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RESERVOIR CHARACTERIZATION OF THE MISSISSIPPIAN RATCLIFFE, RICHLAND CO., MONTANA, WILLISTON BASIN

Topical Report
September 1997

By
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Michael L. Hendricks

July 1998

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RESERVOIR CHARACTERIZATION OF THE MISSISSIPPIAN RATCLIFFE, RICHLAND CO., MONTANA, WILLISTON BASIN

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Topical Report

RESERVOIR CHARACTERIZATION OF THE MISSISSIPPIAN RATCLIFFE, RICHLAND CO., MONTANA, WILLISTON BASIN

Abstract

This topical report is a compilation of characterizations by different disciplines of the Mississippian Ratcliffe in portions of Richland Co., MT. Goals of the report are to increase understanding of the reservoir rocks, oil-in-place, heterogeneity and methods for improved recovery. The report covers investigations of geology, petrography, reservoir engineering and seismic. The Ratcliffe is a low permeability oil reservoir which appears to be developed across much of the study area and occurs across much of the Williston Basin. The reservoir has not been a primary drilling target in the study area because average reserves have been insufficient to payout the cost of drilling and completion despite the application of hydraulic fracture stimulation. Oil trapping does not appear to be structurally controlled. For the Ratcliffe to be a viable drilling objective, methods need to be developed for 1) targeting better reservoir development and 2) better completions. A geological model is presented for targeting areas with greater potential for commercial reserves in the Ratcliffe. This model can be best utilized with the aid of 3D seismic. A 3D seismic survey was acquired and is used to demonstrate a methodology for targeting the Ratcliffe. Other data obtained during the project include oriented core, special formation-imaging log, pressure transient measurements and oil PVT. Although re-entry horizontal drilling was unsuccessfully tested, this completion technology should improve the economic viability of the Ratcliffe. Reservoir simulation of horizontal completions with productivity of three times that of a vertical well suggest two or three horizontal wells in a 258-ha (640-acre) area could recover sufficient reserves for profitable drilling.

RESERVOIR CHARACTERIZATIONS OF THE MISSISSIPPIAN RATCLIFFE RICHLAND CO., MONTANA, WILLISTON BASIN

Executive Summary

This report covers the Ratcliffe member of the Charles Formation in northeastern Richland Co., MT. The Ratcliffe has been historically a secondary completion objective within the study area. The Ratcliffe is found at an average depth of 2590 m (8500 ft) and is consistently developed across large areas but typically has low permeability. Median reserves in the area have been less than 16,220 m^3 (102,000 bbl) which is less than needed for an economical drilling objective. With an ultimate recovery cut-off of 25,438 m^3 (160,000 bbl), less than 40 percent of the Ratcliffe producers in the area would be considered economical drilling targets. Volumetric calculations indicate sufficient oil-in-place; however, recovery is restricted by low permeability. Oil trapping does not appear to be structurally controlled. For the Ratcliffe to be a viable drilling objective, methods need to be developed for 1) targeting better reservoir development and 2) better completions.

This investigation of the Ratcliffe is not completed as several wells should be drilled to test the conclusions reached for optimal exploitation of Ratcliffe oil reserves. The report summarizes multi-disciplinary characterizations of the Ratcliffe in the study area and draws on observations and conclusions made for other Ratcliffe fields in the Williston Basin. A geological model and exploitation methodology are presented for targeting the Ratcliffe.

Geological mapping of various horizons indicates a correlation of better Ratcliffe development and producibility with thick areas of the Ratcliffe to Bakken interval. The Bakken lies at the contact between Mississippian and Devonian time. Productive wells demonstrate tectonic activity during and after Ratcliffe time which uplifted the Ratcliffe reservoirs resulting in a thinning of the interval from the Cretaceous Greenhorn to Ratcliffe. Ratcliffe production in the study area, and at other fields, is frequently better along the flanks of present-day structures. Isopach maps indicate changes in regional trends from Bakken to Greenhorn time which is interpreted as a continual tectonic adjustment. Thin and thick areas change through time indicating movement of horst and graben blocks. This tectonic activity probably resulted in fracturing at the joints of moving blocks.

Several cores in the area have vertical fractures. It is observed in the study area, and at other Ratcliffe producing areas, that vertical fracturing is coincident with better porosity development and productivity. It is concluded that Ratcliffe reservoirs in the study area consist of low energy sediments which have undergone varying degrees of dolomitization. Preserved primary porosity is not a major constituent of reservoir rock. Faulting and fracturing, coincident with deposition, probably provided pathways for downward movement of dolomitizing brine into lower rocks. Thus, fracturing is thought to play a dual role in reservoir development as an important factor in dolomitization and as permeable conduits for production.

Volumetric calculations from log and core data indicate that the Ratcliffe contains from 1701 to 2531 m^3/ha (4331 to 6441 stb per acre) across the study area. Oil recovery from hydraulically fractured, vertical wells has a median of 16,220 m^3 (102,000 bbl) per well and represents about 6 percent of OOIP in a 129-ha (320-acre) spacing unit. Permeability from core and pressure-transient testing indicate the Ratcliffe has a representative permeability of 2.0E-4 μm^2 (0.2 md). Core data indicate that permeability is seldom greater than 9.9E-4 μm^2 (1.0 md).

Reservoir simulations, matching producing rates and pressures, confirm that Ratcliffe wells are capable of draining less than 7 percent of OOIP because of low permeability. Water-injection testing indicates that recovery by waterflooding with vertical wells would be limited by low injection rates.

Two attempts were made to drill a horizontal completion from wells which were previously producing from the Ratcliffe. One well was mechanically drilled with a lateral of 604 m (1980 ft), but did not result in commercial oil rates. Drilling a lateral at a second well was aborted after unsuccessful attempts to achieve a drilling curve from the casing-window exit. The mechanically successful lateral may have been drilled out of zone. It is concluded that the horizontal drilling attempts made during the project do not provide sufficient data to determine whether horizontal completions can be more efficient than hydraulic fracture stimulation in a vertical well. Reservoir simulation of horizontal completions with productivity of three times that of a vertical well suggest two or three horizontal wells in a 640-acre area could recover sufficient reserves for profitable drilling.

The efficient targeting of Ratcliffe wells for maximum reservoir development can be best achieved with seismic data. The majority of wells drilled in the study area were targeted for the Red River from interpretations of 2D seismic data. The criteria used for targeting the Red River are not necessarily appropriate for the Ratcliffe. The wells are widely spaced and may represent in many instances the worst location for Ratcliffe development. Identification of fracturing using converted-wave multi-component data was attempted by acqusition of a special 2D seismic line. It was not possible to exact coherent shear-wave data from these records and further attempts to investigate identification of fracturing using shear-wave data were abandoned. Because of problems identified with a surface weathered zone and the great cost associated with recording a multi-component seismic survey, it was concluded that conventional 3D seismic would be more appropriate for project objectives and budget. A 65-km^2 (25 square-mile) 3D survey across North Sioux Pass Field was used to characterize the Ratcliffe and develop a methodology which should identify areas most prospective for Ratcliffe reservoir development. The methodolgy was developed based on conclusions from geological characteristics at the better Ratcliffe fields in the study area. It was concluded that isopach mapping of the Ratcliffe to the Bakken should help identify thick areas during Ratcliffe deposition. Subsequent to Ratliffe deposition, the isopach of the Greenhorn to Ratcliffe should indicate locations of upward movement as thin areas. Divergence of trends from these two isopachs should indicate areas most likely to have experienced tectonic stress and fracturing at Ratcliffe time. Seismic modeling work indicates that increasing porosity development in the Ratcliffe is expressed as an observable amplitude change. However, the variation of amplitude is subtle and should be used only as a guide after targeting from isopach and structure mapping. Two locations for horizontal drilling are proposed from this work and are shown as a means of explanation of the methodology.

GEOLOGICAL CHARACTERIZATIONS

Mark A. Sippel and Kenneth D. Luff

Introduction

The geological setting is described for carbonate rocks in the Ratcliffe member of the Charles Formation in northeastern Richland Co., MT. Ratcliffe sediments were laid down in ramp/sabkha systems and were influenced by tectonic activity which occurred during Ratcliffe time. Seepage-reflux dolomitization is the primary mechanism for creation of porosity in productive rocks. Fracturing of Ratcliffe rocks influenced dolomitization and producibility. Fracture orientation of northwest-southeast was measured from core and special electrical logs. A major shift in uplift areas during Ratcliffe time resulted in the deposition of two distinct reservoir units in the Ratcliffe. Tectonic and depositional circumstances of these two porosity units in the Ratcliffe play a significant role in the placement of vertical or horizontal wells for the Ratcliffe in the study area.

Oil production from the Ratcliffe in the area has been primarily a secondary target after depletion of deeper oil reservoirs, mainly the Ordovician Red River. Therefore, placement of most Ratcliffe wells has been based on seismic interpretation of deeper structures which may not be coincident with optimal Ratcliffe structure or reservoir development (porosity or fractures). The role of fractures for enhancing production has been documented qualitatively in the literature. Ratcliffe reservoir rocks generally exhibit low permeability of 1 md or less. Ratcliffe completions generally produce with constant water-cut of approximately 50 percent and depleting total fluid rates with time.

Setting

The Ratcliffe study area is located in northeastern Richland Co., MT, approximately 32 km (20 miles) north of the town of Sidney, on the western shelf of the Williston Basin and is approximately 80 km (50 miles) west from the basin center (figure 1). The study area covers approximately 466 km^2 (180 sq miles) containing oil accumulations at several fields which produce from Ordovician through Mississippian-age reservoirs (figure 2). The sedimentary section ranges up to 4570 m (15,000 ft) thick in the central basin area. The oldest producing horizon in the area is the Ordovician Red River at a depth of about 3960 m (13,000 ft). The Ratcliffe is found at an average depth of 2590 m (8500 ft) and is the lower member of the Charles Formation. The Charles Formation is part of the Madison Group which is separated in ascending order into the Lodgepole, Mission Canyon and Charles formations (figure 3). The entire group is of Mississippian age. Mission Canyon and Charles deposition is characterized by complex inter-tonguing of basinal, shallow shelf, and peritidal carbonate and evaporite beds. The Ratcliffe interval is a carbonate to evaporite, shallowing upward, regressive sequence. Locally, dolomitic mudstones and wackestones are oil reservoirs. A type-log of the Ratcliffe interval is shown in figure 4. The thickness of the Ratcliffe interval is between 21 and 27 m (70 and 90 ft).

The Madison group consists of limestones, dolomites, evaporites and thin shale beds which is characterized by widespread, cyclic carbonate deposition. Sea level changes were probably the main cause of cyclic deposition. In the study area, the Lodgepole consists of slightly argillaceous lime-mud deposited in an open-marine sub-tidal environment. The Mission Canyon formation, in general, is a regressive shoaling-upward sequence. Several Mission Canyon cycles are present in the study area but difficult to recognize. The cyclic nature of the Mission Canyon formation is best known in North Dakota where drops in sea level are preserved in the rocks as shoaling-upward carbonate sequences in the near-shore (down-dip and basin-ward) sub-tidal and inter-tidal environments and bedded anhydrite in the up-dip and land-ward environment along and behind the shoreline. During Mission Canyon time, the position of the carbonate-anhydrite shoreline boundary shifted basin-ward. This pattern continued through Mission Canyon time into early Charles time resulting in Ratcliffe regressive carbonate to evaporite deposition in the study area. After Ratcliffe cycle, deposition of the Charles continued with a thick sequence of evaporites.

Structure

The strike across the study area is slightly west of north-south with several monoclinal terraces and localized closures reflected at the base of the Last Charles Salt and top of Ratcliffe markers. A present-day structure map on the top of the Ratcliffe is shown in figure 5. Present-day structural closure is subtle at many Ratcliffe fields. Within the study area, maps from well-log data reflect structural relief on top of Ratcliffe beds of only 3-8 m (10-25 ft) magnitude at Rip Rap Coulee, Cottonwood and Nohly fields in T.25-26N., R.59E. To the west in the North Sioux Pass Field in T.26N., R.58E., Ratcliffe structure is more pronounced. Structure in the area is frequently caused by basement tectonic activity associated with strike-slip and wrench faults (Mueller and Klipping 1978) and salt dissolution of the Prairie Evaporite of Silurian age. A salt-collapse feature resulting from dissolution of the Prairie Evaporite is identified from log and seismic data in the southeastern portion of T.26N., R58E.

