GR_{sh} of 89 API was selected. The V_{cl} for the Ramsey sandstone was then calculated by

$$IGR = (GR - 50)/(89 - 50), \text{ and}$$

$$V_{cl} = 0.33[2^{(2 \times IGR)} - 1.0] \text{ (Atlas Wireline, 1985),}$$

where IGR is gamma-ray index and V_{cl} is volume of clay. A map of V_{cl} distribution (fig. 12) shows that low values occur in the center of the East Ford unit, and V_{cl} increases toward the margins of the unit, where the Ramsey sandstone pinches out into siltstone.

Calculation of Water Saturation

Resistivity logs are electric logs that are used to determine hydrocarbon-versus-water-bearing zones (Asquith and Gibson, 1982). Data from resistivity logs can be used to calculate a formation's water saturation, if several parameters, including true formation resistivity (R_t), formation water resistivity (R_w), cementation exponent (m), and saturation exponent (n), are known (Archie, 1942).

True Formation Resistivity

In the East Ford unit, commonly only a deep laterolog (LDD) was run, with no accompanying log to measure either resistivity of the flushed zone (R_{xo} , which is measured by a Microlaterolog [MLL] or a Microspherically Focused Log [MSFL]), or resistivity of the invaded zone (R_i , which is measured by a Shallow Laterolog [LLS]). When both an LDD and an R_{xo} or an LLS log are available, the LDD can be corrected for invasion by

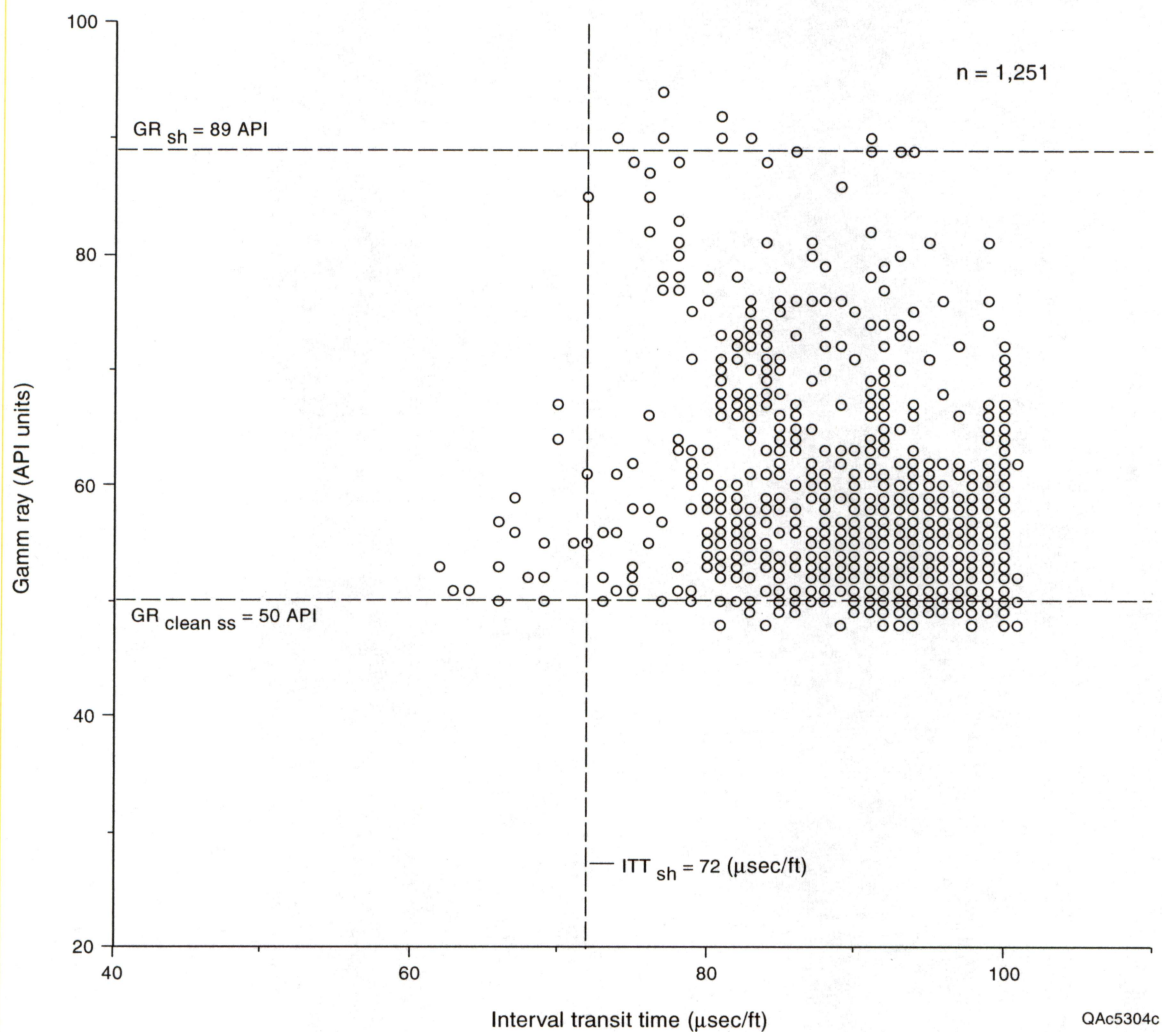


Figure 11. Cross plot of interval transit time (ITT) versus gamma ray (GR) for the Ramsey sandstone interval, East Ford unit. The data in this figure are from 16 wells, and the cross plot was used to determine GR_{cl} (50 API), GR_{sh} (89 API), and ITT_{sh} (72 μsec/ft).

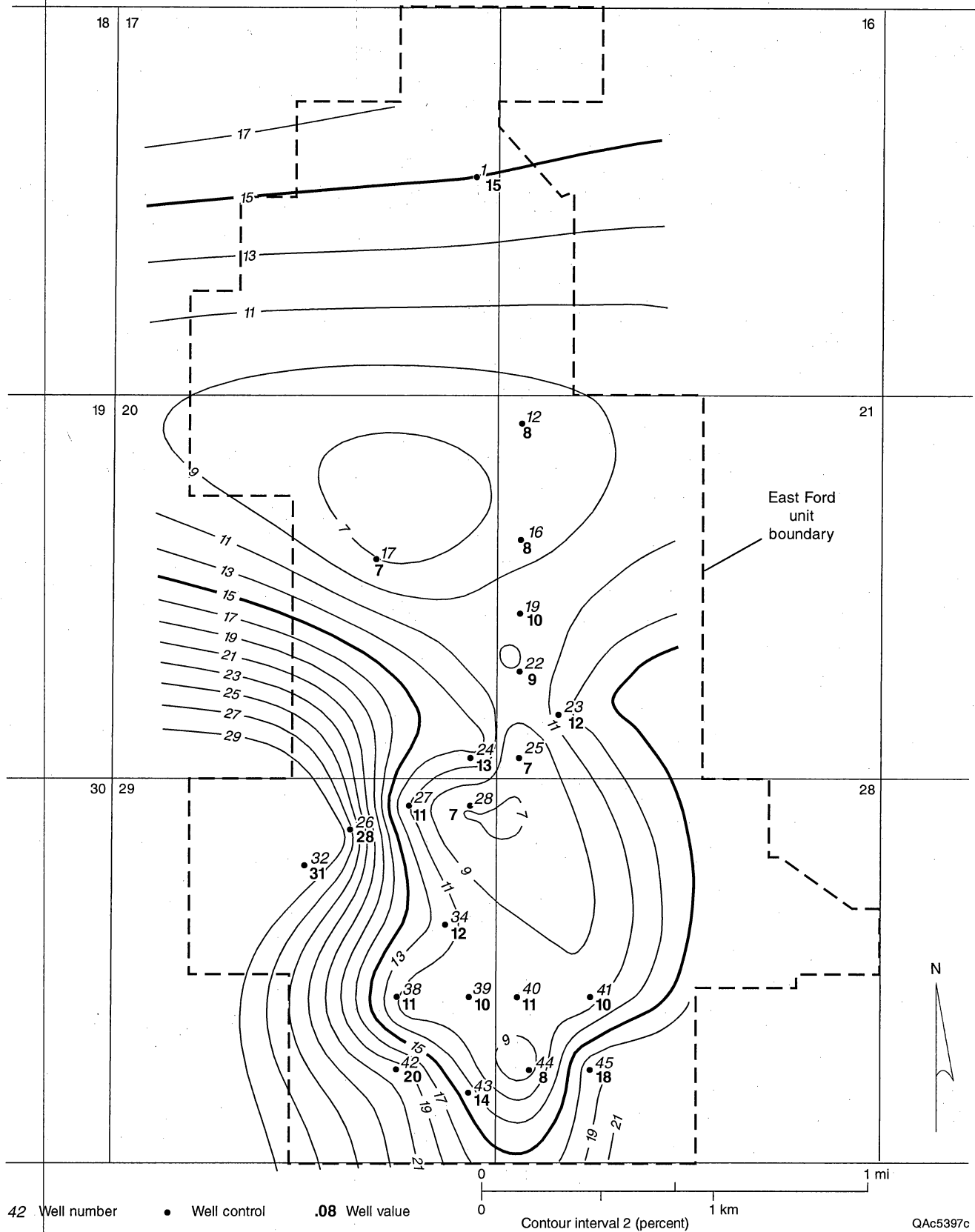


Figure 12. Map of volume of clay in Ramsey sandstone in the East Ford unit. Volume of clay was calculated from gamma ray and interval-transit-time logs.

$$R_t = 1.67 \times \text{LLD} - 0.67 \times \text{MLL} \text{ (Hilchie, 1979), and}$$

$$R_t = 2.4 \times \text{LLD} - 1.4 \times \text{LLS} \text{ (Asquith, 1979),}$$

where

R_t = true formation resistivity (LLD corrected for invasion),

LLD = deep laterolog,

MLL = R_{xo} or flushed zone resistivity, and

LLS = shallow laterolog.

In the Ford Geraldine unit, several wells had both an LLD log and an R_{xo} or an LLS log (Asquith and others, 1997; Dutton and others, 1997a). Using these logs, we calculated R_t values from these equations and plotted R_t versus the LLD values (fig. 13). The calculated linear regression equation is $R_t = 1.3002 \times \text{LLD} + 0.3397$. Scatter on the plot is less at low LLD resistivities (2 to 8 ohm-m), which is the typical range of LLD values for Delaware sandstones. Because of the similarity of the Ramsey reservoir in the East Ford and Ford Geraldine units, the linear regression equation calculated for the Ford Geraldine unit was used to correct LLD to R_t in East Ford wells.

To illustrate the importance of using this LLD- R_t transform to obtain R_t in wells with only a deep laterolog, hydrocarbon pore-feet thickness was calculated in the Ramsey sandstone in a typical Ford Geraldine unit well with and without the correction. When the transform was not used, original oil in place (OOIP) was underestimated by 155,000 bbl in a 40-acre tract (Asquith and others, 1997).

Formation-Water Resistivity

In preparation for calculating water saturations (S_w), we estimated formation-water resistivities (R_w) across the Ford East unit from a contour map of formation-water salinities (fig. 14). Salinity data from four wells in the East Ford unit (EFU 1, 9, 24, and 37) were combined with those from the Ford Geraldine unit (Dutton and others, 1997a) to obtain a more

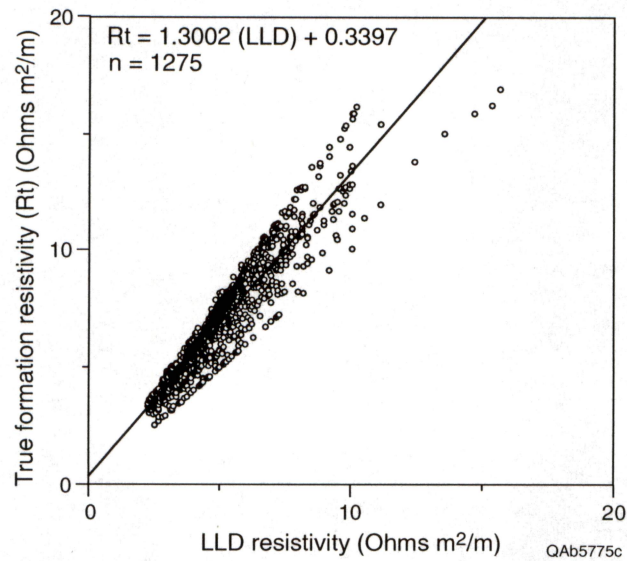


Figure 13. Cross plot of deep laterolog resistivity (LLD) versus true formation resistivity (R_t) for 1,275 data points from 16 Ford Geraldine unit wells having an LLD log plus a microlaterolog (MLL) or a shallow laterolog (LLS). The transform equation $R_t = 1.3002 \times (LLD) + 0.3397$ can be used to calculate R_t from LLD in Ramsey sandstone wells in the East Ford unit, where MLL and LLS logs are unavailable.

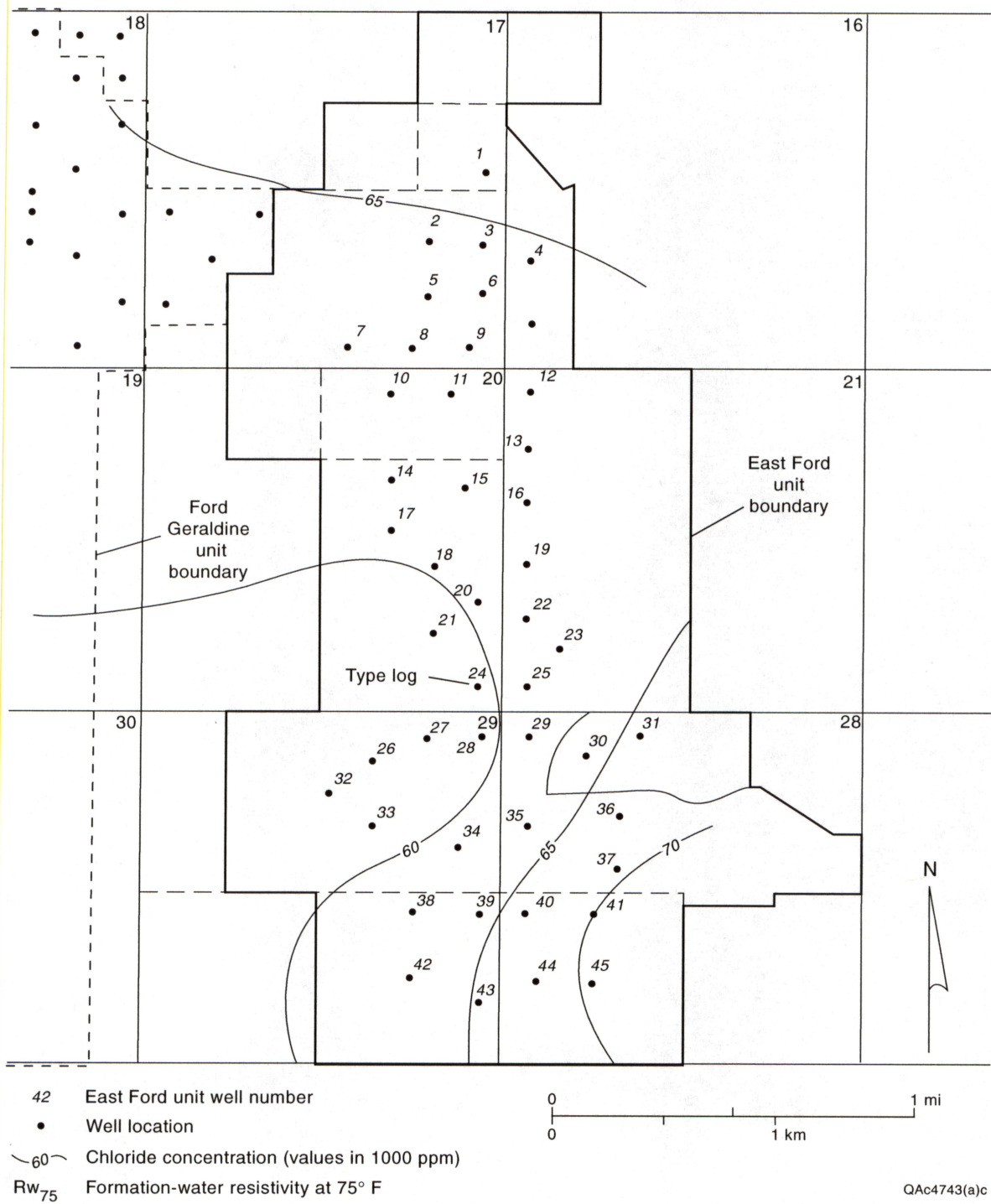


Figure 14. Isosalinity map with formation-water resistivities (R_w) at 75°F for the East Ford unit.

regional view of water salinity. The contour map of salinity was used to assign salinity values for each of the East Ford wells. The formation-water resistivity at 75°F was then read from a chart relating NaCl concentration, temperature, and resistivity (Schlumberger, 1995, chart Gen-9, p. 1–5). Values of R_w at 75°F ranged from 0.10 to 0.12 ohm-m in the East Ford unit (fig. 14). Formation temperatures in each well were calculated from the geothermal gradient in the field and the depth of the middle of the Ramsey sandstone. Values of R_w at formation temperature were then calculated by Arp's formula (Asquith and Gibson, 1982):

$$R_{ff} = R_{temp} \times (Temp + 6.77) / (T_f + 6.77),$$

where

R_{ff} = resistivity at formation temperature,

R_{temp} = resistivity at a temperature other than formation temperature,

Temp = temperature at which resistivity was measured, and

T_f = formation temperature.

Archie Parameters m and n

No special core analyses of cementation exponent (m) or saturation exponent (n) were available from the East Ford unit. The values of m and n determined for Ramsey sandstone in the Ford Geraldine unit (Asquith and others, 1997; Dutton and others, 1997a) were therefore used in the East Ford unit.

Special core analyses from the Ford Geraldine Unit No. 156 well included four measurements of the cementation exponent, m; the average of the measured m values was 1.88. To verify the measured values, log data were used to back-calculate m from ITT porosity and flushed-zone resistivity log values (Asquith and others, 1997). This method gave an m value of 1.83, which was used in the modified Archie equation.

We developed a new technique to calculate the value of the saturation exponent (n) in the Ford Geraldine unit using core porosity and water-saturation values from relative permeability

curves (Asquith and others, 1997; Dutton and others, 1997a). The value of n calculated according to this method was 1.90.

For the Bell Canyon sandstones in the East Ford unit, water saturations (S_w) should therefore be calculated by the following modified Archie equation:

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

where ϕ is porosity.

Net-Pay Cutoffs

Net-pay cutoffs for the Ramsey sandstone in the East Ford Geraldine unit were selected for volume of clay (V_{cl}), porosity (ϕ), and water saturation (S_w). As discussed earlier, accurate values for V_{cl} are difficult to determine for the Delaware sandstones because of the absence of adjacent shales. The selection of a V_{cl} cutoff was therefore based on the work of Dewan (1984), which suggests a V_{cl} cutoff of 15 percent for reservoirs with dispersed authigenic clay. The dispersed-authigenic-clay cutoff was used because of the common occurrence of authigenic clay in the Delaware sandstones (Williamson, 1978; Thomerson, 1992; Walling, 1992; Asquith and others, 1995; Green and others, 1996).

Examination of the core-porosity versus core-permeability cross plot (fig. 8) for the Ramsey sandstone in the East Ford unit resulted in the selection of a porosity cutoff of 17.5 percent, corresponding to a permeability of 5 md.

Five K_{ro} – K_{rw} relative-permeability curves from the Ford Geraldine Unit No. 156 well were used to determine the water saturation (S_w) cutoff because no relative-permeability data were available from the East Ford unit. The five relative-permeability curves for the Ramsey sandstone were normalized according to the method outlined by Schneider (1987) (fig. 15). At a water saturation (S_w) of 60 percent, the relative permeability to oil (K_{ro}) should be approximately eight times the relative permeability to water (K_{rw}). For the Ramsey sandstone in the East Ford unit, a water-saturation cutoff of 60 percent was therefore selected, the same cutoff that was used for the Ford Geraldine unit.

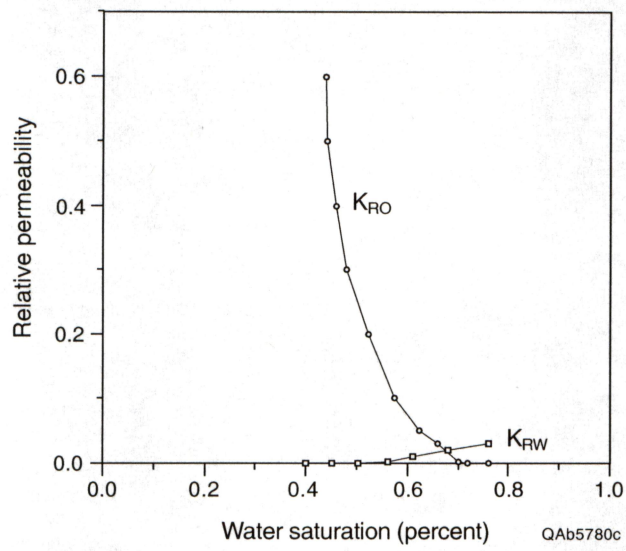


Figure 15. Normalized relative permeability curves for the five curves measured in the Ford Geraldine Unit No.156 well. The method of normalization was based on the work of Schneider (1987).

Residual- and Mobile-Oil Saturation

Residual-oil saturation (ROS) values determined from the relative-permeability curves from the Ford Geraldine Unit No. 156 well were plotted against porosity values from that well, and a regression line fitted to the data gave the relationship $ROS = -0.74 \times \phi + 41.41$ (Dutton and others, 1997a). By combining the modified Archie water saturations (S_w) with residual oil saturations, original mobile-oil saturations (MOS) can be calculated as

$$MOS = (1.0 - S_w) - ROS.$$

These equations and cutoffs developed from the petrophysical analysis were used to map porosity, permeability, net pay, water saturation, mobile-oil saturation, and other reservoir properties in the East Ford unit.

THREE-DIMENSIONAL DESCRIPTION OF RESERVOIR

Areal and Vertical Description

The East Ford unit includes 1,175 acres (table 2). The main reservoir is the Ramsey sandstone, but there is also some production from the underlying Olds sandstone (fig. 6). The Ramsey sandstone is a 0- to 45-ft-thick sandstone that is bounded by the Ford and Trap laminated siltstones. Throughout the East Ford unit, the Ramsey sandstone is divided into two sandstones (Ramsey 1 and Ramsey 2) separated by a 1- to 3-ft-thick laminated siltstone (SH1) (fig. 6).

The subsurface data base for reservoir characterization available from East Ford field includes logs from 44 of the 45 wells in the field, most commonly gamma-ray or gamma-ray and interval-transit-time logs (fig. 7). Core analyses (permeability, porosity, water saturation, and oil saturation) from 620 samples from 11 wells throughout the East Ford unit were entered into a spreadsheet. Areal mapping of reservoir properties across the field was accomplished by means of core-analysis data, geophysical logs, and log-data to core-porosity transforms and core-porosity to core-permeability transforms.

Table 2. Areal and vertical description of reservoir.

Areal extent	1,175 acres
Average porosity	21.7% (from core analyses)
Initial water saturation	44 to 68 percent (most of field 44 to 48 percent)
Water saturation at end of primary production	51.3 percent (W. A. Flanders, Transpetco Engineering, written communication, 1994)
Average permeability	39 md (from core analyses)
Directional permeability (Kv/Kh)	Vertical permeability is typically 90 percent of horizontal permeability
Reservoir dip	1° to the east-northeast
Average net pay thickness	23 ft
Average gross pay thickness	33 ft
Number of reservoir layers	Two; Ramsey 1 and Ramsey 2

Porosity Distribution

Average porosity in the Ramsey interval is 21.7 percent (fig. 16), as determined by 334 core analyses of Ramsey 1 and 2 sandstones. Standard deviation is 3.9 percent. Ramsey 1 sandstones have higher average porosity than do Ramsey 2 sandstones, 22.5 versus 21.4 percent, respectively (table 3). SH1 siltstones have an average porosity of 18.2 percent, and they range from 17.2 to 20.7 percent. Ramsey sandstones, with porosity lower than 17 percent (fig. 16), are interpreted to represent calcite-cemented sandstones.

Areal distribution of porosity was mapped by means of porosity data from core analyses, combined with porosities calculated from ITT logs and the log-core porosity transform (fig. 10). The use of core-analysis data increases available well control and provides a more detailed map of porosity distribution than does the use of porosity-log data alone. In wells that have both porosity logs and core-analysis data, the core-analysis data were used. Porosity values for the Ramsey 1 and 2 sandstones (excluding the SH1 siltstone) were calculated on a foot-by-foot basis, and these values were averaged to determine the average porosity in each well.

The map of average porosity (fig. 17) for the Ramsey sandstone in the East Ford unit exhibits a strong north-south trend of high porosity that follows the positions of the Ramsey 1 and 2 sandstone channels (see later section on Channel Facies, p. 70). The zone of highest porosity (>24 percent) is confined to the central part of the field, with slightly lower porosity at the south end. The same log and core-analysis data were used to map porosity \times thickness (fig. 18). This map shows a similar north-south trend, but with the highest values (>8 ft) shifted toward the south end of the unit.

Saturation Distribution

As is common in Delaware sandstone reservoirs, the Ramsey sandstone at the East Ford unit had high initial water saturation (S_w), and many wells produced some water at discovery. The Ford Geraldine unit averaged 47.7 percent S_w at discovery, well above the irreducible water

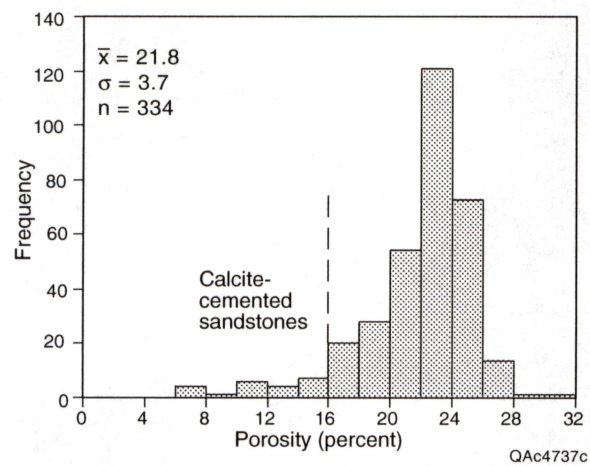


Figure 16. Distribution of porosity in Ramsey 1 and 2 sandstones in the East Ford unit from core analyses. Low porosity values (<16 percent) are probably from calcite-cemented sandstones.

