GRI-93/0334

GEOLOGIC CHALLENGES AND OPPORTUNITIES OF THE CHEROKEE GROUP PLAY (PENNSYLVANIAN): ANADARKO BASIN, OKLAHOMA

Topical Report
(January 1993–March 1993)

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for
Gas Research Institute
Contract No. 5082-211-0708
John Hansen, Project Manager

October 1993

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO. GRI-93/0334	2.	3. Recipient's Accession No.

4. Title and Subtitle

Geologic Challenges and Opportunities of the Cherokee Group Play (Pennsylvanian): Anadarko Basin, Oklahoma

5. Report Date

November 1, 1993

6.

7. Author(s)

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8. Performing Organization Rept. No.

9. Performing Organization Name and Address

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10. Project/Task/Work Unit No.

11. Contract(C) or Grant(G) No.

(C) 5082-211-0708

(G)

12. Sponsoring Organization Name and Address

Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, IL 60631

Project Manager: John T. Hansen

13. Type of Report & Period Covered

Topical Report
January 1993-March 1993

14.

15. Supplementary Notes

16. Abstract (Limit: 200 words)

The Middle Pennsylvanian Cherokee Group composes one of the most active natural gas plays in the Anadarko Basin of Oklahoma, having produced more than 1.2 Tcf from major (>10 Bcf cumulative production) Cherokee reservoirs in Beckham, Custer, Roger Mills, and Washita Counties, the area currently experiencing the most active Cherokee development activity. Preliminary geologic study and telephone survey of 15 Cherokee operators satisfied three primary project objectives: (1) to summarize both the geologic characteristics of the Cherokee Group and the production highlights in the four-county area of current activity; (2) to summarize what current Cherokee producing companies perceive to be the primary geologic challenges they face in developing the Cherokee play; and (3) to suggest geologic strategies to help respond to these challenges.

Geologic questions related to Cherokee gas-production enhancement are fundamental, and answers to these questions have the potential to alter current production strategies, reduce risk, and ultimately to increase natural gas reserves. Most of the surveyed Cherokee operators acknowledge that they have only a partial understanding of regional facies relations within the Cherokee depositional systems tracts. Moreover, there is no clear and integrated perspective of depositional systems, reservoir geometry, and diagenesis among all Cherokee fields in the play area. Reservoir geometry is complex and not readily predictable; therefore, drilling of infill wells, which characterizes the current development strategy of the Cherokee play, is fraught with uncertainty. The high degree of variation in porosity and permeability cannot be predicted from current knowledge of reservoir-quality patterns. A limited per-well drainage area suggests internal compartmentalization of sandstone reservoirs.

Investigations at several scales can provide needed information. Improved and more precise modeling of (1) the regional spectra of Cherokee depositional settings at the play scale, (2) depositional facies and geometry at the field scale, and (3) facies architecture, diagenesis, and fracture distribution at the reservoir scale would aid the efficient exploitation of the remaining natural gas resources in the Cherokee play.

17. Document Analysis a. Descriptors

Cherokee Group, Red Fork formation, Skinner formation, Anadarko Basin, west-central Oklahoma, Cherokee-operator survey, structural geology, depositional facies, sandstone petrology, natural fractures, reservoir characterization and development, production statistics, drilling and formation evaluation, reservoir stimulation

b. Identifiers/Open-Ended Terms

Synopsis of regional geology of Cherokee Group, responses to Cherokee-operator survey, development strategies of Cherokee Group, geologic challenges faced by Cherokee operators, proposed geologic strategies to resolve challenges, benefit analysis

c. COSATI Field/Group

18. Availability Statement	19. Security Class (This Report)	21. No. of Pages
Release unlimited	Unclassified	27
	20. Security Class (This Page)	22. Price
	Unclassified	

(See ANSI—Z39.18) *See Instructions on Reverse* OPTIONAL FORM 272 (4–77) (Formerly NTIS–35) Department of Commerce

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Research Summary

Title	Geologic Challenges and Opportunities of the Cherokee Group Play (Pennsylvanian): Anadarko Basin, Oklahoma
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708
Principal Investigator	S. E. Laubach
Report Period	January 1993–March 1993

Objectives

This report has four objectives: (1) to summarize both the geologic characteristics of the Cherokee Group and its production highlights; (2) to summarize what current Cherokee producing companies perceive to be the primary geologic challenges they face in developing the Cherokee play; (3) to suggest geologic strategies to help respond to these challenges; and (4) to assess the benefits to operators of geologic studies of the Cherokee. To increase the understanding and utilization of natural gas resources in the Cherokee Group of west-central Oklahoma and to help assess future geological and technological needs for efficient development of this resource, this report highlights current geological knowledge of the Cherokee play.

Technical Perspective

This report is based on a review of published literature and discussions with 15 Cherokee operators. Because the Cherokee is a mature development play, the surveyed operators have a good understanding of the problems inherent in producing from the unit. I conducted limited regional mapping and well-log correlation to help illustrate geologic characteristics of the Cherokee and identify reservoir characterization challenges.

Results

The Middle Pennsylvanian Cherokee Group is currently one of the most active natural-gas development plays in the Anadarko Basin. The group has been designated to be tight by the Federal Energy Regulatory Commission in parts of Beckham, Custer, Roger Mills, and Washita Counties, Oklahoma, and has produced more than 1.2 Tcf from the major (>10 Bcf cumulative production) reservoirs since the late 1970's. This region is currently experiencing the most active Cherokee development activity. Producing Cherokee formations, primarily the Red Fork and Skinner, represent fluvial-channel, fluvial-deltaic, and submarine-fan (or distal-deltaic turbidite) facies. Channel-fill sandstones within these depositional systems compose the best reservoir rock but are difficult to penetrate in wells because of their small size and irregular geometry. The trapping mechanism in most Cherokee fields is stratigraphic with local enhancement by positive structural position. Cumulative production is as high as about 250 Bcf (Strong City District) in Cherokee fields; per-well cumulative production is as much as 10 to 20 Bcf.

The 15 surveyed operators were consistent in what they consider to be the primary geologic challenges in developing the Cherokee play. These interrelated challenges are (1) predictability of reservoir geometry and trend, (2) characterization of depositional environments, (3) cause(s) of porosity/permeability variation within reservoirs, (4) reason(s) for limited drainage area of Cherokee wells, and (5) regional stratigraphic correlation of the Cherokee Group, particularly the lower, middle, and upper members of the Red Fork formation.

Gaining an integrated perspective of Cherokee depositional systems, reservoir geometry, and diagenesis should be a basic goal of a full-scale geologic study of the Cherokee Group in the play area. An investigation needs to address geologic problems from the perspective of the play, field, and reservoir scales. Regional, sequence-stratigraphic analysis using good well control is the necessary first step in an overall strategy of eventually focusing in on the fundamental concern of the prospect-driven operator, the geologic attributes of the reservoir. Definition of systems tracts within the sequence-stratigraphic framework would enable enhanced, high-resolution modeling and mapping of major regressive episodes, and thus reservoir trends, during which most sand is deposited. Addressing reason(s) for porosity/permeability heterogeneity and limited drainage area within Cherokee reservoirs requires petrographic analysis of core samples. Core data are also needed to assess the possible occurrence of natural fractures.

The ultimate benefits of a geologic study of the Cherokee play would include (1) more precise delineation of separate genetic depositional episodes for improved projection of productive infill wells, (2) more accurate characterization of reservoir compartments, whether caused by diagenetic or facies variation, (3) better prediction of petrophysical and fracture attributes and compartment size distribution within a reservoir for optimal infill-well location, and (4) improved infill-well placement and fracture-stimulation strategy. Comparison of calculated cost benefit to operators and the cost of such a geologic study suggests that a return on research investment of better than 100:1 is possible.

Technical Approach

The discussions with the surveyed Cherokee operators involved a series of 25 questions that were designed to focus on geologic elements of Cherokee play development, although related economic, drilling/formation evaluation, and stimulation/completion aspects were also discussed.

Project Implications

The importance of resource characterizations in gas sandstone formations has been realized for many years by GRI. Recovery of gas can be enhanced through understanding of the geological processes affecting the source, distribution, and recovery of gas from these reservoirs. This report provides a benchmark of current understanding of the Cherokee play that will help to identify areas where opportunities for more efficient gas production exist through application of technology and improved resource characterization.

John T. Hansen
Project Manager, Natural Gas Supply

Executive Summary

In an effort to better understand the geologic challenges faced by natural gas operators who are active in the Cherokee play of western Oklahoma, a survey of 15 operating companies currently active in Cherokee development was conducted. This survey, a literature search, and limited regional mapping and well-log correlation help to illustrate these challenges. Also in this report, the geology of the Cherokee Group is reviewed, strategies to address the geologic challenges are proposed, and some of the benefits that would result from resolution of these challenges are outlined. Although the Cherokee play in the Anadarko Basin is in a generally mature development phase, the information needed by the operators is surprisingly fundamental. There is generally only a partial understanding of (1) the regional character of the Red Fork and Skinner depositional facies tracts, from shelf to basin in the four-county play area, (2) reservoir geometry, trends, and areal extent, (3) the cause(s) of porosity/permeability variation within reservoirs, (4) the reason(s) for the limited drainage area of Cherokee wells, and (5) the regional lithostratigraphic correlation of the Cherokee Group.

Gaining an integrated perspective of Cherokee depositional systems, reservoir geometry, and diagenesis should be a basic goal of a broad-scope, full-scale geologic study of the Cherokee Group in the play area. An investigation needs to address geologic problems from the perspective of the play, field, and reservoir scales. Regional, sequence-stratigraphic analysis using good well control is the necessary first step in an overall strategy of eventually focusing in on the fundamental concern of the prospect-driven operator, the geologic attributes of the reservoir. Definition of systems tracts within the sequence-stratigraphic framework would enable enhanced, high-resolution modeling and mapping of major regressive episodes, and thus reservoir trends, during which most sand is deposited. Addressing reason(s) for porosity/permeability heterogeneity and limited drainage area within Cherokee reservoirs requires petrographic analysis of core samples. Core data are also needed to assess the possible occurrence of natural fractures. The ultimate benefits of a geologic study of the Cherokee play would include (1) more precise delineation of separate genetic depositional episodes for improved projection of productive infill wells, (2) more accurate characterization of reservoir compartments, whether caused by diagenetic or facies variation, (3) better prediction of petrophysical and fracture attributes and compartment size distribution within a reservoir for optimal infill-well location, and (4) improved infill-well placement and fracture-stimulation strategy. Comparison of calculated cost benefit to operators and the cost of such a geologic study suggests that a return on research investment of better than 100:1 is possible.

Introduction

The Middle Pennsylvanian (Desmoinesian) Cherokee Group, which contains prolific, low-permeability, natural-gas and gas-condensate reservoirs in several formations, is currently a major natural gas play in the deep Anadarko Basin, Oklahoma. The entire group is formally designated to be tight by the Federal Energy Regulatory Commission (FERC) in parts of Beckham, Custer, Roger Mills, and Washita Counties of west-central Oklahoma (fig. 1). This four-county area, which has produced more than 1.2 Tcf from major (>10 Bcf cumulative production) Cherokee reservoirs (Bebout and others, 1993), is currently experiencing the most active Cherokee development activity. Therefore, summaries of the geologic and production character-

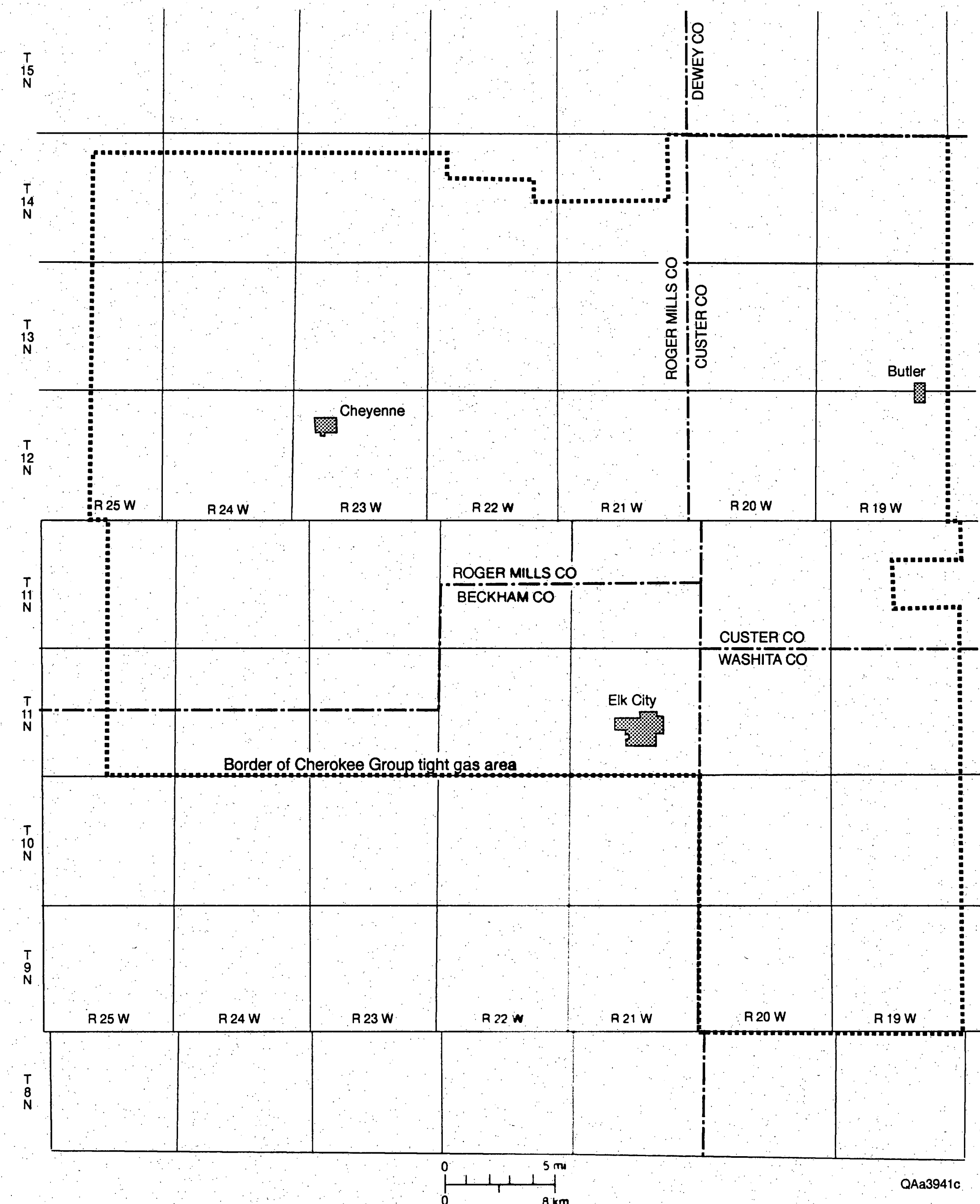

Figure 1. Tight-gas area of the Cherokee Group, west-central Oklahoma.

istics of the Cherokee, the geologic challenges faced by Cherokee producers, and possible responses to these challenges in this area are the focus of this report.