Common structural characteristics are found at the study area and other Ratcliffe fields of the western Williston Basin. These characteristics are strong structural nosing that trends southeast and the absence of significant closure which correlates with oil production from the Ratcliffe. A relatively large Ratcliffe accumulation which lies 16 km (10 mi) to the east in McKenzie Co., ND has been described in the literature (Hendricks 1988). This Ratcliffe complex includes Glass Buff, Elk and Sioux fields which are located in townships T.151-152N., R.101-103W. The structural configuration of this Ratcliffe complex is a series of southeast-plunging structural noses where oil production primarily occurs on the northeastern flanks. Most producing Ratcliffe wells in the Glass Bluff complex lie in embayments where the lower Ratcliffe porosity member slightly thickens. The structural configuration of North Sioux Pass Field is similar to Glass Bluff Field.

Another analogy to the study area is found at Lustre Field, Valley Co., MT, located about 129 km (80 mi) to the northwest in townships T.30-31N., R.43-44E. This Ratcliffe (Charles C zone) reservoir is approximately 13 km (8 mi) long and positioned along a southeast-trending nose with subtle, localized closures (Longman and Schmidtman 1985). The oil-column height is approximately 76 m (250 ft) along the structural nose at Lustre Field. This large field is an example of a Ratcliffe reservoir that is associated with structural relief but is not controlled by a common subsea datum.

Isopach Mapping

An isopach map of the Ratcliffe interval (base of overlying anhydrite to Midale) is shown in figure 6. The map shows a variation from 21 to 29 m (68 to 95 ft) across the study area. There is a general thickening trend of the interval to the northeast at 35°. Regional dip is indicated to have been 0.2 m/km (1 ft per mile). This map indicates that shallower water was toward the southwest during much of Ratcliffe deposition. However, other isopach maps suggest shifting of regional dip through Ratcliffe time.

An isopach map of the combined thickness of the anhydrite and Last Charles Salt (which directly overlie the Ratcliffe) can be used to reconstruct the relative and probable paleo-structure of the study area at the end of Ratcliffe time (figure 7). The map indicates a very gentle setting with shallow relief and localized embayments with thickness variation of 27 to 39 m (87 to 127 ft) across the study area. The regional dip was to the southwest at 230° at less than 0.6 m/km (3 ft per mile). This suggests that at the end of Ratcliffe time, open water lay to the southwest and the shore direction was to the northeast.

Figure 8 shows an isopach map of the Midale to Bakken. The Midale underlies the Ratcliffe and the Bakken is a deeper horizon deposited just before Mississippian time. This isopach has a variation from 400 to 419 m (1311 to 1374 ft) across the study area. The regional dip is to the northeast at 55° at less than 0.6 m/km (3 ft per mile). This suggests that at the beginning of Ratcliffe time, open water lay to the northeast and the shore direction was to the southwest. It is concluded that there was tectonic activity during Ratcliffe time which created a complete reversal of regional dip.

A map of the interval from the Base of the Last Salt to the Bakken (figure 9) displays the same trends as the Midale to Bakken isopach map (figure 8). The use of this map for interpretation of the Ratcliffe setting would mask the change in orientation of dip which occurred during Ratcliffe time.

It is concluded that a thicker Ratcliffe interval was primarily caused by filling of shallow ponds. This conclusion is drawn from the coincidence of thick areas on the Ratcliffe isopach (figure 7) with thick areas of the underlying Midale to Bakken isopach (figure 8). This is most notable at Nohly, Cattails and Rip Rap Coulee fields (figure 2). Although the anhydrite and salt isopach of figure 6 shows thinning over Nohly and Rip Rap Coulee fields, it is thought that this was the result of tectonic activity that occurred at the end of Ratcliffe time when areas to the northeast became more uplifted than areas to the southwest. This is perhaps more clearly demonstrated by the cross-section shown in figure 10. Wells in the eastern portion of the study area are thicker in the lower Ratcliffe interval but thinner in the upper Ratcliffe interval and overlying anhydrite and evaporite beds. Sediments for the lower Ratcliffe filled low areas on the east side of the study area when deeper waters were to the northeast. The cross-section also shows that upper-zone porosity develops where the upper Ratcliffe interval is thicker. Sediments for the upper Ratcliffe filled low areas on the west side of the study area when deeper waters were to the southwest.

After Ratcliffe time there was continued tectonic activity across the area. An isopach map of the interval from Cretaceous Greenhorn to Base Last Charles Salt shows the significant structural growth that occurred at the northwestern portion of the study area during this time (figure 11). Thin areas on the Greenhorn to Base Last Salt isopach represent positive structural growth after Ratcliffe time. Much of the present-day structure found at many fields in the study area appears to have occurred between Ratcliffe and Greenhorn time.

The various isopachs indicate that the area has experienced continual tectonic activity from Mississippian through Cretaceous time. The rotation of regional dip from northeast prior to Ratcliffe time, to the southwest at the end of Ratcliffe time and finally to the southeast by Greenhorn time suggest complex structural movement resulting in strike-slip and wrench faults.

Ratcliffe Depositional Model

Work on Mississippian reservoirs has led to proposals of a variety of depositional models in the literature. These range from an agal-reef model (Hansen 1966) for the Ratcliffe reservoirs in northeastern Montana to a tidal-flat, supratidal-pond model for the Nesson in the Billings Nose area (Altschuld and Kerr 1982). The Ratcliffe is characterized by complex inter-tonguing of basinal, shallow shelf, and peritidal carbonate and evaporite beds. Many facies in the Ratcliffe are similar to those described for modern examples from ramp/sabkha systems in the Persian Gulf. A diagram of such a depositional model is shown in figure 12. Individual facies from a variety of depositional environments have been correlated over large areas at Ratcliffe fields in this portion of the basin. Because primary reservoir facies can be correlated beyond productive limits of these Ratcliffe fields, it is concluded that depositional facies appear to exert only a secondary influence on production (Longman and Schmidtman 1985). Ratcliffe reservoirs in the study area consist of low energy sediments that have undergone varying degrees of dolomitization. Preserved, primary porosity is not a major constituent of reservoir rock. Extensive sabkha and hyper-saline lagoons generate the brines which cause dolomitization. For development of good reservoir rock, there must be a means for the hyper-saline fluids to migrate down into the mudstones and wackestones of the Ratcliffe. Fracturing and faulting contemporaneous with deposition are probable mechanisms which allow migration of these waters which create secondary dolomite.

This depositional model suggests that better reservoir rocks should be found along coastal areas and around barrier islands, inter-tidal buildups and tidal bars. It is frequently observed that fracturing is responsible for many of the better Ratcliffe reservoirs. The most faulted and probably fractured areas are on the flanks of deep structures at Ordovician Winnipeg and Red River depths. This suggests that most Ratcliffe wells have not been drilled and completed in optimal locations for Ratcliffe reservoir development because they were drilled on crestal positions for the Red River.

Isopach maps indicate changes in regional trends from Bakken to Greenhorn time which is interpreted as a continual tectonic adjustment. Thin and thick areas change through time indicating movement of horst and graben blocks. This tectonic activity probably resulted in fracturing at the joints of moving blocks. Several cores in the area have vertical fractures. It is observed in the study area, and at other Ratcliffe producing areas, that vertical fracturing is coincident with better porosity development and productivity. Thus, fracturing is thought to play a dual role in reservoir development as an important factor in dolomitization and as permeable conduits for production.

Porosity Development

Ratcliffe porosity in the study area generally develops either in the lower or upper section (Alexander and Flat Lake intervals, respectively) but never is well developed in both. This observation leads to the conclusion that a dramatic changes in shore-line direction occurred during and after Ratcliffe time. Porosity development on electrical logs is not always an indication of producibility.

Wells in Cattails, Rip Rap Coulee, Cottonwood and Nohly fields (T.26 N., R.59 E.) demonstrate development of the lower-porosity zone (eastern log shown on figure 10). This porosity zone is positioned just above the underlying Midale. It is similar in stratigraphic position as the lower-porosity bench which is labeled the Alexander interval in the Glass Bluff area of North Dakota (Hendricks 1988). Often, the lower-porosity zone exhibits a shallowing-upward profile on logs. Isopach mapping of the lower Ratcliffe at Glass Bluff Field indicates that most producing Ratcliffe wells lie in embayments where the lower intervals slightly thicken due to compensating deposition. In general, the lower-porosity zone consists of limestone or dolomitic lime. The best example wells with lower porosity are in the Rip Rap Coulee Field (figure 4). Isopach mapping the base of the Ratcliffe (top of Midale) to the Bakken indicates that the eastern Ratcliffe fields in the study area are thicker in this interval (figure 8). This map is interpreted to also indicate that these areas were structurally low before Ratcliffe time and therefore susceptible to preferential sediment deposition in low-lying embayments as described at Glass Bluff Field. An isopach map from the Base of the Last Charles Salt to the Bakken (figure 9) shows similar thick areas as the Midale to Bakken map. Both maps exhibit a strike trend of northwest-southeast. An isopach map of the Ratcliffe interval (figure 7) from the base of the overlying anhydrite to the top of the Midale indicates that deposition of the Ratcliffe generally filled basin areas indicated from the Base Last Salt and Midale to Bakken isopach maps. This is most notable on the east side of the study area in T.25-26N., R.59E. where the lower porosity is developed. Thick Ratcliffe areas are coincident with thick areas of the Midale to Bakken interval. The lower Ratcliffe porosity bench is therefore concluded to be the result of sediment deposition in shallow embayments and shore line was generally toward the southwest.

Upper-porosity development is best demonstrated in wells at North Sioux Pass Field located in township T.26 N., R.58E. (western log shown on figure 10). The upper-porosity zone is similar in stratigraphic position as the Flat Lake interval (Hendricks 1988). In the North Sioux Pass Field, most wells that have upper-porosity development appear to be productive. Upper porosity also shows a shallowing-upward profile. Some of the upper-porosity profiles in North Sioux Pass Field exhibit a similarity to lower-porosity profiles in the eastern portion of the study area. This suggests that the upper-porosity zone was deposited in a cycle which was similar to the lower cycle. Development of rocks in the upper-porosity zone at North Sioux Pass Field tends to be more dolomitized than the lower-porosity zone. The cross-section in figure 10 also shows that porosity develops where the upper Ratcliffe interval is thicker. Sediments for the upper Ratcliffe filled low areas on the west side of the study area when deeper waters were to the southwest.

A third type of section is demonstrated in the study area which can be productive yet has minimal porosity development. Porosity develops as thin spikes on logs and rarely exceeds 6 percent (middle log shown on figure 10). These porous spikes consist of limestone. Two wells completed in sections 22 and 27 of township T.26N., R.58E. have been completed in this transitional-type section of the Ratcliffe and have averaged over 15,900 m^3 (100,000 bbl) per well. These wells are an enigma and are presumed to be connected to better porosity through a fracture system.

Fracture Development

The role of fractures for enhancing Ratcliffe production has been documented qualitatively in the literature (Mueller and Klipping 1978; Hendricks 1988; Longman and Schmidtman 1985). At Glass Bluff Field, McKenzie Co., ND, local fracturing is attributed with increasing permeability and reservoir performance (Hendricks 1988). Similarly, at Lustre Field, Valley Co., MT, vertical fractures are credited for enhancing production (Longman and Schmidtman 1985). Cores taken from the Ratcliffe interval in the study area also suggest that fracturing maybe responsible for better porosity development and production. Cores taken at North Sioux Pass, Cattails and Nohly fields have reported vertical fractures.

A 27-m (90-ft) oriented core from the Luff Federal No. 1-17R well (section 17, T.26N., R.58E.) was obtained to confirm observations concerning fracture orientation, facies distribution, and general reservoir characterization (see figure 2 for well location). A formation micro-imaging (FMI) electrical log was also obtained to image fracture orientations and porosity development. Figure 13 shows fracture orientations from observations of the Ratcliffe at the Federal 1-17R. Both the core and FMI log indicate a preferential orientation of fractures aligning northwest-southeast. The FMI indicates a primary orientation of 30° west from north. The core data indicate that fracturing has a primary orientation of 60° west from north. These fractures are nearly vertical with an average angle of 70°. The bedding dip of the Ratcliffe interval is indicated to be 30° east from north. This bedding dip is in good agreement with dip indicated from the isopach maps of Midale to Bakken and Base Last Salt to Bakken (figures 8 and 9).