Table 3. Arithmetic average porosity and permeability of upper Bell Canyon sandstones and siltstones and range of values, East Ford field.

		Average porosity (range) (percent)	Average permeability (range) (md)	Dykstra-Parsons coefficient (V)	Water saturation (percent)	No. samples
35	Trap siltstone	14.7 (2.9–18.8)	1 (0.01–8)		67	23
	Ramsey 2 sandstone	21.4 (6.5–30.6)	34 (0.1–249)	0.57	48	133
	SH1 siltstone	18.2 (17.2–20.7)	4 (0.3–14)		54	19
	Ramsey 1 sandstone	22.5 (6.5–27.0)	46 (0.02–183)	0.44	46	182
	Ford siltstone	15.9 (7.5–22.4)	1 (0.1–5)		65	31

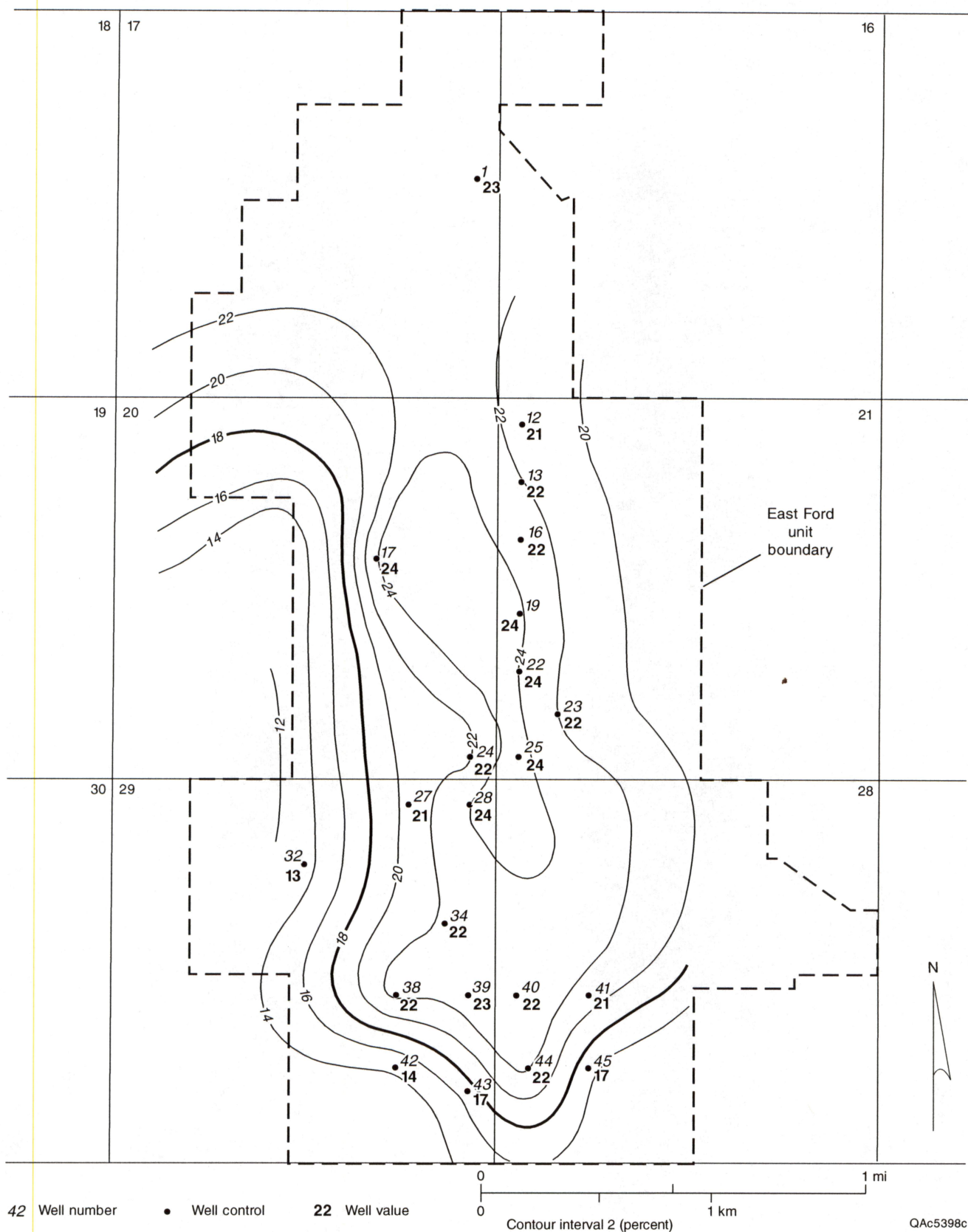


Figure 17. Map of average porosity of the Ramsey sandstone in the East Ford unit. The average porosities were determined from ITT logs and the core-log porosity transform, supplemented by core-analysis data.

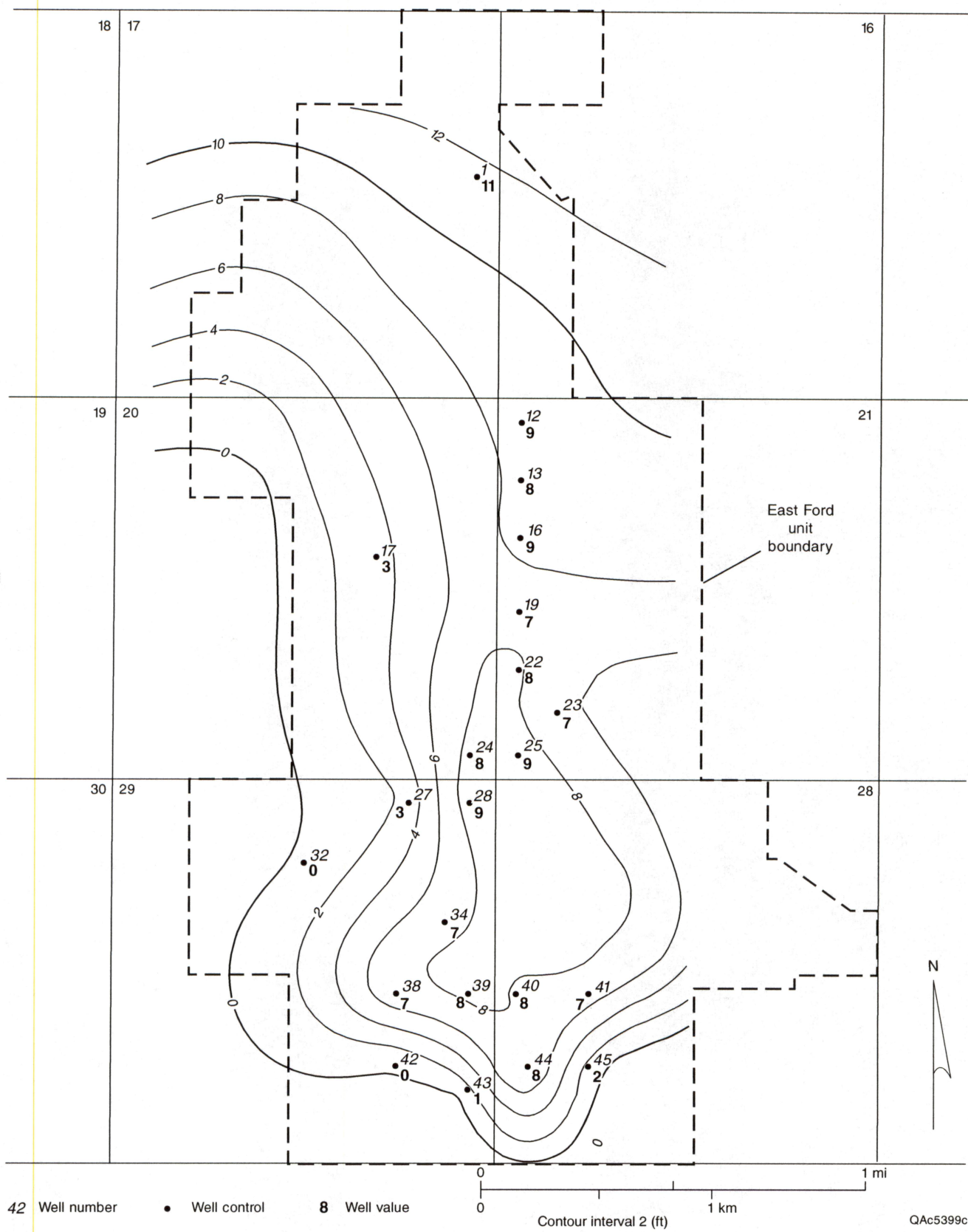


Figure 18. Map of porosity \times thickness of the Ramsey sandstone in the East Ford unit.

saturation of 35 percent (Pittaway and Rosato, 1991), and the Ramsey sandstone at the East Ford unit probably also had initial water saturation greater than irreducible. Average S_w measured in 334 core analyses of the Ramsey 1 and 2 sandstones (excluding the SH1 siltstone) was 47.1 percent, with a standard deviation of 7.2 percent (fig. 19). Ramsey 2 sandstones have slightly higher average core-water saturations than do Ramsey 1 sandstones, 48 versus 46 percent, respectively (table 3). Average water saturation measured in SH1 siltstone cores was 54 percent.

Areal distribution of S_w was mapped from geophysical log data supplemented by water-saturation data from cores. First, we mapped the areal distribution of bulk volume water (BVW) according to the formula $S_w = BVW_{ave}/\phi$, using log data from wells having both ITT and resistivity logs (method described in more detail in Asquith and others, 1997). On the basis of this map, BVW values were then assigned to wells having porosity logs but no resistivity logs. Average S_w values were calculated in these wells, then combined with S_w data from resistivity logs to map S_w distribution in the East Ford unit. This approach resulted in many wells in the main producing trend of the field having calculated S_w greater than 50 percent. Such high water saturations were considered unreasonable because water cuts in these wells are low, so a new method for calculating water saturation was developed.

A plot of all log-calculated S_w values versus percent water cut in initial potential tests had a large scatter in the data. Data from some wells were thought to be invalid and were eliminated if the wells fell into one of the following categories: (1) Wells completed only in the Olds sandstone; these wells had high water cuts from the Olds sandstone that could not be equated to the S_w calculated from the Ramsey sandstone. (2) Wells completed in both the Olds and Ramsey sandstones having high water cuts; these wells probably produced mainly from the Olds sandstone. (3) Wells without resistivity logs, for which S_w was calculated from the BVW map. These wells had high calculated S_w values that were inconsistent with their low water cuts. (4) Other wells with inconsistent log S_w and water-cut data. For a few wells, it was unclear why the calculated S_w was high despite a low water cut, but these inconsistent wells were also

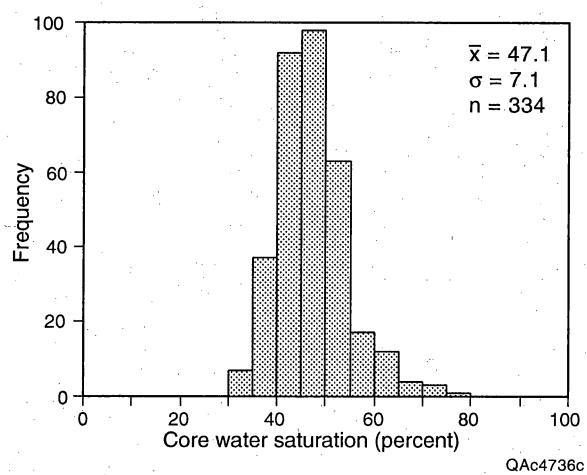


Figure 19. Distribution of water saturation in Ramsey 1 and 2 sandstones in the East Ford unit from core analyses.

eliminated from the data base. The remaining valid data were used to calculate a linear regression line relating water cut to S_w (fig. 20). A map of S_w across the East Ford unit (fig. 21) was then made from the valid log-calculated S_w data (from fig. 20), combined with S_w data calculated from the water-cut– S_w transform. Values of S_w ranged from 0.44 to 0.48 across most of the field. S_w increases to the east and northeast, which is to be expected because that direction is down structural dip.

No gas cap was originally present in the field, so oil saturation at field discovery was $1.0 - S_w$. Mobil-oil saturation (MOS) was calculated from log data by the formula $MOS = (1.0 - S_w) - ROS$. The values for residual oil saturation (ROS) were calculated according to the porosity–ROS transform developed from relative-permeability curves measured in the Ford Geraldine unit: $ROS = -0.74 (\text{porosity}) + 41.41$ (Asquith and others, 1997; Dutton and others, 1997a). A map of MOS distribution shows that the highest MOS values (>30 percent) are concentrated in the south part of the East Ford unit (fig. 22).

Permeability Distribution

Arithmetic average permeability determined by core analyses of Ramsey sandstones in the East Ford unit is 39 md (table 2; fig. 23), and the standard deviation is 35 md. Geometric mean permeability of the Ramsey sandstone is 20 md, with a standard deviation of 5 md. Vertical permeability is typically 90 percent of horizontal permeability (W. A. Flanders, Transpetco Engineering, written communication, 1994). Ramsey 1 sandstones have higher average permeability than do Ramsey 2 sandstones, 46 versus 34 md, respectively (table 3). SH1 siltstones have an average permeability of 4 md.

Plots of the cumulative distribution functions (CDF) of the East Ford permeability data (Ramsey 1, Ramsey 2, and total Ramsey) are close to straight lines on a logarithmic scale (fig. 24), indicating that the permeability data are approximately log normally distributed. All three populations are negatively skewed, having a tail of low permeability values that are

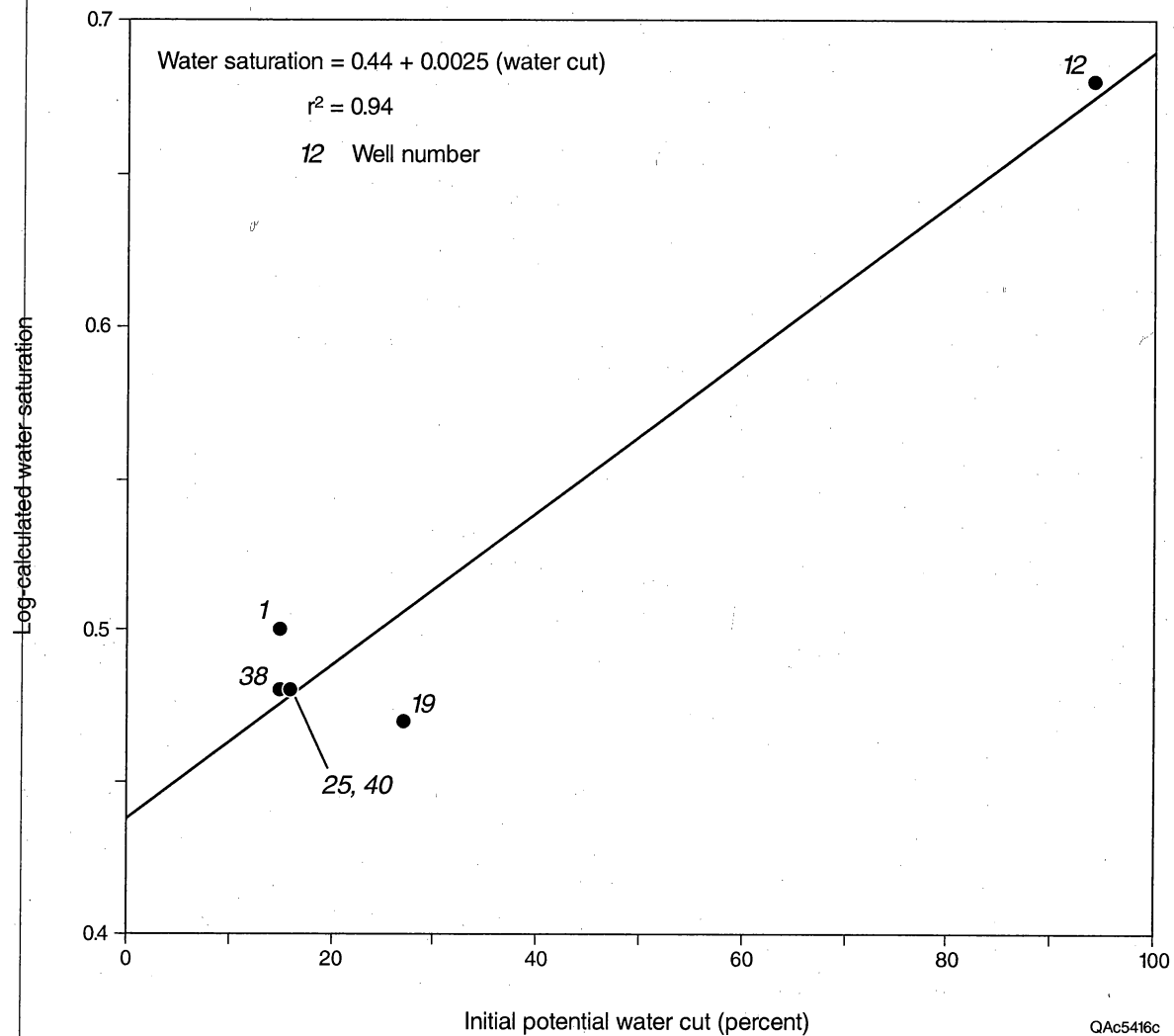


Figure 20. Plot of valid log-calculated water saturation (S_w) versus percent water cut in initial potential tests.

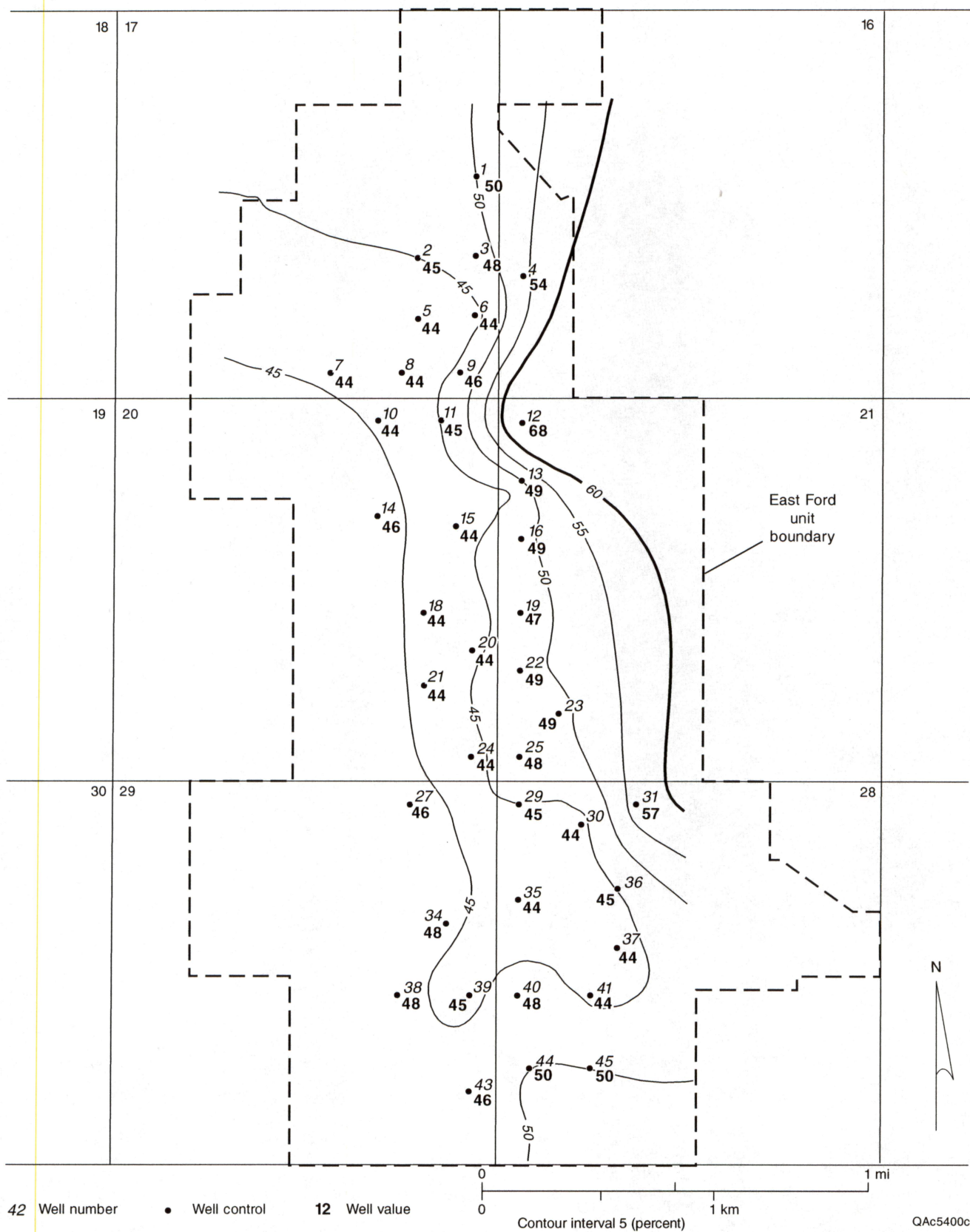


Figure 21. Map of water saturation (S_w) of the Ramsey sandstone in the East Ford unit. The S_w values are either valid log-calculated data (wells in figure 20) or calculated from the water-cut- S_w transform shown in figure 20.

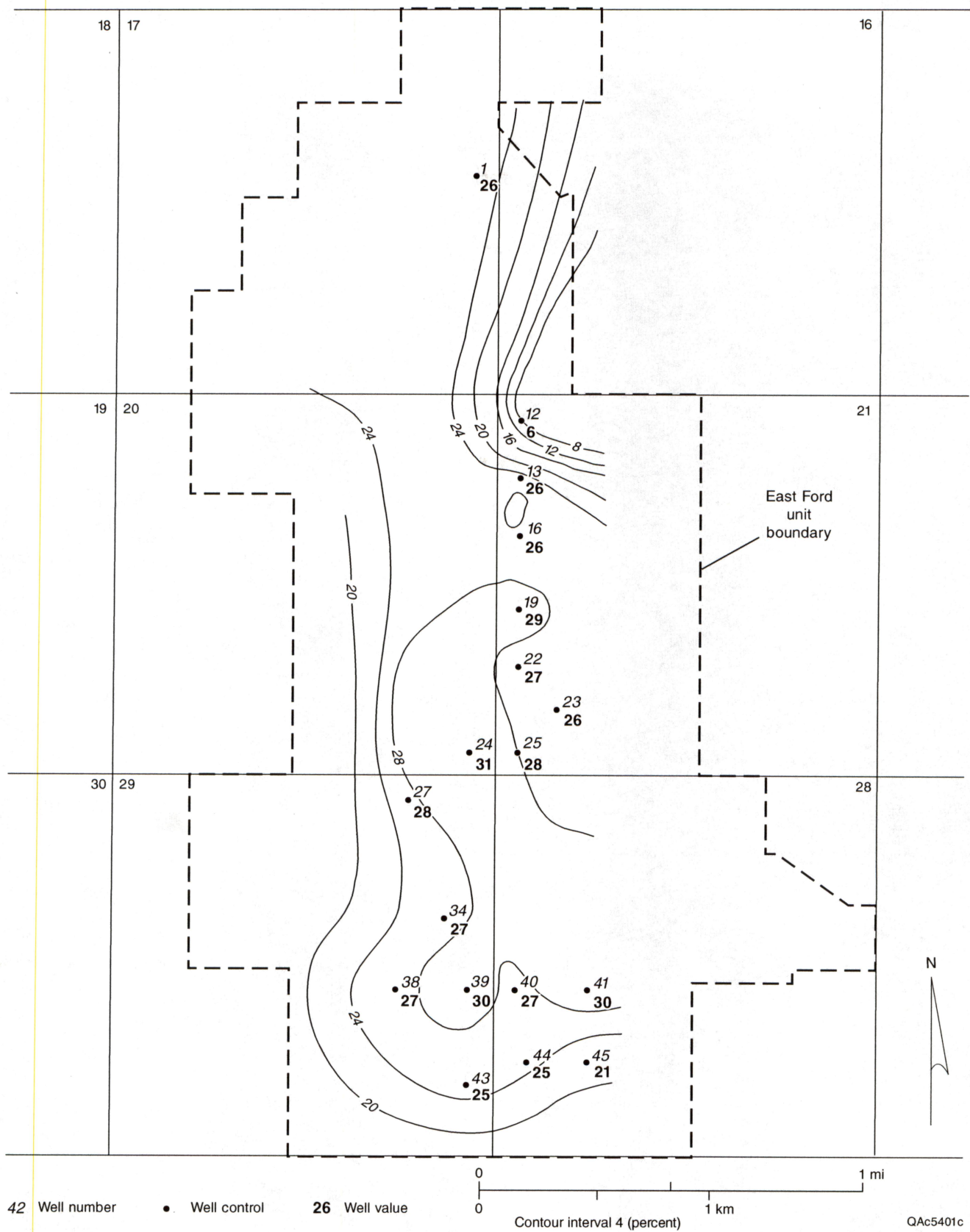


Figure 22. Map of mobile-oil saturation (MOS) of the Ramsey sandstone in the East Ford unit.