Decreased taxes levied on natural gas produced in this region because of the FERC tight-gas designation was a strong incentive for producers to explore and develop the tight Cherokee play beginning in the late 1970's. Although this tax incentive recently expired for wells drilled after January 1, 1993, producers continue to develop by infill drilling in established Cherokee fields and by minor step-out exploratory drilling. Because gas pipelines and the associated infrastructure are already in place, gas production from new (post-1992) wells in the four-county area is largely economical at current natural gas prices. The western Oklahoma Cherokee play is currently a major development objective; most Cherokee operating companies that were contacted for this report consider development of the Cherokee play to be a primary component of their current overall economic (business) strategy.

Objectives

This report has four objectives: (1) to summarize both the geologic characteristics of the Cherokee Group and the production highlights in the four-county area of current activity; (2) to summarize what current Cherokee producing companies perceive to be the primary geologic challenges they face in developing the Cherokee play; (3) to suggest geologic strategies to help respond to these challenges; and (4) to assess the benefits to operators of geological studies of the Cherokee.

Methods

A telephone survey of a representative sampling of active Cherokee producing companies composes a principal data source for this report, the other primary source being published articles. These 15 companies are AnSon Gas Corporation; Apache Corporation; Enron Oil & Gas Company; Louisiana Land and Exploration Company; Marathon Oil Company; Maxus Exploration Company; Meridian Oil, Incorporated; RB Operating Company; Sanguine Limited; Samson Resources Company; Sonat Exploration Company; T-K Exploration Company; Vestige Energies; Vintage Petroleum, Incorporated; and Ward Petroleum Corporation. This company list was compiled by initially contacting those few geologists who had published data on the Cherokee play (Clement, 1991; Anderson, 1993; Tolson, 1993). They directed me to specific geologists in other petroleum companies that are aggressively developing the Cherokee play; these geologists also added names to the list. The company list includes the majority of the most active (and in most cases the largest) Cherokee operators in the Anadarko Basin, as well as some of the numerous smaller, relatively less active companies. The opinions expressed by the surveyed geologists are not necessarily representative of those of their respective companies.

The survey involved a series of 25 questions designed to focus on geologic elements of Cherokee play development, although related economic, drilling/formation evaluation, and stimulation/completion aspects were also discussed (Appendix). Conversation with each geologist lasted between 1.0 and 2.5 hours. Because there was a high degree of consistency in the answers to the survey questions provided by the respondents, the survey responses are believed to be generally representative of the views and concerns of all Cherokee producers active in the four-county area.

Geology of the Cherokee Group

Structural Setting

The Cherokee Group is productive throughout much of Oklahoma (fig. 2) in the Anadarko Basin and adjacent shelf areas of the south-central and northern parts of the state, respectively. The Anadarko Basin is the deepest Phanerozoic sedimentary basin within the North American craton. Much of the basin's present structural configuration was the result of the prominent Pennsylvanian orogenic episode that affected a large region of the south- central United States (Ham and Wilson, 1967). During the Pennsylvanian orogenic period (late Morrowan and early Atokan), the active Amarillo-Wichita Uplift was separated from the Anadarko Basin by a series of large-displacement, moderate- to high-angle reverse faults formed by compressional deformation. Concurrently, the adjacent basin subsided markedly; large volumes of coarse arkosic sediment (granite wash) were deposited throughout the Pennsylvanian Period along the southern margin of the rapidly subsiding Anadarko Basin adjacent to the granitic Wichita and Amarillo highlands. During the Desmoinesian Epoch, fluvial-deltaic systems represented by the Cherokee Group prograded generally westward to southwestward into the northern part of the Anadarko Basin across the Kansas Shelf (Clement, 1991).

Structure of the top of the Cherokee Group in Beckham, Custer, Roger Mills, and Washita Counties comprises a monocline that dips southwestward into the markedly deeper, northwest-trending axial portion of the deep Anadarko Basin (fig. 3). Although not

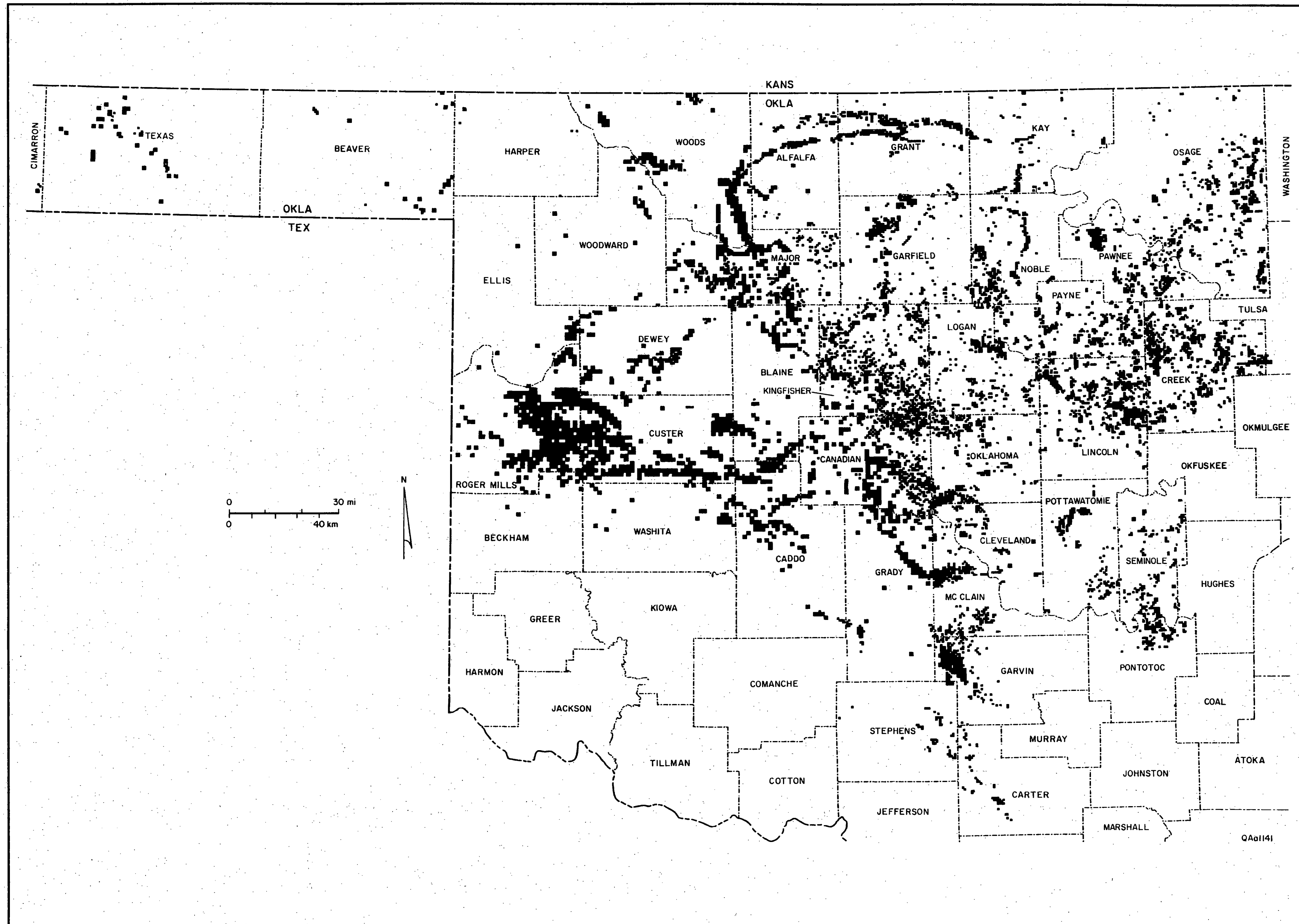

Figure 2. Areas from which Cherokee Group strata have produced natural gas from 1979 through 1990. From Bebout and others (1993).

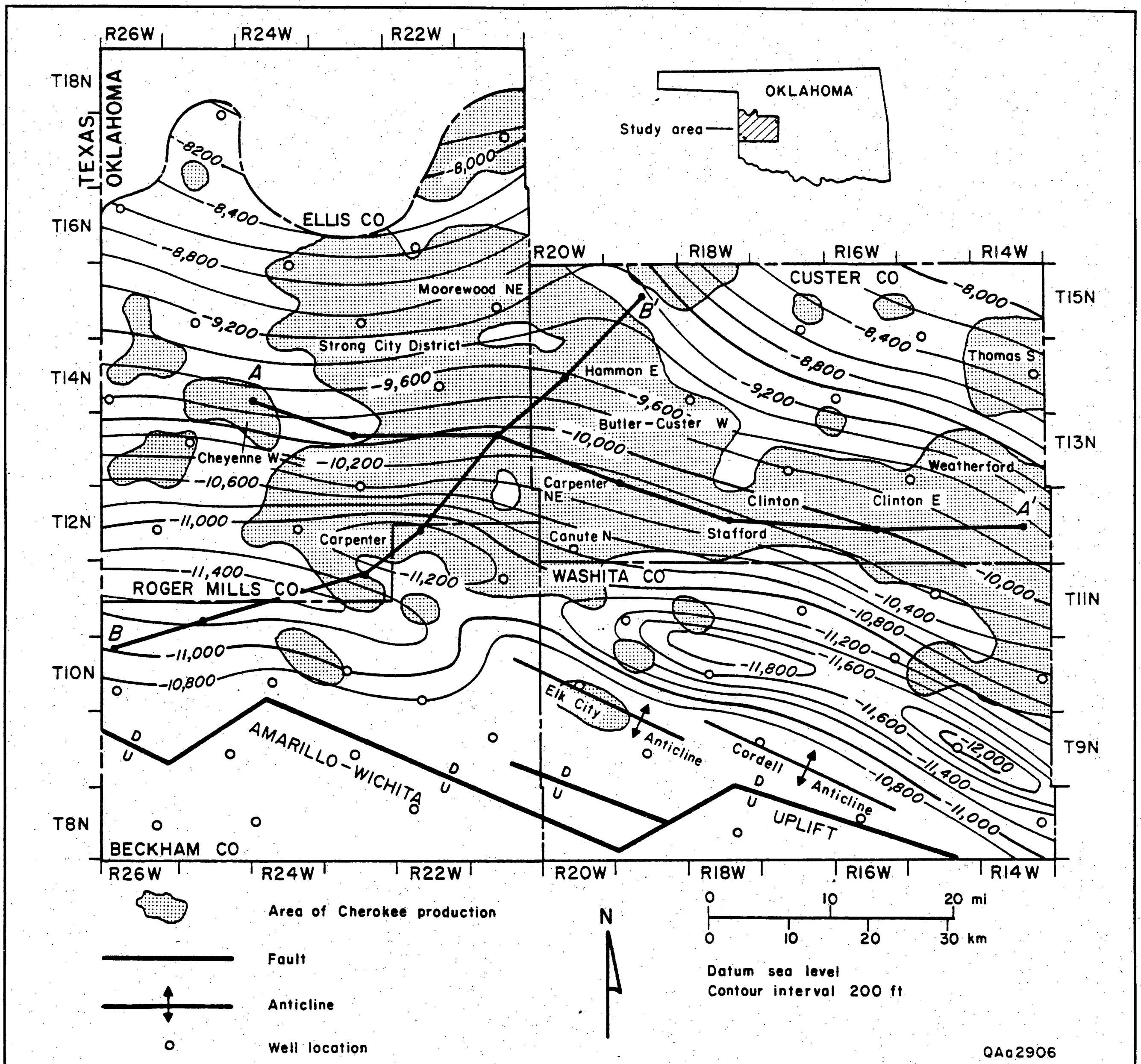

Figure 3. Structure-contour map of the top of the Cherokee Group in Beckham, Custer, Roger Mills, and Washita Counties, currently the most active area of development of the Cherokee play. Also illustrated are the generalized boundaries of Cherokee production. Cross sections A–A′ and B–B′ are shown in figures 4 and 5, respectively.

resolvable on the generalized structure-contour map (fig. 3), local anticlines, such as the Corn/Eakly-Fort Cobb anticline of northeastern Washita County, and several structural noses interrupt the monocline (Clement, 1991). Cherokee-equivalent granite wash beds abut moderate- to high-angle reverse faults (Brewer and others, 1983) that define the northern flank of the Amarillo-Wichita Uplift. At least two structures in the four-county area, the parallel Elk City and Cordell anticlines, record Middle Pennsylvanian compressional deformation immediately north of the Amarillo-Wichita Uplift (Evans, 1979) (fig. 3).