It is concluded that the primary fracture orientation at the Federal No. 1-17R is parallel to the axis of the structural nose at North Sioux Pass Field (figure 5) and is between 300° and 330°. This orientation probably reflects wide-spread tectonic activity, both locally in the study area and regionally as indicated by the numerous fields that have orientations of northwest-southeast. However, it may be that the orientation indicated at the Federal No. 1-17R is only local. Detailed mapping of horizons using 3D seismic at North Sioux Pass Field indicates other lineaments exist which have orientations of northeast-southwest.

Reservoir Trapping

Reservoir trapping is primarily stratigraphic in nature and occurs locally with the presence of vertical fracturing and where seepage-reflux of magnesium-rich brines was favorable for dolomitization. Primary controls on production are the degree of dolomitization of burrowed mudstone and wackestone facies and vertical fracturing. Individual facies from a variety of depositional environments can be correlated across the area, but depositional facies appear to exert only a secondary influence on production. At larger Ratcliffe fields, better oil production is located off structure and along flanks of paleo structures where most producing Ratcliffe wells lie in embayments and the porous intervals slightly thicken due to compensating deposition. It is observed in the study area, and elsewhere, that productive Ratcliffe is associated with subtle structure but is not controlled by a common subsea datum.

Heterogeneity

There are three types of heterogeneity observed in the Ratcliffe. The most regional heterogeneity is the development of the upper and lower zones (Flat Lake and Alexander intervals). These intervals were deposited in two different cycles which were affected by a shifting regional setting. Well-developed porosity does not occur simultaneously in the Flat Lake and Alexander intervals. The second type of heterogeneity is the degree of dolomitization and porosity development through diagenesis. The third type of heterogeneity is faulting and fracturing. Fracturing appears to play a dual role in reservoir development as a factor in dolomitization and as permeable conduits for production. There is also evidence of structural compartmentalization in one Ratcliffe completion in the study area. Targeting better reservoir development involves locating areas conducive to deposition of thicker facies and subsequent fracturing by tectonic movement. The application of horizontal drilling should improve producibility from the Ratcliffe because of the low-permeability nature of the reservoir. Because better Ratcliffe production is associated with fracturing, a horizontal drain hole offers the potential for connection with more fractures and greater producibility if the fractures are not damaged by invasion during drilling.

Conclusions

The Ratcliffe is characterized by complex inter-tonguing of basinal, shallow shelf, and peritidal carbonate and evaporite beds. The sediments were laid down in ramp/sabkha systems. This depositional model suggests that better reservoir rocks should be found along coastal areas and around barrier islands, inter-tidal buildups and tidal bars. Individual depositional units (facies) in the Ratcliffe can be correlated beyond productive limits and it is concluded that deposition of facies exerts only a secondary influence on production. The primary control on production is dolomitization of reservoir facies. Dolomitization of these rocks is the result of downward-migrating magnesium-rich brines. Faulting and fracturing during and after Ratcliffe deposition are mechanisms which were probably most efficient for allowing the migration of these dolomitizing brines from overlying hyper-saline ponds.

In the study area, there are two productive intervals which generally are not coincident with the other. Both upper and lower Ratcliffe porosity zones (Flat Lake and Alexander intervals) appear to have been deposited areas of shallow ponds. Isopach mapping indicates a dramatic shift of shore-line orientation for these units. It appears that a major northwest-southeast trending basement lineament was active during Ratcliffe time causing a shifting of uplift areas. The lower porosity bench was deposited when the shore-line direction was to the southwest and deeper water was to the northeast. The upper porosity bench was deposited when the shore-line direction was to the northeast and deeper water was to the southwest. Trend direction for both of these reservoir units should be northwest-southeast.

The most faulted and probably fractured areas are on the flanks of deep structures found at Ordovician Winnipeg and Red River depths. Seismic data across the study area show faults at the Red River and Winnipeg on the flanks of many of these structural features. The dominant direction of basement lineaments are northwest-southeast. After Ratcliffe time, the was significant structural growth which occurred to the northwest as shown by the Greenhorn to Base Last Salt isopach map. This uplifting to the northwest resulted in another set of faulting lineaments which run northeast-southwest.

It is concluded that many Ratcliffe completions are in wells which were not drilled in optimal locations for Ratcliffe reservoir development because they were drilled on crestal positions for the Red River. The full potential of the Ratcliffe at in the study area is still to be determined. The geological model presented suggests a methodology for exploitation of better Ratcliffe reservoirs. Thicker reservoir facies should occur in thick areas suggested by isopach mapping the Ratcliffe to Bakken interval. Divergence of the Ratcliffe to Bakken isopach and the Greenhorn to Ratcliffe isopach should indicate maximum tectonic movement which should be favorable to fracturing of Ratcliffe beds. Positive present-day structural closure or nosing which is coincident with these characteristics should offer maximum potential for better Ratcliffe reservoir development. The subtle complexity of the Ratcliffe environment cannot be clearly resolved from widely spaced well-log data from Red River tests. Only 3D seismic data can offer the resolution required to accurately predict the previously described conditions which are thought to be conducive to maximum Ratcliffe potential. The section on seismic characterization of the Ratcliffe presents the methodology by examples.

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PETROGRAPHICAL CHARACTERIZATIONS

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Introduction

A core and petrographic study was undertaken in order to understand the development of porosity within the Ratcliffe beds of the Charles Formation (Meramecian) within portions of Richland County, Montana. Graphical descriptions were made from available slabbed cores and were augmented by petrographic study of thin sections. Cores and thin sections examined for this study are currently available at the Core Research Center of the U.S. Geological Survey, Denver Federal Center, Lakewood, Colorado. This report summarizes petrographic descriptions of Ratcliffe reservoir and non-reservoir lithofacies within the study area. Interpretations of depositional environments and diagenetic processes that have altered original depositional facies are also included. Color and texture are important components of core description; however, converting core images to black and white and then reproducing them frequently does the images an injustice. Core photographs in color with electrical logs and descriptions will be available on CD-ROM as a project product.

The Madison Group in the Williston Basin includes the Lodgepole, Mission Canyon, and Charles formations. Lodgepole (Kinderhookian) deposition occurred along aerially extensive prograding clinoforms which filled the early Mississippian Williston Basin. At or near the toes of the clinoforms, Waulsortian-type mounds occur locally. Mission Canyon (Osage and Meramecian) and Charles (Meramecian) deposition is characterized by complex inter-tonguing of shallow basinal, shallow shelf, and peritidal carbonates and evaporite beds. Both the Mission Canyon and Ratcliffe intervals of the Charles Formation are carbonate to evaporite, shallowing-upward, regressive sequences. Locally in the Ratcliffe, dolomitic mudstones and wackestones are oil reservoirs.

Ratcliffe beds in the study area occur at depths of approximately 2680 m (8800 ft) and have a gross thickness of about 26 m (85 ft). Most completions in the Ratcliffe have been secondary after depletion of deeper oil reservoirs, primarily the Ordovician Red River.

Petrophysical Properties

Conventional porosity and permeability measurements were studied from four cores within the study area at Nohly, Cattails and North Sioux Pass fields (figure 14). Measurements of permeability to air from Ratcliffe rocks are low and do not exceed 4.9E-3 μm^2 (5 md). The geometric mean is only 1.4E-4 μm^2 (0.14 md) with a range from 3.9E-5 to 7.8E-4 μm^2 (0.04 to 0.79) md at one standard deviation for rocks with porosity greater than 4 percent. Core porosity ranges from 6 to 12 percent with an average of 9 percent.

Density-neutron logs from 23 wells were analyzed in the Ratcliffe interval for net-pay thickness and storage. The average net-pay thickness is 5.5 m (18 ft) with a range from 2.7 to 8.5 m (9 to 28 ft) at one standard deviation. Potential storage (porosity-thickness) ranges from 0.24 to 0.76 m (0.79 to 2.50 ft) with an average of 0.50 m (1.64 ft). Water saturations typically range from 45 to 50 percent in productive intervals.

Sequence Stratigraphy and Vertical Facies Successions

Ratcliffe lithofacies can be arranged in a vertical assemblage that depicts inter-tonguing of shallow shelf, restricted subtidal, peritidal, and supratidal facies associated with forward stepping, shallowing-upward paracycles (figure 15). Ratcliffe reservoir beds in the study area include the Alexander and Flat Lake sub-intervals. Reservoir facies are incompletely to completely dolomitized mudstones and wackestones that occur in the middle and upper portions of paracycles. Forward stepping and vertical stacking of lithofacies controlled sediment accumulation and lateral distribution. Progradation of the Ratcliffe system was from east to west and sediment off-lapping produced facies belts that are laterally continuous along depositional strike. This ramp style of deposition characterizes the entire Ratcliffe.

In the project area, progradational facies belts crossed paleo-anticlines. Burrowed mudstones and wackestones became sites for selective dolomitization. Magnesium-rich brines which developed in overlying sabkha environments percolated through these restricted subtidal sediments producing porous, but generally low permeable reservoirs. Local fracturing which occurred during the Laramide Orogeny (Early Paleocene) enhanced these reservoirs.

Depositional Environments

Ratcliffe core lithofacies were described from three wells in order to determine lithology, textures, skeletal and non-skeletal allochems, cements, porosity types and oil shows. Descriptions of these cores are shown with density-neutron porosity logs on figures 16, 17 and 18. Ratcliffe sediments gradually filled the Charles basin with off-lapping or progradational wedges of carbonates and evaporites. From base to top, the Ratcliffe is characterized by shallowing-upward and salinity-restricting paracycles. A summary of Ratcliffe depositional facies in the project area correlated to log response is shown in figure 19.

Facies 1. Black to dark gray, shaley lime mudstones with sparse crinoid skeletal fragments (figure 20) were deposited in open marine environments during base level rise. These sediments represent the deepest Ratcliffe depositional environments in the study area. This facies commonly displays an increased gamma-ray response on electrical logs.

Facies 2. Open marine sediments are dark gray to black and contain crinoids, bryozoans, brachiopods, rugose and tabulate corals, and sparse mollusks (figure 21). These lime wackestones and packstones were deposited in normal marine environments. Minor oscillations in bathymetry produced inter-tonguing of these sediments with restricted subtidal sediments.

Facies 3. Brown, burrow-mottled sediments locally contain normal marine fauna, but were probably deposited in environments that were slightly to highly stressed by elevated salinity and/or low oxygen levels (figure 22). *Thalassinoides, Rhizocorallium, Chondrites,* and *Planolites* trace fossils are common, and are part of the *Cruziana* ichnofacies which has been described along shallow shelf environments (Pemberton et al. 1992). Burrowed sediments are slightly to completely dolomitized. It is inferred that burrowing infauna probably increased sediment transmissibility and made these shallow subtidal sediments susceptible to seepage dolomitization from overlying gypsum (anhydrite) beds.

Facies 4. Light brown to brown, algal and skeletal lime mudstones and wackestones were deposited in protected-shelf and lower-shoal environments. These sediments are sparsely burrowed, slightly dolomitic, and generally not reservoirs (figure 23). Algal fragments are broken and coated *Ortonella* fragments, and skeletal fragments are ostracods.

Facies 5. Upper shoal environments commonly cap burrowed mottled sediments. Shoal sediments are peloidal and algal mudstones to packstones (figure 24). Textural variations are related to differences in depositional energy and relative bathymetry across ancient structural noses. Shoal sediments were probably deposited in very shallow subaqueous environments based on the presence of the Codiacean alga *Ortonella.* This alga characteristically is nodular with well developed radiating microtubules. Peloidal grains indicate reworking of muddy substrates and algal fragments in swash zones and possibly intertidal environments. Coated grains are sparse. Original porosity within grain-rich beds is commonly occluded by calcite spar cements and secondary anhydrite. Because of early cementation and sparse dolomitization, the shoal facies in the study area is generally not a reservoir.