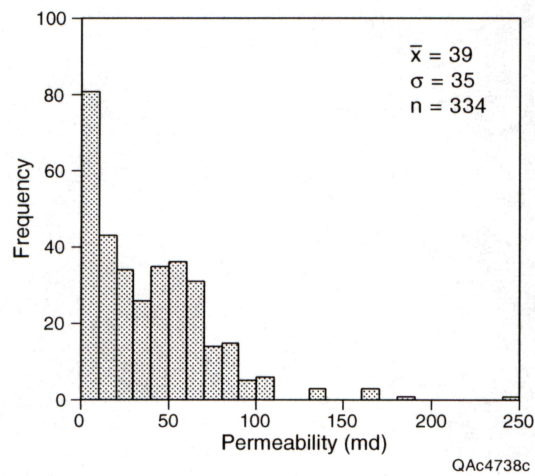


Figure 23. Distribution of permeability in Ramsey 1 and 2 sandstones in the East Ford unit, based on core analyses.

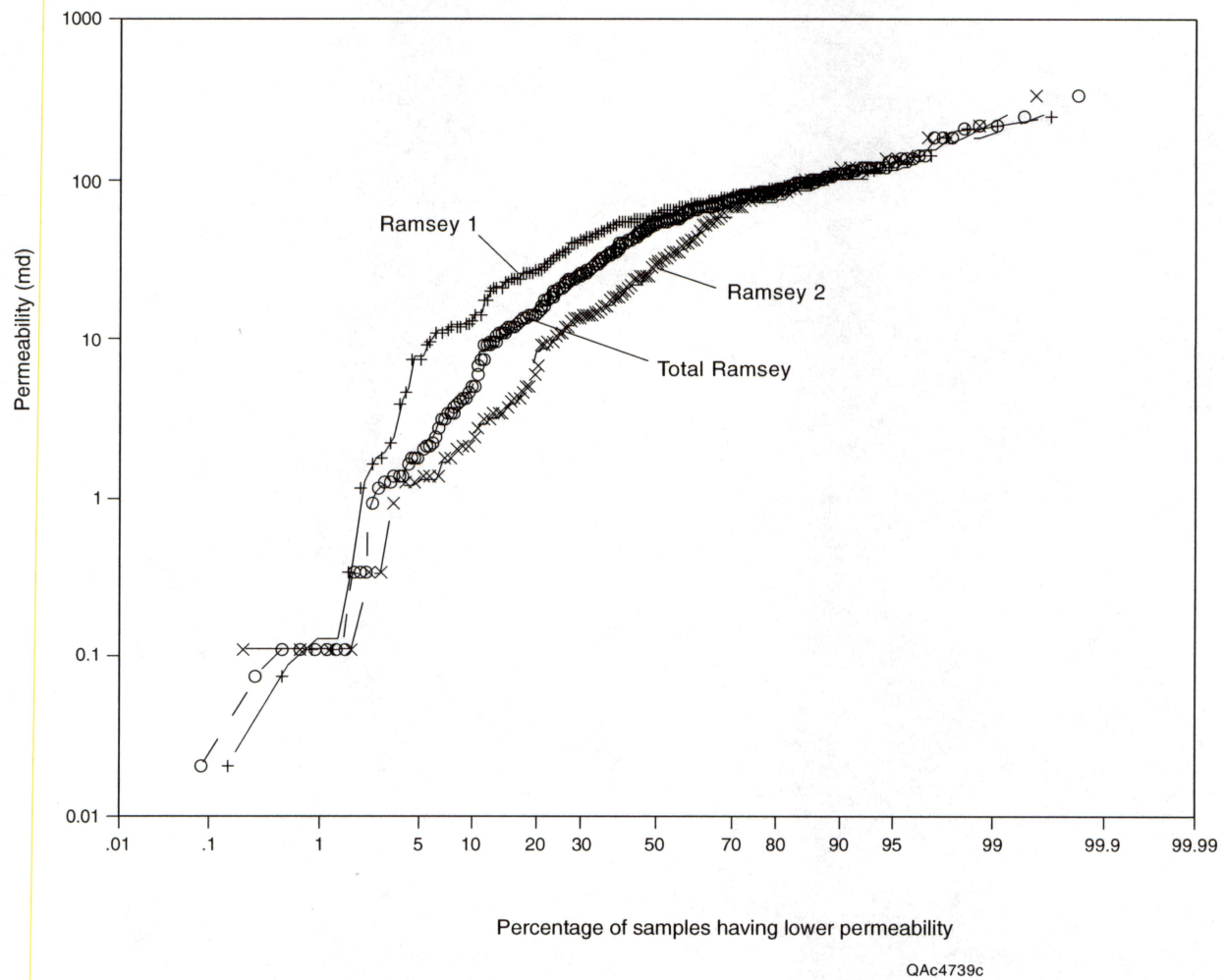


Figure 24. Cumulative distribution function of core-analysis permeability for Ramsey 1 and 2 sandstones in 11 wells in the East Ford unit.

interpreted to represent calcite-cemented sandstones. On the basis of the Dykstra–Parsons heterogeneity coefficient (V), a measure of permeability heterogeneity (Dykstra and Parsons, 1950), the Ramsey sandstone in the East Ford unit was found to be moderately homogeneous ($V = 0.52$). The Ramsey 2 sandstone is more heterogeneous than is the Ramsey 1 sandstone. The Dykstra–Parsons coefficient for the Ramsey 2 sandstone is 0.57, compared with 0.44 for the Ramsey 1 sandstone (table 3). The Dykstra–Parsons mean permeability of the Ramsey 1 sandstone is 41 md, compared with 29 md for the Ramsey 2 sandstone. The combined Ramsey 1 and 2 sandstones have a Dykstra–Parsons mean permeability of 42 md.

We mapped areal distribution of permeability from core data and geophysical-log data using the log-porosity to core-porosity transform (fig. 10) and the core-porosity to permeability transform (fig. 9). For all wells having a porosity log, permeability was calculated on a foot-by-foot basis, and these values were averaged to determine the arithmetic average permeability in each well. The map of average permeability values in the Ramsey sandstone (fig. 25) shows that the highest average permeability occurs generally in the center of the field and follows the trend of high porosity (fig. 17). The map of permeability \times thickness shows a similar distribution (fig. 26).

Structure

The Ramsey sandstone at the East Ford unit dips 1° to the east-northeast (table 2; fig. 27), almost directly opposite the original depositional dip, because Late Cretaceous movement associated with the Laramide Orogeny tilted the Delaware Basin eastward (Hills, 1984). No faults are interpreted to cut the Ramsey sandstone at the East Ford unit. Production from the East Ford unit and other upper Bell Canyon fields in the Delaware Basin occurs from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits (fig. 28). Most hydrocarbons in these fields are trapped by structurally updip facies changes from higher permeability reservoir sandstones to low-permeability siltstones. Several of

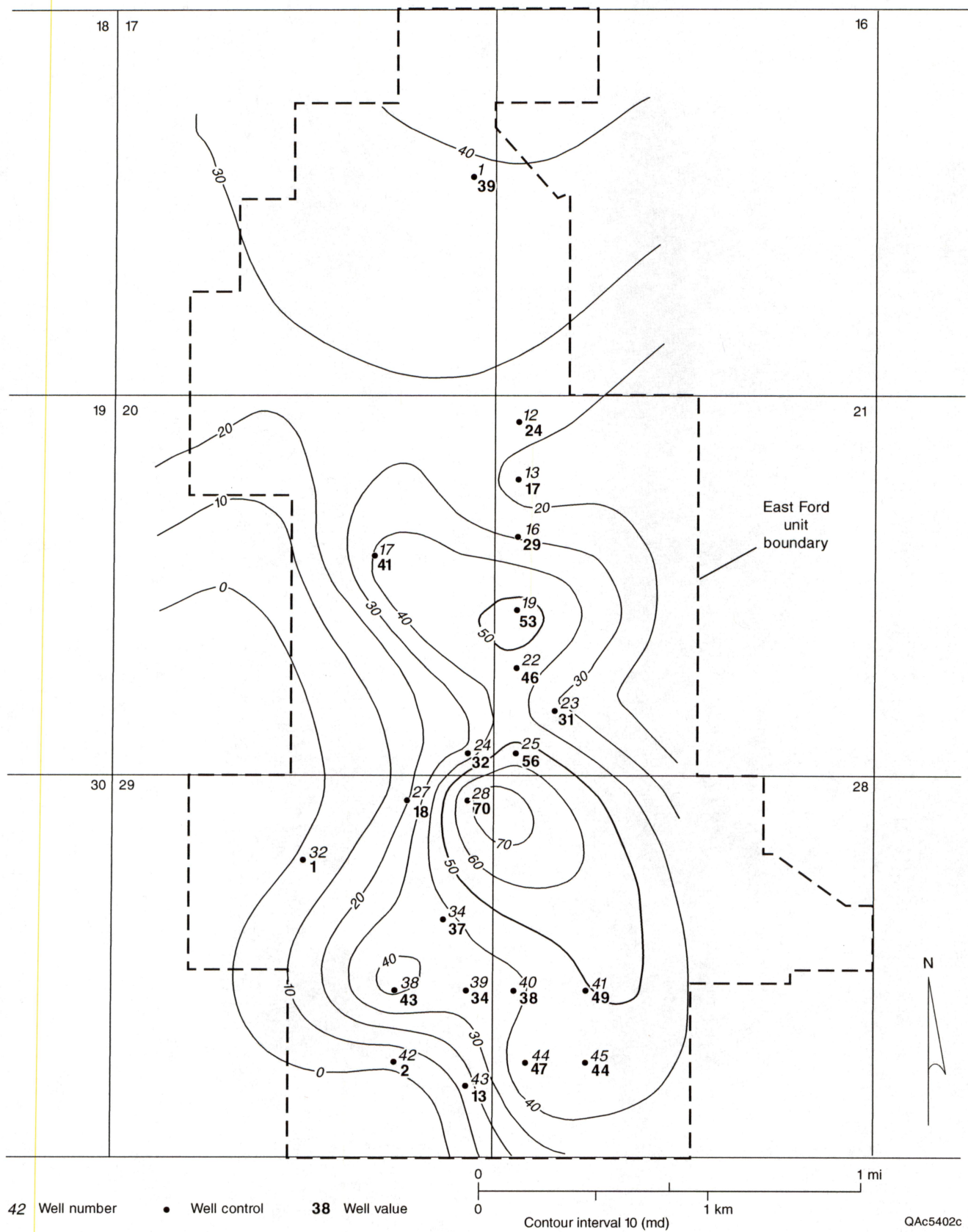


Figure 25. Map of arithmetic average permeability of the Ramsey sandstone in the East Ford unit. The average permeabilities were determined from ITT logs and the core-porosity to core-permeability transform, supplemented by core-analysis data.

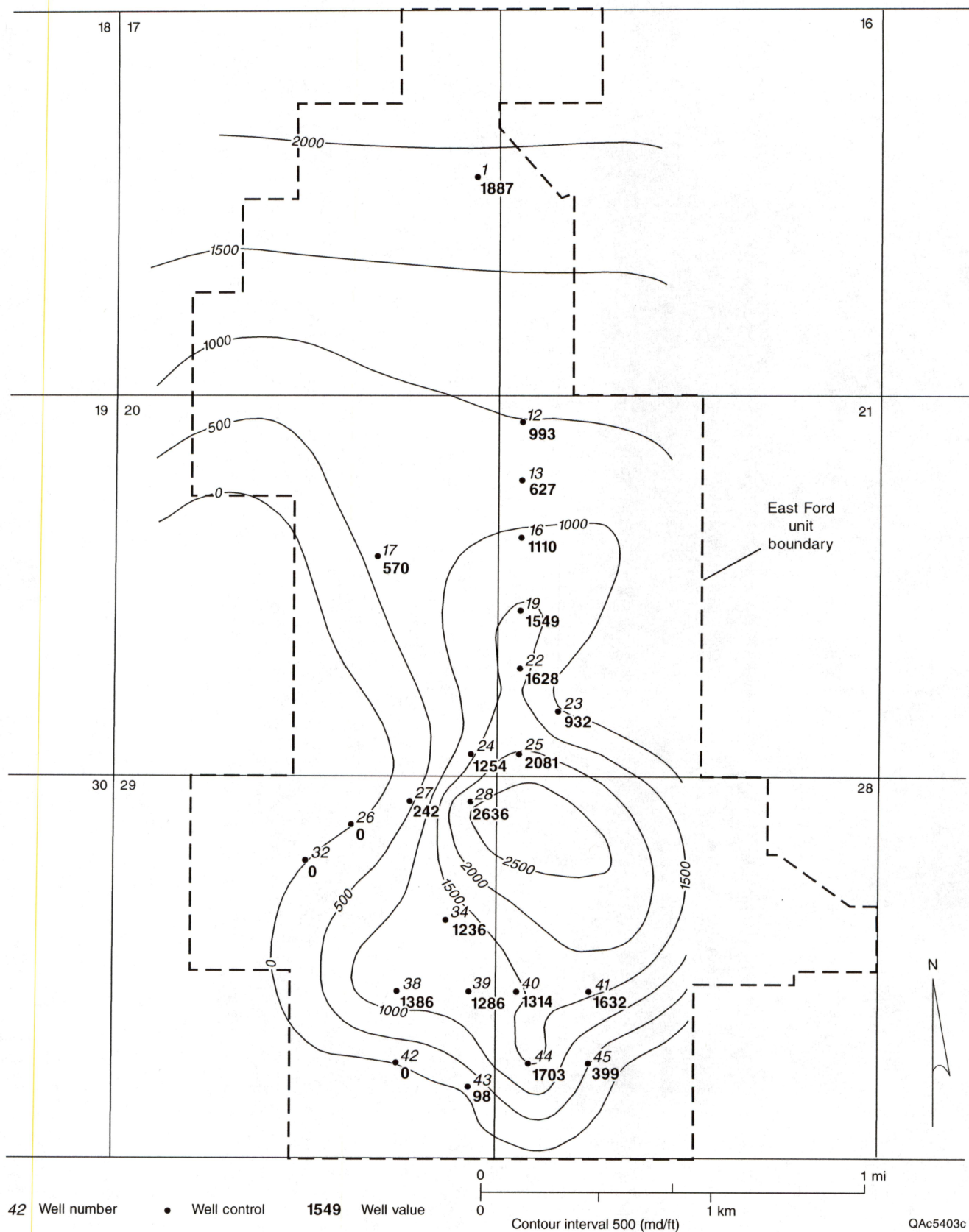


Figure 26. Map of permeability × thickness of the Ramsey sandstone in the Ford Geraldine unit.

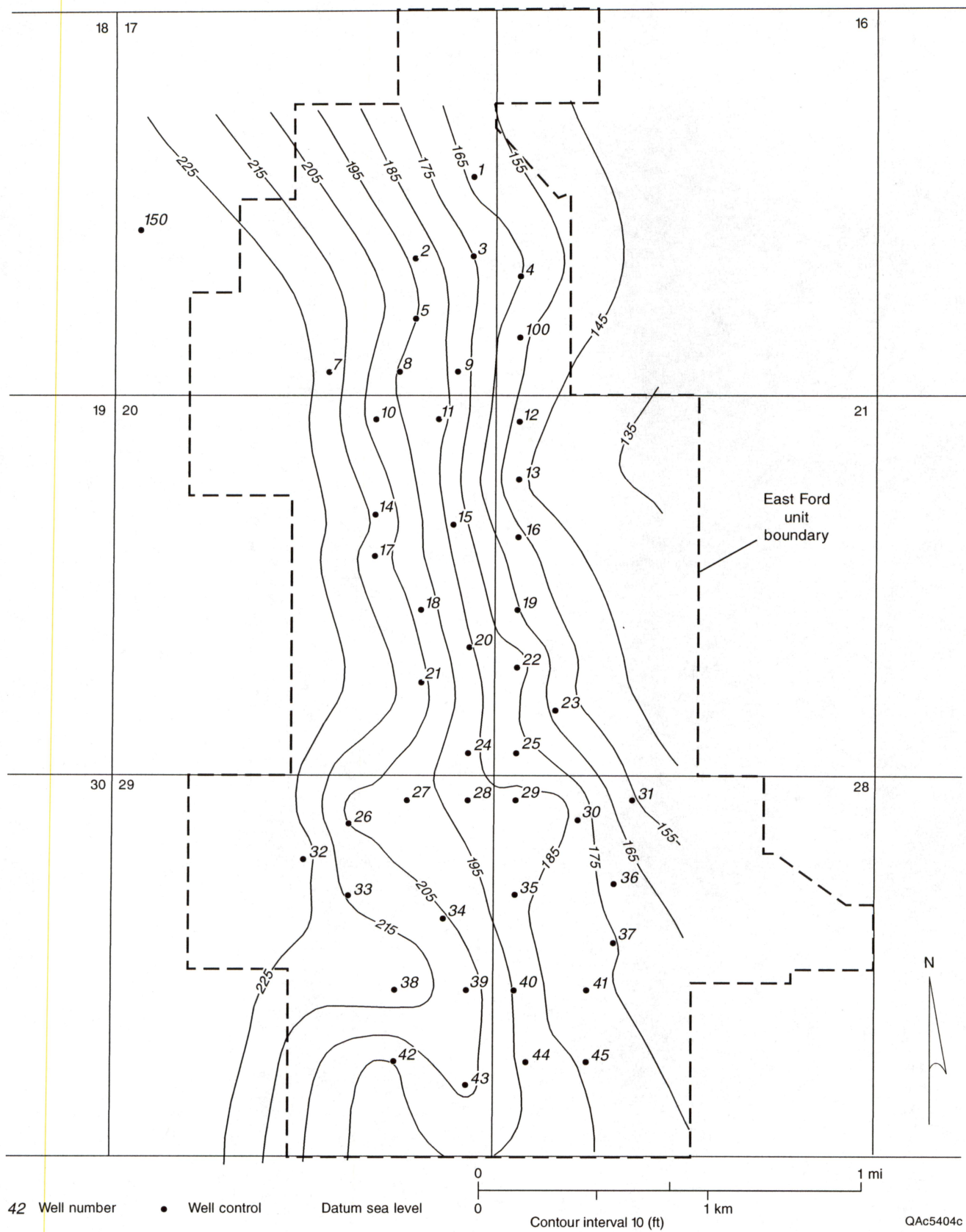


Figure 27. Structure contours on the top of the Lamar limestone dipping to the east in the East Ford unit. The trap is formed by pinch-out of permeable sandstone into low-permeability siltstone up structural dip.

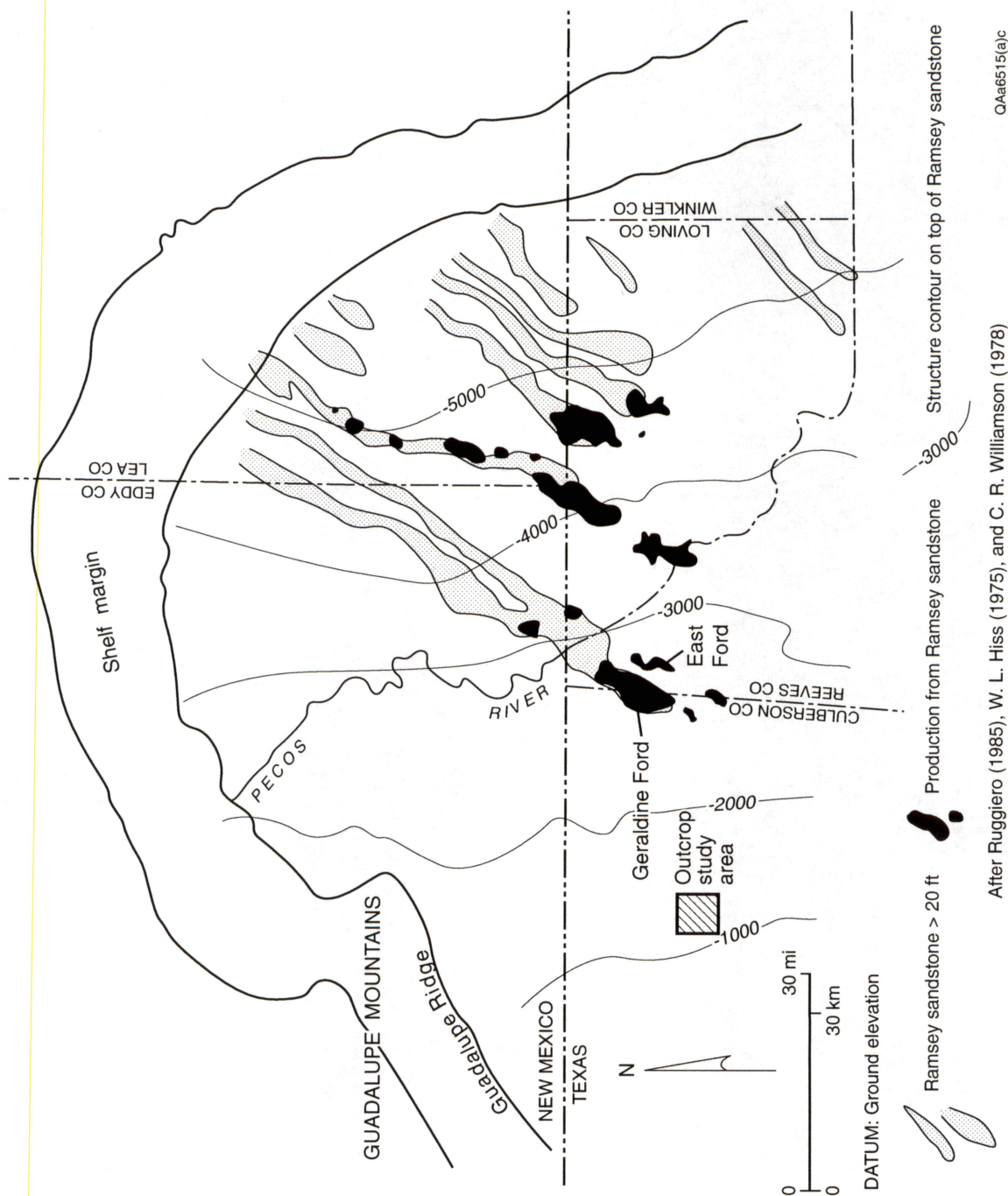


Figure 28. Production from East Ford and other upper Bell Canyon fields in the Delaware Basin from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits. Modified from Ruggiero (1985), after Hiss (1975) and Williamson (1978).

the fields show minor structural closure because linear trends of thick sandstones formed compactional anticlines by differential compaction during burial (Ruggiero, 1985, 1993).

Net Pay

Net pay in the Ramsey reservoir was calculated from geophysical logs, according to the cutoffs established for volume of clay (≤ 15 percent), porosity (≥ 17.5 percent), and water saturation (< 60 percent). The arithmetic average of the 17 net-pay values calculated from geophysical logs is 23.0 ft (table 2). This value is somewhat higher than the average net pay cited by W. A. Flanders (Transpetco Engineering, written communication, 1994) of 20.7 ft. Net pay is greatest down the central axis of the field (fig. 29). It decreases to the west, where the Ramsey sandstone pinches out into siltstone, and to the east, where the sandstone dips below the oil-water contact.

Areas on the margins of the field have a few feet of net pay, even though they fall outside the apparent areas of cutoff, that is, they fall in areas showing less than 17.5 percent porosity, more than 15 percent Vcl, or more than 60 percent water saturation. The reason for this apparent discrepancy is the foot-by-foot method of calculation of net pay from the petrophysical data. For example, although a well may average less than 17.5 percent porosity in the Ramsey sandstone, some intervals may have porosity greater than the cutoff. These zones will be tallied in the calculation of net pay, even though the average porosity for the Ramsey interval is less than 17.5 percent.

Gross pay, calculated as the thickness of the total Ramsey sandstone interval (Ramsey 1 sandstone, SH1, and Ramsey 2 sandstone), averages 33 ft. The trend of gross-pay thickness follows the north-south elongate outline of the East Ford unit (fig. 30).

The map of hydrocarbon pore-feet ($S_o \times \emptyset \times H$) (fig. 31) shows a strong north-south trend of high values (>4 ft) down the central part of the unit, similar to that on the map of porosity \times thickness. The loss of $S_o \times \emptyset \times H$ to the east is to be expected because of the structurally lower position of the Ramsey sandstone.

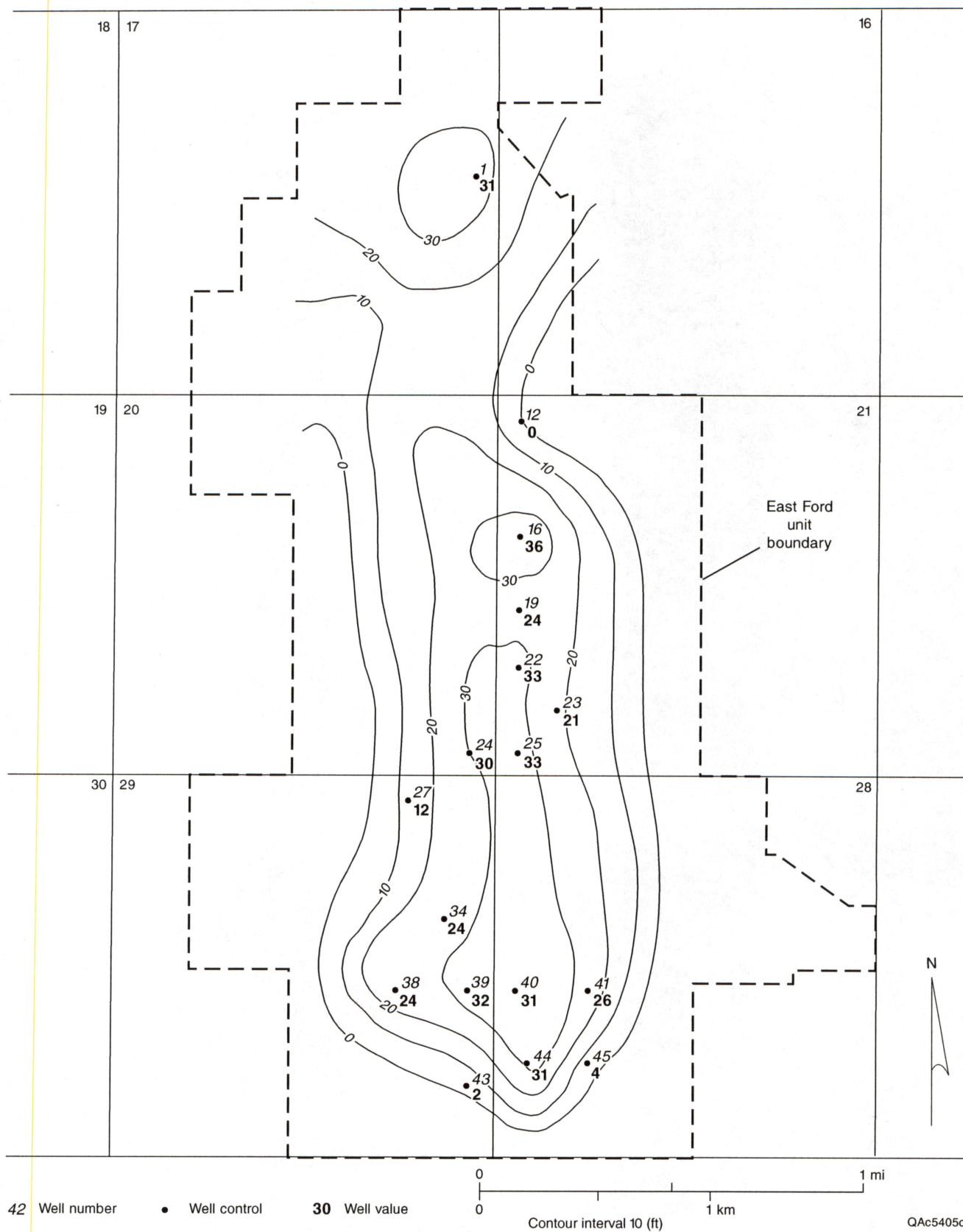


Figure 29. Map of net pay of the Ramsey sandstone in the East Ford unit. The cutoffs for net pay were $V_{cl} \leq 15$ percent, $\phi \geq 17.5$ percent, and $S_w < 60$ percent.