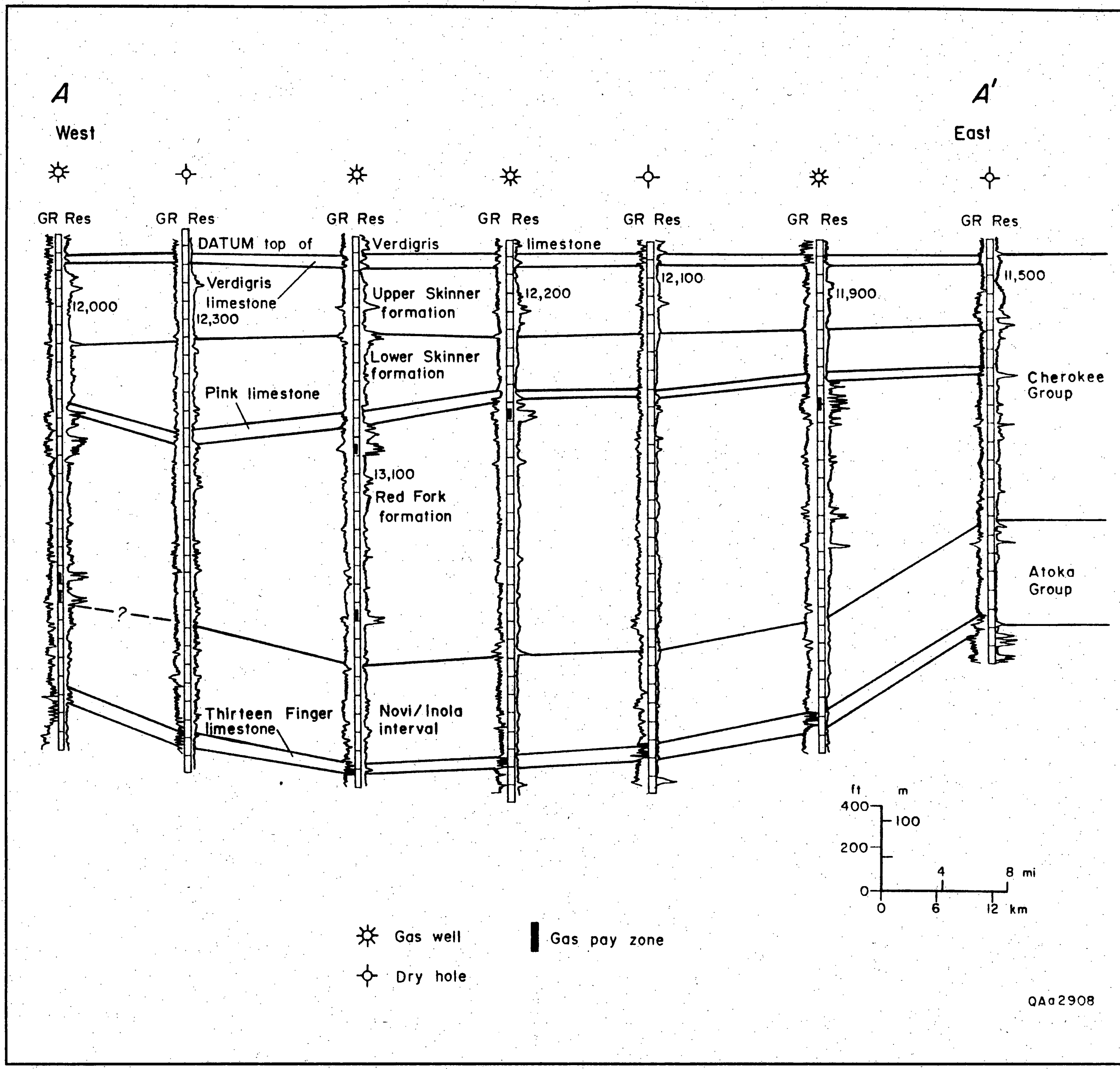

Figure 4. Stratigraphic cross section A–A′ showing correlated tops of all Cherokee formations and producing zones within the selected wells. Cross section is aligned parallel to the axis of the Anadarko Basin. The Atoka Group is also shown to illustrate the similarity of well-log signatures between the two groups and, therefore, difficulty in correlating the shale-on-shale disconformity that marks the base of the Cherokee. Section line shown in figure 3.

Stratigraphy and Depositional Facies

In the western Anadarko Basin the Cherokee Group is divided into four informal subsurface formations (in ascending order): Red Fork formation, Pink limestone, Skinner formation, and Verdigris limestone (Clement, 1991) (figs. 4 and 5). Only the sandstone-bearing Red Fork and Skinner intervals are currently being aggressively developed primarily in the four-county study area (Beckham, Custer, Roger Mills, and Washita Counties), although parts of adjacent counties, particularly Caddo, Blaine, and Dewey Counties, are also active. The Red Fork composes most of the lower part of the Cherokee Group in west-central Oklahoma and is informally divided into lower, middle, and upper mem-

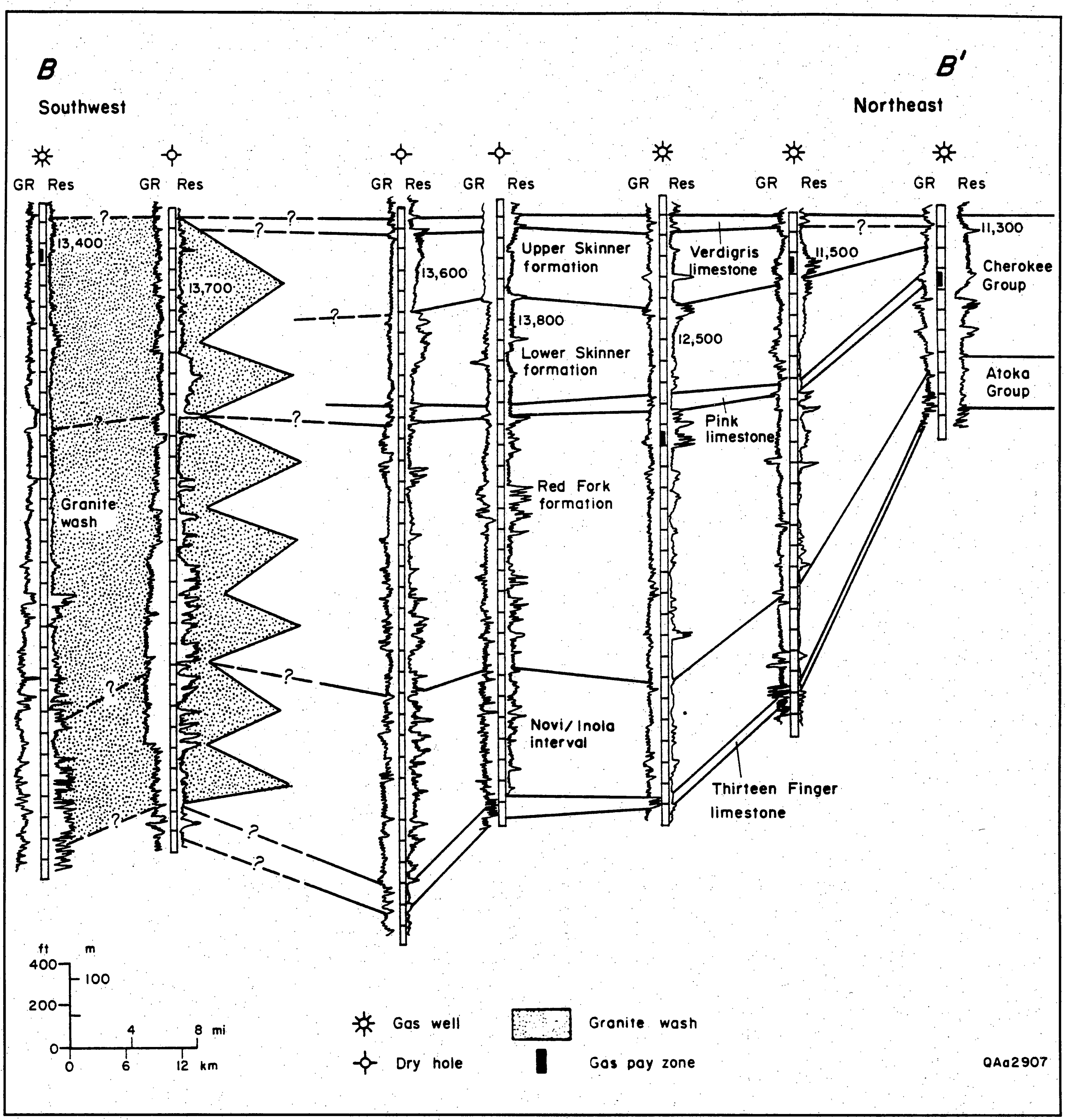

Figure 5. Stratigraphic cross section B–B′ oriented approximately normal to the axis of the Anadarko Basin and showing internal division of the Cherokee Group, granite wash deposits along the northern flank of the Amarillo-Wichita Uplift, and producing zones within the selected wells. Section line shown in figure 3.

bers. The three members of the Red Fork were not differentiated in figures 4 and 5 because of the difficulty in correlation without close well control. The Skinner is divided into two members. Many of the surveyed operators mention the Prue or the "Skinner/Prue" as being a reservoir zone within the Cherokee; this nomenclature is well established. However, the Prue sandstone actually overlies the Verdigris limestone (top of Cherokee Group) and has been miscorrelated by some with the upper part of the upper Skinner in the four-county area where the Verdigris is shaly and not as easily recognized as a stratigraphic marker as it is in shelfward areas where it is a well-developed limestone (W. A. Clement, personal communication, 1993). Because of its wide distribution and consistent log character, the Pink limestone is a commonly used datum for regional mapping of the Cherokee Group.

Regionally, the Cherokee thickens greatly from 200 to 300 ft in the northern and eastern shelf areas to greater than 4,000 ft along the axis of the Anadarko Basin (Whiting, 1984). In the four-county area, the Cherokee is about 700 ft to greater than 3,000 ft thick, thickening southward and westward toward the axis of the Anadarko Basin (Clement, 1991). Depth to the top of the Cherokee in the four-county area varies from about 9,900 ft to more than 13,500 ft; the top of the Red Fork in the same area ranges from less than 10,000 ft to more than 14,300 ft deep (Whiting, 1984; Clement, 1991; Bebout and others, 1993).

In the four-county area, the depositional facies of the Red Fork formation are the best studied, although among the producing companies surveyed, there is some disagreement in facies interpretation. However, most believe that this interval, particularly the upper Red Fork, in part or wholly consists of (generally grading from east to west) fluvial-channel, fluvial-deltaic, and submarine-fan (or distal-deltaic turbidite) deposits. The Skinner interval probably consists of mostly fluvial-deltaic and strandplain facies. Primarily because of the great depths (and therefore, great expense) involved, whole cores from the Red Fork and Skinner intervals have only been rarely taken, thus limiting detailed depositional facies analysis by the producing companies.

The Red Fork section is regionally variable in facies stacking patterns. In general, basinal facies in downdip areas, especially within the axial parts of the deep Anadarko Basin area, are thick successions (as much as 700 ft) of shale and siltstone and thinly interbedded sandstones and shales, expressed as thick intervals of subdued to spikey gamma-ray and resistivity log signatures. These facies predominate in the lower and middle Red Fork in downdip positions (western part of four-county area) and are interpreted to represent submarine turbidite and slope and basinal accumulations (Clement, 1991; Anderson, 1993). In an alternative viewpoint, Whiting (1984) postulated that all reservoir sandstones in the upper Red Fork throughout the tight-gas area originated as deep-marine, channelized submarine-fan deposits. However, Clement (1991) concluded that turbidite facies described by Whiting (1984) are distal prodeltaic components of the upper Red Fork delta. In updip positions all three Red Fork members generally contain more sandstone, and log signatures are upward-coarsening, upward-fining, and blocky (figs. 4 and 5). These deposits record fluvial and deltaic sedimentation (Hawthorne, 1985; Clement, 1991). Subregionally, especially in the east–west-oriented Clinton–Weatherford field trend in southern Custer County (figs. 3 and 6), the middle and upper Red Fork members are inferred to contain stacked incised-valley fluvial-channel deposits that range from less than 10 ft to greater than 150 ft thick and that exhibit as much as 300 ft of erosional relief (Clement, 1991). However, several surveyed geologists believe that a distributary-channel model is a reasonable alternative interpretation for the Clinton–Weatherford area.

Petrology and Diagenesis

Published petrographic analyses of Cherokee reservoirs are restricted to the Red Fork formation; no such analyses were found for the Skinner formation. Reservoir characteristics of the Red Fork sandstones vary within the four-county area, apparently largely because of differences in depositional environment (Cornell, 1989). However, some generalizations can be made. Reservoir sandstones of the Red Fork formation, which are typically very fine to fine-grained, are classified as sublitharenites, litharenites, and feldspathic litharenites, with an average composition of $Q_{68}F_{14}R_{18}$ (Levine, 1984). Quartz constitutes 58 to 70 percent of the essential framework grains in core samples from throughout the tight-gas area, whereas feldspar and rock fragments range from 14 to 21 percent and 10 to 17 percent, respectively (Levine, 1984). Feldspars, which are commonly dissolved or partially/wholly replaced, are chiefly orthoclase and plagioclase; microcrystalline volcanic grains are the most common rock fragments. Clay matrix in Red Fork sandstone samples varies between 7 and 18 percent of the whole rock volume, with an average of 12 percent. Sandstone cements include (1) carbonate (calcite, ankerite, and dolomite), with an average of 9 percent of the whole rock volume, (2) quartz (as overgrowths), with an average of 3 percent of the whole rock volume, and (3) authigenic clay (illite, chlorite, and kaolinite), with an average of 2 percent of the whole rock volume (Levine, 1984; Clement, 1991).