Although not cored in the project area, laminated beds commonly underlie and immediately overlie sabkha sediments. These intertidal beds are dolomites with millimeter-scale, flat to wavy laminations. This facies was deposited in environments where the trapping and binding activities of cyanobacteria were common. Desiccation features are sparse, and in situ fossils are missing.

Anhydrite caps the shallowing-upward paracycles. The presence of anhydrite (gypsum) indicates that restriction accompanied progradation and basin filling. Displacive nodular and enterolithic anhydrites are common, and it is inferred that deposition of gypsum was in coastal sabkhas which were both intermittently wet and desiccated.

Diagenesis

In the study area, Ratcliffe oil is typically entrapped within dolomitized burrow-mottled mudstones and wackestones (Facies 3 shown in figure 22). Dolomites are fabric preserving and microcrystalline to cryptocrystalline (figure 25). Most of the visible porosity is associated with burial diagenetic processes (moldic and vuggy pores). Intercrystalline porosity is poor to fair and associated permeability is the same.

Vuggy and channel pores commonly occur within dolomitic strata and possibly developed during burial diagenesis (figure 26). Late burial dissolution associated with chemical compaction, maturing hydrocarbons, or hydrothermal processes may be a common control in Ratcliffe reservoir development (Dravis 1993). This evaluation has shown that Ratcliffe dolomitic reservoirs were subjected to burial diagenesis which modified pre-existing reservoir conditions and both improved and reduced porosity and permeability.

Anhydrite and calcite replacement are locally present in Ratcliffe reservoirs (figure 26). These occluding and diagenetic minerals decrease both porosity and permeability. Anhydrite commonly occurs as a late precipitating and occluding cement, and calcite is locally present as a pore occluding mineral. Both minerals precipitated during mesogenesis.

Natural fractures within the Ratcliffe are developed within limestones and dolomitic beds and are observed in each core studied (figure 27). These fractures are nearly vertical and have fluorescence. Many fractures within limestones were subsequently occluded by sparry calcite. Fractures in dolomites are usually 0.15 to 0.60 m (0.5 to 2.0 ft) long and occur within the burrow-mottled facies (Facies 3). Swarms or closely spaced vertical fractures are also present, but within thin beds.

Pressure-solution features, ranging from micro-stylolites to high-amplitude stylolites, wispy seams, and individual or isolated solution seams are present in Ratcliffe beds. Stylolitization is more common in non-reservoir limestones and these compaction features do not appear to adversely affect dolomitic reservoirs.

Porosity Prediction

During Ratcliffe deposition, paleo-anticlines were probably shallow areas on the self which allowed preferential development and deposition of burrowed facies (Facies 3) and subsequent dolomitization by gravity-induced seepage of magnesium-rich brines. Localization of porosity along these paleo-structures was enhanced by later structural deformation and associated fracturing. Better Ratcliffe production is more likely to occur along the flanks of present day and paleo-structures where the main reservoir facies is thicker due to compensating deposition. Between structural noses and within synclines, burrowed sediments were replaced by a facies change which consists of skeletal lime wackestones and packstones with poor porosity and permeability. The relationship of Ratcliffe production to relative position along the flanks of present day and paleo-structures is documented at Glass Bluff Field, McKenzie county, North Dakota (Hendricks 1988). Restricted, subtidal dolomites of the Ratcliffe are reservoirs along the flanks of paleo-structures in this field.

Conclusions

Reservoir facies are incompletely to completely dolomitized mudstones and wackestones that occur in the middle and upper portions of paracycles. Forward stepping and vertical stacking of lithofacies controlled sediment accumulation and lateral distribution. Progradation of the Ratcliffe system was from east to west and sediment off-lapping produced facies belts that are laterally continuous along depositional strike.

In the project area, Ratcliffe reservoirs are fractured and burrow-mottled dolomites and calcareous dolomites. Originally, these sediments were deposited along a shallow dipping carbonate and evaporite ramp. Localization of restricted subtidal facies across and along paleo-structures provided for later diagenetic replacement of micrite by dolomite. The main reservoir facies is thicker along the flanks of structures. Subsequent structural deformation during Laramide time fractured the dolomitic beds which increased permeability and reservoir effectiveness.

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ENGINEERING CHARACTERIZATIONS

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Introduction

This section summarizes Ratcliffe reservoir fluids and functional characteristics in northeast Richland Co., MT (figure 28). Functional reservoir characteristics include transmissibility from pressure transient tests, cores and production analysis. A review of general characteristics is made for the area along with data and analysis collected from demonstration wells. These data include oriented core with special core analysis and pressure-transient tests. These data were used in computer simulation models to help evaluate potential reserves from various development scenarios with vertical and horizontal wells.

Oil production from Madison Group rocks in the study area has been established from both Ratcliffe and upper Mission Canyon intervals. The majority of the production, however, is attributed to the Ratcliffe interval. This conclusion is reached from drill-stem test results and porosity development on electrical logs. Upper Mission Canyon completions do not appear to be commercial alone and are always commingled with the Ratcliffe. Productive limits of the Ratcliffe in the study area are not well understood but may be more related to porosity and fracture development than structural position.

Problems encountered in Ratcliffe completions include rapid production decline and low ultimate recovery. Salt precipitation in perforations and production equipment is a continual problem and treatments with fresh water down the tubing-casing annulus are routinely performed on most wells. While considerable improvements in producibility of the Ratcliffe have been achieved through proppant fracturing since the 1980's, the average expected ultimate recovery is perceived as less than is necessary to economically justify drilling as a single-completion reservoir target.

Because of low average reserves, the Ratcliffe has been historically a secondary or re-completion objective after depletion of deeper reservoirs. Ultimate oil recovery has an average of 16,217 m^3 (102,000 bbl) per completion which represents a recovery factor of 6 percent of the volumetric oil-in-place in a typical 129-ha (320-acre) spacing unit. Economic analysis indicates that ultimate recovery of 25,438 m^3 (160,000 bbl) of oil and stabilized initial production of greater than 15.9 m^3 oil per day (100 bopd) are necessary to justify drilling for the Ratcliffe. Modern hydraulic-fracture stimulation techniques have improved producibility of Ratcliffe completions but not to the level necessary for justification of drilling a Ratcliffe objective in much of the study area. Oil-in-place calculations from log data indicate from 1700 to 2530 m^3/ha (4330 to 6440 stb per acre) and suggest there is sufficient OOIP to justify drilling if recovery factors can be improved.

The Ratcliffe is considered a good candidate for horizontal drilling. Two wells were selected for testing re-entry horizontal completions. One attempt was a mechanical failure as it was not possible to build a drilling curve after departure from the casing window. The other attempt was a mechanical success but a failure with regard to oil production. It is concluded that the horizontal drilling attempts made during the project do not provide sufficient data to determine whether horizontal completions can be more efficient than hydraulic fracture stimulation in a vertical well.

Drilling and Completion

Before discussion of reservoir characterizations, a brief review of drilling and production operations will help put the reservoir discussions in an economic perspective. Most completions in the Ratcliffe member in the study area have been recompletions after depletion of a deeper reservoir or failed completion in a deeper reservoir. All economically successful completions thus far have been from vertical wellbores.

Wells drilled in this area typically have a 31.1 cm (12¼-in.) surface hole drilled to approximately 610 m (2000 ft). Surface casing, 24.4 cm (9⅝-in.) OD, is run and cemented up to ground surface. An 22.2 cm (8¾-in.) hole is then drilled to total depth and, if justified, 14.0 cm (5½-in.) OD casing is run to total depth. Cement is accomplished usually in two stages. The first stage cement is designed to cover up from total depth to a stage collar which is normally located in the casing string below the Mission Canyon Formation. The second stage cement is designed to cover up from the stage collar to above the Dakota Formation.

Casing string design and cement coverage are extremely important in this area because of problems with salt zones. Heavy casing, preferably 14.3 cm (5⅝-in.) OD, 17.9 kg/m (26.7 lb/ft), is typically run across all salt sections. The base of the massive Charles Salt interval lies about 27.4 m (90 ft) above the top of the Ratcliffe member. It has a history of casing collapses, dog-legs and corrosion problems associated with it throughout the Williston Basin. The combination of gauge hole, heavy casing and effective cement appears to provide the best protection from casing failures in the salt zones.

The preferred drilling fluid in this area is an oil based reverse emulsion system. Saturated salt systems have been used extensively but have not provided gauge holes in salt sections. Although they are significantly more expensive, the oil based systems yield gauge holes through the salt sections.

If prudent drilling practices are followed, holes can usually be drilled without problems. There are no common lost circulation zones. Problems can be experienced with nitrogen flows from the Minnekahta or Minnelusa formations if sufficient hydrostatic head is not maintained. This typically only requires keeping the hole full during trips since normal drilling fluid densities are quite adequate to maintain control.

Since wells are not normally drilled in this area to just Ratcliffe depth, there is no history of costs. However, it is estimated that a vertical well drilled and completed in this formation would cost approximately $900,000 which includes $125,000 for hydraulic fracture stimulation. Drilling rig time for a Ratcliffe well would normally be about 20 days with total depth through the Mission Canyon at about 2865 m (9400 ft).

There has recently been horizontal drilling activity in the Ratcliffe member close to the study area of this project. It appears that mixed results have occurred. It is estimated that a completed horizontal Ratcliffe well would cost $1,200,000 which includes pumping unit and production facilities.

Operating cost for wells depends much on electrical power and water disposal requirements. Most Ratcliffe wells are produced by beam and rod pumps to individual production facilities and tankage. Generally, well operating costs range from $3500 to $4500 per month.

Characterization by Production Data

Table 1 summarizes production characteristics by field in the Richland study area. The table shows Ratcliffe reserves range from 4,610 to 35,610 m^3 (29,000 to 224,000 bbl) per completion with an geometric mean of 16,220 m^3 (102,000 bbl). Stabilized initial production is typically less than 11.1 m^3 oil per day (70 bopd) and ranges from 6.0 to 15.4 m^3 oil per day (38 to 97 bopd).

A total of 55 completions in the Richland study area were evaluated by production type-curve analysis to characterize the Ratcliffe to establish certain baseline data for productivity, reserves and drainage area. Figure 28 shows the apparent drainage area of Ratcliffe completions on a structure map of the Ratcliffe. The reservoir parameters were calibrated by finite-difference black-oil simulation of eight Ratcliffe completions in the North Sioux Pass Field. Late-time production performance and ultimate recovery were the primary objectives of the computer simulations. The primary calibration parameter is compressibility which is used for calculation of contacted pore volume and oil-in-place. The system compressibility (C_t) which most frequently matched pore volume calculations from type-curve analysis and computer simulation was determined to be 1.67E-6 vol/vol/kPa (11.5E-6 vol/vol/psi). Oil PVT data from the Iversen No. 2-2 (Sec. 2, T.25N., R.58E.), South Otis Creek Field, were used for the computer simulations and production type-curve analyses. Water saturations of about 50 percent produced results which matched reported water production. The majority of Ratcliffe completions have a water-oil ratio of nearly one over the producing life. All wells were analyzed using the same values for pore-feet, water saturation, and pressure conditions. Projected recoverable reserves were extrapolated to an economic limit of 1.3 m^3 oil per day (8 bopd).

Reserves and Economics

Volumetric analysis indicates there is potential for sufficient oil-in-place to achieve economical drilling for the Ratcliffe in the study area. Using reservoir parameters of 5.5 m (18 ft) for net pay thickness, 9 percent for matrix porosity, 50 percent for water saturation and an oil volume factor (Bo) of 1.282, the average oil-in-place is calculated to be 1925 m^3/ha (4900 stock-tank barrels per acre). The average recovery factor from contacted drainage is indicated to be 13 percent for the 55 wells in the production study as shown in table 1. Potential recoverable oil is calculated at 250 m^3/ha (637 stock-tank barrels per acre) using this recovery factor. In a 129-ha (320-acre) spacing unit, the potential recoverable reserves are therefore calculated to be 32,400 m^3 (203,800 bbl). The Ratcliffe can be an economical, single-zone drilling target if the risked reserves are greater than 25,438 m^3 (160,000 bbl) and completed-well costs are less than $900,000 with an oil price of $18.00 per barrel.