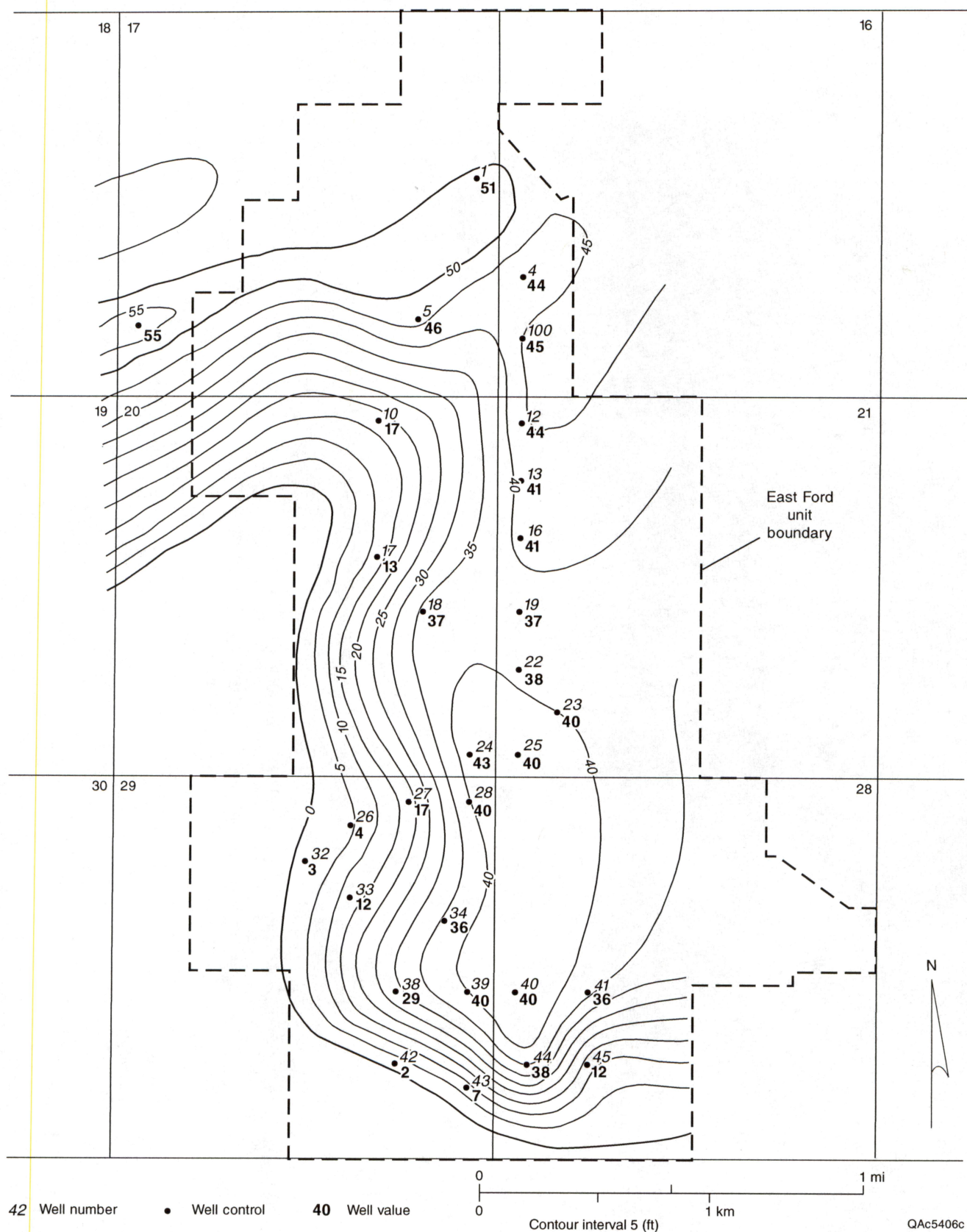


Figure 30. Map of thickness of the total Ramsey sandstone interval, from the base of the Trap siltstone to the top of the Ford siltstone, which is equivalent to gross pay thickness. Average Ramsey sandstone (gross-pay) thickness in the East Ford unit is 33 ft.

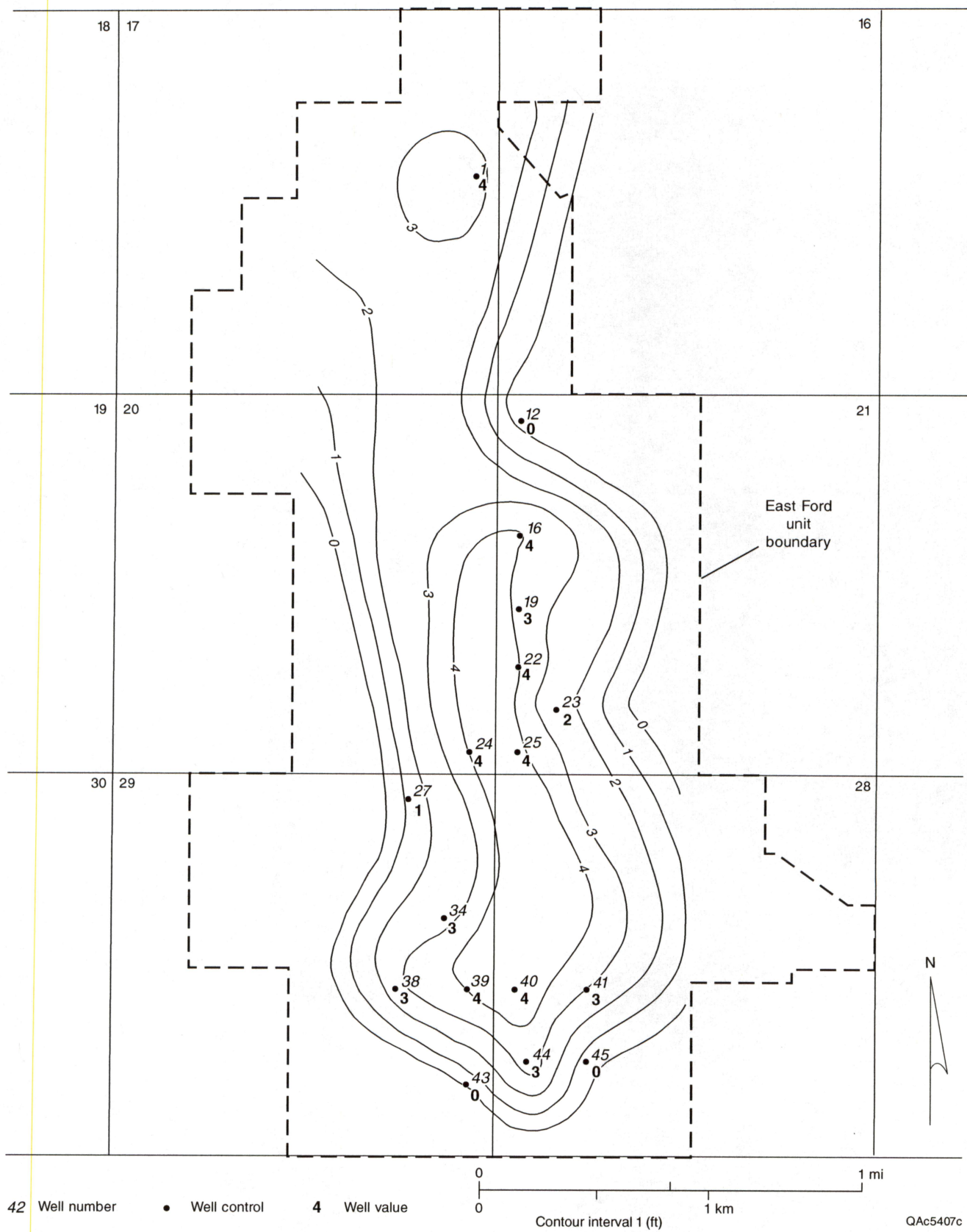


Figure 31. Map of hydrocarbon pore-feet ($S_0 \times \emptyset \times H$) of the Ramsey sandstone in the East Ford unit.

Vertical Porosity and Permeability Profiles

Vertical permeability profiles through the Ramsey sandstone are quite variable (fig. 32). The higher permeabilities of the Ramsey 1 and 2 sandstones are separated by the low-permeability SH1 siltstone. Even within the Ramsey 1 and 2 sandstones, permeability is highly variable, with numerous spikes of high and low permeability. In several wells, the highest permeability streaks occur at the top of the Ramsey 2 sandstone (see wells EFU-1 and EFU-19, fig. 32). High permeability also occurs at the top of the Ramsey 1 sandstone in many wells (see EFU-40, fig. 32). In some wells, low permeability occurs immediately below the high-permeability streaks at the top of the Ramsey 2 (see EFU-1, fig. 32). The low-permeability zones probably correspond to calcite-cemented nodules (Dutton and others, 1997a), and the high-permeability streaks may result from leaching of carbonate cement (Dutton and others, 1996).

Vertical porosity profiles show a similar irregular distribution of porosity (fig. 33), with numerous low-porosity streaks throughout Ramsey 1 and 2 sandstones. Low-porosity zones are interpreted as corresponding to the low-permeability, calcite-cemented nodules.

Natural Water Influx

Low reservoir energy suggests that natural water influx into the field is limited. An oil–water contact was identified at 88 ft above sea level (W. A. Flanders, Transpetco Engineering, written communication, 1994).

Geological Characteristics

Lithology

No cores from the East Ford unit were available for this study, but the Ramsey sandstones in this unit are inferred to be similar to those in the Ford Geraldine unit. Three major rock types are present in the Ford Geraldine unit—very fine grained sandstone, laminated siltstone

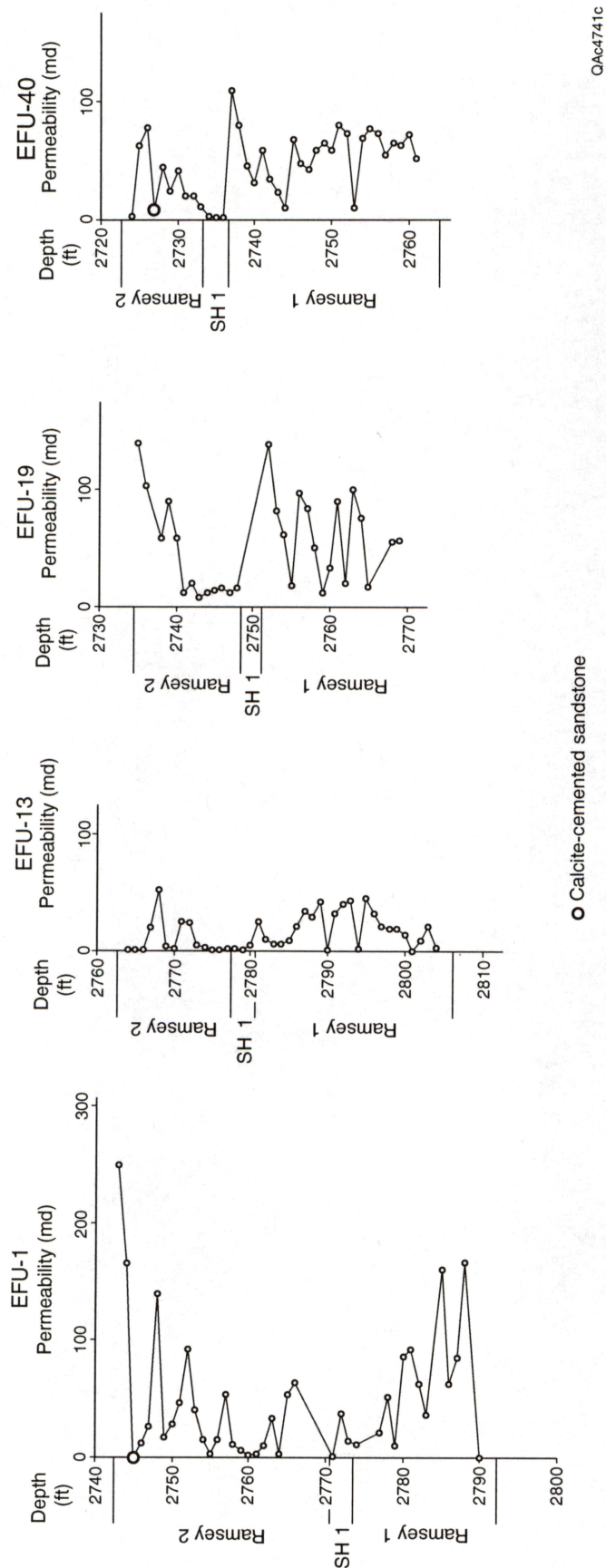


Figure 32. Vertical permeability profiles from core-analysis data of four wells in the East Ford unit. Well locations shown in figure 5.

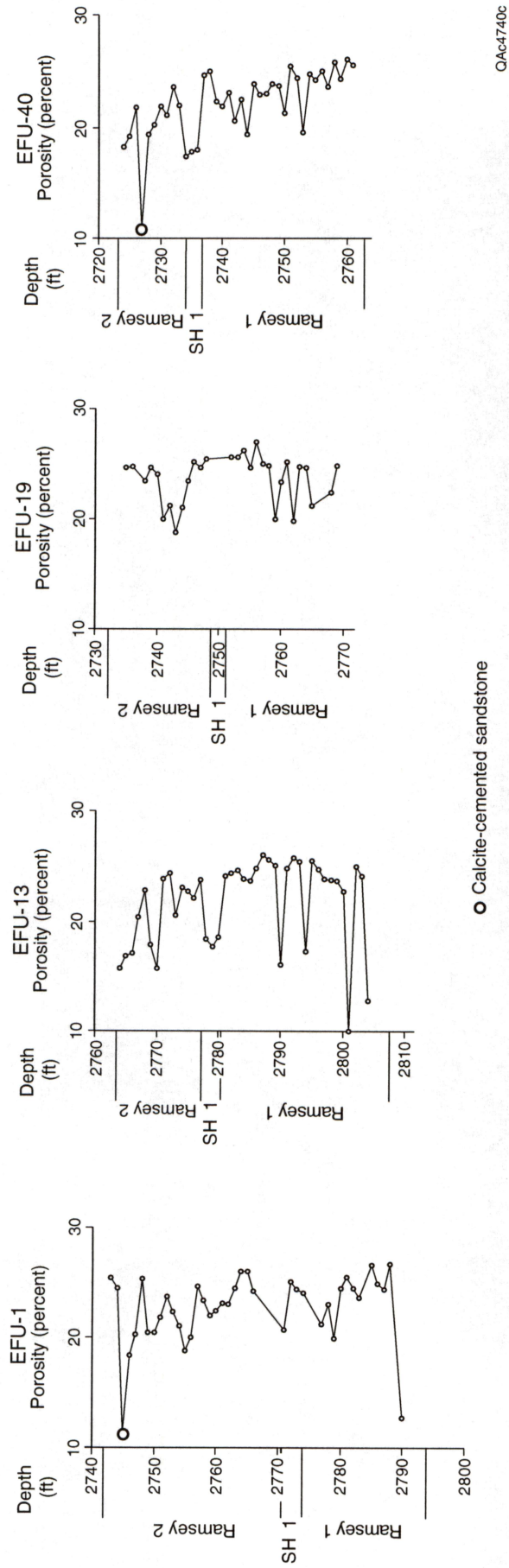


Figure 33. Vertical porosity profiles from core-analysis data of four wells in the East Ford unit. Well locations shown in figure 5.

(laminite), and organic-rich siltstone (lutite) (Ruggiero, 1985; Dutton and others, 1997a). The sandstone facies (a silty, very fine grained, well-sorted arkose) forms the reservoir. The laminite facies consists of parallel-laminated siltstone alternating with laminae (0.2 to 2 mm thick) of organics and silt. The laminated siltstone forms the seal of the stratigraphic trap. Lutite (a dark, fissile, organic-rich siltstone) also contributes to the seal.

Ramsey sandstones in the Ford Geraldine unit have a very narrow range of grain sizes. The average grain size in sandstone samples is 0.092 mm, and the range is 0.069 to 0.103 mm. The proportion of silt grains in the sandstones ranges from 0 to 28 percent. The sandstones are mostly well sorted, having an average standard deviation of 0.42 Ø. Because clay minerals in Ramsey sandstone are interpreted as being authigenic, the Ramsey sandstones are unusual in their lack of detrital clay, as was noted by other, previous workers (for example, Williamson, 1978; Berg, 1979).

Five laminated siltstone samples from the Ford Geraldine unit have an average grain size of 0.062 mm, and they contain 28 to 62 percent silt grains. A lutite sample near the base of the Lamar has an average grain size of 0.033 mm (4.94 Ø), and it contains 46 percent silt, 46 percent organic matter, and 8 percent sand.

Geologic Age

The Ramsey sandstone is in the upper part of the Bell Canyon Formation in the Permian Guadalupian series (fig. 3). The age of the Guadalupian series is 255 to 270 my (Hills and Kottowski, 1983).

Mapping of Ramsey Sandstone Genetic Units

The Ramsey sandstone in the East Ford unit is a 0- to 45-ft-thick sandstone that is bounded by the Ford and Trap laminated siltstones. Lutites in the underlying Ford siltstone and the

overlying Trap siltstone (fig. 6) are interpreted to be condensed sections that mark the top and base of a genetic unit, equivalent to a high-order cycle (Gardner, 1992; Kerans and others, 1992). In the East Ford unit, the Ramsey is divided into two sandstones (Ramsey 1 and Ramsey 2) separated by a 1- to 3-ft-thick laminated siltstone (SH1). The Ramsey high-order cycle is thus subdivided into the following five units, from oldest to youngest: (1) upper Ford siltstone, from the Ford condensed section to the top of the Ford siltstone; (2) Ramsey 1 sandstone; (3) SH1 siltstone; (4) Ramsey 2 sandstone; and (5) lower Trap siltstone, from the base of the Trap siltstone to the Trap condensed section (fig. 6).

We correlated key stratigraphic horizons using digitized logs from 45 wells in the East Ford unit. A seven-layer, three-dimensional, deterministic geologic model was constructed by means of stratigraphic-interpretation computer software.

Upper Ford Siltstone

The upper Ford thins from the northwest side of East Ford field (15 to 16 ft) to the southeast (11 to 12 ft) (fig. 34). By analogy with the Ford Geraldine unit, the upper Ford is interpreted as being composed of organic-rich siltstone laminae interbedded on a millimeter scale with organic-poor siltstone laminae. The average grain size of the silt coarsens upward from the Ford condensed section to the top of the Ford, and the percentage of sand, amount of burrowing, and thickness of organic-poor laminae all increase toward the sandstone. Gamma-ray response decreases over this interval, probably because much of the radioactivity is contained in organic matter within the organic-rich layers.

Porosity in the Ford siltstone in the East Ford unit ranges from 7.5 to 22.4 percent and averages 15.9 percent (table 3). Permeability ranges from 0.1 to 5 md and averages 1 md. Average water saturation measured in cores is 65 percent.

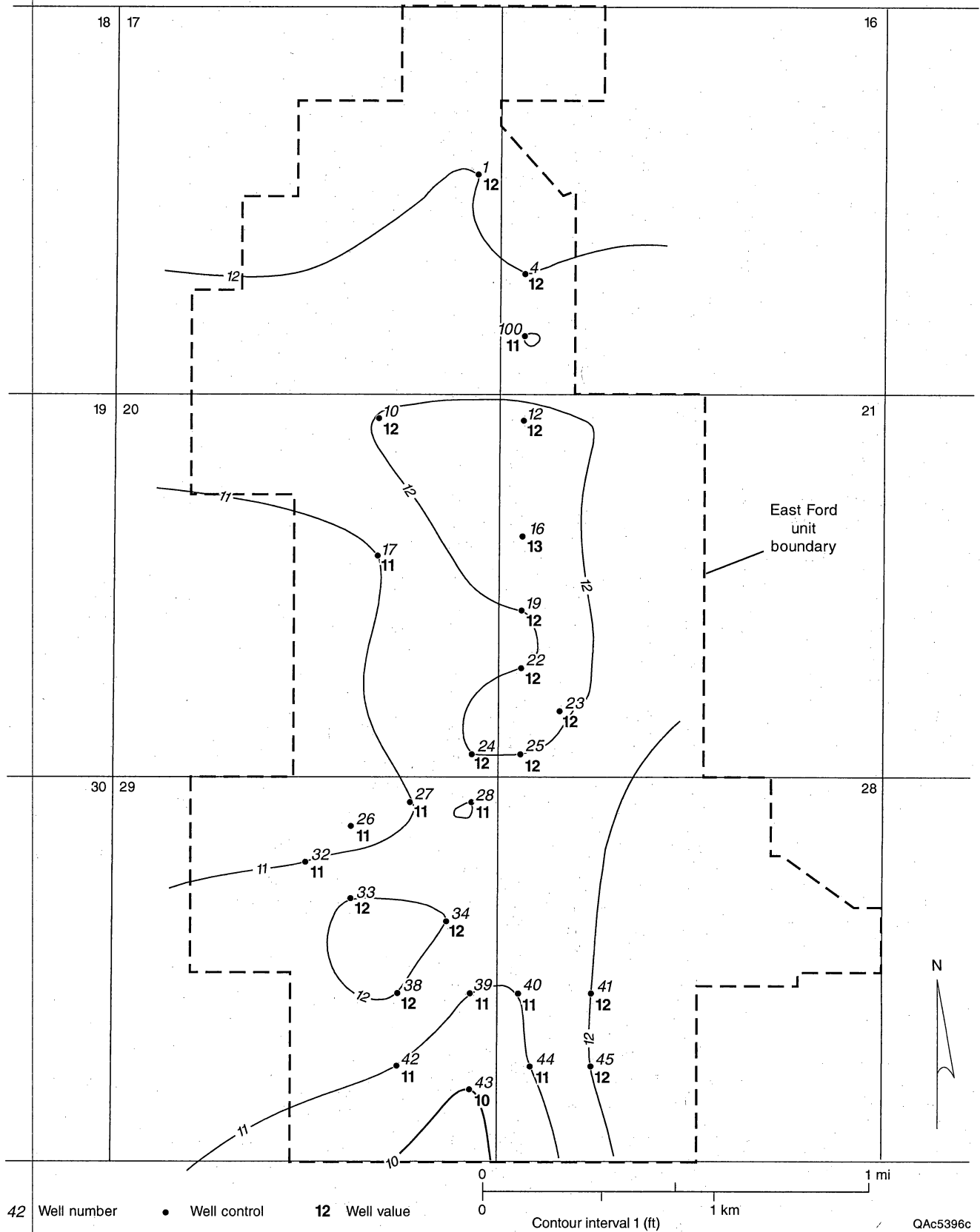


Figure 34. Isopach map of the upper Ford laminated siltstone, measured from the Ford condensed section to the top of the Ford (see figure 6).

Ramsey 1 Sandstone

The Ramsey 1 sandstone is thickest on the east side of the East Ford unit (fig. 35). 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 Ramsey 1 sandstone has at least two branches, one of which forms the reservoir at the Ford Geraldine unit and the other in the East Ford unit (fig. 35). The two branches divide north of the East Ford unit.

In most wells the gamma-ray response in the Ramsey 1 sandstone is distinctly lower than in the underlying Ford siltstone; in some wells the gamma response continues to decrease upward in the lower Ramsey 1 interval. Porosity in the Ramsey 1 sandstone ranges from 6.5 to 27.0 percent and averages 22.5 percent (table 3). Permeability ranges from 0.02 to 183 md and averages 46 md. Average water saturation measured in cores is 46 percent.

SH1 Siltstone

The SH1 siltstone represents a break in sandstone deposition within the Ramsey interval, when laminated siltstone was deposited. The SH1 siltstone forms a broad sheet that is 2 to 3 ft thick across most of the East Ford unit (fig. 36). In the Ford Geraldine unit, the SH1 siltstone is composed of laminated siltstone similar to that of the Ford; burrows are common. Porosity in the SH1 siltstone in the East Ford unit ranges from 17.2 to 20.7 percent and averages 18.2 percent. Permeability ranges from 0.3 to 14 md and averages 4 md. Average water saturation measured in SH1 siltstone cores is 54 percent.