The relative order of events in Red Fork formation diagenesis is (1) growth of clay rims on framework grains, (2) calcite cementation, (3) partial feldspar and rock fragment dissolution, (4) formation of authigenic clays and quartz overgrowths, (5) grain replacement by calcite and ankerite, and (6) partial dissolution of calcite cement (Levine, 1984).

Red Fork reservoir porosity is almost entirely secondary and developed by dissolution of authigenic cements, detrital framework grains, and replacive grains; average Red Fork porosity is 9.0 percent (Levine

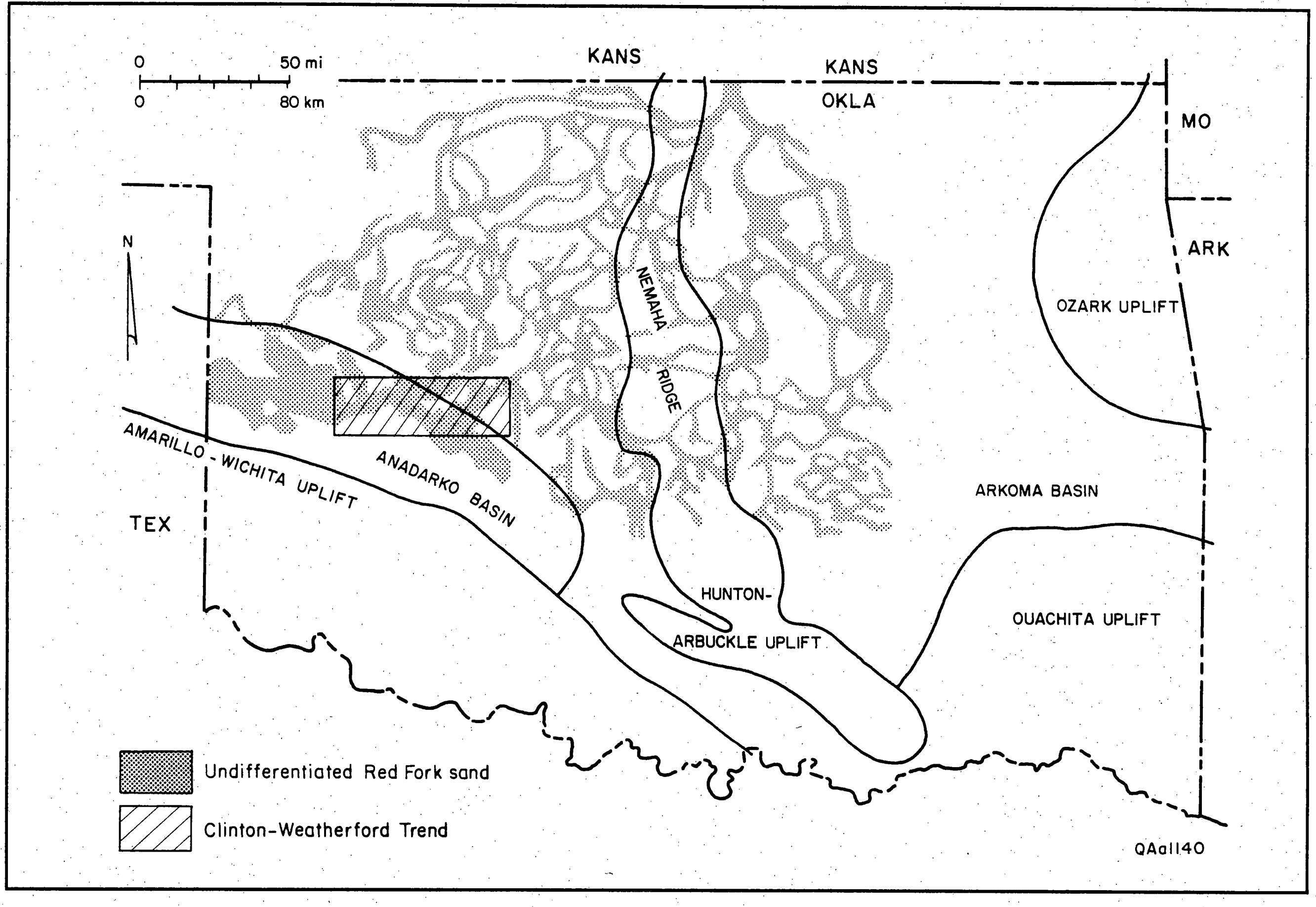

Figure 6. Map showing (1) distribution of Red Fork sandstones in central and western Oklahoma and (2) location of the Clinton–Weatherford trend. From Clement (1991).

1984). Average porosity values of the Red Fork increase northward in the four-county area, varying from 5 percent or less in most of Beckham and Washita Counties to 10 percent or greater in northern Custer and Roger Mills Counties (Levine, 1984). Both primary interparticle and secondary porosity exist in Red Fork reservoir sandstones, with secondary porosity, formed by dissolution of framework grains and cement, being the most common (Clement, 1991). Permeability of Red Fork reservoirs ranges from less than 0.1 to 0.7 md (Levine, 1984), with locally higher values (as high as 20 md) in East Clinton field (Clement, 1991).

Trapping Mechanism

The trapping mechanism in most Cherokee fields is stratigraphic, with only local enhancement by positive structural position (Clement, 1991; Bebout and others, 1993). In East Clinton field, for example, incised fluvial-channel sandstones are trapped laterally against older marine shales and siltstones or contemporaneous terrigenous shales and vertically by younger terrigenous shales and shaly valley fills (Clement, 1991). Along the valley-fill trend in southern Custer County, fluvial reservoirs are overpressured and encasing shales acted as source rock for natural gas (Clement, 1991).

Natural Fractures and In Situ Stress

All respondents to the survey believe natural fractures to have little or no influence on natural gas production from the overpressured Red Fork and Skinner reservoirs, except possibly in those few instances where the trap involves a structural element, such as a fold or fault. Levine (1984) concluded that fracture porosity is generally negligible in Cherokee sandstones. In the few Cherokee cores retrieved, natural fractures are rare, mostly vertical, and healed with calcite. However, the presence of any vertical fractures at all in the limited horizontal dimension of the cores suggests that natural fractures are potentially critical reservoir elements in the Cherokee play. Moreover, the possibly greater abundance of natural fractures in Cherokee reservoirs than has been inferred by the surveyed operators is indirectly indicated by high leakoff in some wells; successful stimulation of Red Fork reservoirs requires proper selection of a fluid-loss additive to control leakoff to natural fractures (Cornell, 1991). Even locally developed natural fractures could affect reservoir-stimulation results and may be important for the design of deviated-well strategy.

Northeast-trending maximum horizontal stress is predicted in the mid-plate stress province of Zoback and Zoback (1989), where Cherokee reservoirs are located. Limited results from two Red Fork wells in western Oklahoma (Cornell, 1991) are inconsistent with this prediction, however. The methods used to find maximum horizontal stress orientation in these wells were measurement of anelastic strain recovery and the strike of coring-induced fractures, but actual measurements were not presented by Cornell (1991) and the quality and statistical significance of these results cannot be evaluated. According to Cornell, strain-recovery methods gave limited information that suggests east-trending maximum horizontal stress, but the data are imprecise because of rapid core relaxation. The strike of coring-induced fractures agrees with this interpretation of the strain-recovery results (Cornell, 1991). Stress directions are thus poorly defined in the Cherokee play area, although their uniformity in the mid-plate stress province suggests that they may be sufficiently defined from regional patterns for the purposes of field- development design. Operators did not indicate that they currently consider this information in infill-well strategy, but in areas where wells are becoming more closely spaced, such information may be significant by being the best indicator of gas-drainage anisotropy.

No published stress profiles of Cherokee reservoirs are currently available. Such profiles are useful for design of hydraulic fracture treatments (Voneiff and Holditch, 1992).

Highlights of Current Activity

Producing Zones and Major Fields

Natural-gas and gas-condensate reservoirs in the sand-rich fluvial, deltaic, and turbidite facies of the Red Fork formation (Cornell, 1989; Clement, 1991), particularly in the upper lower, middle, and upper members, are the primary Cherokee drilling targets in the four-county area. Fluvial-deltaic and transgressive-marine ("bar") sandstones of the upper and lower Skinner formation are secondary Cherokee targets for most of the surveyed producers (figs. 4 and 5). Survey respondents generally agree that fluvial, delta-distributary, and/or submarine-fan channel-fill sandstones have the highest porosity/permeability and form the best reservoirs ("sweet spots").

There are 13 major Cherokee fields in the four-county area: Butler-West Custer, North Canute, Carpenter, Northeast Carpenter, West Cheyenne, Clinton, East Clinton, East Hammon, Northeast Moorewood, Stafford, Strong City District, South Thomas, and Weatherford (fig. 3). Strong City District and East Clinton field are the largest, with 246 Bcf and 153 Bcf cumulative Red Fork production, respectively (Bebout and others, 1993). Several of the major Red Fork fields (Clinton, East Clinton, Stafford, Weatherford) contain reservoirs producing from multiple pay zones comprising complexly stacked fluvial and distributary-channel fills (Clement, 1991). Butler-West Custer field and Strong City District are examples of Red Fork fields that produce from low-permeability delta-front and submarine-fan (turbidite) facies, respectively (Cornell, 1989). In the same region, conventional gas resources occur in underlying Mississippian and Pennsylvanian (Springer, Morrow) reservoirs.

Depth of major reservoirs ranges from 10,640 ft (South Thomas field) to 13,930 ft (Carpenter field) in Custer and Roger Mills Counties, respectively; net pay varies from 7 ft to about 206 ft (Clement, 1991; Bebout and others, 1993).

Production Statistics

Using pre-1989 production statistics, Hugman and others (1992) estimated the ultimate recovery for natural gas from the entire tight Cherokee Group to be 1.04 Tcf. They attributed the majority of this resource base, or 876 Bcf, to the Red Fork formation, whereas other siliciclastic and carbonate units of the Cherokee Group accounted for only 165 Bcf of the total ultimate recovery. However, as of early 1992, total cumulative production from major (>10 Bcf cumulative production) Red Fork and other Cherokee (Skinner formation and other unspecified units of the Cherokee Group) gas reservoirs in the four-county tight-gas area was 943 Bcf and 258 Bcf, respectively (Bebout and others, 1993). As is evident, the recent cumulative production figures of Bebout and others (1993) already exceed the ultimate recovery estimates of Hugman and others (1992), thus highlighting the reserve growth potential of the Cherokee reservoirs.

Production parameters of individual Red Fork and Skinner wells, the oldest of which came on line

14 years ago, are now well established and can be generalized. These per-well data given by the surveyed producers are remarkably consistent, in part because most of the respondents have been most active in the same two areas: the Strong City District (Roger Mills County) and/or the Clinton–Weatherford trend (Custer County) (fig. 3). Initial potential of Cherokee wells in the four-county area ranges from about 0.5 MMcf/d to 6.0 MMcf/d with typically 20 to 50 barrels of condensate per day; rare wells have initial flow rates of as much as 10 to 12 MMcf/d. Cumulative production per well ranges from less than 0.25 Bcf and 10,000 barrels of condensate to typically 8 to 10 Bcf with more than 250,000 barrels of condensate. Southwest Leedy field in northern Roger Mills County is noted for its atypically high maximum cumulative totals of 20 to 25 Bcf per well. In contrast, a typical Cherokee well has produced 2 to 4 Bcf. For a Red Fork or Skinner well to be profitable at current gas prices, a minimum cumulative yield of 1.5 to 3.0 Bcf per well is necessary. Survey respondents believe that the economic lifespan of a typical Cherokee well is at least 15 to 20 years.

Drilling and Formation Evaluation

The Cherokee play is considered by all survey respondents to be primarily or wholly a development play, with most operators involved in infill-well drilling programs. Only a few of the operators conduct minor step-out exploratory drilling, although most agree that there is potential for reserve additions by more aggressive extension of known producing areas. Cherokee wells drilled each year in which the operating company has whole or part working interest varies widely from 4 to 50 wells per company, with most companies drilling more than 15 wells per year. Total cost for a completed Cherokee well is between $600,000 and $1.9 million. Skinner completions typically cost about $900,000, whereas deeper Red Fork completions generally cost about $1.2 to $1.4 million. Greater cost of Red Fork completions is due to several factors, including greater depth of drilling and the necessity of setting intermediate casing in the overpressured formation. Many operators try to minimize drilling costs by drilling "slim holes" (with 2 7/8 inch tubing). Total dry hole drilling costs per well range from about $450,000 in the Skinner to $750,000 in the Red Fork.

For the most active Cherokee operators, determination of gross sand-bed (reservoir) thickness and porosity/permeability are the critical concerns in evaluating the economic status of a well. Some uncertainty is involved in these estimates because reservoir size and shape, and the distribution and type of internal reservoir barriers and baffles generally cannot be identified directly. Because cores are rarely taken, operators must rely exclusively on well logs and mud-log data to get sand-bed thickness and porosity/permeability information. The log suite of choice generally includes at least the dual induction (with gamma ray and SP) and neutron/density porosity logs. Other logs, such as Formation Microscanner (FMS) and dipmeter (SHDT), are also run by a minor number of the surveyed operators, although they are generally not viewed as cost effective for most.