Hypothetical, unrisked drilling economics are shown in table 2 for three representative fields in the study area. Nohly Field demonstrates sufficient reserves and rate to justify drilling. Cattails Field demonstrates sufficient reserves and rate to be marginally economic. However, the average Ratcliffe does not develop sufficient reserves in the North Sioux Pass area to justify drilling. Only 40 percent of the Ratcliffe completions in the production study area shown in figure 28 have projected ultimate recoveries greater than 25,438 m^3 (160,000 bbl).

Stimulation by Proppant Fracturing

Stimulation is normally required to successfully complete a well in the Ratcliffe (Woo and Cramer 1984). Low efficiency slick-oil and gelled-water treatments were unsuccessfully applied to Madison reservoirs during the 1950's and 1960's. In the 1970's, acid systems using 15% and 28% hydrochloric acid were more successfully applied. The moderately high reservoir temperature of 104-118°C (220-245°F) and other factors prevent deep penetration in the formation. Since the reservoir rock is highly soluble in hydrochloric acid, at these reservoir temperatures the chemical reaction is complete in seconds and rock removal is limited to a few feet from the wellbore. A high initial production rate was followed by a rapid decline after large acidizing treatments. During the 1980's, many previously pad-acidized wells were proppant fractured with a cross-linked guar system. High fluid leakoff was determined to be an obstacle to successful treatments where the main source of fluid loss was identified as secondary fracture systems that open adjacent to the induced fracture. Significant advances were made in designing proppant-fracture systems with fluid-loss control during this decade. Fluid-loss control systems were developed using mixtures of silica flour and 100-mesh sand or oil-soluble resin and 100-mesh sand. The large majority of the proppant used was 20/40 mesh Ottawa sand in concentrations up to 0.72 kg/l (6 lb per gal). Treating rates were normally 6.4 m^3 (40 bbl) per minute. Typical treatments consisting 454 m^3 (120,000 gal) and 99,800 kg (220,000 lb) 20/40 sand were reported (Cramer 1984) to have fracture heights from 16.8 to 33.5 m (55 to 110 ft) and computer-modeled fracture lengths from 169 to 395 m (555 to 1297 ft).

Production response to modern hydraulic-fracture techniques is quite good. Increases of production rates immediately after fracture stimulation can be over 300 percent with stabilized rates increasing an average of 66 percent. The typical increase in ultimate recovery is 136 percent.

Production rates from 9 wells (with prolonged post-completion pump testing prior to fracture treatment) were evaluated in 1984 for pre-frac and post-frac performance of the Ratcliffe at Glass Bluff Field in North Dakota (Cramer 1984). This study concluded that the average oil production rate increased by 330 percent after retreating with proppant-fracture systems. Of 31 wells included in the study, there were three wells which did not experience a positive response to proppant fracturing. The study did not make estimates of ultimate reserves before or after stimulation treatments.

A production study was made for this report to evaluate the long-term production response after proppant-fracturing. The study evaluated production data from 17 Ratcliffe and Ratcliffe with upper Mission Canyon completions which were completed by fracture stimulation from 1983 through 1985. The average treatment used 98,430 kg (217,000 lb) of 20/40 proppant. These wells are in fields mostly in Richland Co., MT along the Montana-North Dakota border from T.23N. to T.27N. and R.57E. to R.60E. The wells were selected based on having from 6 months to 18 months of pumping data prior to re-stimulation with a proppant-fracture system. Production type-curve analysis after the method of Fetkovich was used to estimate stabilized production rates, reserves and productivity.

The projected ultimate reserves from these wells prior to re-stimulation are estimated at a median recovery of 11,450 m^3 (72,000 bbl) per well. After re-stimulation with proppant-fracture systems, the ultimate reserves are projected at a median recovery of 27,030 m^3 (170,000 bbl) per well. While production increases immediately after stimulation of up to 200 percent are observed, the increase in stabilized productivity is determined to average 66 percent over pre-fracture trends. Pre-fracture stabilized rates average 7.3 m^3 oil per day (46 bopd), while post-fracture stabilized rates average 11.4 m^3 oil per day (72 bopd). Of the 17 wells, 3 wells exhibited no improvement in stabilized long-term production trends or ultimate reserves.

Reservoir Fluids

At formation depth and temperature in the study area, Ratcliffe reservoirs are initially under-saturated systems and exhibit black-oil characteristics. The Ratcliffe produces a paraffinic, slightly sour crude oil with a density of 0.85-0.88 gm/cc (30° to 35° API) and contains associated gas with a specific gravity of nearly 1.0 with a heating value of about 1400 BTU/ft^3. Produced gas-oil ratios in the area vary from 53 to 107 m^3/m^3 (300 to 600 scf/bbl). Water produced from the Ratcliffe is saturated brine with total dissolved solids in excess of 300,000 mg/l. An oil sample was obtained for PVT analysis from the Iversen No. 2-2 (section 2, T. 25 N., R. 58 E.) and a summary of results is shown in table 3 and also in figure 29. The recombined sample is based on a solution-gas content of 88 m^3/m^3 (495 scf/stb) at a reservoir temperature of 102°C (215°F) which results in a bubble-point pressure of 13,670 kPa (1983 psi). Viscosity ranges from 6.5E-4 Pa•s (0.65 cp) at bubble-point pressure to 7.9E-4 Pa•s (0.79 cp) at initial conditions. The original reservoir pressure in the area is about 28,270 kPa (4100 psi) with a maximum of 31,030 kPa (4500 psi).

Porosity and Permeability

Data from four Ratcliffe cores indicate permeability has a geometric mean of 2.2E-4 μm^2 (0.22 md) with a range from 5.9E-5 to 7.6E-4 μm^2 (0.06 to 0.77 md) at one standard deviation. Porosity ranges from 3.0 to 12.8 percent with a mean of 9.3 percent. Vertical fractures with fluorescence in pay intervals are frequently observed in cores. Density-neutron porosity logs from 22 wells were analyzed in the Ratcliffe interval and it was found that net-pay thickness from logs has a mean of 5.5 m (18 ft) with a range from 2.7 to 8.5 m (9 to 28 ft) at one standard deviation. Porosity-thickness ranged from 24 to 76 percent-m (78 to 250 percent-feet) with a mean value of 50 percent-m (164 percent-feet). Calculated water saturations are usually about 50 percent in productive intervals.

Log calculations from the Ratcliffe interval at the Federal 1-17R well (Sec. 17, T.26N., R.58E.) North Sioux Pass Field indicate a total productive thickness of 4.6 m (15 ft) with average porosity of 8.8 percent and water saturation of 45.8 percent within the gross interval from 2684 to 2703 m (8806 to 8868 ft). The apparent oil-in place is 1701 m^3/ha (4330 stb per acre). The petrophysical properties of the Ratcliffe in the Federal 1-17R are similar to other wells in the North Sioux Pass Field. A comparison of petrophysical properties of the Ratcliffe at Cattails Field and the Federal 1-17R is provided in table 4 and also shown on figure 30. At Cattails Field, apparent net pay in the thicker wells is 9.1 m (30 ft) and contains 2531 m^3/ha (6441 stb per acre). Petrophysical calculation of productive intervals utilized neutron-density logs for average porosity. Water resistivity of 0.011 Ω-m is based on a salinity of 325,000 mg/l TDS at 107°C (225°F). Porosity cut-off of 4 percent and water saturation cut-off of 80 percent were used to discriminate productive intervals.

Drill-stem tests in the Ratcliffe are generally run with a two or three-hour flow period and recoveries are usually less than 305 m (1000 ft) of oily mud-emulsion with some water. In many tests, reservoir fluid does not rise above the drill collars and fluid recovery is less than 0.5 m^3 (3 bbl). Storage and after-flow usually dominate the entire character of the shut-in pressure data. Original reservoir pressure ranges from 27,579 to 31,026 kPa (4000 to 4500 psi). Transmissibility (kh/μB) calculations average 9.0E+6 μm^3/Pa•s (30 md-ft/cp) and range from 9.0E+5 to 1.8E+7 μm^3/Pa•s (3 to 60 md-ft/cp) for tests in the study area. Analysis of drill-stem tests indicate that the Ratcliffe is frequently damaged during drilling with skin factors of 10 or more. Prospective Ratcliffe intervals are judged by the presence of oil in pipe recovery and sample chamber and also the amount of free water. Relative pressure gradients, calculated from shut-in pressure data and depth, are also used to identify better completion prospects in the Ratcliffe.

Transmissibility from post-completion, pressure-transient testing at North Sioux Pass Field is determined to be about 6.0E+6 μm^3/Pa•s (20 md-ft/cp). Permeability to liquid is about 3.9E-4 μm^2 (0.4 md) for 7.6 m (25 ft) and a viscosity of 5.0 E-4 Pa•s (0.5 cp).

Data from Demonstration Wells

The Ratcliffe member of the Charles Formation was targeted for data collection and analysis in the North Sioux Pass Field (sections 16 and 17 of T.26N., R.58E.) where production has been established in three wells. Key data consist of core and pressure-transient tests for assistance in the description of production behavior with a reservoir simulator. Three post-completion, pressure-transient tests were performed. It was found that the average transmissibility is 6.0E+6 μm^3/Pa•s (20 md-ft/cp) to total fluid which is comparable to data from drill-stem tests. An oriented core indicates the presence of fractures which are similar to those observed in core from other fields in the area. Locations of wells used for data collection and field demonstrations are shown in figure 31.

State No. 2-16. The State No. 2-16 was completed in the Ratcliffe from 2720 to 2734 m (8924 to 8969 ft) in 1982. Initial production rate was 12.7 m^3 oil and 10.2 m^3 water per day (80 bopd and 64 bwpd) after stimulation with 37.9 m^3 (10,000 gal) 15% gelled hydrochloric acid. Cumulative oil production was 3058 m^3 (108,000 bbl) as of December 1995 when the well was shut-in as uneconomical.

This well was utilized for pressure-transient testing by injection of water. Pressure data were recorded for 10 days of injection build-up and 5 days of fall-off. Following the injection test, a horizontal completion was attempted by drilling through a window in the casing. A lateral of 604 m (1980 ft) was drilled in the Ratcliffe; however, the re-entry completion did not yield commercial oil rates.

The water injection test at the State No. 2-16 allowed calculations of transmissibility and reservoir pressure. Water was injected for 10 days with a mechanical pressure gauge at 2707 m (8881 ft) above Ratcliffe perforations from 2720 to 2734 m (8924 to 8969 ft). The injection rate was 15.9 m^3 water per day (100 bwpd) and the bottomhole pressure increased from a static of 21,787 kPa to 33,233 kPa (3160 psi to 4820 psi) at the end of 10 days. The data were analyzed by an analytical and finite-difference simulator assuming a single-layer reservoir. Both methods achieved similar results. A match of the pressure data with the finite-difference simulator is shown in figure 32. The reservoir pressure at the start of the test was found to be 3200 psi. Transmissibility (kh/μB) was determined to be 6.68E+6 μm^3/Pa•s (22.2 md-ft/cp). Assuming a productive thickness of 7.6 m (25 ft) and water viscosity of 3.5E-4 Pa•s (0.35 cp), permeability to water is 3.2E-4 μm^2 (0.32 md). This measurement of dynamic permeability is in close agreement with point data from cores and confirms the low-permeability nature of Ratcliffe reservoirs. The stabilized injection rate is predicted to be 15.9 m^3 (100 bbl) water per day with a pressure of 37,900 kPa (5500 psi) at reservoir depth.

State-Pass No. 16-1. The State-Pass No. 16-1 (Sec. 16, T.26N., R.58E.) was completed in the Ratcliffe from 2694 to 2715 m (8840 to 8908 ft) in 1992. Initial production rate was 17.5 m^3 oil and 17.5 m^3 water per day (110 bopd and 110 bwpd) after hydraulic-fracture stimulation with 371 m^3 (98,000 gal) gelled water and 81,600 kg (180,000 lb) sand. Cumulative oil production was 8900 m^3 (56,000 bbl) as of March 1997 when the well was producing 4.8 m^3 oil and 4.8 m^3 water per day (30 bopd and 30 bwpd).

This well was utilized for pressure-transient testing by build-up from a pumping condition. The calculated pressure from acoustic soundings was 13,950 kPa (2023 psi) after 10 days of shut-in. The pressure was still building at a rate of 17 kPa/hr (2.5 psi/hr) and analysis of the transient pressure data indicates that the middle-time region was not reached by the end of the test. Original pressure in the Ratcliffe was measured to be 26,100 kPa (3787 psi) by drill-stem test.