Ramsey 2 Sandstone

The younger sandstone in the Ramsey cycle, the Ramsey 2, is thickest along a north-south trend that is shifted to the west, as compared with the underlying Ramsey 1 sandstone (fig. 37). The offset of the Ramsey 2 sandstone trend suggests that the younger sandstones were deposited in the adjacent topographic depression created by deposition of the preceding Ramsey 1

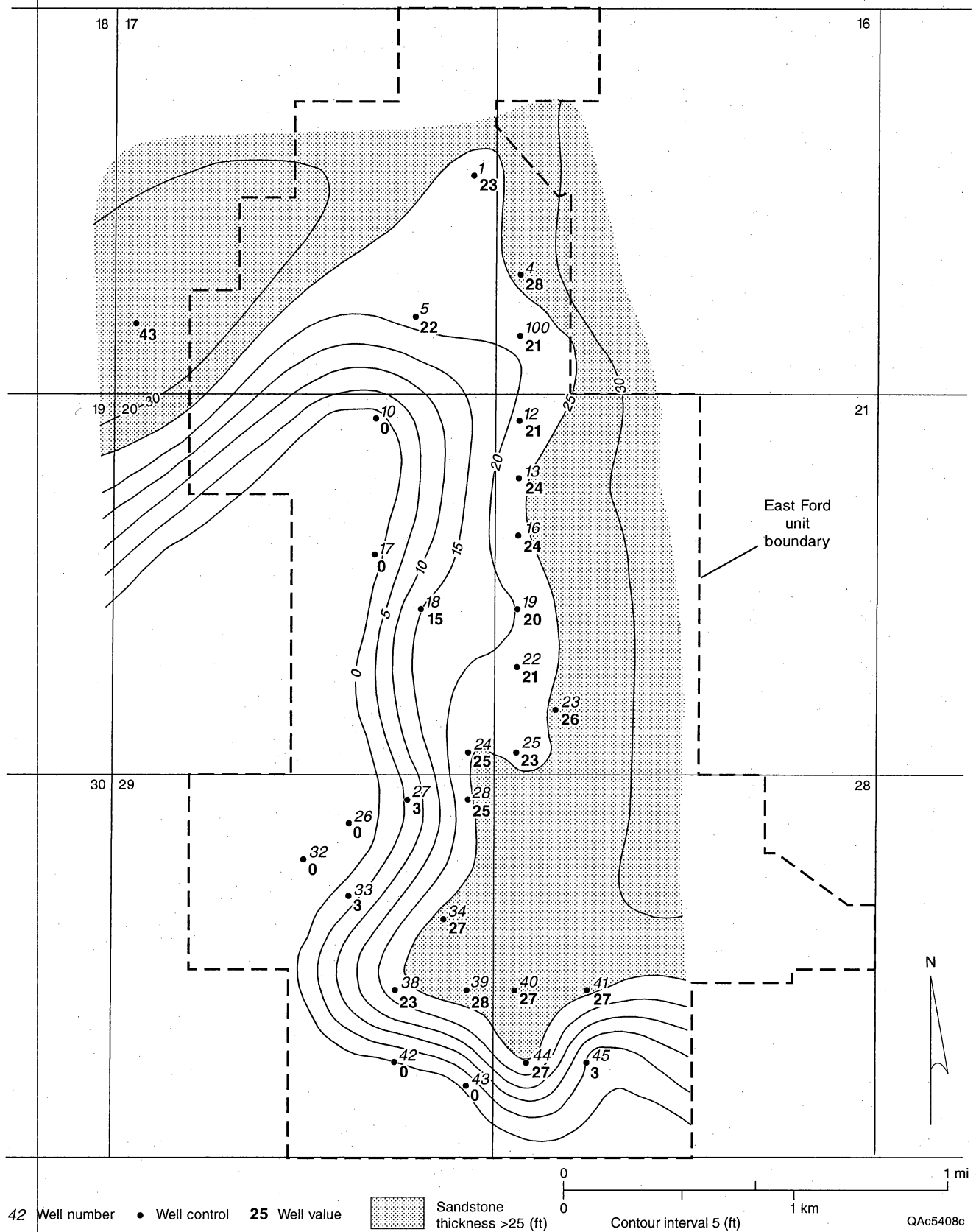


Figure 35. Isopach map of the Ramsey 1 sandstone, which is thickest along a north-south, elongate trend on the east side of the East Ford unit.

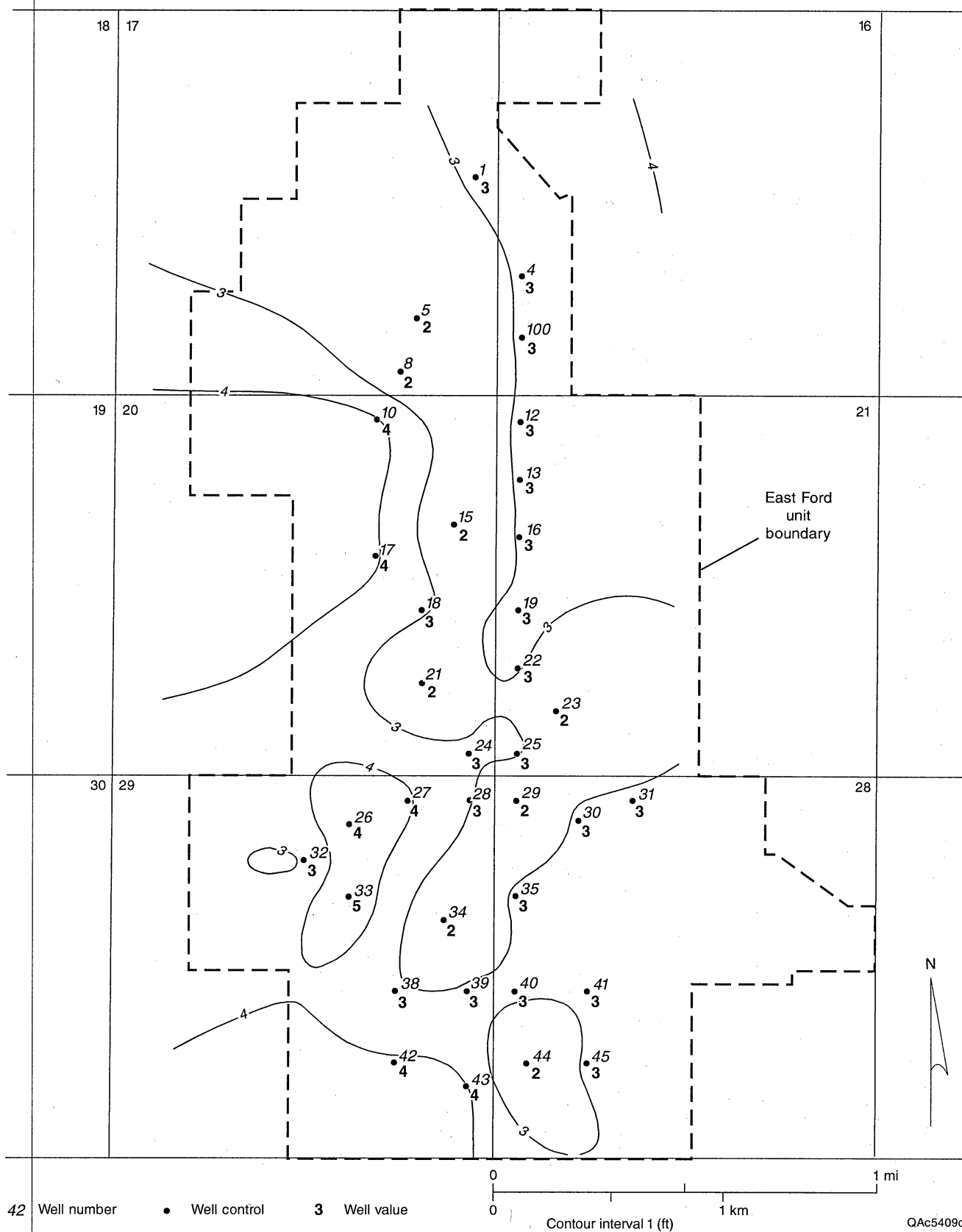


Figure 36. Isopach map of the SH1 laminated siltstone, which was deposited during a break in Ramsey sandstone deposition.

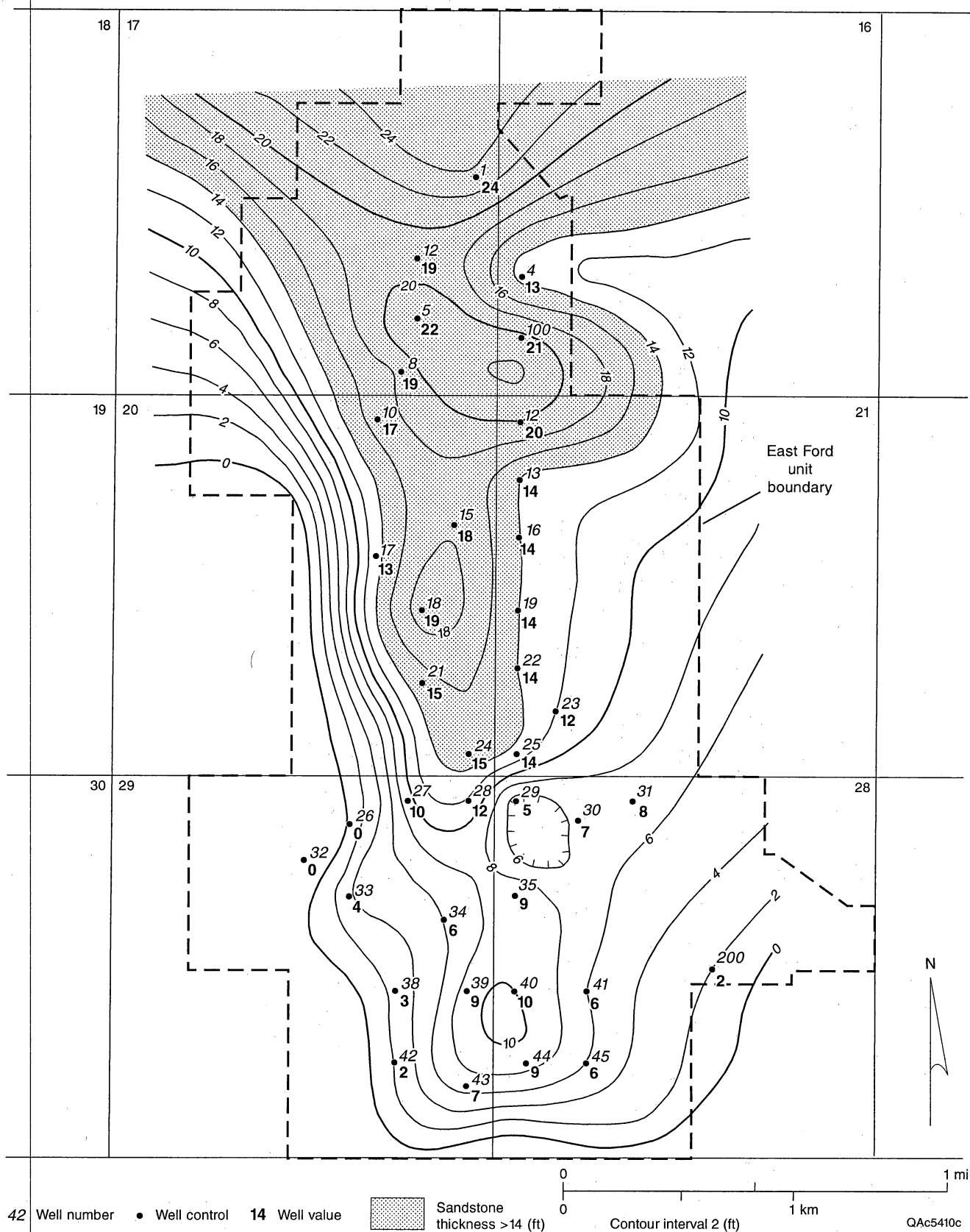


Figure 37. Isopach map of the Ramsey 2 sandstone. The thickest Ramsey 2 sandstone is shifted to the west of the Ramsey 1 sandstone, suggesting that Ramsey 2 sandstones were deposited in the adjacent topographic depressions created by deposition of the preceding Ramsey 1 sandstone.

sandstone. The Ramsey 2 sandstone is thinner than the Ramsey 1, having a maximum thickness of 24 ft at the north end of the unit and 10 ft at the south end.

Porosity in the Ramsey 2 sandstone in the East Ford unit ranges from 6.5 to 30.6 percent and averages 21.4 percent. Permeability ranges from 0.1 to 249 md and averages 34 md. Average water saturation measured in Ramsey 2 sandstone cores is 48 percent.

Lower Trap Siltstone

The Ramsey cycle is capped by the Trap laminated siltstone. An isopach map of the lower Trap siltstone, measured from the top of the Ramsey sandstone to the Trap condensed section (fig. 6) shows a broad sheet that is mostly 7 to 8 ft thick (fig. 38). Like the Ford siltstone, the Trap is composed of organic-rich siltstone laminae interbedded on a millimeter scale with organic-poor siltstone laminae. The average grain size of the silt decreases upward from the base of the Trap to the Trap condensed section, and the percentage of sand, amount of burrowing, and the thickness of organic-poor laminae all decrease away from the sandstone. Gamma-ray response increases over this interval as the amount of organic matter increases toward the condensed section. Porosity in the Trap siltstone ranges from 2.9 to 18.8 percent and averages 14.7 percent. Permeability ranges from 0.01 to 8 md and averages 1 md. Average water saturation measured in Trap siltstone cores is 67 percent.

Facies Analysis of Bell Canyon Sandstone in Outcrop

Interpretation of the reservoir sandstones at the East Ford unit was based strongly on characterization of upper Bell Canyon exposed in outcrop (Barton, 1997; Dutton and others, 1997a, 1998b, in press; Barton and Dutton, in press). Outcrops of the Bell Canyon Formation are present within 25 mi of the East Ford unit (fig. 2). These outcrops were studied to better interpret the depositional processes that formed the reservoirs at the Ford Geraldine and East Ford units

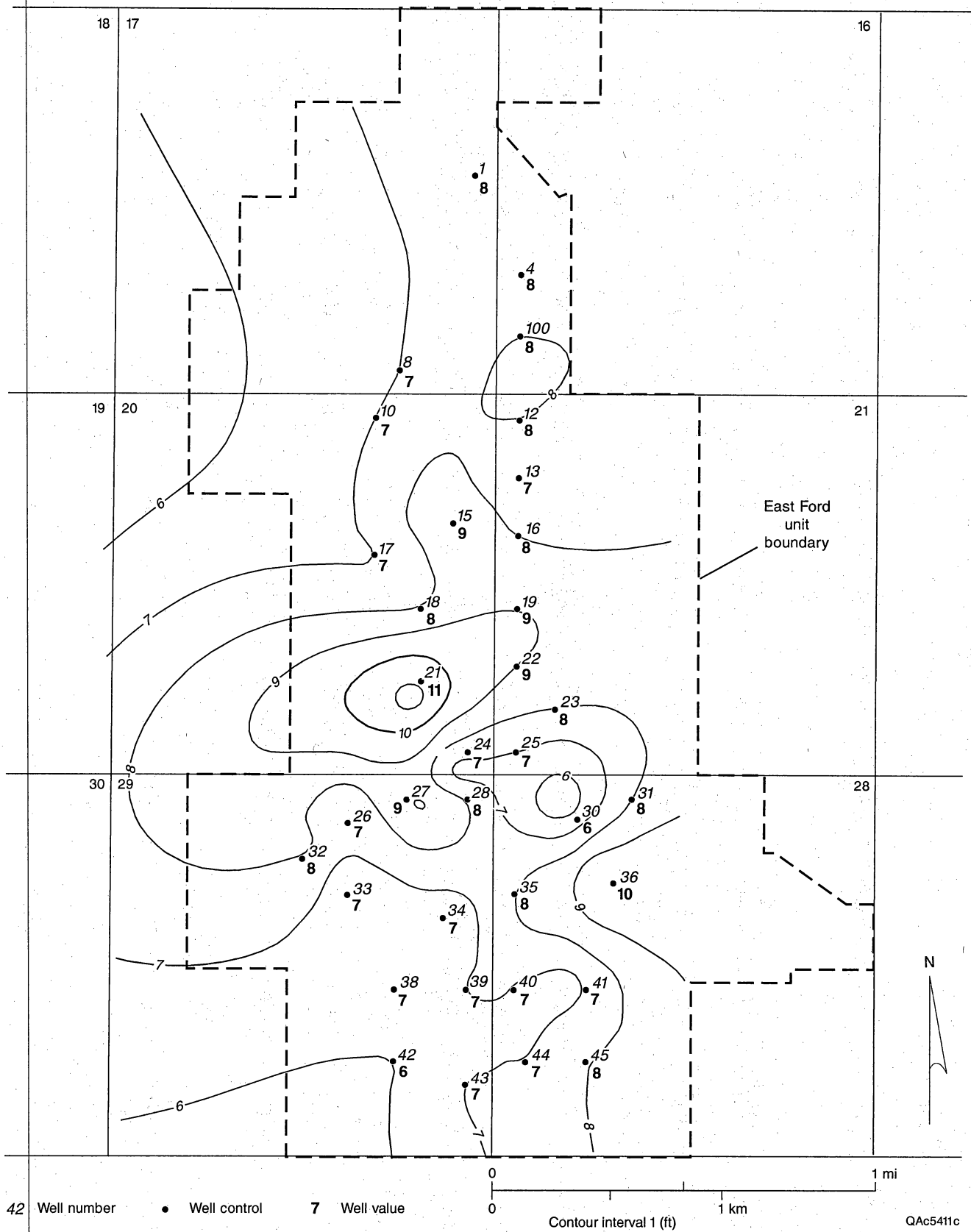


Figure 38. Isopach of the lower Trap laminated siltstone, measured from the top of the Ramsey sandstone to the Trap condensed section (see figure 6).

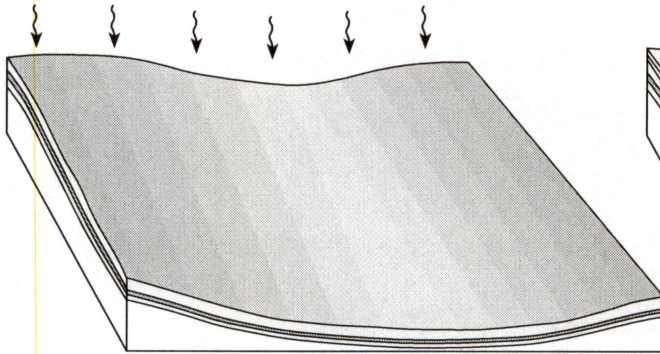
and to determine the dimensions and characteristics of reservoir sandstone bodies in well-exposed sections.

The outcrop study focused on a stratigraphic unit in the Bell Canyon Formation that is analogous to, but older than, the Ramsey sandstone. The interval is the uppermost high-order cycle below the McCombs limestone (fig. 3). The scale and position of this stratigraphic unit are analogous to that of the Ramsey interval, which is the uppermost high-order cycle below the Lamar limestone (figs. 3, 6).

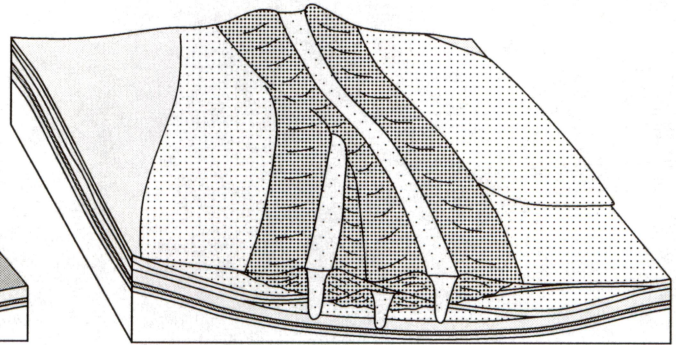
We documented stratigraphic relationships in outcrop by mapping facies and bounding surfaces. The data consist of measured sections and photomosaics that provided complete coverage of the outcrops. Six facies were identified: facies 1 is a massive to wavy-bedded, organic-rich siltstone; facies 2 is a finely laminated organic-rich siltstone; facies 3 is a laminated siltstone; facies 4 consists of thin-bedded sandstones and siltstones that display abundant current laminations and partial Bouma sequences (Bouma, 1962); facies 5 is a structureless or massive sandstone; and facies 6 is a large-scale, cross-laminated sandstone (Barton, 1997; Barton and Dutton, in press). The sequence of stratification types and abundance of ripple-drift cross-lamination indicate that facies 4 was deposited from waning, turbulent, sediment-gravity flows. The paucity of lamination, presence of floating clasts, and abundance of water-escape and load structures suggest that the facies 5 sandstones were rapidly deposited from high-density sediment-gravity flows (Lowe, 1982; Kneller, 1996). The scale, form, and occurrence of the cross-laminations in facies 6 suggest that the sands were deposited from confined, highly turbulent sediment-gravity flows.

Stratigraphic relationships indicate that the outcrop sandstones were deposited in a basin-floor setting by a system of leveed channels having attached lobes and overbank splays that filled topographically low interchannel areas (fig. 39) (Barton and Dutton, in press). Lobe sandstones, as much as 25 ft thick and 2 mi wide, are composed of massive or structureless sandstones, and they display a broad tabular geometry. Channels, as much as 60 ft thick and 300 to 3,000 ft wide,

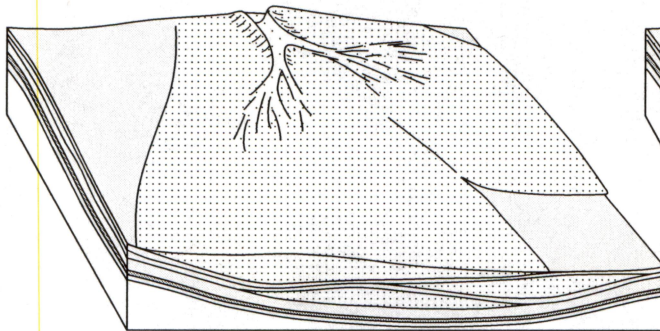
I. Deposition of silt and organic matter from suspension



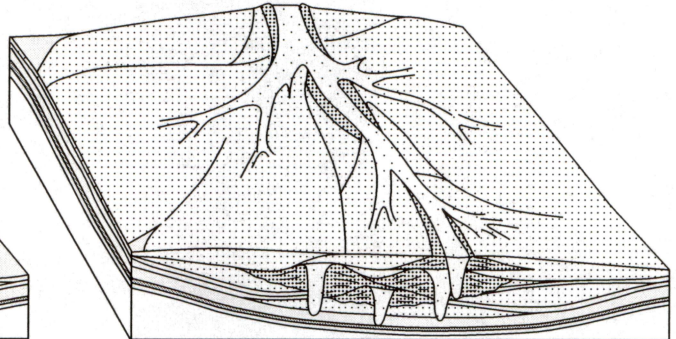
III. Deposition of channel and levee deposits; may be preceded by erosion



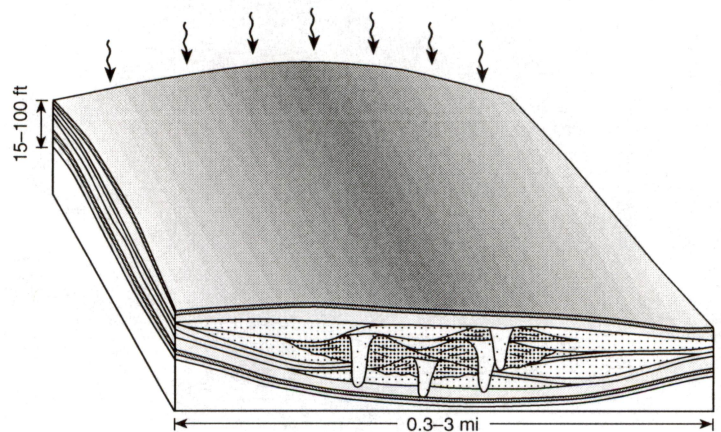
II. Deposition of lobes and laminated siltstones








IV. Deposition of lobes in interchannel areas



V. Deposition of silt and organic matter from suspension



FACIES

	Organic-rich, laminated siltstone
	Laminated siltstone
	Thin-bedded, rippled, and horizontally laminated sandstone and siltstone
	Massive sandstone
	Cross-stratified sandstone

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Figure 39. Diagram illustrating the depositional model developed from outcrop study of a high-order cycle in the upper Bell Canyon Formation (from Barton, 1997; Dutton and others, 1998b). Bell Canyon sandstones are interpreted to have been deposited in submarine channels with levees and attached lobes.

are largely filled with massive and cross-stratified sandstone. The channels bifurcate and expand downdip (fig. 39). Flanking the channels on both sides are wedges composed of thinly bedded sandstone and siltstone that are interpreted as levees. The levees thin away from the channel, decreasing in thickness from 20 to 3 ft over the distance of 0.5 mi. The levees are onlapped by massive sandstones interpreted as overbank splays having an irregular geometry.

Individual channel-levee and lobe complexes appear to stack in a compensatory fashion and are separated by laterally continuous, 3-ft-thick laminated siltstones. The laminated 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. The paleogeographic setting, abundance of sandstone, absence of mass-movement features, and high preservation of facies indicate that the outcrop sandstones were deposited in a basin-floor setting.

Facies Analysis of Ramsey Sandstone Reservoirs

No Ramsey sandstone cores from East Ford field were available for this study, but 70 cores of the Ramsey sandstone from the nearby Ford Geraldine unit were examined during reservoir characterization of that field (Dutton and others, 1997a, b, 1998a, b). Because the two fields are so close, Ramsey sandstone facies observed in the Ford Geraldine unit are assumed to be the same as those in the East Ford unit.