Reservoir Stimulation

All survey respondents indicate that all or the vast majority of Red Fork and Skinner completions require acidization and fracture stimulation. Post-stimulation gas production per well is typically 2 to 5 times (as high as 10 times) greater than initial production. Because of the great depth of the Cherokee reservoirs and the high reservoir pressures, which range from 2,500 to 10,000 psi (Dutton and others, 1993), it is necessary to use bauxite or other high-density proppant material in addition to, or in place of, sand during fracture stimulation. A water-based gel with sequestering agents or a CO_2 foam is used in fracture stimulation by most companies to prevent clay swelling and iron-mineral precipitation in the formation. No significant borehole or completion problems that are particularly inherent to Cherokee wells were reported by the surveyed operators, although operators generally qualified this statement by indicating that drilling companies now have considerable experience in the Cherokee Group and can effectively anticipate potential problems with the deep, overpressured reservoirs. For example, experience has shown that running drill stem tests is risky in the overpressured environment because obtaining a good packer seat is difficult (therefore casting doubt on the test results), and there is always the risk of hole collapse at the great depths involved. Shale popping (natural gas within shales forcing borehole sloughing after pressure release) is sometimes encountered. Several surveyed operators emphasize that they keep logging runs to a minimum to specifically avoid getting the tool stuck, suggesting that at least some problems in drilling-mud formulation may exist.

Geologic Challenges and Solutions

Geologic Strategies

The majority of the 15 surveyed operators consider geologic studies and development of the Cherokee play to be major components of their company's current overall economic (business) strategy. Maximum possible well control and a workable depositional model are generally critical to geologists who are developing the Cherokee play. Standard subsurface mapping is the primary geologic technique used by all survey respondents; mapping techniques include interval isopach, gross and net sandstone, and porosity mapping. Conventional 2-D seismic profiling is also a primary or secondary development strategy for many of the operators. Other companies use 2-D seismic on a limited basis or not at all; these generally smaller companies do not find the technique to be cost effective. Moreover, several operators believe that the vertical resolution of 2-D seismic profiles is not sufficient to identify sandstone bodies with reasonable precision. Less than half of the operators have used 3-D seismic technology for prospect generation. The primary advantage of 3-D over 2-D seismic results is the ability to more precisely define the geometry and areal limits of the complex channel-fill and discontinuous deltaic/marine sandstones that compose the reservoirs. Most of the operators acknowledge the potential of 3-D seismic data but find the technique to be prohibitively expensive. As stated above, whole cores are infrequently available; however, rotary sidewall cores used for petrographic and diagenetic analysis are more common.

Geologic Challenges of the Cherokee Group

The surveyed operators were consistent in what they consider to be the primary geologic challenges in developing the Cherokee play. These interrelated challenges are (1) predictability of reservoir geometry and trend, (2) characterization of depositional environments, (3) cause(s) of porosity/permeability variation within reservoirs, (4) reason(s) for limited drainage area of Cherokee wells, and (5) regional stratigraphic correlation of the Cherokee Group, particularly the lower, middle, and upper members of the Red Fork formation.

Increasing the well density within fields by infill-well drilling characterizes the current development strategy of Cherokee operators. The Oklahoma Corporation Commission (OCC), the oil and gas regulatory agency of the state, established a 640-acre well spacing for Cherokee gas wells. To increase well density over this currently allowable well spacing, Cherokee operators must demonstrate to the OCC using available geologic evidence that infill-well drilling is necessary to more effectively drain the section. Consequently, it is important to the operators that they be able to predict the geometry (thickness, areal extent) and porosity/permeability of the reservoir to accurately project infill well locations on available drilling locations. This is typically a difficult task because of the high degree of Cherokee reservoir complexity caused by depositional and possible diagenetic variations. Dutton and others (1993) documented a variety of low-permeability sandstone formations in which depositional setting and diagenesis are major controls on reservoir quality. The most productive Cherokee reservoirs are generally narrow (less than 2,000 ft wide) and commonly sinuous and branching fluvial, distributary, and/or submarine-fan channel-fill sandstones. Reservoirs also comprise pod-shaped distributary-mouth bar and probable strandplain facies. Great drilling depths further complicate the precision with which operators can penetrate areally restricted reservoirs. In many fields, numerous, commonly vertically closely spaced sandstones of varying reservoir quality occur in the Cherokee section, making accurate correlation and interval mapping critical to optimizing reservoir exploitation. For example, Clement (1991) described three fluvial-channel depositional episodes (Stages I–III) in the upper Red Fork of the East Clinton field, Custer County, Oklahoma, that form commonly three superimposed reservoir sandstones (fig. 7). Stages I and II channel fills are generally only poor producers because of high clay content and poor sorting, whereas the well-sorted and coarser grained Stage III channel fills contain by far the highest natural gas reserves. Without this understanding of the stratigraphy in this field and the ability to differentiate the three channel fills, predictability of reservoir geometry would be greatly hindered.

Operators believe that knowledge of the areal and vertical distribution of depositional systems within the Cherokee Group will also aid predictability of sandstone trends and reservoir quality. From a regional perspective, is there a coincidence between specific depositional environments and reservoir-quality strata? On a more local level, can one distinguish, for example, between nonreservoir interdistributary sandstones from juxtaposed, productive distributary-mouth bar facies with reasonable confidence and consistency? What is the morphology of the submarine-fan lobes and of their productive suprafan channel fills in the deep (western) part of the Red Fork facies tract? These are some of the questions that concern Cherokee operators. However, with only a few possible exceptions, the drilling programs of most survey respondents is limited to scattered areas of development within large fields (for example, Strong City District) or within widely separated fields. Operators generally believe that they have an incomplete understanding of the regional architecture of the shelf-to-basin facies tracts of the Red Fork and Skinner intervals and that this hinders the efficiency of their drilling programs.

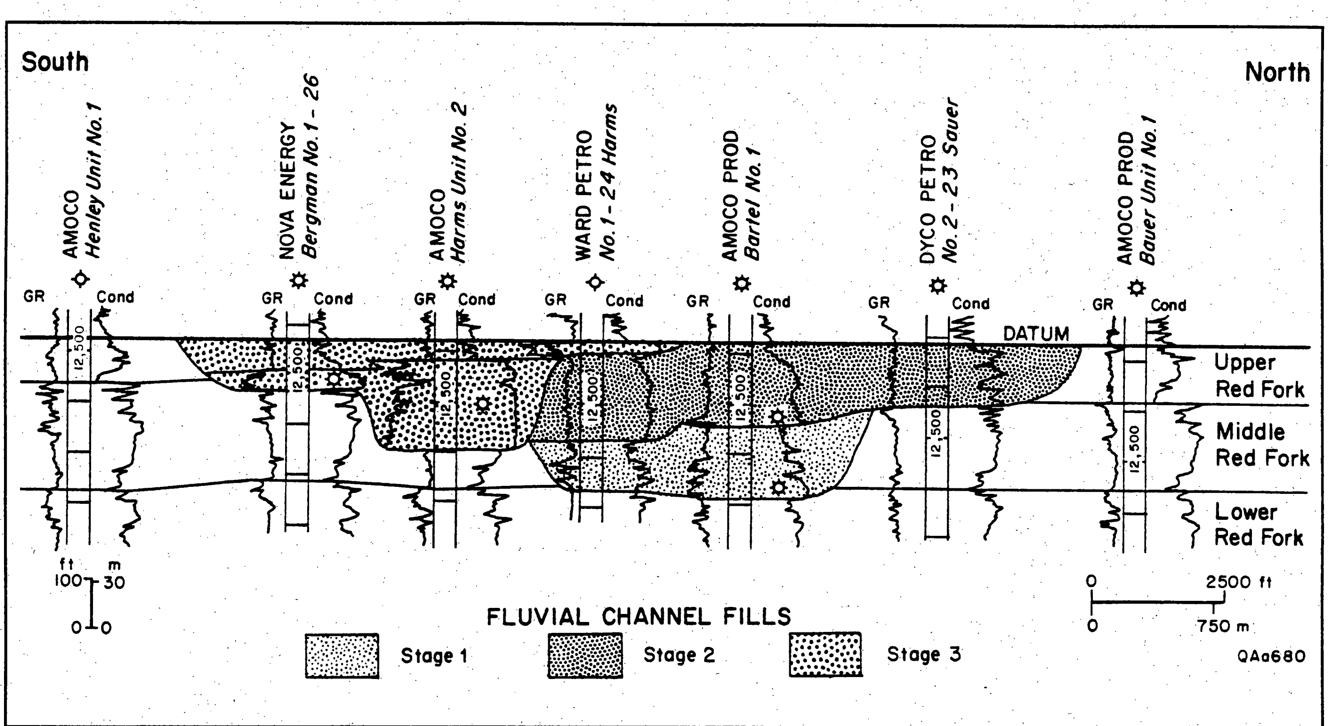

Figure 7. North-south stratigraphic cross section of the Red Fork formation across East Clinton field, illustrating superimposition of three fluvial channel-fill reservoirs. Modified from Clement (1991).

Survey respondents note that in some Cherokee fields, offset wells in a productive trend can have all the log and seismic attributes of a potential producer but will be dry. Porosity/permeability variations may be due to diagenetic factors, depositional control, and/or sporadic distribution of natural fractures. Studies of other low-permeability sandstones suggest that this phenomenon could result from variations in diagenetic history, and that with sufficient knowledge of diagenetic history and controls, reservoir quality can be predicted (Dutton and others, 1993). Possible diagenetic causes of variations in reservoir quality are lateral changes in type of cement or degree of cementation or an increase in clay content. At least one operator noted that permeability tends to decrease with depth, but previous studies of low-permeability sandstones have shown that cementation and related permeability variations are typically more complex than simple depth-related variation (Dutton and others, 1993). Clay plugs in fluvial channel fills or soft-sediment (growth) faults in deltaic strata may compartmentalize reservoirs, as some operators suggested. However, the reasons for these local, abrupt changes in reservoir conditions are not clear.

The drainage area of a typical Red Fork well is limited, rarely being over 160 acres and is most commonly about 80 to 100 acres. This limited drainage area may be partly because of the limited width of channel-fill reservoirs, but non-channel reservoirs are also affected. Survey respondents agree that the causes of limited reservoir drainage area are presently unknown. Operators realize that if they better understood what reservoir attributes where controlling effective drainage area, they would be able to make more informed judgments of appropriate development strategy.

Accurate regional correlation of the Cherokee Group and component formations and members across the extensive producing area is essential for any regional or local characterization of the depositional systems, structure, and sandstone distribution. Accurate regional depositional models are key to predictions of local reservoir size, shape, and orientation. Such regional models are not currently well developed and may be flawed by incorrect regional lithostratigraphic correlations. The Cherokee Group disconformably overlies Atokan strata (Clement, 1991); this disconformity is commonly a shale-on-shale contact across much of the four-county area (figs. 4 and 5) and is difficult to identify without good well control. Correlation of the three members of the Red Fork formation is similarly a challenge without closely spaced well logs, but this effort is necessary to define sandstone bodies within the same systems tracts. Lithostratigraphic division of the Skinner formation is even more poorly defined. Granite wash deposits that are adjacent to the Amarillo-Wichita Uplift and equivalent to the Cherokee section (fig. 5) are productive, but the precise stratigraphic relation between the two units is unclear. Even with a rock interval of less regional scale, such as Clement's (1991) three-phase channel-fill system previously described, accurate differentiation of closely spaced or superimposed sandstone bodies of varying reservoir quality may mean the difference between a producing well and a dry hole.

Recommended Responses to Geologic Challenges

It is clear from the survey results that the basis of any full-scale geologic study of the Cherokee Group in the four-county area must be a broad-scope survey of the entire shelf-to-basin depositional transect of the unit. Surveyed operators readily acknowledge that they do not have the benefit of a clear and integrated perspective of Cherokee depositional systems, reservoir geometry, and diagenesis either among fields or across the producing area. Even within individual fields there is some controversy, for example, regarding the depositional setting of the reservoir facies. At a more local scale, natural-gas production within sandstone reservoirs composing part of the depositional framework is limited by an incomplete understanding of reservoir-sandstone trends and porosity/permeability distribution and why this distribution is so unpredictable. Moreover, complex stacking patterns of sandstones within individual fields present a bewildering array of potential reservoir zones with commonly differing petrophysical attributes. Consequently, operators see the need to be able to consistently identify the producing units on well logs for efficient field development. From the practical viewpoint of the Cherokee operator, the improved predictability of reservoir location reduces risk. To achieve this, a full-scale geologic investigation that integrates regional depositional and stratigraphic analysis with field-scale facies and diagenetic study is needed. Because most Cherokee traps are stratigraphic, structural geologic analysis of Cherokee strata is a secondary concern.

Sequence-stratigraphic analysis is an effective, and currently favored, method for study of the large-scale distribution of genetically related depositional facies. These facies occur in regionally distinctive stratal stacking patterns and define highstand, lowstand, and transgressive systems tracts (fig. 8). Using a sufficient density of well control, sequence-stratigraphic analysis yields a high-resolution chronostratigraphic framework for subsurface correlation of these facies (Van Wagoner and others, 1990). The resulting analysis provides a powerful predictive model for the vertical and areal occurrence of potential reservoirs, sealing strata, and source rocks within the stratigraphic interval studied. Clement (1991) presented compelling evidence of deposition of upper Red Fork channel-fill sandstones of East Clinton field in a lowstand incised valley (figs. 7 and 9). My mapping shows parasequences (upward-coarsening rock cycles), the building blocks of systems tracts, are apparent in well logs of regional cross sections of the Cherokee Group (figs. 4 and 5). Moreover, the Cherokee section contains sporadic, thin, high-gamma-ray shale beds that closely resemble marine-condensed sections identified in the overlying Desmoinesian Marmaton Group to the west in the northeastern Texas Panhandle (Hentz, in press). Consequently, well-log patterns of the Cherokee Group appear, at first glance, to display elements of sequence stratigraphy and thus the unit's potential for sequence-stratigraphic analysis.