The State-Pass No. 16-1 and State No. 2-16 wells are separated by about 0.40 km (0.25 mile). These wells represent typical porosity and producibility characteristics for the Ratcliffe at North Sioux Pass Field. The reservoir pressure at the State No. 2-16 well was found to be 22,100 kPa (3200 psi) while the maximum extrapolated pressure at the State-Pass 16-1 well was determined to be 18,600 kPa (2700 psi) during May 1996. The difference in reservoir pressure is probably the result of the State No. 2-16 being shut-in for 18 months prior to the pressure testing. The original reservoir pressure is interpreted to be about 28,600 kPa (4150 psi) from nearby drill-stem test data. The State-Pass No. 16-1 had a drill-stem test pressure of 26,100 kPa (3787 psi) in October 1984 which is after a cumulative withdrawal of 4290 m^3 (27,000 bbl) of oil. Shortly after the re-completion of the State-Pass No.16-1 in the Ratcliffe in 1992, the State No. 2-16 experienced a dramatic decline from previous production trends. It was inferred that the two wells were in communication from the low pressure at the State-Pass No. 16-1 and the production changes at the State No. 2-16. Material-balance calculations, aided by a finite-difference simulator, indicate that the minimum oil-in-place contacted by these two wells is 508,800 m^3 (3,200,000 bbl). Using an OOIP factor of 1689 m^3/ha (4300 stb/acre), a contacted drainage of 299 ha (740 acres) is computed. The combined cumulative oil production is about 26,200 m^3 (165,000 bbl) with a projected 7790 m^3 (49,000 bbl) remaining to be produced from the State-Pass No. 16-1. The total recovery from these two wells represents about 6.7 percent recovery of the OOIP calculated by material balance.

Trudell No. M-17. The Trudell M-17 (Sec. 17, T.26N., R.58E.) was completed in the Ratcliffe from 2652 to 2670 m (8701 to 8759 ft) in 1993. Initial production rate was 11.1 m^3 oil and 12.7 m^3 water per day (70 bopd and 80 bwpd) after hydraulic-fracture stimulation with 397 m^3 (105,000 gal) gelled water and 92,500 kg (204,000 lb) sand. Cumulative oil production was 2703 m^3 (17,000 bbl) as of July 1995.

This well was utilized for pressure-transient testing by build-up from a pumping condition at 2.7 m^3 oil and 3.2 m^3 water per day (17 bopd and 20 bwpd). The calculated pressure from acoustic soundings was 7805 kPa (1132 psi) after 14 days with pressure still increasing at 10 kPa/hr (1.5 psi/hr). Analysis of the transient pressure data indicates a maximum static reservoir pressure of 9820 kPa (1424 psi). Calculations for transmissibility indicate about 5.72E+6 $\mu m^3/Pa \cdot s$ (19 md-ft/cp). Permeability to oil is indicated to be 3.6E-4 μm^2 (0.36 md) using a net pay thickness of 7.9 m (26 ft). Original pressure in the Ratcliffe was measured by drill-stem test to be 26,300 kPa (3810 psi).

At the Trudell M-17 well, pressure data obtained by build-up test indicate a limited reservoir. The build-up data were obtained in November 1994 after the well had produced about 2230 m^3 (14,000 bbl) of oil. This indicates a contacted oil-in-place of less than 79,500 m^3 (500,000 bbl) assuming the reservoir is still above bubble-point pressure; however, PVT data indicate a bubble-point pressure of about 13,700 kPa (1980 psi). This is equivalent to a drainage area of 299 ha (116 acres) using 1689 m^3/ha (4300 stb/acre) for OOIP. If the reservoir is below the bubble-point pressure, a small drainage of about 12 ha (30 acres) is computed. Since the Ratcliffe porosity is very similarly developed across much of North Sioux Pass Field, it is concluded that the reservoir at the Trudell M-17 may be compartmentalized by faulting. The extrapolated ultimate recovery for the Trudell M-17 is only 5720 m^3 (36,000 bbl) of oil.

The well was selected as a candidate for re-entry horizontal completion because of the apparent compartmentalization. Attempts to drill a lateral failed using two drilling systems.

Federal No. 1-17R. The drilling of the Federal No. 1-17R for the deeper Red River was utilized as an opportunity for obtaining oriented core and formation micro-imaging (FMI) log of the Ratcliffe. Both the core and FMI log indicate a preferential orientation of fractures aligning northwest-southeast. The FMI indicates a primary orientation of 30° west from north. The core data indicate that fracturing has a primary orientation of 60° west from north. In addition to fracture characterization, oil-water relative permeability was measured using unsteady-state procedures from two core samples. The core plugs are representative of the Ratcliffe with porosity of 14 percent and air permeability of 0.5 md. These data were used to construct an oil-water permeability relationship for computer simulation (figure 33). The irreducible water saturation is interpreted to be 20 percent with a residual oil saturation of 30 percent. Relative permeability to oil at the initial mobile water saturation is 0.48 (referenced to air permeability). Relative permeability to water at flood-out condition is 0.29 (referenced to air permeability). Oil-water permeability relationships were adjusted to result in a producing water-oil ratio of 1.0 at 50 percent water saturation.

Field Summaries

Nohly Field. The Nohly Field is located in northeastern Richland Co., MT (figure 28) and covers approximately 10 km^2 (4.0 square miles). As of August 1994, the field was developed by nine wells with cumulative oil production of 156,000 m^3 (981,000 bbl). The extrapolated ultimate recovery (EUR) from the nine wells is estimated at 351,000 m^3 (2,210,000 bbl).

The Nohly Field consists of multiple reservoirs. The deepest reservoir is the Ordovician Red River and the shallowest is the Ratcliffe. The Ratcliffe began producing in 1984 following development of deeper horizons. The Ratcliffe produces from depths ranging from 2696 to 2745 m (8844 to 9008 ft). Typical pay thickness is 7 m (23 ft) which averages 9 percent porosity. A type-log from the Ratcliffe is shown in figure 34.

The original reservoir pressure was 30,100 kPa (4372 psi) at 2697 m (8850 ft) by drill-stem test measurement. Two cores taken in the field indicate permeability of 2.0 E-4 μm^2 (0.2

md) at the geometric mean and average porosity of 9 percent (samples greater than 4 percent). Core descriptions indicate natural fractures in the Ratcliffe interval.

The Ratcliffe oil at Nohly Field averages 0.865 gm/cc (32° API) and the produced water is saturated with 325,000 mg/l total dissolved solids. Average producing gas-oil ratio is 84 m^3/m^3 (470 scf/bbl).

Analysis of production data indicate an EUR per well of 35,600 m^3 (224,000 bbl) at the geometric mean and typical initial rate of 15.4 m^3 oil per day (97 bopd). The water-oil ratio has remained fairly constant at 0.6 over the producing life of the field. Normalized plots of average production are shown in figure 35. Production analysis using type-curves was performed to estimate effective drainage from the nine wells at Nohly and was found to average 110 ha (272 acre) per well. The maps in figure 36 show the computed drainage area for each of the Ratcliffe completions.

Structural configuration of the Nohly (Ratcliffe) Field is shown in figure 36. The figure shows structure at the top of the Ratcliffe and two isopach maps which cover important intervals below and above the Ratcliffe. The isopach maps are the base Last Charles Salt to Bakken and Greenhorn to base Last Charles Salt. The base Last Charles Salt lies just above the capping anhydrite of the Ratcliffe dolomite. The base Last Charles Salt to Bakken isopach indicates a subtle thickening toward the southwest side of the field. This map indicates the Ratcliffe was deposited in a shallow pond or depression. The Ratcliffe structure map indicates approximately 9 m (30 ft) of relief while the Greenhorn to base Last Charles Salt isopach indicates that nearly two-thirds of this structural growth occurred between Ratcliffe and Greenhorn time.

Cattails Field. The Cattails Field is located in northeastern Richland Co., MT (figure 28) and covers approximately 10 km^2 (4.0 square miles) in townships T.25-26N., R.59E. As of 1994, the field was developed by 12 wells with cumulative oil production of 124,000 m^3 (780,000 bbl). The extrapolated ultimate recovery (EUR) from the 12 wells is estimated at 228,000 m^3 (1,435,000 bbl).

The Cattails Field consists of a single producing horizon which is the Ratcliffe. The Ratcliffe began producing in 1987 after drilling unsuccessfully to deeper horizons. The Ratcliffe produces from depths ranging from 2720 to 2739 m (8924 to 8985 ft). Log analysis indicates typical pay thickness of 7.0 m (23 ft) which averages 9 percent porosity. A type-log from the Ratcliffe is shown in figure 37.

The original reservoir pressure was 29,180 kPa at 2697 m (4232 psi at 8850 ft) by drill-stem test measurement. A core taken in the field indicates permeability in the Ratcliffe of less than 1.0 E-4 μm^2 (0.1 md) but the main pay interval was not covered by the core. Core descriptions indicate natural fractures in the Ratcliffe interval.

The Ratcliffe oil at Cattails Field averages 0.865 gm/cc (32° API) and the produced water is saturated with 325,000 mg/l total dissolved solids. Average producing gas-oil ratio is 77 m^3/m^3 (430 scf/bbl).

Analysis of production data indicate an EUR at the geometric mean per well of 17,300 m^3 (109,000 bbl) and typical initial rate of 12.7 m^3 oil per day (80 bopd). The water-oil ratio has remained fairly constant at 0.67 over the producing life of the field. Production analysis using type-curves was performed to estimate effective drainage from the 12 wells at Cattails and was found to average 70 ha (173 acre) per well. The maps in figure 38 show the computed drainage area for each of the Ratcliffe completions.

Structural configuration of the Cattails Field is shown in figure 38. The figure shows structure at the top of the Ratcliffe and two isopach maps which cover important intervals below and above the Ratcliffe. The isopach maps are the base Last Charles Salt to Bakken and Greenhorn to base Last Charles Salt. The base Last Charles Salt lies just above the capping anhydrite of the Ratcliffe dolomite. The base Last Charles Salt to Bakken isopach indicates the Ratcliffe was not deposited on a paleo high but rather in a shallow embayment. The Ratcliffe structure map indicates that structural closure does not control production. The Greenhorn to base Last Charles Salt isopach indicates that most of the present day structure occurred between these two geological events

North Sioux Pass Field. The North Sioux Pass Field is located in northeastern Richland Co., MT (figure 28) and covers approximately 39 km^2 (15 square miles) in townships T.26N., R.57-58E. As of 1996, the Ratcliffe reservoir was developed by six wells with cumulative oil production of 79,200 m^3 (498,000 bbl). The extrapolated ultimate recovery (EUR) from the six wells is estimated at 131,200 m^3 (825,000 bbl).

The North Sioux Pass Field consists of multiple reservoirs. The deepest reservoir is the Ordovician Red River and the shallowest is the Ratcliffe. The Ratcliffe began producing in 1978 following development of deeper horizons. The Ratcliffe produces from an average depth of 2679 m (8790 ft). Log analysis indicates typical pay thickness of 3 m (10 ft) which averages 9 percent porosity. A type-log from the Ratcliffe is shown in figure 39.

The original reservoir pressure was 27,840 kPa at 2659 m (4038 psi at 8725 ft) by drill-stem test measurement. A core taken in the field indicates permeability in the Ratcliffe of 2.2 E-4 μm^2 (0.22 md) at the geometric mean and average porosity of 11 percent (samples greater than 4 percent). Core descriptions indicate natural fractures in the Ratcliffe interval.

The Ratcliffe oil at North Sioux Pass Field averages 0.865 gm/cc (32° API) and the produced water is saturated with 325,000 mg/l total dissolved solids. Average producing gas-oil ratio is 93 m^3/m^3 (520 scf/bbl).

Analysis of production data indicate an EUR at the geometric mean per well of 10,200 m^3 (64,000 bbl) and typical initial rate of 8.7 m^3 oil per day (55 bopd). Normalized plots of average production from two wells in section 16, T.26N., R.58E. are shown in figure 40. The water-oil ratio has remained fairly constant at 1.0 over the producing life of the field. Production analysis using type-curves was performed to estimate effective drainage from the six wells at North Sioux Pass and was found to average 62 ha (154 acre) per well. The maps in figure 41 show the computed drainage area for each of the Ratcliffe completions.