The facies observed in Ramsey sandstone cores are similar to those that were identified in upper Bell Canyon sandstones in outcrop (Dutton and Barton, in press). The core facies are (1) organic-rich siltstone (lutite); (2) laminated siltstone (laminite); (3) structureless or massive sandstones having few laminations but containing floating siltstone clasts, water escape features, and load structures; (4) rippled or convoluted sandstone; (5) cross-stratified sandstone, and (6) massive sandstone. Massive sandstones are volumetrically the most abundant sandstone facies in the core, although that may partly be an artifact of the narrow range in grain sizes, which makes sedimentary structures indistinct and difficult to see in core. On outcrop,

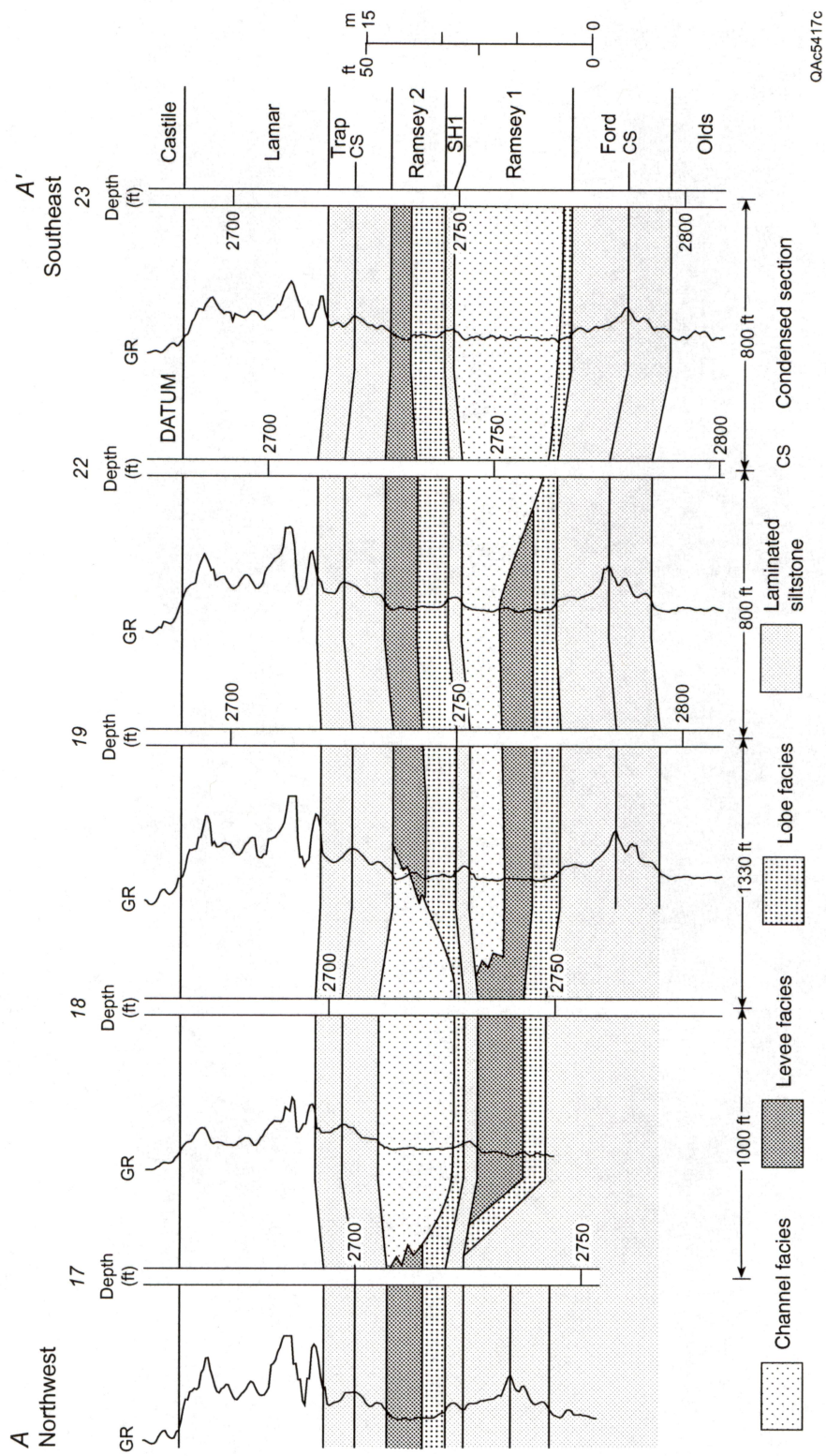
weathering processes may help to accentuate the sedimentary structures and make them more visible. Some sandstones described as massive in the core may thus actually contain sedimentary structures that could not be distinguished.

In the Ford Geraldine unit, comparison of sedimentary structures viewed in core with facies identified in outcrop was key to interpreting the Ramsey sandstones as channel-levee and lobe deposits and mapping the facies distribution. No core is available from the East Ford unit, but the Ramsey reservoir sandstones in this field are also interpreted to be channel-levee and lobe deposits. This interpretation is based on (1) similarity of the Ramsey sandstone thickness and geometry to that in the Ford Geraldine unit, (2) the apparent bifurcation of the Ramsey sandstone to the north of both units, resulting in one channel forming the Ford Geraldine reservoir and the other forming the East Ford reservoir (fig. 30), and (3) the similarity of log patterns in East Ford field to those in the Ford Geraldine unit. Because of the narrow range of grain sizes in Ramsey sandstones and the absence of detrital clay, log responses are muted, and log patterns are not always reliable for facies identification. When combined with sandstone-thickness data, however, log facies can contribute to facies interpretation at the East Ford unit. The interpreted vertical and lateral distribution of facies is illustrated on representative cross sections through the central and south parts of the East Ford unit (figs. 40 through 43).

On the basis of geophysical log data from the East Ford unit and core data from the nearby Ford Geraldine unit (fig. 44), combined with information on facies distribution of Bell Canyon sandstones mapped in continuous outcrops (Barton, 1997; Dutton and others, 1997a, in press), the Ramsey sandstone at the East Ford unit is interpreted as consisting of channel, levee, and lobe deposits (figs. 40 through 43).

Channel Facies

Channel facies consist of massive and crossbedded sandstones interpreted to have been deposited from high-density turbidity currents (Lowe, 1982). As interpreted from the strike-



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Figure 40. Strike cross section A-A' of the central part of the East Ford unit. Location of cross section shown in figure 5.

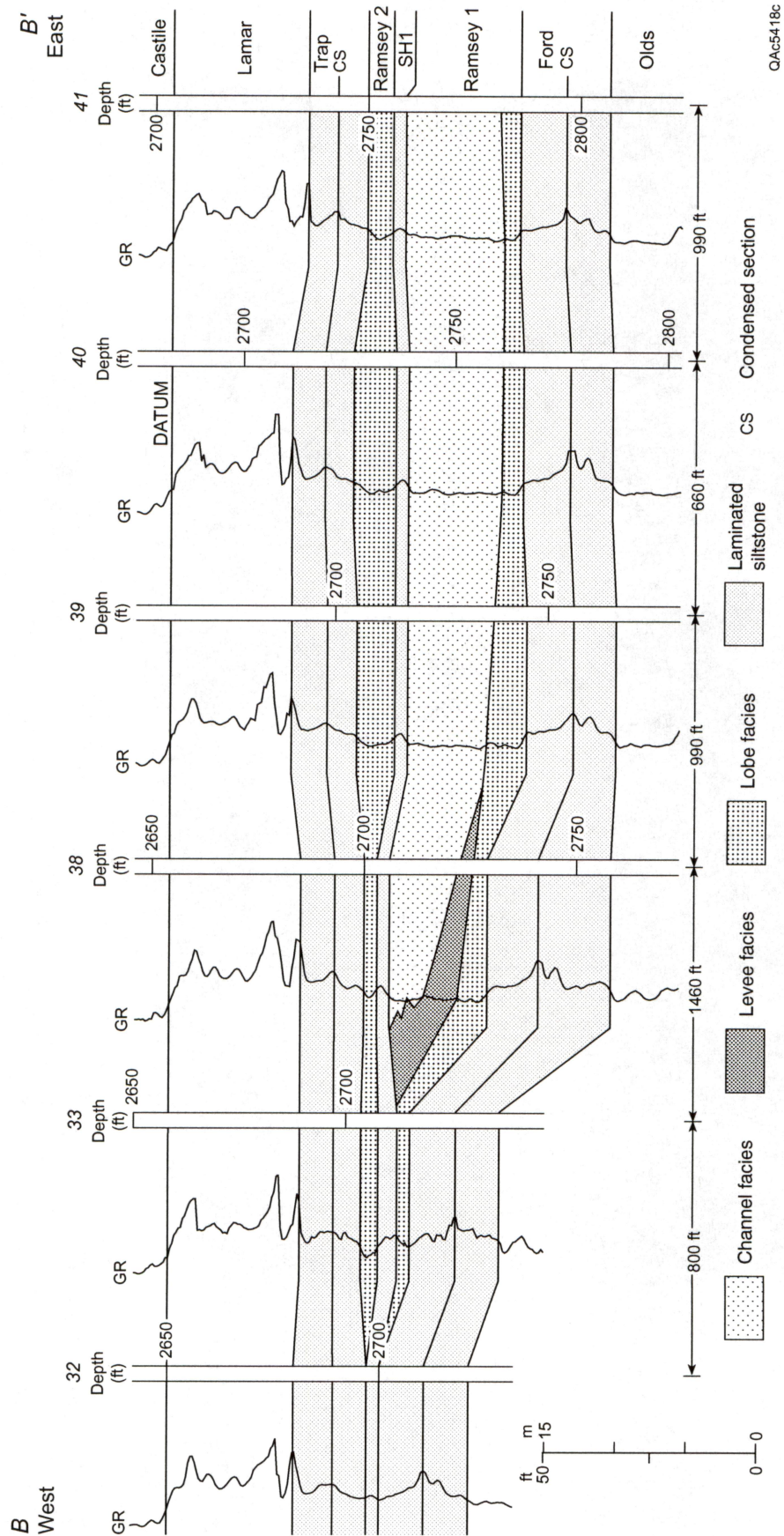
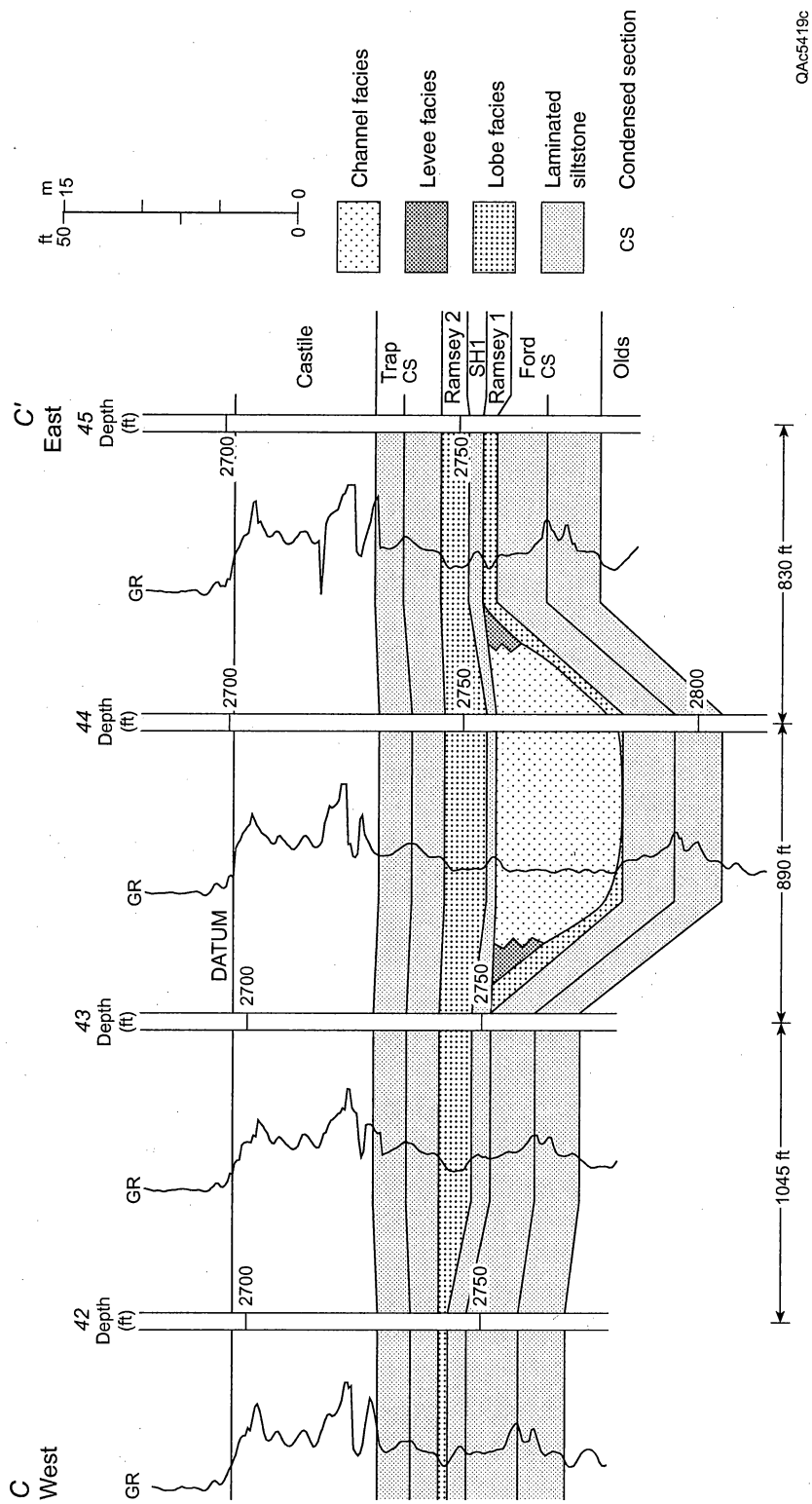


Figure 41. Strike cross section B-B' of the south part of the East Ford unit. Location of cross section shown in figure 5.



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Figure 42. Strike cross section C-C' of the south tip of the East Ford unit. Location of cross section shown in figure 5.

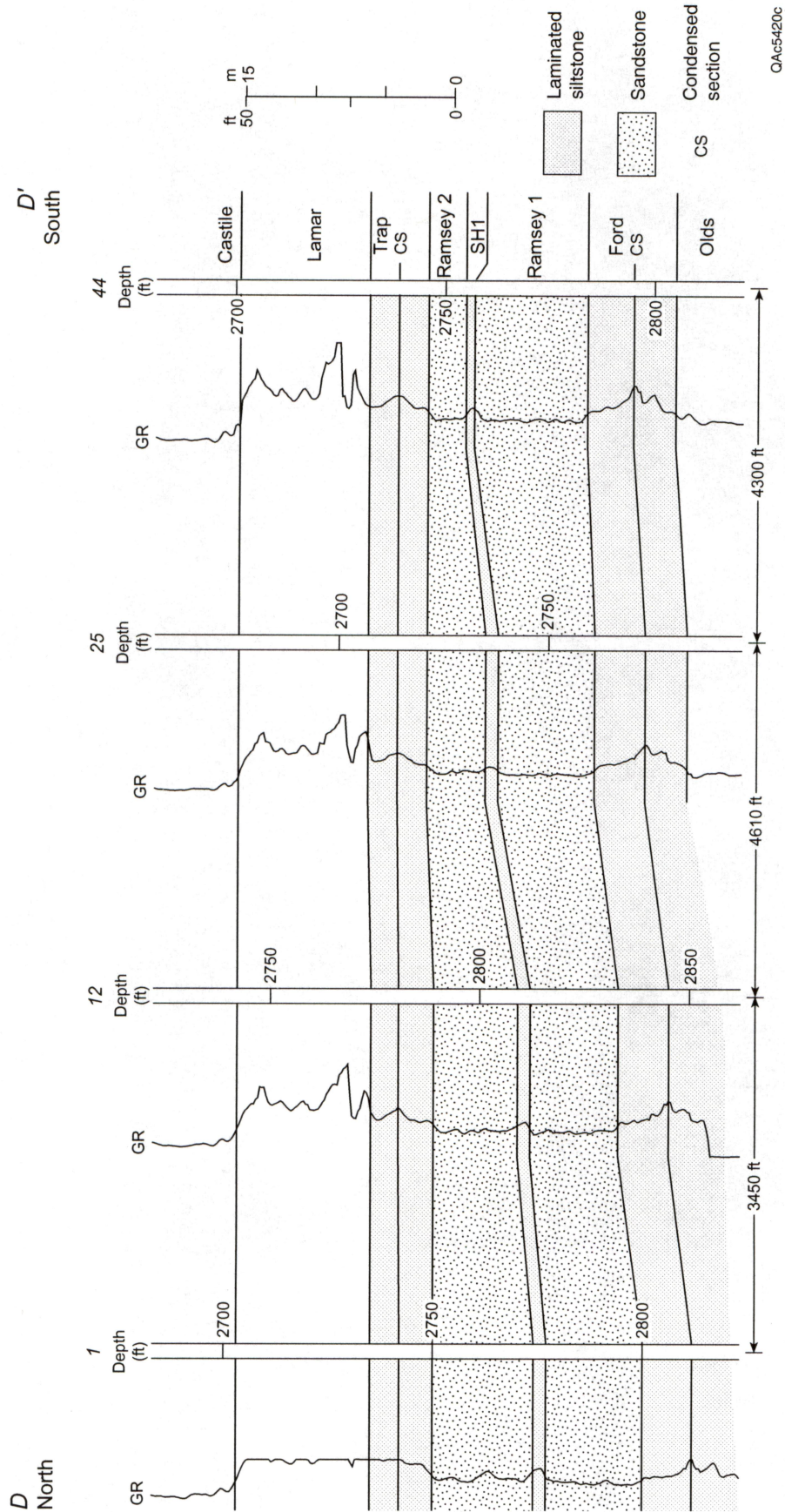


Figure 43. Dip cross section D-D' down the length of the East Ford unit. Location of cross section shown in figure 5.

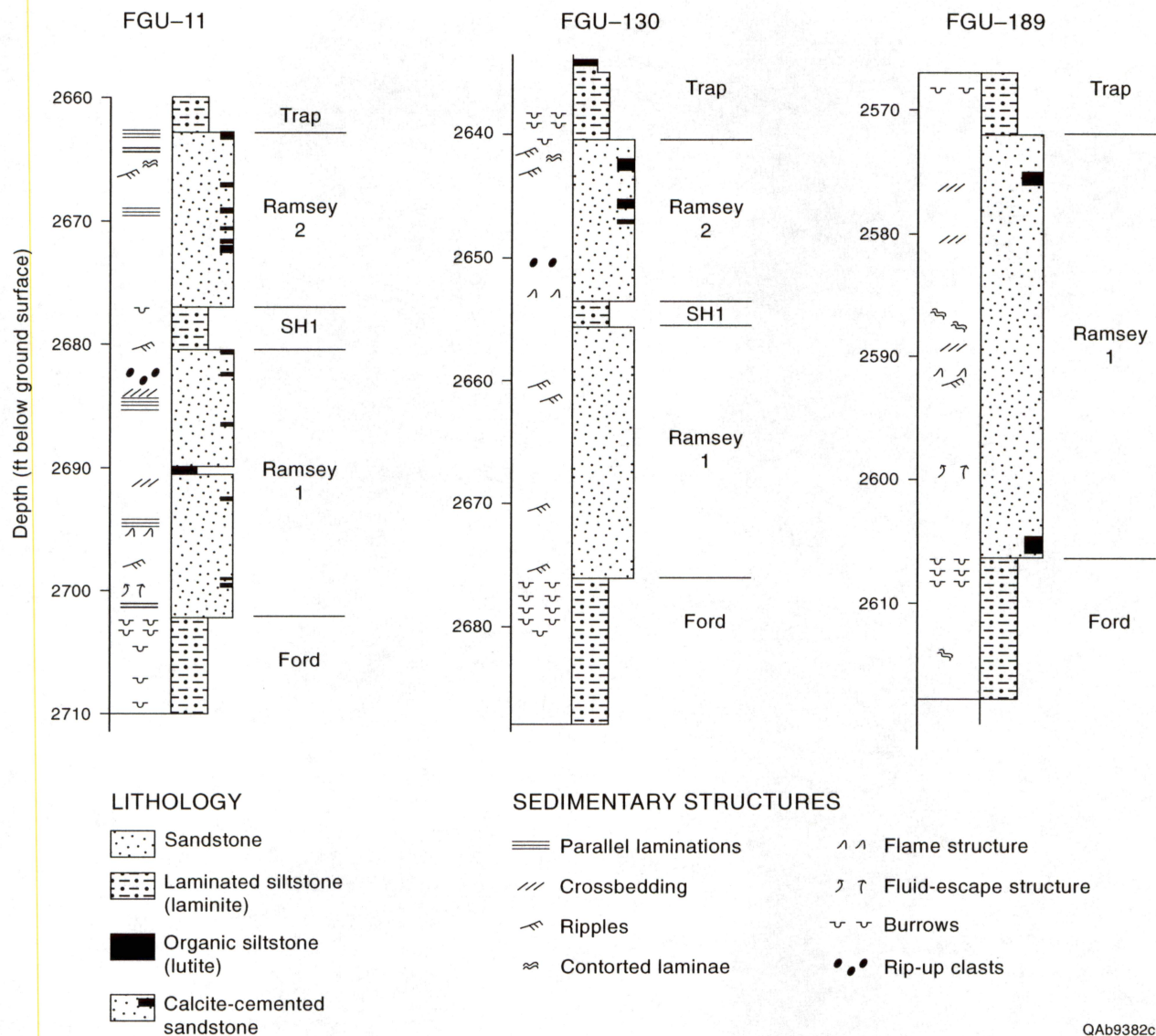


Figure 44. Representative cores of the Ramsey sandstone and Trap and Ford laminated siltstones from the Ford Geraldine unit. No cores were available from the East Ford unit, but the Ramsey reservoir sandstones in East Ford are interpreted to be similar to those in the Ford Geraldine unit.

oriented cross sections (figs. 40 through 42) and isopach map (fig. 35), channels in the Ramsey 1 sandstone are 25 to 35 ft thick and 950 ft to perhaps as much as 2,000 ft wide. It is difficult to determine the width of Ramsey 1 channels precisely. The Ramsey 1 sandstone extends east of the unit, but its limits are unknown because of the absence of well control where it dips below the oil–water contact. Ramsey 2 channels are thinner, about 15 ft thick, and about 950 ft wide (figs. 37, 41). In outcrop, many channels were seen to be nested and laterally offset from each other (Barton, 1997; Barton and Dutton, in press). Similar nesting of multiple channels may occur in the East Ford unit, but the core control is not sufficiently close to distinguish separate channels. The aspect ratio (width:thickness) of Ramsey 1 channel deposits is 30:1 to as much as 80:1. Ramsey 2 channel deposits have aspect ratios of about 60:1. Log response is generally blocky (for example, fig. 41, well 40).

The Ramsey 1 sandstone pinches out rapidly along strike and at the distal end (fig. 35). Unlike the Ramsey 1 sandstone in the Geraldine Ford unit, which tapers gradually at the distal end, the Ramsey 1 sandstone in the East Ford unit ends quite abruptly, thinning rapidly from 27 to 0 ft. The distal end of the Ramsey 1 sandstone in the East Ford unit spreads out over a wide area, as a result of either channel bifurcation or lobe deposition beyond the channel mouth. The south end of the Ramsey 1 sandstone is lobate, but the log patterns are blocky (for example, well 19, fig. 40), which is characteristic of channel deposits.

The thickest part of the Ramsey 2 sandstone occurs to the west of the Ramsey 1 channel (figs. 35, 37, 40), suggesting that the Ramsey 2 was deposited in the topographic low to the west of the thickest Ramsey 1 sandstone. There is evidence of channel bifurcation or overbank deposition at the north end of the Ramsey 2 sandstone (wells 12 and 100, fig. 37). The distal end of the Ramsey 2 sandstone may represent lobe deposition, indicated by the thinner sandstones to the south of well 28 (fig. 37).

Levee Facies

Levee facies occur as a sediment wedge along the margins of the channels (figs. 35, 37, 40). In the Ford Geraldine unit, channel-margin deposits consist of sandstones with partial Bouma sequences, particularly ripples and convoluted ripples, and interbedded siltstones. They are interpreted as channel levees formed by overbanking of low-density turbidity currents. The thickness of the levee facies decreases away from the channels, and the volume of interbedded siltstones increases. Log response is more serrated than in the channels because of the presence of interbedded siltstones.

Lobe Facies

Lobe facies, deposited by unconfined, high-density turbidity currents, occur in broad sheets at the mouths of channels. In the Ford Geraldine unit, lobe facies are characterized by massive sandstones and graded sandstones with dewatering features such as dish structures, flame structures, and vertical pipes, features that indicate rapid deposition and fluid escape. They were deposited at high suspended-load fallout rates. In a prograding system such as the Ramsey sandstone, lobe facies, after having prograded into the East Ford area first, would have then been overlain and partly eroded by the narrower prograding channel-levee system (figs. 40 through 42). Lobe deposits are therefore found at the distal ends of the Ramsey 1 and 2 sandstone channels and also underlying and laterally adjacent to the Ramsey 1 and 2 channels and levees (figs. 35, 37, 40 through 42). Because deposition of lobe sandstones was periodic, laminated siltstones are interbedded with the lobe sandstone sheets. Some lobe deposits show an upward-coarsening log pattern (fig. 41, wells 39 and 40), but many have a blocky log response (fig. 40, well 22).

Laminated Siltstone Facies

The laminated siltstone facies consists of organic-rich siltstone laminae interbedded on a millimeter scale with organic-poor siltstone laminae. The pattern of upward coarsening into the Ramsey sandstone and then upward fining above it suggests that the laminated siltstones are part of the sea-level cycle that resulted in the progradation and retrogradation of the channel levee and lobe. The siltstones may represent windblown silt from the shelf margins that was deposited in the basin by fallout from the wind and settling through the water column, forming widespread, topography-mantling, laminated siltstones of relatively uniform thickness (figs. 34, 38) (Dutton and others, in press). Periods of relative sea-level fall may have exposed increasingly larger areas on the shelf, lowered the water table, and allowed the wind to carry away greater volumes of silt, resulting in thicker organic-poor siltstone layers.