Definition of systems tracts allows construction of interval isopach and paleogeographic maps of major regressive episodes during which most sand is deposited (fig. 10). These maps delineate depositional and potential reservoir trends and would thus be of great value to the operators. Most surveyed operators strongly recommended that a series of isopach maps representing separate genetic depositional episodes within the entire producing interval, such as those presented in Brown and others (1990), is necessary to accurately delineate regional reservoir trends. Construction of these maps would require good well control, no more than 3- to 5-mi well spacing, to capture the narrow channel-fill and local deltaic-sandstone reservoir trends in parts of the producing area.

Log-facies mapping may also be useful in differentiating productive channel and nonchannel trends from nonreservoir facies. Finley and others (1992) and Levey and others (1992) demonstrated that construction of field-scale 3-D horizontal slice maps is an effective means of delineating productive fluvial-channel trends in a thin-bed reservoir of the Frio Formation, Seeligson field, South Texas. These Frio channel trends are similar to those in parts of the Cherokee sequence. Although now viewed as too expensive by most Cherokee operators, 3-D seismic analysis will become increasingly important in advanced reservoir development. The use of 3-D seismic technology may become more cost effective for Cherokee operators with more precise

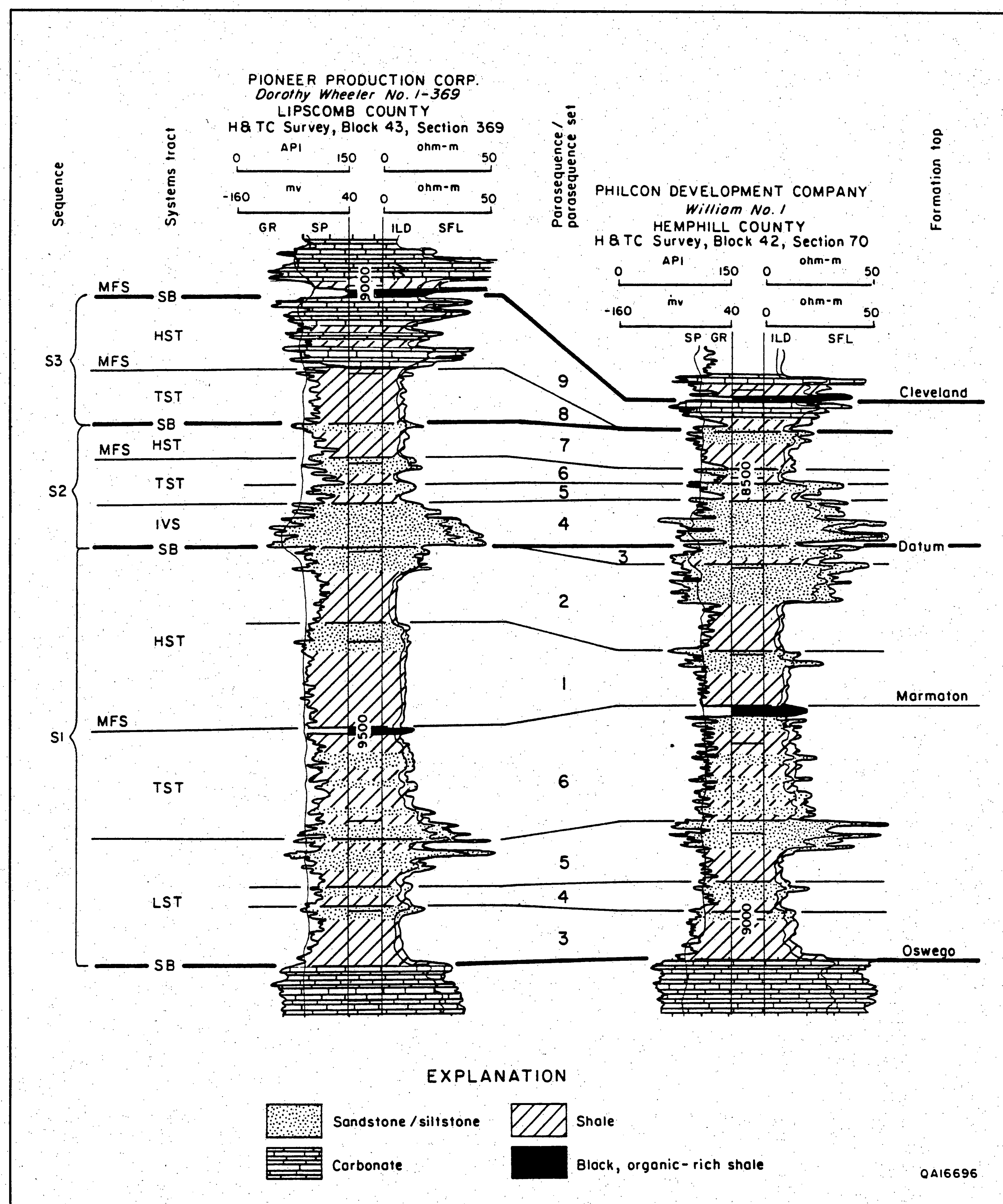

Figure 8. Well logs of the lower Missourian Cleveland formation and part of the upper Desmoinesian Marmaton Group in the western Anadarko Basin, Texas Panhandle. Figure illustrates example of correlation of sequences, parasequences, and systems tracts on well logs, a technique that could probably be readily applied to a sequence-stratigraphic study of the Cherokee Group. MFS = maximum flooding surface; SB = sequence boundary; LST = lowstand systems tract; TST = transgressive systems tract; HST = highstand systems tract; and IVS = incised-valley system. From Hentz (in press).

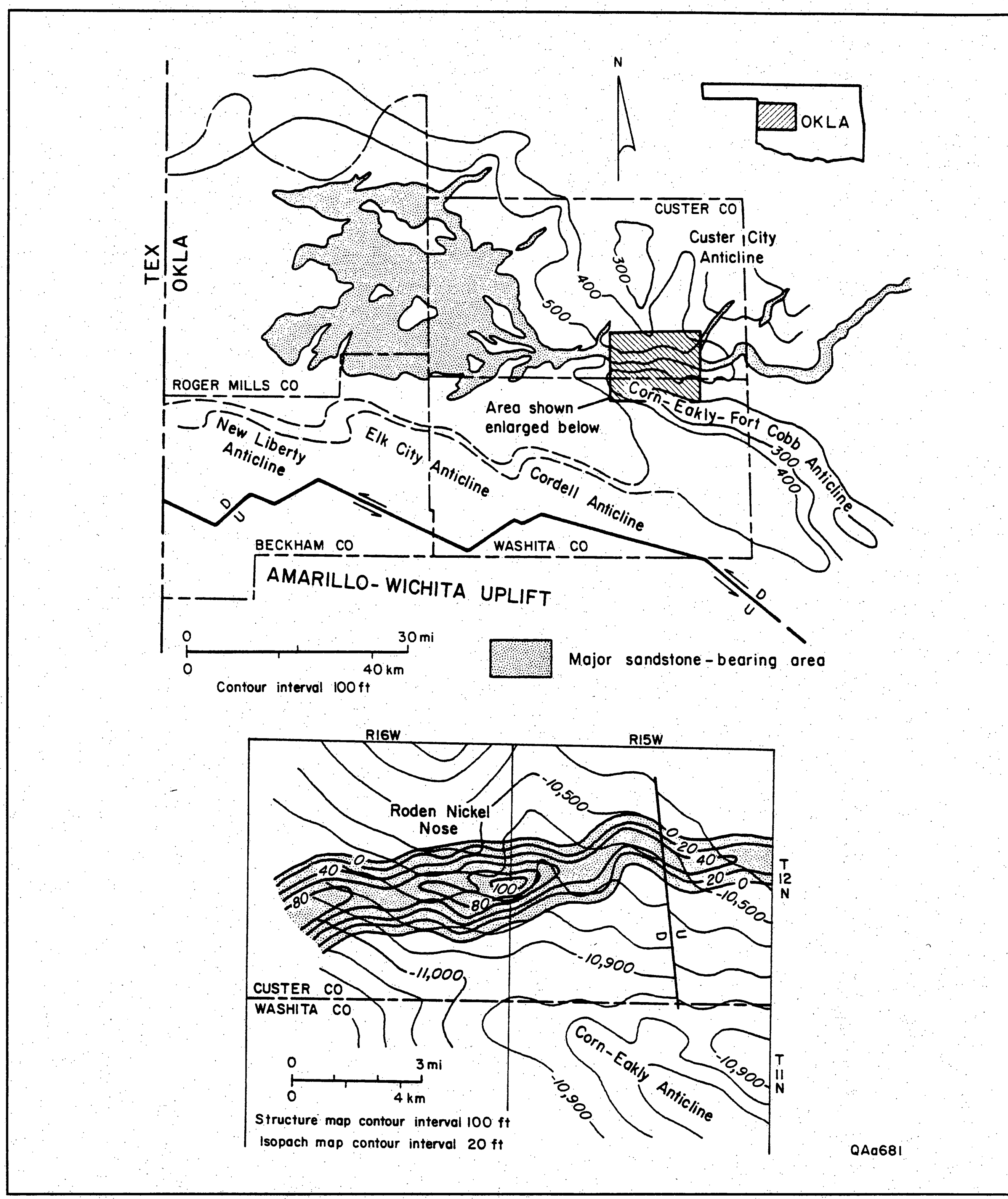

Figure 9. Sandstone-distribution and isopach map of the middle and upper Red Fork formation. Inset is gross-sandstone isopach map of the upper Red Fork superimposed on structure-contour map of the top of the Red Fork in East Clinton field, southeastern Custer County. Modified from Clement (1991).

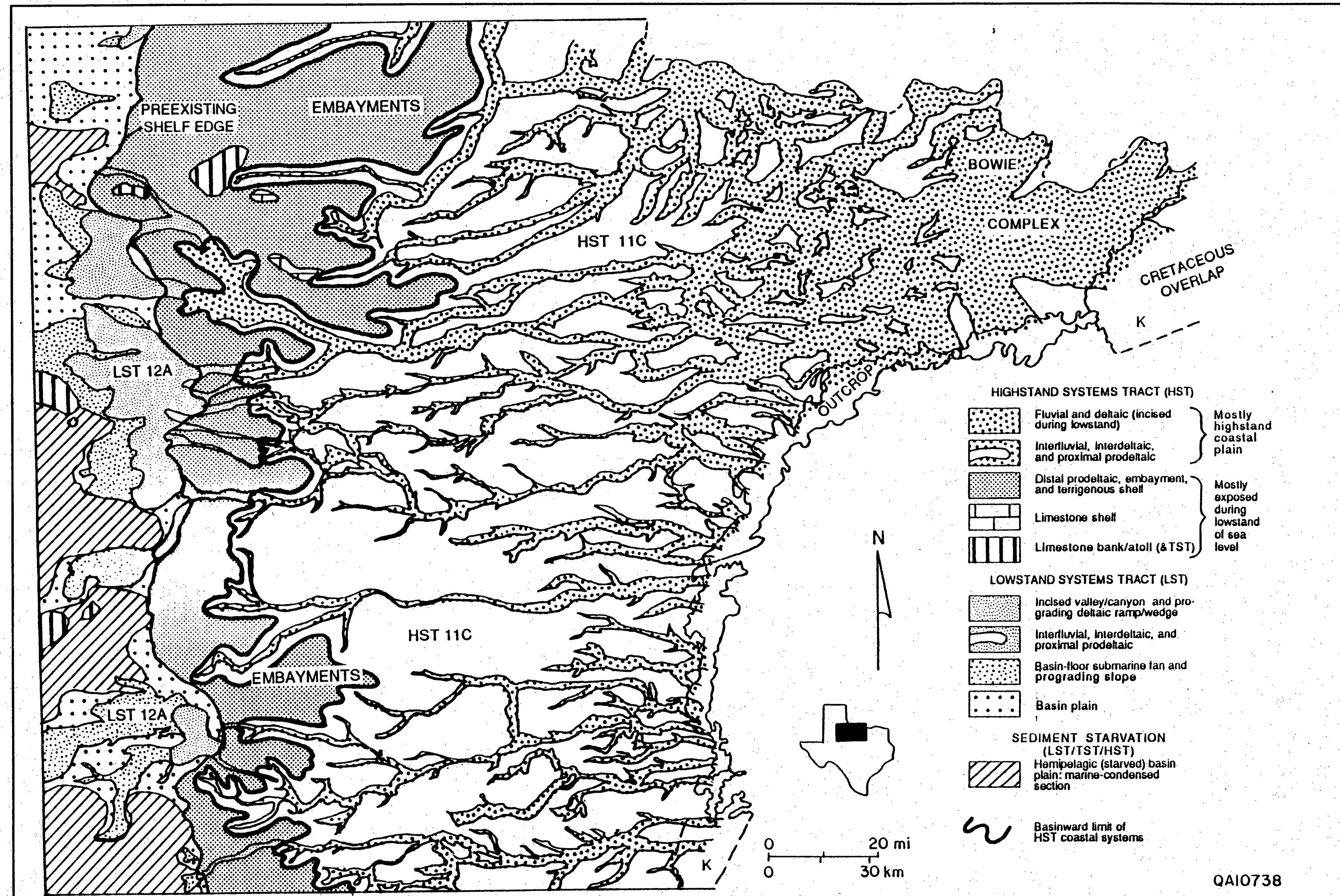

Figure 10. Example of detailed, regional paleogeographic map of Lower Permian coastal plain to marine-basin depositional systems of the Tannehill regressive episode, Eastern Shelf of the Midland Basin. Figure is derived directly from an interval-isopach map of the Tannehill sandstone stratigraphic interval. Sequence-stratigraphic interpretations also shown; abbreviations are same as those defined in figure 8 caption. From Brown and others (1990).