Structural configuration of the North Sioux Pass (Ratcliffe) Field is shown in figure 41. The figure shows structure at the top of the Ratcliffe and two isopach maps which cover important intervals below and above the Ratcliffe. The isopach maps are the base Last Charles Salt to Bakken and Greenhorn to base Last Charles Salt. The base Last Charles Salt lies just above the capping anhydrite of the Ratcliffe dolomite. The Greenhorn to base Last Charles Salt isopach indicates that much of the present day structure occurred between these two geological events and later.

Simulation of Recovery with Vertical Wells

The reservoir data obtained from wells in North Sioux Pass allow the construction of a reasonable reservoir model of the Ratcliffe for purposes of forward modeling. A single-layer, isotropic model was constructed using a thickness of 7.6 m (25 ft) with a porosity of 9 percent and water saturation of 45 percent. Effective fluid permeabilities were adjusted to match data from core and pressure-transient testing. Recoveries from a 129-ha (320-acre) model were calculated for various development situations. This model contains an OOIP of 383,500 m^3 (2,405,800 bbl) at 28,600 kPa (4150 psi).

Two wells completed in a 129-ha (320-acre) reservoir, separated by 850 m (2800 ft), are predicted to produce 25,300 m^3 (159,000 bbl) of oil after 13 years to an abandonment rate of 1.4 m^3 oil per day (9 bopd) per well. This represents a recovery factor of 6.6 percent. Final average reservoir pressure is computed to be about 11,000 kPa (1590 psi) from an original pressure of 28,600 kPa (4150 psi). The recovery predicted by the model is about half the reserves needed for economic justification of drilling two vertical wells.

Waterflooding the two-well reservoir was modeled with one well injecting 15.9 m^3 water per day (100 bwpd). A recovery of 54,200 m^3 (341,000 bbl) is predicted after 27 years for a recovery factory of 14.2 percent of OOIP. Final producing rate is computed to be 3.3 m^3 oil and 12.7 m^3 water per day (21 bopd and 80 bwpd). Of course, this model is fully contained with no injection losses and is therefore optimistic. However, the amount of recoverable oil is almost sufficient to justify drilling.

The same 129-ha (320-acre) model was used to predict recovery using four wells, two producers and two water injectors. Injection was constrained to 15.9 m^3 water per day (100 bwpd) per well as indicated from the injection test at the State No. 2-16 well. Recovery after 27 years is indicated to be 80,700 m^3 (507,800 bbl) of oil at a final rate of 3.3 m^3 oil and 28.6 m^3 water per day (21 bopd and 180 bwpd). A recovery factor of 21.1 percent of OOIP is indicated from this hypothetical model. While the recovery factor is a substantial improvement, the average recovery per well is only 20,200 m^3 (127,000 bbl) and provides insufficient economic incentive for drilling new wells.

Simulation of Recovery with Horizontal Wells

Recovery using horizontal wells was simulated with the same 129-ha (320-acre) model as described previously. Horizontal wells were represented using a narrow grid with high permeability and a length of 790 m (2600 ft). Productivity of the horizontal wells was assumed to be three times that of the vertical wells in previous models. A productivity factor of three is arbitrarily based on analogy with horizontal wells in thin-bed Red River reservoirs.

Depletion of the model with two horizontal wells is predicted to produce 55,500 m^3 (349,000 bbl) of oil after 19 years. This represents a recovery factor of 14.5 percent of OOIP and is barely sufficient for economic justification of two new horizontal wells. The final production rate from both wells is 2.5 m^3 oil and 3.5 m^3 water per day (16 bopd with 22 bwpd) at an abandonment pressure of 6300 kPa (917 psi).

Injecting 47.7 m^3 water per day (300 bwpd) into one horizontal well in the model results in a predicted recovery of 74,700 m^3 (470,000 bbl) of oil after 27 years. The ending producing rate is 2.7 m^3 oil and 45.3 m^3 water per day (17 bopd and 285 bwpd) after recovery of 19.6 percent of OOIP. This recovery is sufficient for economic justification of two new horizontal wells.

Recoveries predicted by these models are idealized using reservoir pore-thickness that is found in about one-third of the Ratcliffe wells in the area. Additionally, about half of the pore-thickness in most wells is concentrated in a more permeable layer that has a thickness of about 3.0 m (10 ft). Incremental oil recovery by waterflooding would be less than predictions made by the simple models described above.

Horizontal Completion Demonstrations

Two wells were chosen for application of re-entry slim-tool mudmotor short-radius technology. These wells are the No. 2-16 State and the M-17 Trudell. The horizontal lateral on the No. 2-16 State well was successfully drilled with a lateral section of 812 m (2667 ft) and 604 m (1982 ft) in the Ratcliffe interval. The M-17 Trudell horizontal attempt was abandoned after unsuccessful attempts to build angle for departure from the casing.

The No. 2-16 State well was originally completed in the Ratcliffe in 1982 after depletion of the deeper Red River. The original Ratcliffe completion was by perforation and acidizing with 38 m^3 (10,000 gal). Production from the Ratcliffe completion had declined to 1.9 m^3 oil and 1.6 m^3 water per day (12 bopd and 10 bwpd) by 1994 and was shut-in after a cumulative of 17,200 m^3 (108,193 bbl) oil. A pressure-transient test was performed by injecting water for 10 days prior to drilling the re-entry lateral to quantify bottomhole pressure and transmissibility. The bottomhole pressure was measured to be 21,800 kPa (3160 psi) which is 6200 kPa (900 psi) less than the original pressure. An oriented core from a well one mile west indicated natural fractures orienting northwest-southeast in the Ratcliffe. It was concluded that the presence of natural fractures and high bottomhole pressure made the No. 2-16 State well a good candidate for a lateral drain hole.

After drilling operations were completed, the well was put on pump. The well was produced for 108 days and averaged about 0.5 m^3 oil and 16.7 m^3 water per day (3 bopd and 105 bwpd). Although the No. 2-16 State well was producing significantly more fluid than from the previous vertical completion, the fluid volume was not much greater than the offset State-Pass No. 16-1 well. The State-Pass No. 16-1 well is structurally lower at the Ratcliffe than the State No. 2-16 and was producing 5.6 m^3 oil and 5.6 m^3 water per day (35 bopd and 35 bwpd) at the time. Pressure and production data indicate hydraulic communication between these two wells. The horizontal completion results from the State No. 2-16 are therefore perplexing and disappointing. There are several possible explanations for the results from the State No. 2-16 horizontal completion attempt: 1) a water-bearing fracture was encountered, 2) the wells are located in separate reservoirs, and 3) the lateral was drilled out of zone.

Conclusions

The Ratcliffe is considered a low-permeability oil reservoir and substantial stimulations are generally required for commercial production. Permeability from cores indicates a geometric mean of 2.2E-4 μm^2 (0.22 md) to air. Drill-stem tests and other pressure-transient tests indicate average fluid transmissibility of less than 9.0E+6 $\mu m^3/Pa \cdot s$ (30 md-ft/cp). Transmissibility to oil is indicated to be about 3.0E+6 $\mu m^3/Pa \cdot s$ (10 md-ft/cp) from production analysis.

Ratcliffe reservoirs are characterized by an under-saturated black-oil system. Water-cuts generally remain at about 50 percent over the life of a well. Similarly, produced gas-oil ratios remain constant and are less than 90 m^3/m^3 (500 scf/stb). The drive mechanism is characteristically fluid expansion

The effectiveness of modern hydraulic-fracture stimulation has been presented. It has been found that fracture stimulation can increase sustained productivity by 66 percent over low-volume acid treatments. Hydraulic fracturing also increases recoverable reserves an average of 130 percent.

Oil-in-place calculations from log data indicate from 1700 to 2530 m^3/ha (4330 to 6440 stb per acre) and suggest there is sufficient OOIP to justify drilling if the average recovery factor can be improved. Production analysis indicates an historical average recovery of 16,217 m^3 (102,000 bbl) per well which represents about 6 percent of OOIP in 129 ha (320 acres). For the Ratcliffe to be an economic drilling objective, ultimate reserves need to be 25,438 m^3 (160,000 bbl) or greater with a crude price of $18.00 per bbl.

Computer simulation confirms that poor recovery from Ratcliffe reservoirs is a function of low permeability. Computer models predict that vertical wells on 64.5-ha (160-acre) spacing and waterflooding could improve recovery to 21.1 percent of OOIP but would not result in an economic venture because of the great cost associated with drilling and completing wells. The drilling of horizontal wells on 64.5-ha (160-acre) spacing is predicted to be almost economically viable. If horizontal wells in the Ratcliffe can achieve three-fold productivity over vertical completions, it is concluded that two or three horizontal wells in a 259-ha (640-acre) spacing unit would have the best chance for efficient recovery and sufficient reserves to be economical.

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Table 1
Production Characteristics of Ratcliffe Completions

Field or Area	Wells	Initial Rate		Reserves		Drainage	
Cattails	13	80 bopd	12.7 m^3/D	109,000 bbl	17,300 m^3	173 acre	70 ha
Fairview	7	38 bopd	6.0 m^3/D	29,000 bbl	4,600 m^3	90 acre	36 ha
Nohly	9	97 bopd	15.4 m^3/D	224,000 bbl	35,600 m^3	272 acre	110 ha
No. Sioux Pass	11	55 bopd	8.7 m^3/D	64,000 bbl	10,200 m^3	154 acre	62 ha
Riprap Coulee	5	59 bopd	9.4 m^3/D	217,000 bbl	34,500 m^3	326 acre	132 ha
Total Study	55	67 bopd	10.7 m^3/D	102,000 bbl	16,200 m^3	186 acre	75 ha

Note: Characteristic values represent the expected case per completion. Apparent drainage area is based on net thickness of 5.5 m (18 ft), porosity of 9% and water saturation of 50%.

Table 2
Drilling Economics for Ratcliffe Fields (per average well - unrisked)

	Nohly Field		Cattails Field		No. Sioux Pass Field	
Oil Reserves	224,000 bbl	35,600 m^3	109,000 bbl	17,300 m^3	64,000 bbl	10,200 m^3
Gas Reserves	89,600 mcf	2537 Mm^3	43,600 mcf	1235 Mm^3	25,600 mcf	725 Mm^3
Oil Price	$18.00/bbl		$18.00/bbl		$18.00/bbl	
Gas Price	$1.80/mcf		$1.80/mcf		$1.80/mcf	
Operating Revenue	$3,564,288		$1,734,408		$1,018,368	
Operating Expense	$893,144		$492,416		$355,133	
Severance, Ad Val	$534,643		$260,161		$152,755	
Capital Cost	$900,000		$900,000		$900,000	
Cashflow	$1,236,501		$81,830		($389,520)	
Payout Time	2.8 years		6.4 years		None	
Profitability Index	2.37		1.09		0.57	

Table 3
Characteristics of Ratcliffe Oil

Oil Property	Customary	Metric
Oil Gravity	30° API	0.88 gm/cc
Temperature	215°F	102° C
Initial Pressure	4500 psi	31,030 kPa
Initial Viscosity	0.794 cp	7.9E-4 Pa•s
Initial Volume Factor	1.282 rb/stb	1.282
Bubble Point Pressure	1983 psi	13,670 kPa
Bubble Point Viscosity	0.649 cp	6.5E-4 Pa•s
Bubble Point Volume Factor	1.318	1.318
Solution Gas	495 scf/stb	88 m^3/m^3

Table 4
Petrophysical Properties of Ratcliffe from Electrical Logs

Property	North Sioux Pass		Cattails Field	
Productive Thickness	15 ft	4.6 m	30 ft	9.1 m
Average Porosity	8.8 %		7.1 %	
Average Water Saturation	45.8 %		49.7 %	
Hydrocarbon Thickness	0.715 ft	0.218 m	1.071 ft	0.326 m
Oil-in-Place	4300 stb/ac	1689 m^3/ha	6441 stb/ac	2531 m^3/ha

GEOPHYSICAL CHARACTERIZATIONS

Mark A. Sippel

Introduction

The study area has been successfully explored with 2D seismic for many years with a focus on oil production from the Ordovician Red River. Exploration methods for the Red River include identification of paleo structure using isochron maps which indicate thin intervals between the Red River to Greenhorn, Mission Canyon and Nisku. From the discussions presented in previous sections on geological and engineering characterizations, it is concluded that a different approach is required to seismically target reservoir development in the Mississippian Ratcliffe. Having previously concluded that fracturing is associated with better Ratcliffe reservoir development, an attempt was made to record shear-wave seismic data with a special 2D line across a Ratcliffe field. This attempt was unsuccessful. Further seismic investigations of the Ratcliffe were focussed on 3D compressional-wave data. A conventional 3D survey was recorded over a 65-km^2 (25 sq-mile) area and used to develop a methodology for targeting the Ratcliffe. Synthetic seismic models were created to show response to variation of porosity development. Conclusions were drawn for locating new drilling locations for Ratcliffe wells. These locations had not been tested at the time of this report, but are planned for the near future.