Lutite Facies

The organic-rich siltstones are interpreted as condensed sections that formed in the Ford and Trap intervals during times of very slow siltstone deposition. They contain abundant organic matter, including spores. The organic matter is probably derived from settling from suspension of planktonic organisms. In the Ford Geraldine unit, other lutites occur within the Ramsey 1 and 2 sandstone intervals, where they form drapes along the tops of sandstone beds. They probably formed by fallout from suspension of silt and organic matter from a turbulent sediment gravity flow; they are equivalent to the E division of the Bouma sequence. The average porosity in eight lutites in the Ford Geraldine field is 13.1 percent, and average permeability is 0.13 md.

Proposed Depositional Model for the East Ford Unit

Ramsey sandstones at the East Ford unit are interpreted as having been deposited by sandy high- and low-density turbidity currents. The sands were deposited on the basin floor in a

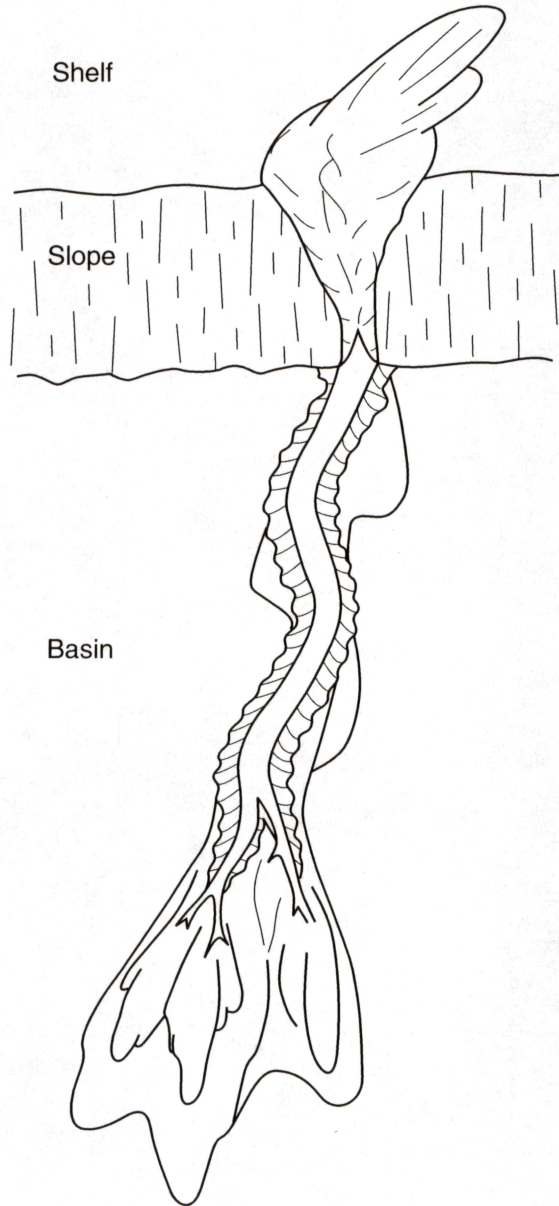
channel-levee system with attached lobes (fig. 45). The deposits formed a complex about 2,500 to 4,000 ft wide, similar in dimensions to the channel-levee and lobe system that was studied in outcrop (fig. 39) (Barton and Dutton, in press). Individual channels within the complex were approximately 1,000 to 1,500 ft wide and 15 to 30 ft deep. Levee deposits thin away from the channel over a distance of about 1,000 to 1,500 ft. Lobe sandstones, deposited at the mouth of the channels, form broad, tabular deposits that were partly incised and replaced by prograding channels.

Instead of filling a large channel, as suggested by the saline-density current model (Ruggiero, 1985, 1993), Ramsey sandstones were probably deposited on the basin floor (Barton, 1997). Younger sandstones were deposited in topographically low areas created by deposition of the preceding bed, resulting in offset stacking of lobes, called compensation lobes by Mutti and Normark (1987). The confinement of sandstones within narrow linear trends (fig. 45) may partly result from reef topography on the highly aggradational carbonate platform (Williamson, 1978; Gardner, 1997).

The narrow range of sediment size in the Ramsey sandstones, mostly very fine sand, supports the interpretation of Fischer and Sarnthein (1988) and Gardner (1992) of an eolian sediment source for sandstones of the Delaware Mountain Group. In their 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 absence 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 low-stands of sea level, dune sands were driven across the exposed shelf to the shelf edge, where they fed unstable, shallow-water sand wedges. Slumping of the sand wedges gave rise to turbidity currents that carved channels and filled them with well-sorted sandstone. During highstands in sea level, the platform was flooded and the dunes prevented from migrating to the shelf edge.

Sediment gravity flow

Slumping of sand masses on the shelf and slope generate dense, sediment-rich waters.



- Waters move through channels flanked by levees.
- Channels bifurcate and terminate in broad, sandy lobes.

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Figure 45. Depositional model proposed for the Ramsey sandstone in the East Ford unit (from Barton, 1997; modified from Galloway and Hobday, 1996).

Characterization of Diagenetic Heterogeneity

The composition of Ramsey sandstones in the Ford Geraldine unit was determined from 32 thin sections from sandstones having a wide range of permeability. Because the Ramsey sandstones in the East Ford unit come from a branch of the same channel as those in the Ford Geraldine unit, the composition is assumed to be the same. Ramsey sandstones at the Ford Geraldine unit are arkoses having an average composition of $Q_{63}F_{32}R_5$. Fossil fragments and carbonate rock fragments occur in several sandstone samples, particularly in the calcite-cemented zones.

Cements and replacive minerals constitute between 4 and 30 percent of the sandstone volume in Ramsey sandstones, with calcite and chlorite being the most abundant. Calcite cement (average = 7 percent, range 1 to 29 percent) occurs both in primary pores and in secondary pores, where it has replaced feldspar grains. Chlorite (average = 3 percent) forms rims around detrital grains, extending into pores and pore throats. Authigenic quartz, anhydrite, leucoxene, siderite, ankerite, mixed-layer illite-smectite (Williamson, 1978), pyrite, and feldspar overgrowths (both K-feldspar and Na-feldspar) also occur in the Ramsey sandstones, generally in volumes of less than 1 percent.

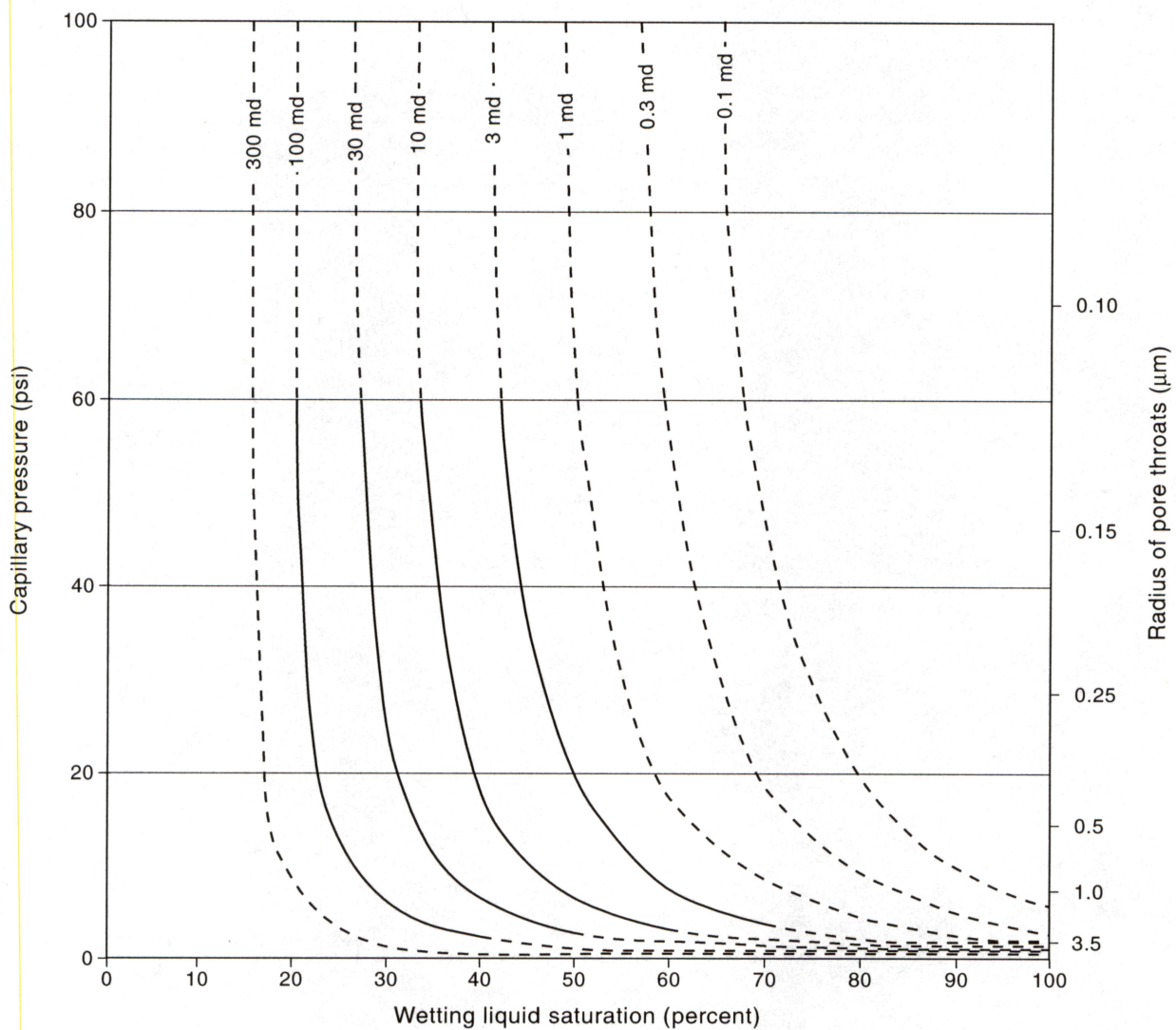
Calcite cement is an important control on reservoir quality in Ramsey sandstones in the Ford Geraldine unit (Dutton and others, in press), and it probably is important in the East Ford unit as well. Brief core descriptions that accompany core analyses from the East Ford unit mention calcite in some low-porosity and -permeability Ramsey sandstones. Some of the spikes of low permeability and porosity in vertical profiles (figs. 32, 33) are probably caused by calcite cement. In the Ford Geraldine unit, average permeability in sandstones having less than 10 percent calcite is 65 md, and average porosity is 23.1 percent. In contrast, average permeability in sandstones having more than 10 percent calcite cement is 10 md, and average porosity is 14.4 percent.

The distribution of calcite cement in the Ford Geraldine unit was determined from cores because highly calcite cemented sandstones have a distinct white color. Calcite-cemented sandstones occur in all three sandstone facies—channel, levee, and lobe (Dutton and others, 1997a, in press). Most cemented zones are approximately 0.5 to 1 ft thick. Although they can occur anywhere within the Ramsey sandstone section, they are more common near the top and base of sandstones. Total thickness of calcite-cemented sandstones in the Ford Geraldine unit increases near the margins of the field (Dutton and others, 1999). The occurrence of calcite cement preferentially at the top and base of the Ramsey sandstone and at the margins of the field suggests that calcium carbonate was mobilized by acid generation in the surrounding organic-rich siltstones and transported into the adjacent sandstones. Calcite then precipitated in the Ramsey sandstone as a result of loss of acidity, for example, by consumption of hydrogen ions during feldspar dissolution.

Evaluation of Reservoir Heterogeneity

Microscopic heterogeneity of Ramsey sandstones is controlled primarily by diagenesis. Precipitation of calcite and chlorite has the greatest effect on pore-throat-size distribution. Capillary pressure curves from the Ford Geraldine unit well FGU-156 show that uncemented sandstones, which have permeabilities in the 30- to 300-md range, have 60 to 80 percent of their pore-throat radii greater than 1.0 μm (fig. 46). Cemented sandstones having permeabilities of 0.1 to 3 md have just 4 to 40 percent of their pore-throat radii greater than 1.0 μm . Core-analysis data from Twofreds field, which is located about 40 mi southeast of East Ford field, indicate that the mean hydraulic radius of the pore throats in Ramsey sandstones in that reservoir is 2.85 μm (Flanders and DePauw, 1993).

Megascopic (field-scale) heterogeneity in the East Ford unit is caused by subdivision of the reservoir. Throughout the unit, the Ramsey 1 and Ramsey 2 sandstones are separated by a 1- to 3-ft-thick laminated siltstone (SH1) that probably acts as a barrier between the two sandstone reservoirs.



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Figure 46. Capillary pressure curves and calculated radii of pore throats for Ramsey sandstones from the Ford Geraldine Unit No. 156 well. Curves are based on analyses of six samples having permeability ranging from 1.1 to 116 md. Dashed lines indicate extrapolated data. The analyses were done using the centrifuge method with air and kerosene. Ramsey sandstones in the East Ford unit are interpreted to have pore-throat distribution similar to those in the Ford Geraldine unit.

Fluid Characteristics

Fluid characteristics of Geraldine Ford field are summarized in table 4. Initial pressure in the field was 1,480 psi. Pressure declined in the reservoir during primary production to 850 psi by January 1991 (fig. 47). Oil gravity is 43° API. Reservoir temperature is 83°F, and the original bubble-point pressure was 1,383 psi.

FIELD-DEVELOPMENT HISTORY

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. Primary cumulative oil production was 3,209,591 bbl (fig. 48). An estimated 10 percent of the total production, or 320,959 bbl, was from the Olds sandstone (W. A. Flanders, Transpetco Engineering, written communication, 1994). The estimated 2,888,632 bbl produced from the Ramsey sandstone represents 14.6 percent of the 19.8 MMbbl of original oil in place.

Primary production data in the East Ford unit were collected by lease, not by individual well. Two different methods were used to map primary oil production. In the first method, production for each lease was plotted at the geographic center of the wells that produced from the Ramsey sandstone (fig. 49). In this method, all production was assumed to be from the Ramsey sandstone. The highest production generally follows the trend of low-percentage water cut during IP tests (fig. 50). In the Ford Geraldine unit, the percentage of water produced during IP tests was the single best predictor of eventual total production from a well (Dutton and others, 1997b), and it appears to be a good predictor in the East Ford unit as well.

In the second method, production from each lease was apportioned among the wells on the lease by initial-potential (IP) test data (fig. 51). For each lease, the barrels of oil per day (bopd) produced by each well during IP tests were summed to get a total value of bopd for the lease, then the percentage contribution of each well to the total was calculated. That fraction was used to apportion total production from the lease to individual wells. Four wells produce only from the

Table 4. Fluid characteristics of reservoir.

Initial reservoir pressure	1,480 psi
Reservoir temperature	83°F
Oil gravity	43°
Oil viscosity at reservoir temperature	0.775 cp
Initial oil formation volume factor (B_o)	1.278 bbl/stb
Bubblepoint pressure	1,383 psi
Initial gas in solution (R_s)	575 solution GOR, scf/stb
Minimum miscibility pressure (MMP)	900 psi
Fluid composition (sample from EFU-9)	CO ₂ = Trace N ₂ = 0.21 H ₂ S = Nil Hydrocarbons = 99.79
Gas gravity	1.13
Water salinity	59,200 to 70,300 mg/l chlorides

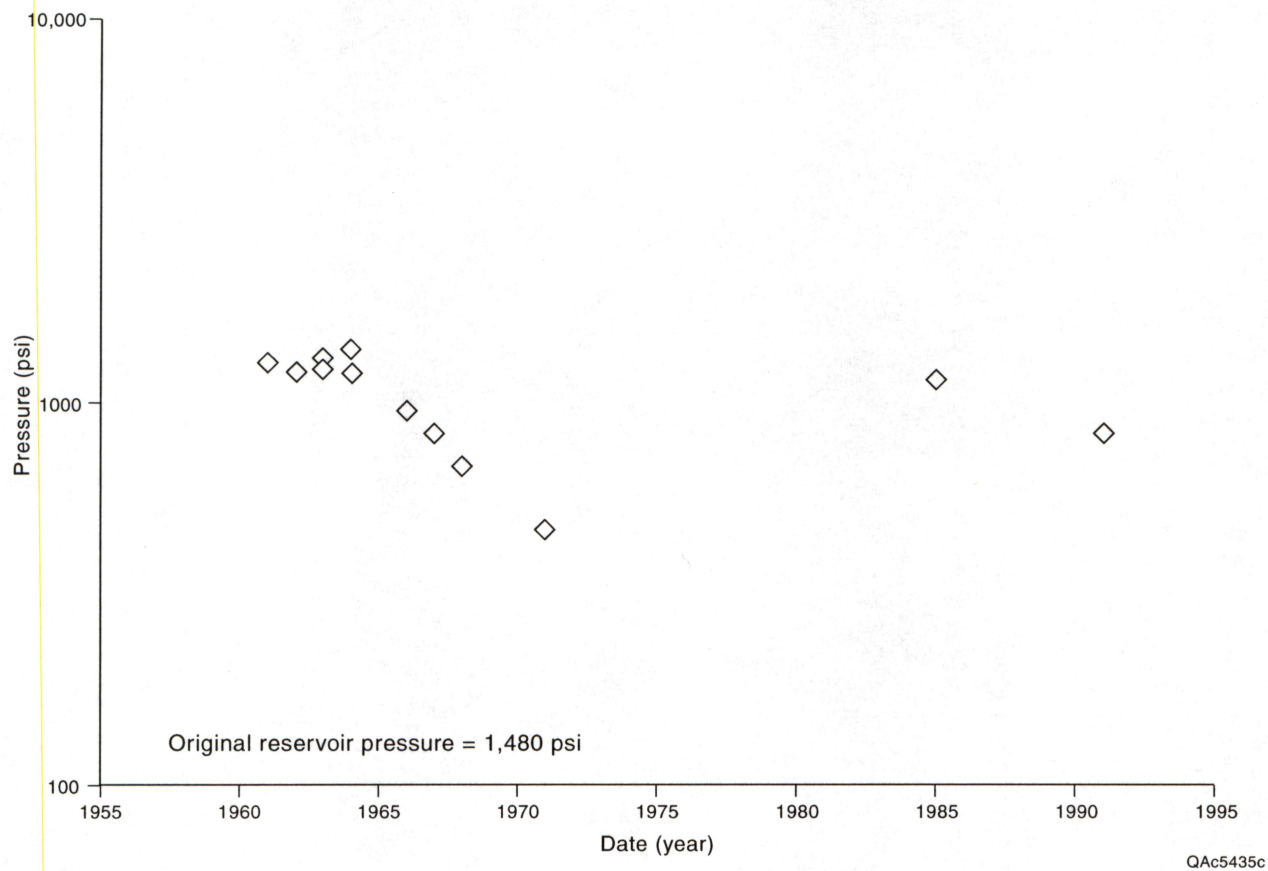
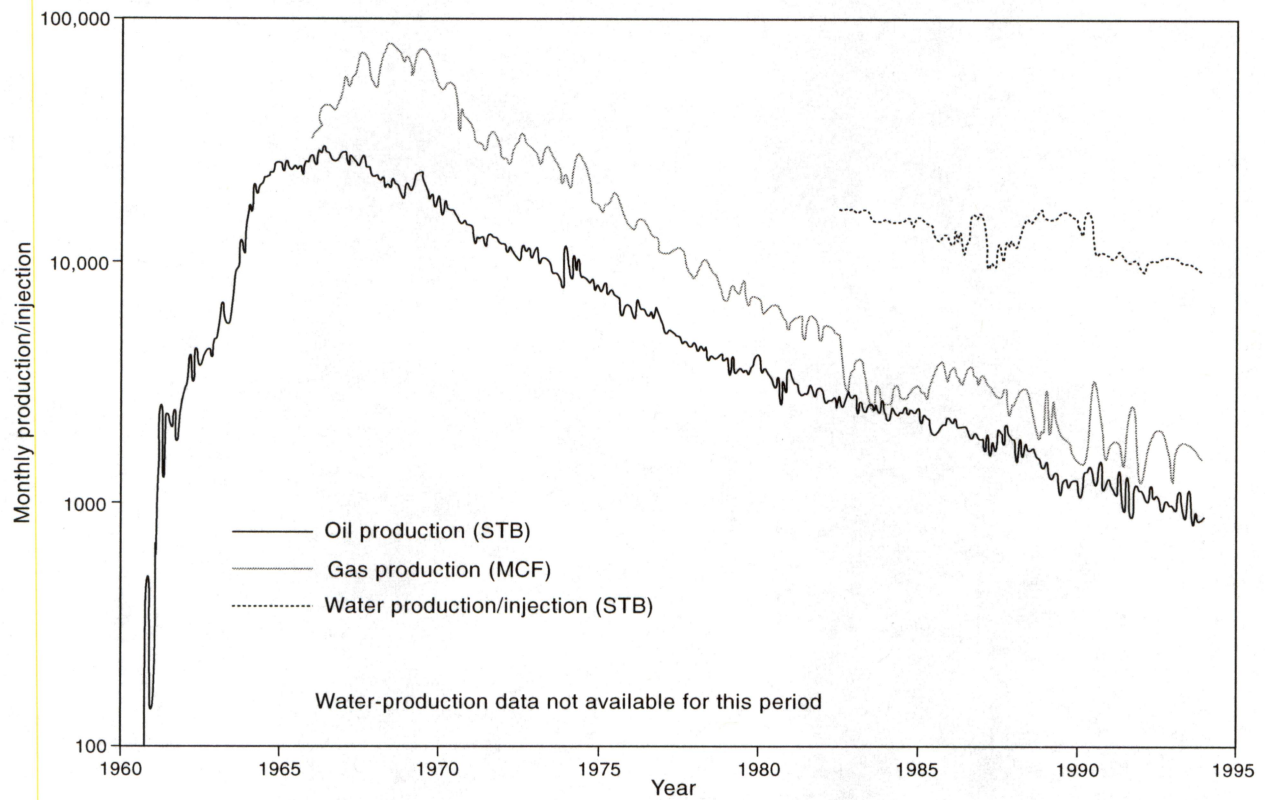


Figure 47. Plot of average reservoir pressure through time for the East Ford unit during the period of primary recovery.



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Figure 48. Plot of primary oil and gas production in the East Ford unit and volumes of water produced and injected.

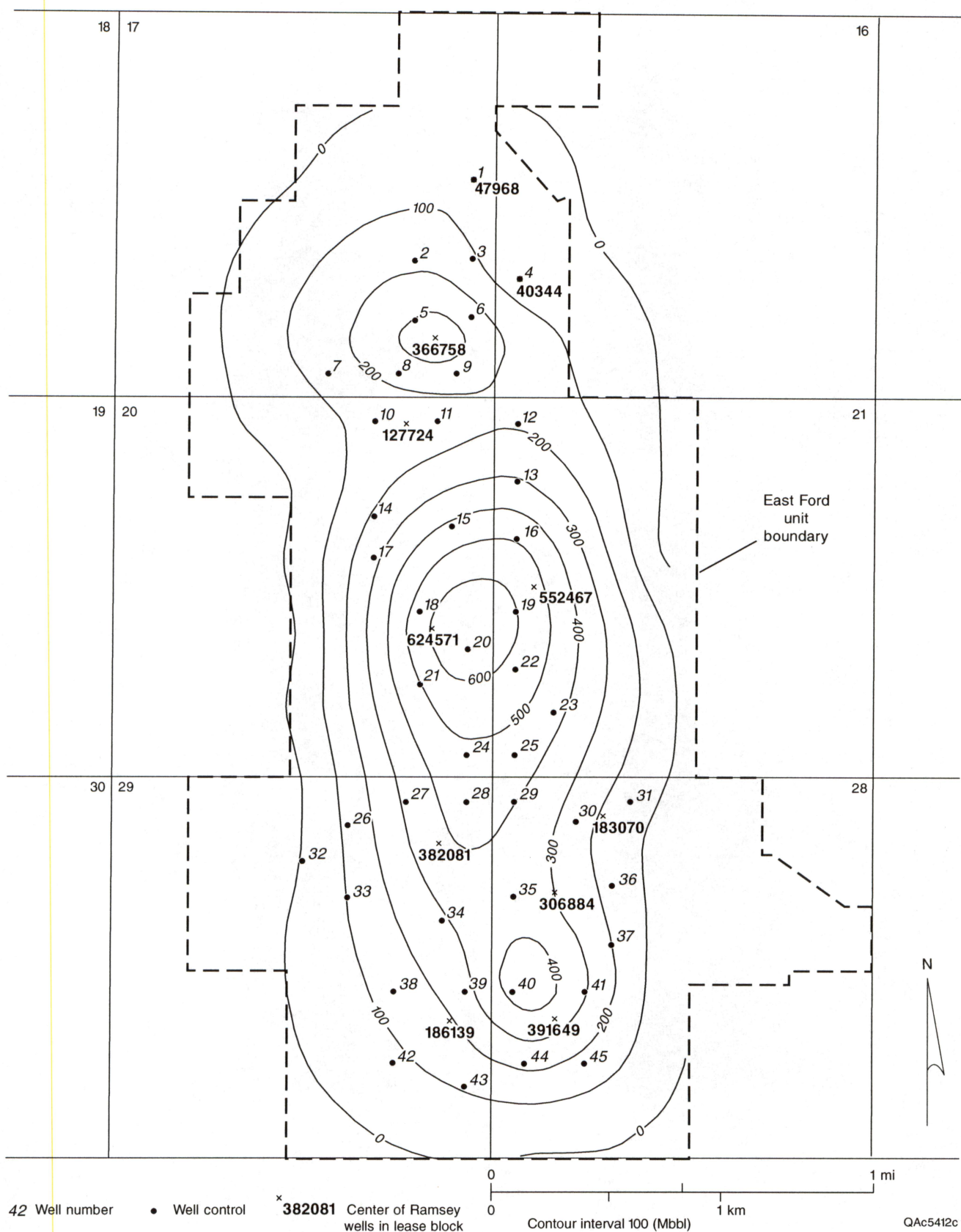


Figure 49. Map of primary oil production from the Ramsey sandstone in the East Ford unit. Production for each lease was plotted at the geographic center of the wells producing from the Ramsey sandstone within the lease.