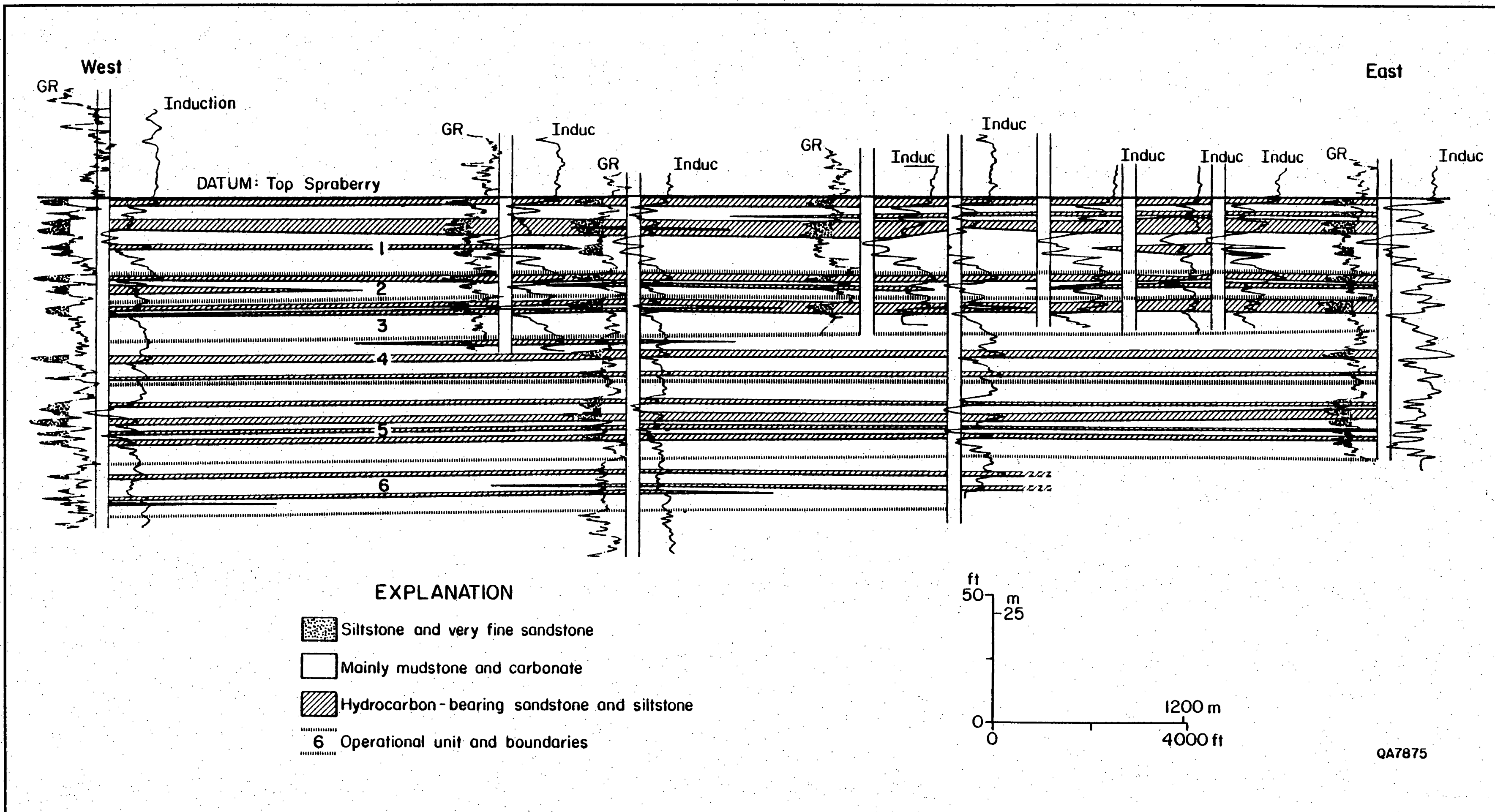

Figure 11. Stratigraphic cross section showing the complexity and pronounced stratification of hydrocarbon-bearing intervals in submarine-fan facies of the upper Spraberry Formation, Midland Basin. From Tyler and Gholston (1988).

and selective siting of shorter seismic transects across local prospect areas. However, improved modeling of depositional facies, especially in the western part of the four-county play area, would be needed to enable such precise site selection.

Broad-scale sequence-stratigraphic analysis provides a consistent reference framework for the more precise reservoir mapping at the subregional to field scale. Sandstone bodies that have been segregated within separate systems tracts would need to be differentiated by detailed correlation. The sequence-stratigraphic perspective provides a depositional model that can be used to anticipate field-scale sandstone trends and geometry. Studies by Guevara (1988) and Tyler and Gholston (1988) of the Spraberry Trend of the Midland Basin, West Texas, are representative of investigations of distal deltaic and/or basinal submarine-fan deposits that are believed by many operators to compose much of the western facies tract of the lower and middle Red Fork in western Custer and Roger Mills Counties. The Spraberry and Dean Formations are probably part of a lowstand basin-floor fan complex (N. Tyler, personal communication, 1993) that produces from highly stratified, laterally complex, and compartmentalized fan channels (fig. 11), much like what probably exists in the distal Red Fork sections. Conclusions from log-facies, net-sandstone, and isopach maps of separate Spraberry/Dean intervals in part enabled Guevara (1988) and Tyler and Gholston (1988) to make recommendations for more effective infill drilling programs (fig. 12). Analogous, field-scale assessments of reservoir quality in incised-valley channel fills (for example, Ethridge and Dolson [1989] and Weimer and Sonnenberg [1989]) could similarly serve as models for study of valley-fill facies believed to exist in proximal parts of the Red Fork facies tract in Custer County.

Addressing the possible reasons for porosity/permeability heterogeneity and limited drainage area within Cherokee reservoirs would necessarily involve extensive petrographic work to determine if diagenesis was a contributing factor. Field-scale mapping studies outlined previously can be designed to identify possible depositional controls. Given the paucity of whole core from the Cherokee section, rotary sidewall cores would be the source of rock samples. Petrographic study would identify detrital and authigenic mineral composition, pore type, grain size, and texture. By combining this information with core-analysis data, the effect of each parameter on porosity and permeability could be determined. Petrographic studies would also reveal the nature, extent, and depth distribution of diagenetic reactions. Further geochemical analyses would determine the chemical conditions and timing of diagenetic alteration. The resulting integrated diagenetic history of selected reservoir zones would provide a method for predicting reservoir quality throughout the formation.

To determine whether natural fractures exert control on reservoir producibility, several avenues of study are possible. All available Cherokee cores would need to be examined in detail for fracture identification and characterization, especially those cores from Cherokee reservoirs within the few flexures in the play area that form traps. Studies of macroscopic fractures can be combined with microscopic studies and rock-anisotropy testing to establish fracture trends in samples lacking large fractures (Laubach, 1989). Hower (1990) described a method by which production data can be used to identify areas of fracture-enhanced permeability within fields of the Upper Cretaceous Pictured Cliffs Sandstone in the San Juan Basin. Using the cumulative gas volume produced (MMcf) per net change in average reservoir pressure (depletion ratio), Hower (1990) delineated areas of prolific production that he ascribed to natural fractures. Areas dominated by fracture porosity in the Pictured Cliffs have high depletion ratios. Contour mapping of depletion ratios of the Red Fork and Skinner reservoirs and curvature analysis (Schultz-Ela and Yeh, 1992) can be used to determine whether local variation in fracture abundance may be a cause of the observed permeability heterogeneity in the reservoirs.

Assessment of Potential Benefits of Regional Geologic Studies

Regional geologic studies that improve predictions of reservoir distribution and attributes will directly benefit Cherokee Group producers by leading to improved gas recovery through more successful field-development programs. The results of an increase in the success rate of infill-well completions within reservoirs of the Cherokee Group trend are obvious: increased reserve additions. Moreover, by helping to identify and quantify the location, geometry, and quality of Cherokee reservoirs, there is potential for decreased risk of unsuccessful wells and, as discussed below, increased near-term revenue through establishment of additional production allowables per section. Regional studies can also help improve step-out exploration success.

Reserve Additions and Finding Success

A key area of potential research benefit is in contributing to more successful and efficient field-development programs through increased reserve

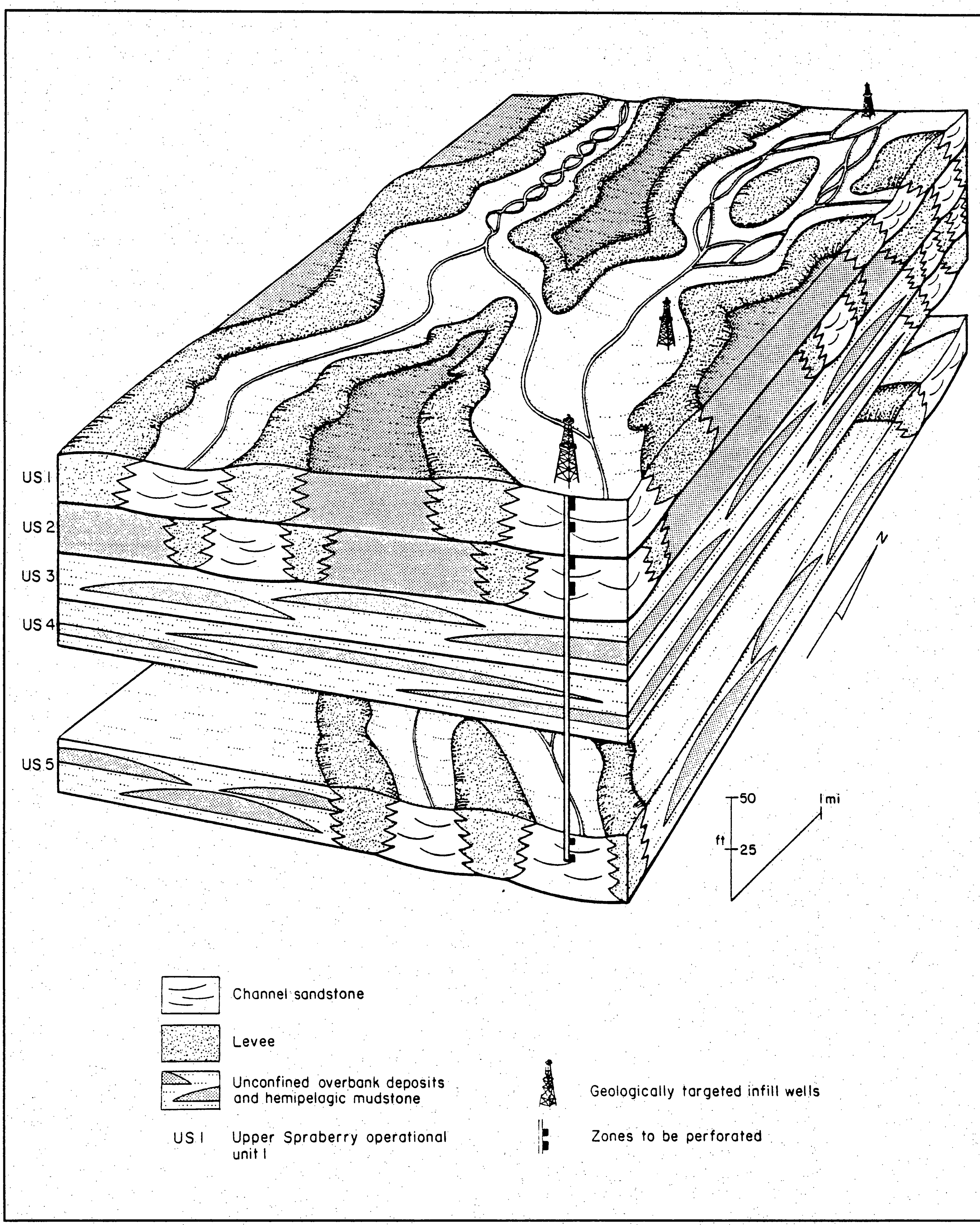

Figure 12. Schematic architecture of upper Spraberry submarine-fan reservoirs in the Spraberry Trend illustrating the complex depositional framework of the sandstones and opportunities for infield development. From Tyler and Gholston (1988).

additions and a decreased number of unsuccessful wells. Many of the surveyed Cherokee producers indicated a need for increased ability to predict reservoir geometry and trend and greater knowledge of the causes of limited drainage in mature Cherokee fields. Although in some of the best-known areas operators report that 70 percent or more of development wells drilled are completed and are considered economic successes and about 90 percent of Cherokee wells drilled per year are completed, part of this apparent success is attributed by operators to the abundance of stacked or closely spaced channel-fill and/or delta-front reservoirs within some fields. Even where the sandstone targeted by the well is nonproductive or absent, completion in one or more nontargeted sandstone can make the well successful.

It is not currently possible to quantify the number of isolated, gas-filled compartments in a field that are missed by development wells, but among Cherokee producers the general interest in additional geologic studies, such as 3-D seismic surveys, and concerns about inadequate drainage suggest that producers appreciate the possibility that current field development may locally bypass significant gas reserves. This view is consistent with the overall complexity of Cherokee stratigraphy and the success of detailed geologic studies undertaken in a few fields by some producers for delineating isolated sandstone bodies and isolated reservoirs. In sandstone reservoirs having depositional patterns similar to those of the Cherokee, previous studies that used 3-D seismic data and extensive geologic mapping and reservoir-pressure data have shown that significant potential gas reserves can be missed in conventional gas reservoirs even where average well spacing is as close as 40 acres (Levey and others, 1993), significantly closer than average well spacing in Cherokee fields.

Greatest potential for reserve additions in the mature Cherokee play likely includes (1) location of bypassed and compartmentalized sandstone reservoirs within increasingly densely drilled fields and (2) expansion of step-out drilling and exploration outside the established producing areas. Analysis of depositional environment within the Cherokee facies tract will help identify specific channel-fill type (fluvial, distributary channel, submarine fan) and therefore the potential for reservoir compartmentalization. Regional information of this type can considerably improve the accuracy of sandstone geometry determinations and compartment location during infield analysis by providing an additional constraint on interpretations based on local maps, offset well data, and seismic information. Such studies can highlight areas that would benefit from additional geological and geophysical tests, permitting more efficient placement and use of seismic data, core, and advanced modeling and well-log analysis. Exploratory and step-out drilling can benefit from broad-scale facies-tract and sequence-stratigraphic analysis through identification of regional stratigraphic associations and sandstone thickness patterns. An example of this type of analysis in a tight sandstone formation in the Anadarko Basin is provided by a recent study of the Cleveland formation (Hentz, in press).

The potential benefit of regional geologic studies could be an increase in gross revenue on the order of $450 million or more over a 10-year period. This estimate of potential benefit was calculated as follows. Cherokee gas fields encompass about 1,260 sections in the 4-county producing area described in this report (fig. 3). Although the total number of completed Cherokee wells per section varies among and within fields, three completed wells per section throughout the producing area is typical (fig. 13). A representative section in the Cherokee producing area contains two economic wells, one marginal well, and one dry hole (W. A. Clement, personal communication, 1993). The primary producing unit of the Cherokee Group is the Red Fork formation. Red Fork wells have produced an average of about 3 Bcf after about 10 years, based on production statistics gathered since the late 1970's. Operators believe that the economic lifespan of a typical Red Fork well is at least 15 to 20 years, and as a generalization, variation in decline rate depends on whether the completed unit is tight or not. In non-tight Red Fork wells, such as those in the East Clinton field, which can produce significantly more than 3 Bcf per well over 10 years, approximately 90 percent of recoverable resources is produced after about 12 years (W. A. Clement, personal communication, 1993). Lifespans of tight wells are longer, but these wells produce less gas per year. In the potential-benefit calculation, an average 3 Bcf per well over a 10-year period was used.

With the generalizations and limitations inherent in the foregoing numbers in mind, an approximation of some of the expected benefits to Cherokee operators of in-depth geologic studies can be calculated by combining an estimate of the total expected production per well and reasonable assumptions of increases in percentage of economically successful completed wells per section. If the result of improved regional information led to conversion of only one-eighth (12.5 percent) of the unsuccessful wells per section to economically successful wells, 158 (0.125 well x 1,260 sections) additional economic Red Fork wells could be completed. Given current regional stratigraphic knowledge and the scope of this study, it is not possible to rigorously justify this level of improvement. Nevertheless, given the level of stratigraphic complexity revealed in the most heavily drilled areas, the sparse

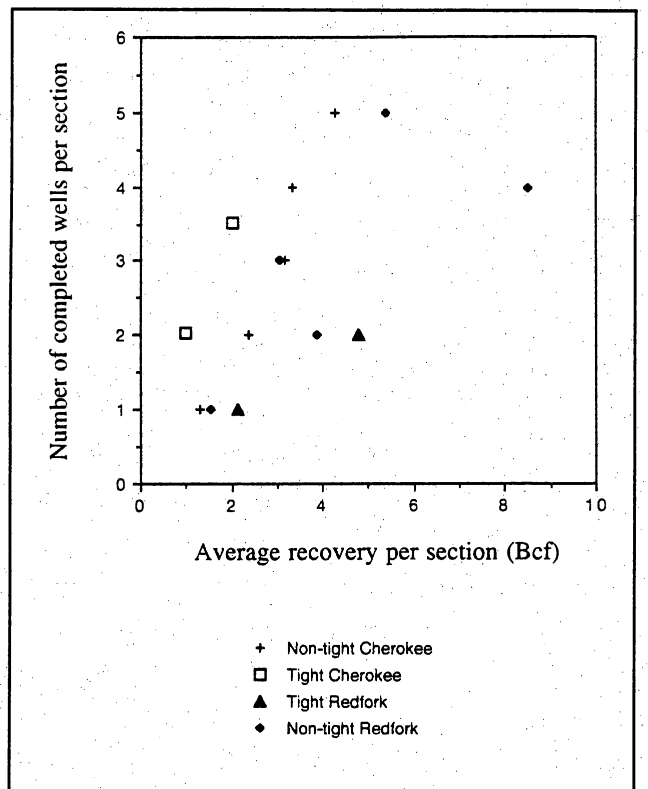

Figure 13. Graph of number of completed Cherokee wells per section versus average recovery per section. Data from Hugman and others (1992).

well spacing (approximately 4 wells per section) in many areas, and the marked percentage of unsuccessful wells, this estimate is plausible.

Using the current natural gas price of about \$2.00/mcf and an average 3 Bcf cumulative production per well over a 10-year period, these additional wells would yield gross increases in revenue of \$740 million after subtraction of typical Red Fork drilling and completion costs (\$1.3 million per well) and about \$550 million after subtraction of 3/16 royalty fees, 7 percent severance tax, and \$2,000 per month operating costs. Finding costs, which can be substantial, are not considered in this calculation because we assume that the wells used in the calculation would have been drilled in any case. Elements that increase the uncertainty of the estimate include varying drilling and completion costs, gas price, royalty fees, and operating costs, and the speculative nature of the appraisal of possible increases in success rate of development wells used in the calculation.

The cost of a thorough regional research effort to develop and transfer technology could be as much as \$4.5 million for a 3-year study if extensive data collection and well testing are included. In order to implement the new technology, operators would likely need additional site-specific geological and geophysical tests that can be generously estimated in the range of \$80,000 per section. This appraisal of implementation cost per section is based on an estimation of \$50,000 per section of acquired, processed, and interpreted 3-D seismic data and \$30,000 per section for added geological assessment, modeling, and incremental well-log analysis. Assuming maximum utilization of these methods in all sections of the Cherokee play, revenue minus implementation costs is about \$450 million.

Comparing the cost of a \$4.5 million 3-year research and technology transfer effort to the potential benefit of undiscounted increases in gross revenue on the order of \$450 million over a 10-year period indicates a return on research investment of more than 100:1.

Unit Allowables

Field-development rules in the Cherokee play also affect the potential for regional geologic studies to lead to increased revenue for producers. Cherokee fields are developed using the "unit allowable" system; that is, the total amount of gas that can be produced per year from a 640-acre (1-mi^2) drilling and spacing unit is determined by a certain (seasonally variable) percentage of the calculated open-flow rate of the best producing well in the section. If the allowable is set but a demonstrably separate reservoir (an isolated channel-fill sandstone, for example) is later located within the same section, an additional allowable for that section can be established. To do this, a Cherokee producer must convincingly demonstrate to the Oklahoma Corporation Commission that such a separate reservoir is present. Possession of the knowledge necessary to design a development strategy in which specific isolated pay zones are predicted, identified, and delineated can help show that clearly separate reservoirs exist. Thus operators can increase their daily production early in the life of the well and their revenue.

Summary

The calculated amount of revenue increase that would result from improved finding success illustrates the substantial potential benefits of regional geologic studies. Using conservative estimates of improved finding success leads to large increase in revenue over a 10-year period. Comparing this potential benefit and the cost of such a study suggests that a return on research investment of better than 100:1 is possible.

Moreover, other factors may tend to augment the benefits of more accurate reservoir delineation. For example, through better identification of isolated reservoirs, additional production allowables can be more readily established, resulting in more rapid production rates and additional revenue. This could have a significant effect on net operator profitability by helping to generate more income early in the life of the well.

Although many factors enter into maximizing the economic success of Cherokee development and step-out drilling, more reserve additions per dollar spent on drilling through such factors as improvement in the rate of completion success are attainable given the regional field- and reservoir-scale variability in Cherokee geology, and the views of operators that such improvements are possible. The large size of the potentially productive area (figs. 2 and 6) and the significant size of the Cherokee resource, which is approximated by the substantial estimated ultimate recovery from existing Cherokee wells as of 1989 (1.04 Tcf for the tight gas area alone [Hugman and others, 1992], an amount already exceeded by cumulative production in mid-1993 [Bebout and others, 1993]) suggests that large increases in revenue and profit can accrue from small improvements in development-well success rates.

Conclusions

Although the Cherokee play of western Oklahoma is within a mature hydrocarbon province (Anadarko Basin) and the Cherokee play itself is well into its infield-development phase, remaining geologic questions related both directly and indirectly to Cherokee gas-production enhancement are relatively fundamental (table 1). However, the answers to these questions have the potential to alter current production strategies and ultimately to increase natural gas reserves. Most of the surveyed Cherokee operators acknowledge that they have at best only a partial understanding of regional facies relations within the entire Red Fork and Skinner depositional systems tracts. Moreover, there is no clear and integrated perspective of depositional systems, reservoir geometry, and diagenesis among all Cherokee fields in the four-county play area. Areal and vertical reservoir geometry is complex and not readily predictable; therefore, drilling of infill wells, which characterizes the current development strategy of the Cherokee play, can be uncomfortably speculative for operators. This is especially true for the Red Fork formation, the major gas-producing interval of the Cherokee Group. A seemingly random variation in porosity and permeability in some areas and a consistently limited per-well drainage area within reservoirs compound this problem.

The recommended approach to addressing the Cherokee operators' needs involves several scales of investigation (table 1). Improved and more precise modeling of (1) the regional spectra of Red Fork and Skinner depositional settings at the play scale, (2) depositional facies and geometry at the field scale, and (3) facies architecture, diagenesis, and fracture distribution at the reservoir scale is essential to efficiently exploit the remaining natural gas resources in the Cherokee play.

Acknowledgments

This work was prepared for, and funded by, the Gas Research Institute under contract no. 5082-211-0708, Stephen E. Laubach, Principal Investigator. Critiques by Robert J. Finley and Stephen E. Laubach significantly improved portions of this text. Figures were prepared under the direction of Richard L. Dillon. Word processing was by Susan Lloyd, Diane Ruetz, and Margaret L. Evans. Layout was by Margaret L. Evans.

Table 1. Summary of geologic challenges posed by Cherokee producers and their proposed solutions.

Problem	Technical issues	Approach	Benefit
Uncertain regional variation in reservoir character	Incomplete understanding of local and regional facies tracts	Sequence-stratigraphic analysis using closely spaced well logs	Provides integrated model of local to regional facies associations
Unpredictable reservoir geometry, trends, and areal extent	Reservoirs are commonly geometrically complex for depositional and/or diagenetic reasons	Interval isopach and paleogeographic mapping, 3-D seismic analysis	Precise delineation of separate genetic depositional episodes for improved projection of productive infill wells
Porosity/permeability variation within reservoirs	Diagenetic factors, depositional control, and/or sporadic distribution of natural fractures	Field-scale petrographic and geochemical analysis, interval mapping, and mapping of depletion ratios; detailed examination of available cores	Better prediction of petrophysical and fracture attributes within a reservoir for optimal infill well location
Limited drainage area of wells	Diagenesis and/or limited dimensions of depositionally controlled reservoir geometry	Same as above	Improved fracture-stimulation strategy, targeted infill drilling
Uncertain regional lithostratigraphic correlation	Regional stratigraphic complexity	Sequence-stratigraphic analysis using closely spaced well logs	Better prediction of reservoir size, reservoir character, stacking pattern of reservoir-quality sandstones, and distribution of sealing strata
Formation evaluations not core calibrated	Few cores available	Detailed examination of available cores, new cores	Enables more accurate characterization of depositional facies, reservoir compartments, and fracture occurrence
High drilling costs	Deep, overpressured reservoirs; need to minimize wellbore damage, improve hydrocarbon detection, and control drilling rates	Slim-hole drilling, other advanced drilling methods	Reduction in development costs

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Appendix: Questionnaire to Cherokee Producers

General:

(1) Do you consider the Cherokee play to be a exploration or development play? In which formation(s) of the Cherokee are you active?

(2) How long has your company been involved in Cherokee exploration and/or development?

(3) In which counties and fields (Oklahoma) are you currently active in Cherokee exploration/development? What depositional environment(s) are represented in the reservoir facies? What are the depth ranges of the producing intervals?

(4) Are Cherokee geologic studies a primary, secondary, or minor element of your company's current *overall* economic strategy?

Economics:

(1) What is range of initial well potential in your company's Cherokee wells?

(2) What is range of the economic lifespan of Cherokee wells?

(3) What is range of cumulative production per well?

(4) What is typical cumulative production necessary to cover costs per well at current gas prices (i.e., break-even point)?

Exploration and Development:

(1) What is your primary emphasis: exploration or infield development? Roughly, what is relative percentage of each?

(2) What geological information (i.e., depositional modeling, diagenesis, structure) is most important to your company for exploration/development in the Cherokee play? Please rank in relative order of importance.

(3) Development strategies: What geological techniques (i.e., logging, mapping, 2-D and 3-D seismic, etc.) are most useful to you in Cherokee exploration/development?

(4) Where are the greatest expenses incurred in Cherokee exploration/development?

(5) What are the greatest problems/challenges for you in Cherokee exploration/development (e.g., reservoir geometry, compartmentalized reservoirs)?

Drilling and Formation Evaluation:

(1) How many Cherokee wells does your company drill per year?

(2) What is the approximate range of drilling costs per completed Cherokee well?

(3) What formation-evaluation techniques are most useful to you (i.e., log types)?

(4) What are the main problems/challenges for you in down-hole formation evaluation?

Stimulation and Completion:

(1) What percent of your Cherokee wells need to be stimulated?

(2) What kind(s) of stimulation technique(s) do you use?

(3) Is fracture (natural or stimulated) analysis important to you?

(4) What is the order of magnitude increase in production after fracture stimulation?

(5) What kinds of borehole problems do you encounter?

Closing Questions:

(1) What kinds of geologic studies would help you more efficiently exploit the Cherokee resources?

(2) What would be the best method of information transfer (i.e., journal articles, short courses, personal contacts)?

(3) What is your view of the overall economic future of the Cherokee play?