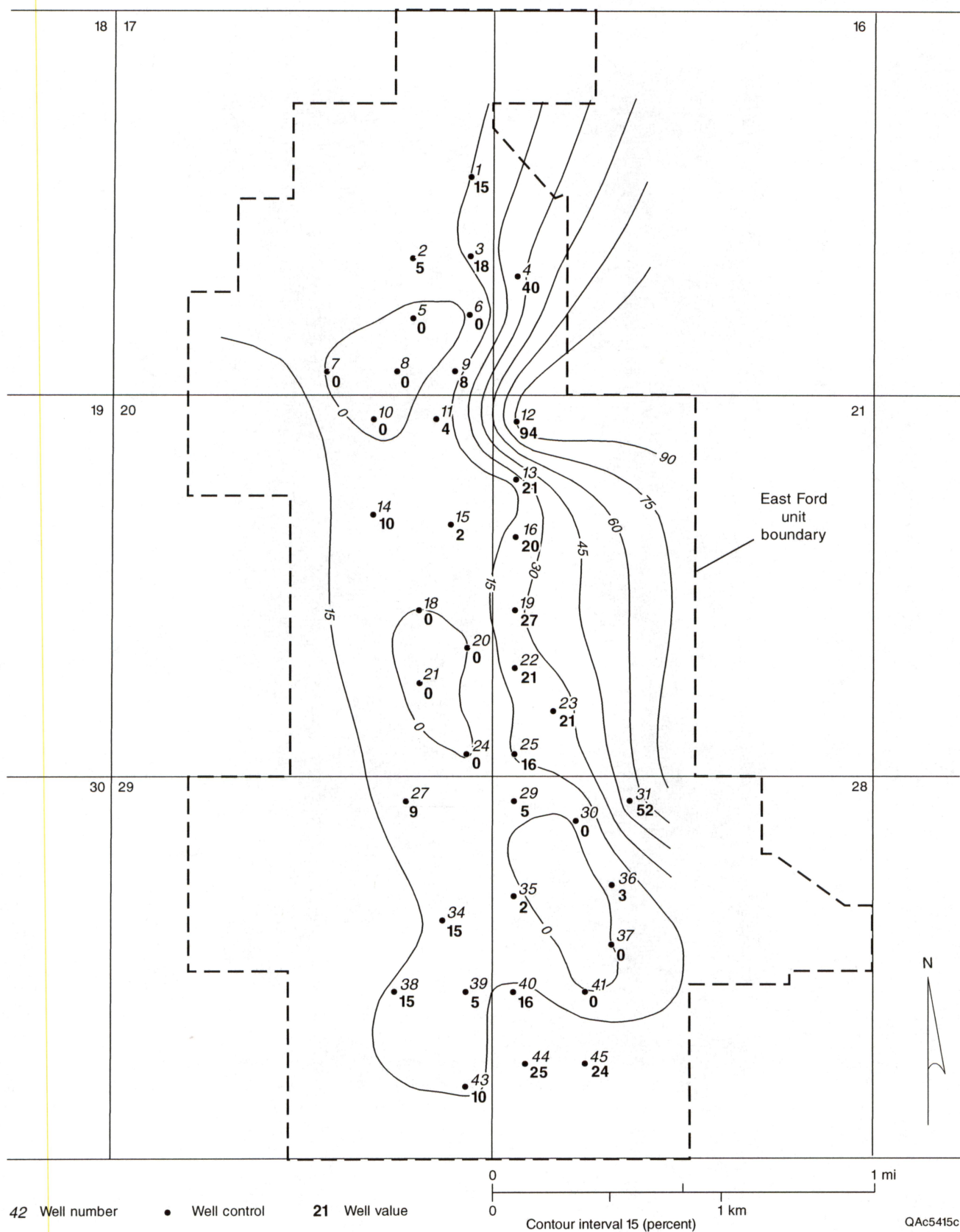


Figure 50. Map of the percentage of water (water cut) produced during initial-potential tests.

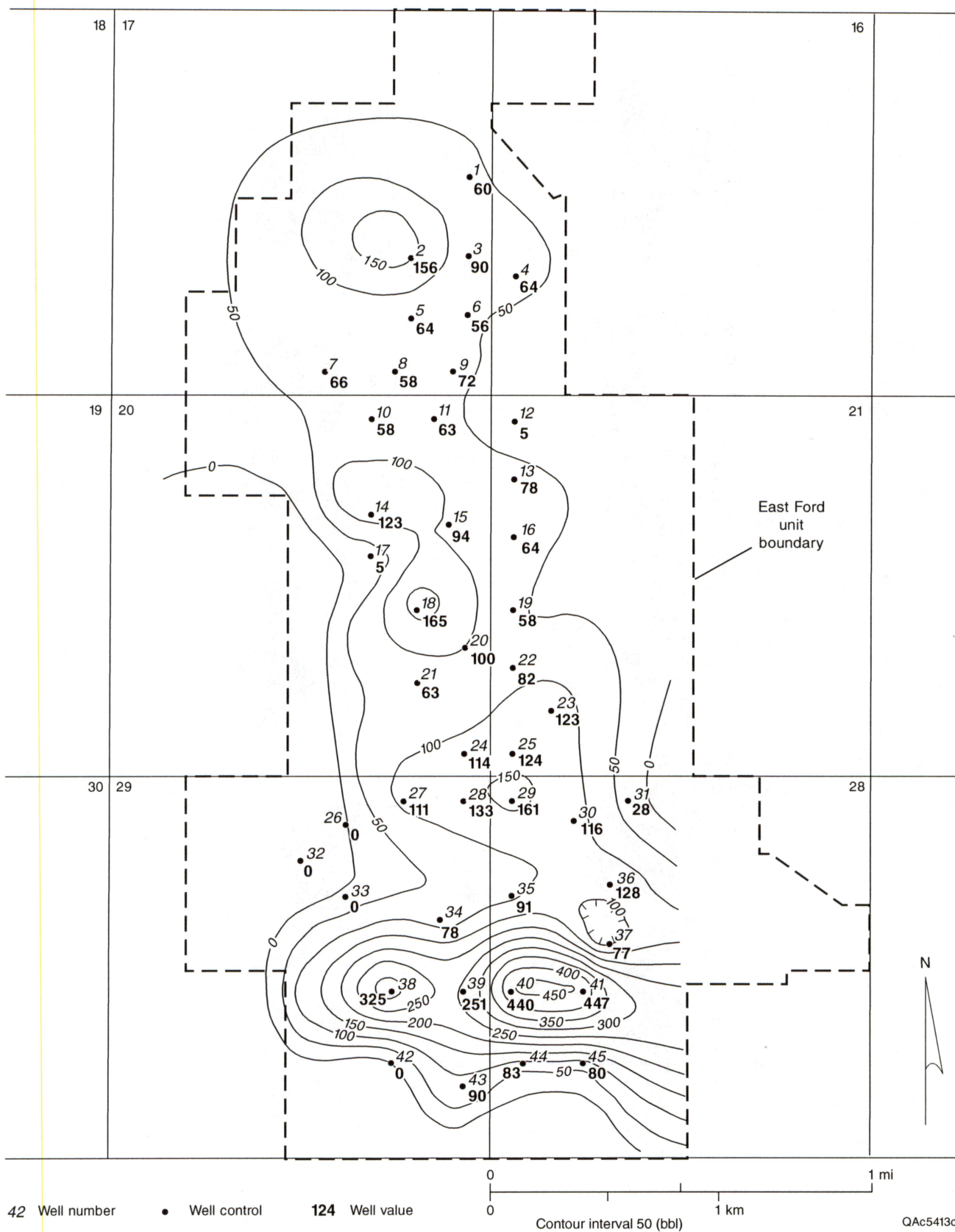


Figure 51. Map of oil produced during initial-potential tests in wells of the East Ford unit.

Olds sandstone (EFU-26, 32, 33, and 42; fig. 51), so none of the production from those wells was included in the map of Ramsey primary production. Six other wells (EFU-17, 27, 28, 34, 39, and 45) produce from both the Ramsey and Olds zones (fig. 51), and Ramsey production is interpreted as being 90 percent of the total. Total primary production assigned to those wells was reduced by 10 percent to account for the Olds production.

The map of primary production (fig. 52) shows that the best-producing wells in the north part of the field (EFU-14 and 18) penetrate the Ramsey 2 channel facies (fig. 37). The better wells from the south part of the unit (EFU-25, 30, 40, and 41) are offset toward the east, where the Ramsey 1 sandstone is thickest (fig. 35).

The East Ford unit did not undergo secondary recovery by waterflooding. In Ramsey sandstone reservoirs in other fields, waterflooding has not been very successful. In the Ford Geraldine unit, waterflooding added only an estimated 3.5 percent of the OOIP to the total recovery by the end of secondary development (Pittaway and Rosato, 1991). Low secondary recovery is not unique to the Ford Geraldine unit; secondary recovery from Twofreds field was only 4 percent (Kirkpatrick and others, 1985; Flanders and DePauw, 1993).

Tertiary recovery in the East Ford unit by CO₂ injection began in July 1995, and production response to the CO₂ injection was observed in December 1998. During Phase 2 of the project, production from the East Ford unit will be monitored and compared with predictions made on the basis of flow-model simulations. This comparison will provide an opportunity to evaluate the success of these operations and to test the accuracy of reservoir-characterization and flow-simulation studies as predictive tools in resource preservation of mature fields.

ESTIMATE OF TERTIARY RECOVERY

To estimate the tertiary recovery potential of the East Ford unit, fluid-flow simulations of a CO₂ flood were performed (Dutton and others, 1997b, 1998b; Malik, 1998). A quarter five-spot area at the north end of the Ford Geraldine unit was selected for flow simulation because

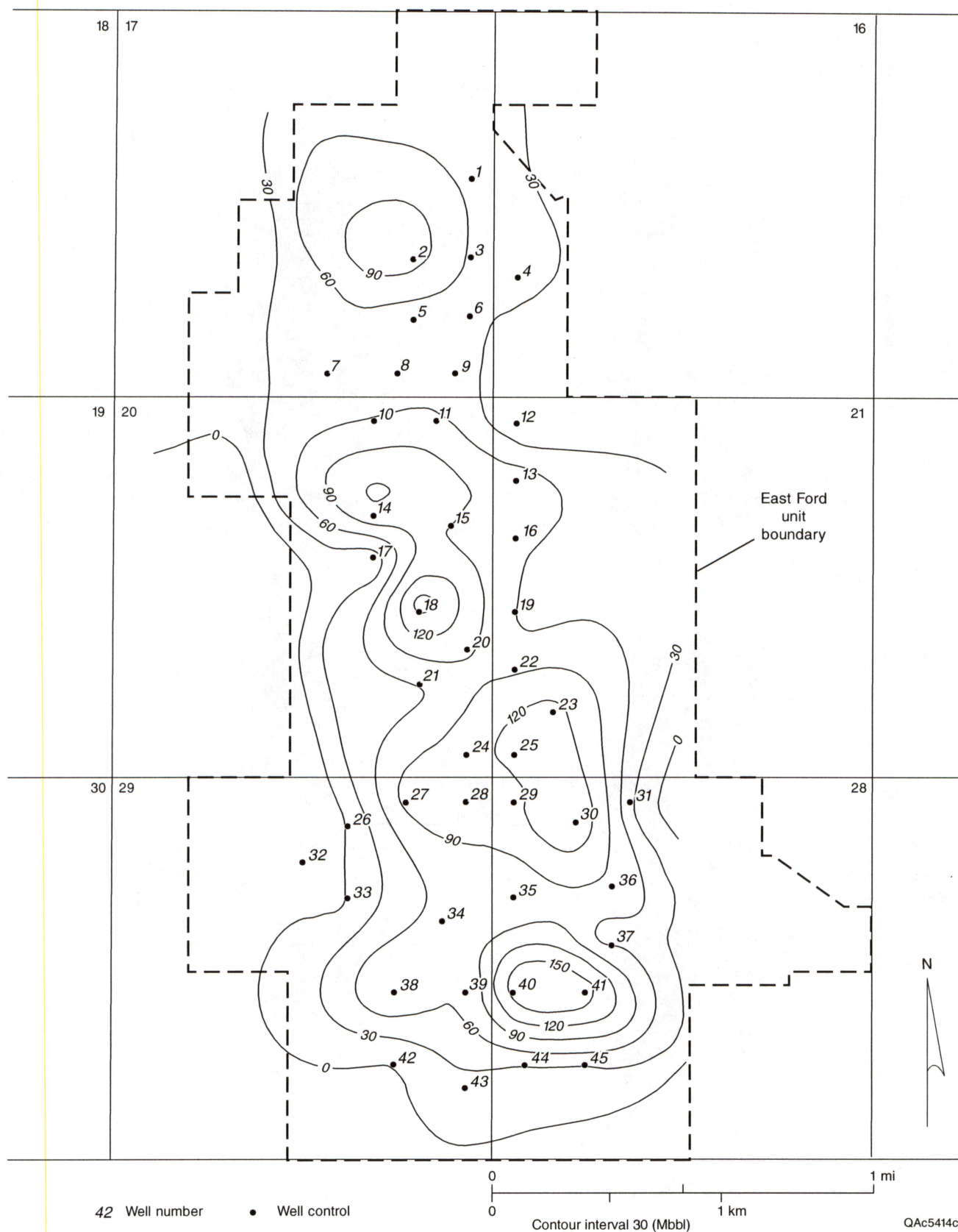


Figure 52. Map of primary oil production from the Ramsey sandstone in the East Ford field. Production from each lease was apportioned among the wells on the lease according to the volume of oil produced during initial-potential tests.

abundant log and core data were available to develop a stochastic, 3-D model of permeability distribution. This area is similar to the East Ford unit, both in terms of reservoir thickness and in the separation of the Ramsey sandstone into two parts by the SH1 siltstone. Independent estimates of potential tertiary recovery from the East Ford unit were also made on the basis of the results of the CO₂ flood performed in the south part of the Ford Geraldine unit.

Estimate of Tertiary Recovery from Ford Geraldine Production Data

Production results from the south part of the Ford Geraldine unit were used as one method to estimate tertiary recovery potential of the East Ford unit. A conservative estimate of 83.5 MMbbl of original oil in place (OOIP) for the entire Ford Geraldine unit was used for this analysis (Conoco, 1987); OOIP has been estimated to be as high as 110 MMbbl (Conoco, 1987; Pittaway and Rosato, 1991). Primary, secondary, tertiary, and cumulative recovery as a percentage of OOIP was calculated for each area within the unit (fig. 53). Only area 5 has not undergone tertiary production. The average primary recovery in the Ford Geraldine unit, excluding area 5, was 14.5 percent, very similar to the 14.6-percent primary recovery in East Ford field. Secondary and tertiary development in the Ford Geraldine unit recovered 17.8 percent of the remaining oil in place after primary development, increasing total recovery of OOIP to 31 percent. A CO₂ flood in the East Ford unit might be expected to recover an additional 18 percent of the remaining oil in place, or 3 MMbbl. This may be a conservative figure because the East Ford unit did not undergo an ineffective secondary waterflood but went directly from primary production to a CO₂ flood.

Simulations of Tertiary Recovery

To estimate the tertiary recovery potential of the East Ford unit by another technique, we evaluated the results of flow simulations performed for a CO₂ flood in area 5 of the Ford Geraldine unit (Malik, 1998). A quarter of a five-spot injection pattern was selected for the

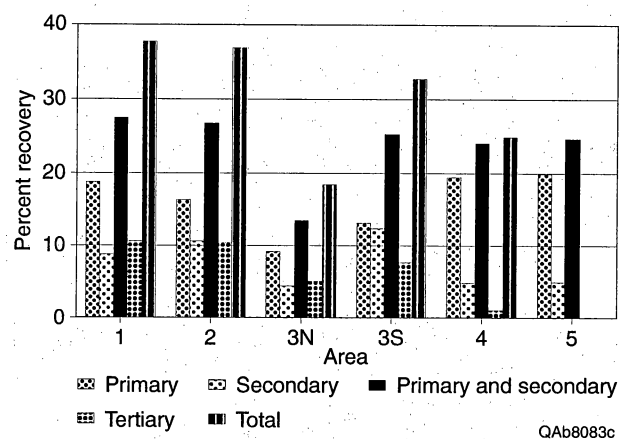


Figure 53. Primary, secondary, primary + secondary, tertiary, and total recovery in the Ford Geraldine unit production areas through December 1995 as a percentage of original oil in place (from Dutton and others, 1997b).

simulations, and because of the similarity of area 5 to the East Ford unit, the results were used as an estimate of East Ford tertiary recovery.

Two cases of permeability distribution were considered. In the first case, stochastic permeabilities generated by conditional simulation (Malik, 1998) were used. The second case used layered permeabilities. The Ramsey 1 and 2 sandstones are both present in simulation area 5, and average total sandstone thickness in the area is 32 ft (Dutton and others, 1997a). A permeability cutoff of 5 md was used to exclude the nonproducing zones, and maximum permeability was limited to 200 md.

Three-phase simulations for a CO₂ flood were performed by means of UTCOMP, an isothermal, three-dimensional, compositional simulator for miscible gas flooding (Chang, 1990). An average oil saturation of 37 percent and five hydrocarbon components were used in these simulations. Injection pressure was limited to 2,000 psia, and production wells have a flowing bottom-hole pressure of 700 psia, in conformity with the prevailing practices in the CO₂ flood in other parts of the Ford Geraldine unit.

Simulation Results

A plot of oil recovery (fraction of remaining oil in place, ROIP) as a function of dimensionless time or pore volumes injected (PVI) for the two cases is shown in figure 54a. This figure shows breakthrough oil recovery of 24 percent for stochastic permeabilities and 10 percent for layered permeabilities. Unlike in a waterflood, these simulations indicate that CO₂ injection results in a gradual increase in recovery even after breakthrough in both cases. Ultimate recovery can exceed 38 percent of ROIP.

Oil-production rates increase until breakthrough (fig. 54b). At the time of breakthrough, the oil rate rises sharply to its peak value and declines gradually thereafter. The water:oil ratio (WOR) decreases gradually with the progress of the flood and remains low even after breakthrough (fig. 55a), but the gas:oil ratio (GOR) continues to increase after breakthrough

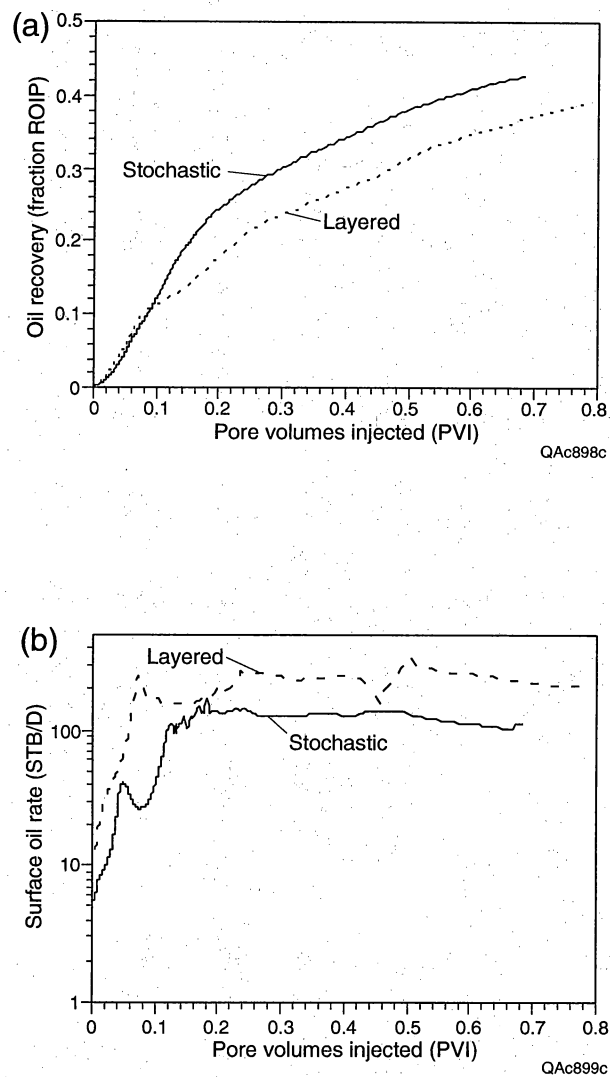


Figure 54. Results of simulation of a CO₂ flood in the Ramsey sandstone (from Malik, 1998). (a) Oil recovery as a fraction of remaining oil in place for stochastic and layered permeability cases. (b) Surface oil rate in stock tanks barrels/day (STB/D) for stochastic and layered permeability cases.

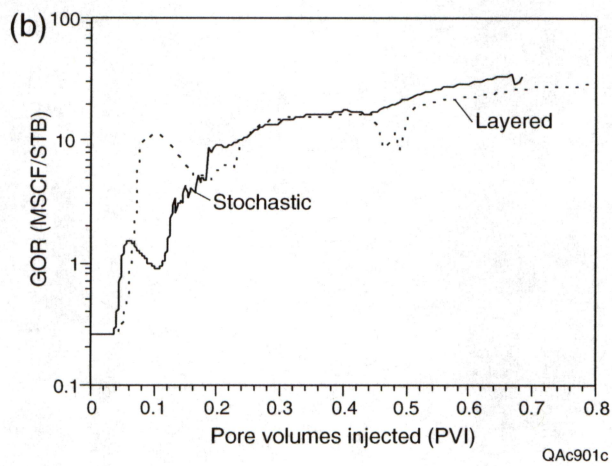
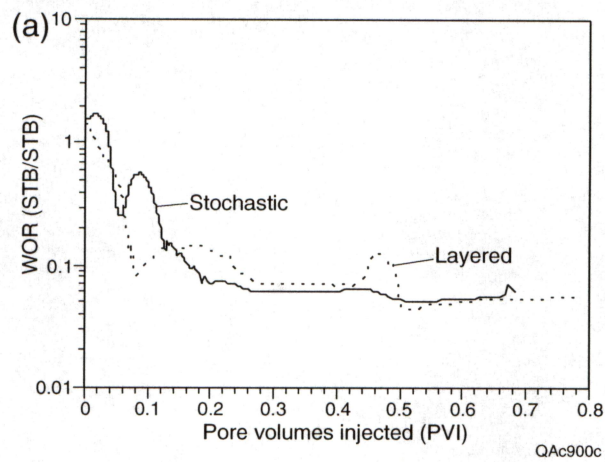


Figure 55. Results of simulation of a CO₂ flood in the Ramsey sandstone (from Malik, 1998).
 (a) Surface water:oil ratio (WOR) (STB/STB) for stochastic and layered permeability cases.
 (b) Surface gas:oil ratio (GOR) (MSCF/STB) for stochastic and layered permeability cases.

(fig. 55b). Although oil rates are quite high for some time after breakthrough (fig. 54b), the limiting factor in a CO₂ flood may be excessive gas production.

Estimated OOIP in the Ramsey sandstone in the East Ford unit was 19.8 MMbbl (W. A. Flanders, Transpetco Engineering, written communication, 1994), and approximately 2.9 MMbbl of oil was produced through primary depletion. Remaining oil in place (ROIP) in the East Ford unit is approximately 16.9 MMbbl. Results of the simulations indicate that a minimum of 10 percent of ROIP, or 1.69 MMbbl, is recoverable through CO₂ flood. This more conservative estimate is based on the breakthrough recovery of a layered model. The stochastic permeability model shows a breakthrough recovery of more than twice this estimate. If the increased gas production after breakthrough can be handled economically, ultimate CO₂ flood recovery could exceed 30 percent of ROIP.

CONCLUSIONS

Research during this year of the project concentrated on (1) reservoir characterization of the Ramsey sandstone reservoir in the East Ford unit and (2) estimating the results of a CO₂ flood in the East Ford field. Reservoir characterization of the East Ford unit provided an opportunity to test the transferability of the geologic model and log-interpretation methods developed during characterization of the Ford Geraldine unit to another field in the Delaware sandstone play. The geologic model that was developed by study of Bell Canyon sandstones in outcrop and in the Ford Geraldine unit was used as a guide to interpret the reservoir at the East Ford unit. The apparently successful transfer of the geologic model to another Delaware sandstone field is not surprising because of the uniform depositional conditions throughout the basin. Furthermore, the Ramsey sandstone in the East Ford unit is a branch of the channel that forms the Ford Geraldine reservoir, so that a high degree of similarity should be expected between the two reservoirs.

Most aspects of the log-interpretation methodology developed for the Ford Geraldine unit were used successfully in the East Ford unit. The approach that was used to interpret water

saturation from resistivity logs, however, had to be modified because in some East Ford wells, the log-calculated water saturation was too high and inconsistent with the actual production. In addition, the use of bulk-volume water mapping to determine water saturation in wells having no resistivity logs did not yield results consistent with production. A cross plot of valid log-calculated water-saturation versus water-cut data provided a transform that was used to estimate water saturation from water-cut data in wells without good resistivity logs.

The East Ford unit is a good candidate for improved recovery by CO₂ flood. Flow simulations performed by UTCOMP, a compositional simulator for miscible gas flooding, indicate that 10 to 30 percent (1.7 to 5 MMbbl) of remaining oil in place can be produced by CO₂ injection. In contrast, waterflooding is unlikely to be an effective or economical recovery technique. Poor recovery from the waterflood of the Ford Geraldine unit resulted from reduced sweep efficiency caused by high mobile water saturation. Because water saturation was also high in the Ramsey sandstone in the East Ford unit at discovery and increased during primary production, secondary recovery by waterflood was not attempted there. Simulations indicate that water production will be lower during a CO₂ flood.

To minimize the impact of geologic heterogeneity, CO₂ should be injected into both the Ramsey 1 and 2 sandstones, above and below the widespread siltstone that subdivides the reservoir vertically. The highest porosity and permeability in the Ramsey 1 and 2 sandstones follows the north-south channel orientations. These trends of higher permeability should be taken into account when determining the injection rates in wells that penetrate the channel, so that lower injection rates could be used where a line of injectors crosses the channel trend. The goal is to avoid rapid breakthrough of CO₂ along high-permeability pathways.

ACKNOWLEDGMENTS

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