Test for Multi-Component Seismic

A 4.8-km (3-mile), 2-dimensional 3-component (2D-3C) seismic line was recorded in May 1995, using converted, compressional waves (dynamite) over the Cattails Field in Richland Co., MT (figure 42). The data were processed twice by different well-known geophysical companies. Parameters used for acquisition and recording of the Cattails were based on modeling performed by the first processor. The quality of converted-wave data was poor. Field recordings show a significant source-generated noise train that dominates the split-spread records. The converted-wave data were processed again by another processor. The second processing effort also did not yield coherent shear-wave data. It is concluded that adequate data do not exist on the processed horizontal components to evaluate applicability of converted-wave methodology for fracture detection and characterization or to measure shear-wave splitting. A thick, surface-weathering zone is a major impediment for shear-wave acquisition in the study area. A display of the compressional-wave section at the Ratcliffe is shown in figure 43. There are amplitude variations and wavelet splitting which may be related to reservoir development.

The purpose of the Cattails 2D-3C acquisition was to make use of converted shear waves, recorded on the horizontal phones (inline and crossline) to locate vertical fractures in the Ratcliffe reservoir. Three-component geophones were used to record the data. There were initially four goals of the 2D-3C acquisition:

1) locate fractures by means of effects in the shear-wave data,
2) evaluate the feasibility of recording converted waves with slightly modified P-wave acquisition,
3) determine S-wave (converted wave) quality in the area, and

4) design acquisition techniques that can be used for future surveys.

It is still not known if shear-wave data can help identify fractures in the Ratcliffe study area. Recording converted waves does not appear to be feasible or practical. Several possible problems were identified with the acquisition, and recommendations were made for future multi-component recording. However, the existence of a thick, weathered layer in the area suggests that quality shear waves would be very difficult to record.

The data were first processed in June 1995. The processing output was subsequently examined by two geophysical consultants and they recommended that the data should be re-processed by a company more experienced with mode-converted shear-wave data. The conclusions reached after the second processing are that the recorded line does not contain sufficient converted shear-wave energy to be useful. All stacks produced from inline and transverse components indicated an absence of coherent events. This can be attributed to either (or both) a lack of signal energy reaching the surface geophones or severe noise generated by the shots. This does not fully answer the question whether usable converted-wave data can be acquired in the area. Some problems with the original recording are identified and several suggestions follow that should improve any efforts to conduct future multi-component seismic acquisition.

Several possible mistakes were made during the first-round of processing. The processor lacked experience with mode-converted data. At that time, the first processing company did not have specialized software for handling noise reduction and static solutions of shear-wave (S-wave) data. In displaying the data originally, they used a vertical scale factor of 2.0 rather than 1.5. This is appropriate for pure S-wave data generated by a shear-wave source, but not for mode-converted waves that only travel upward as shear, but downward as compressional waves (P-waves). This made it more difficult to compare the S-wave section to the P-wave section.

The second processor followed a processing flow which has been successful on other data. The key to imaging shear waves is to resolve the statics. Shear waves are more affected by the degree of consolidation than P-waves, since their propagation depends on the rigidity of the rock matrix. They do not propagate at all in liquids and in very loose soil. Shear waves are greatly slowed in poorly consolidated (and fractured) rock. Because of this, S-wave statics can be from two to ten times as great as P-wave statics. For converted waves, processor 2 first resolves the P-wave statics, then uses the P-wave shot statics and double the P-wave receiver statics as a first pass S-wave static solution. The static program is then iterated, focusing on some coherent event, until convergence on the S-wave receiver static. In order for the automatic static routine to work, a reflector must be resolved sufficiently to allow correlation along the line. Eventually, the event must be associated with a corresponding P-wave reflection.

With the Cattails data, no reflection was sufficiently coherent on the S-wave section to correlate across the data (figures 44 and 45). This was the case despite the pre-processing performed to reduce noise and improve the signal (surface-consistent de-convolution and Radon transform). Because no coherent signal could be identified, there was no basis for running the static routine. At this point, processor 2 recommended that processing be discontinued.

The first-round processing of the converted-wave data produced a section that has low-frequency periodic events across the lower portion of the section. These "events" were previously correlated to P-wave events, despite lack of significant character. It is now concluded that these events may have been artificially produced by processing procedures such as auto-statics, Miser, and subsequent dip-discrimination (F-K) filter. It is possible that the first processor overworked the data until something was imaged, where the second processor, with the benefit of their experience with converted waves, recognized that there was no meaningful shear-wave signal.

The question remains whether the line was properly recorded, or whether the area simply does not allow recording converted shear-wave data. One indication that the area may be unsuitable for shear waves is a thick, weathered layer. Shot holes were drilled 120 ft deep, probably because the weathering was that thick. As stated above, shear-wave statics can be much larger than P-wave statics. An unusually thick weathered layer compounds the problem of statics, and may absorb much of the shear-wave energy. The recording and acquisition parameters for the Cattails 2D-3C data are summarized in table 5.

There are some field techniques which may improve future shear-wave data acquisition. The offsets should be longer. The Cattails acquisition used a split spread with maximum offset of 5368 ft, except on both ends of the line where they shot through the cable and the offset increased to over 10,000 ft. (However, the fold decreased because of the taper). For the depths of the Ratcliffe zone, offsets should have been at least 8000 ft for optimal mode conversion.

There was a strong noise cone, generated by the shot, that obliterated the near traces and spread with depth, covering most of the traces at target depth. A smaller charge or deeper shot holes may improve this situation.

The line was shot at 12 fold and is lower than is desirable. It is recommended that 24 to 30 fold be used for future acquisitions of this type.

Ground coupling for shear-wave phones is more critical than for P-wave data. Each horizontal phone must be leveled, with more care warranted than with vertical phones. The phones are also often buried to improve coupling. It is recommended that a consultant experienced in shear-wave recording be placed on the crew to supervise planting of geophones. Processor 2 also recommended that recording be done in winter because frozen ground couples better and minimizes the static problem for shear waves.

The initial processing of the 2D-3C data may not have been ideal; however, subsequent processing by a company with successful shear-data experience also failed to image shear waves. This leads to the conclusion that better processing of the existing data will not produce results. The existence of a thick, weathered layer in the area suggests that quality shear waves would be very difficult to record.

3D Seismic Acquisition

Subsequent to the attempt to record and process shear-wave seismic data, efforts were focussed on other seismic data which may provide indirect inference for locating favorable Ratcliffe drilling locations. In previous sections of this report there are conclusions with regard to criteria favorable for probable better Ratcliffe development. These criteria include: 1) compensating deposition in low areas results in thicker productive facies, 2) post-Ratcliffe structural movement and 3) fracturing. Most of the wells drilled in the area were targeted for deeper Red River production. Unfortunately, criteria for locating Red River wells do not appear compatible with Ratcliffe reservoir development.

A 3D-seismic survey was recorded over the North Sioux Pass Field in Richland Co., MT during December 1996. The survey covered approximately 65 km^2 (25 sq-miles). The receiver and shot-line spacings were 402 m (1320 ft). The energy source was 2.3 kg (5 lb) of dynamite placed in shot holes drilled to 18 m (60 ft). The nominal fold ranges from 15 to 20. The data were recorded by Geco-Prakla using an I/O System 2 recording unit. Processing was performed by Tricon Geophysical. Recording parameters and statistics for the North Sioux Pass 3D seismic survey are summarized in table 6. An example seismic section from the 3D survey is shown in figure 46. The Ratcliffe occurs at about 1.900 seconds at the crest of the North Sioux Pass Field.

Following the observations and conclusions made in the sections covering geological and engineering characterizations of the Ratcliffe, seismic events corresponding to the Greenhorn, Ratcliffe and Bakken were picked and mapped. Summaries of the seismically enhanced mapping of these horizons and intervals follow.

Ratcliffe to Bakken Isopach

The Ratcliffe to Bakken isopach was computed from seismic interval time and velocity trends from well-data formation tops (figure 47). This isopach map shows details which are not possible from electrical-log data alone. The map shows an amorphous collection of thick and thin areas which represent lows and highs during Mississippian deposition. The prevailing trend of these thick and thin areas is nearly northeast-southwest. The thicker areas on this map are likely to contain thicker Ratcliffe facies. This is the first map for selecting areas favorable for better Ratcliffe development.

The interval from the Ratcliffe to the Bakken can be used to identify areas which were probably low prior to and during Ratcliffe deposition. The Bakken Formation was deposited at the end of Devonian and beginning of Mississippian time. Thick areas from this isopach correlate very well with better Ratcliffe completions found at Nohly and Cattails Fields. Other investigators have made similar conclusions at other Ratcliffe fields in Montana and North Dakota (Longman and Schmidtman 1985; Hendricks 1988).

Greenhorn to Ratcliffe Isopach

The second interval map for screening of Ratcliffe potential is the Cretaceous Greenhorn to Ratcliffe isopach. The map shown in figure 48 was constructed from seismic data and well-data formation tops as discussed for the previous map. Thin areas on this map represent positive structural movement occurring after Ratcliffe deposition. It is interpreted from this map that a strong northwest-southeast trending structure developed during the period between Ratcliffe and Greenhorn deposition. This structural growth was dominated by a regional uplifting to the northwest.

Overlaying the Greenhorn-Ratcliffe and Ratcliffe-Bakken isopach maps is the next step in targeting areas which have favorable conditions for better Ratcliffe development. Divergent trends of contours are interpreted to indicate a change in location of tectonic stress. Areas of structural movement after Ratcliffe time which were low before Ratcliffe time are thought to be most likely fractured, especially those which are normal to basement lineaments trending regionally northwest-southeast.

Ratcliffe Structure

A computed Ratcliffe structure map is shown in figure 49. It was constructed from seismic time and integrated with velocity trends from well-log formation tops. The map shows a large structural platform trending northwest-southeast. Ratcliffe production on the North Sioux Pass Field has been from recompletions in wells which produced previously from the deeper Red River. These wells are located on the northeast and southeast hinge lines of the platform and are also shown on figure 49. Structural nosing and areas of steep dip are thought to be prone to fracturing. The Ratcliffe structure with the Ratcliffe to Bakken isopach can be used to identify positive present-day structure with thick deposition during Ratcliffe time.

Seismic Modeling

Synthetic seismograms were constructed from sonic and density log data with modifications to show minimum and maximum porosity development within the two Ratcliffe porosity zones (Alexander and Flat Lake intervals) present in the area. Figure 50 shows type logs of Ratcliffe development in the Alexander and Flat Lake intervals. Logs from wells in the area do not indicate simultaneous development of thick porosity in the Flat Lake and Alexander intervals. Models were constructed with a zero-phase, band-pass filter using frequencies of 10/12 - 60/70 Hz. Examples of the models with normal polarity are shown in figure 51. The modeling shows that seismic response to porosity variation within the 26-m (85-ft) Ratcliffe interval produces variation in one trough and one peak event. With normal polarity, the absolute value of trough amplitude increases with increasing porosity for both the Flat Lake and Alexander porosity benches (either individually or in combination). The underlying peak event also increases in amplitude with porosity development in the Ratcliffe. Increasing amplitude of the underlying peak is most notable when the lower-porosity zone (Alexander interval) is well developed.

Amplitude Mapping

At North Sioux Pass Field, the Ratcliffe develops the greatest porosity in the upper or Flat Lake interval. It is concluded that amplitude of the seismic-trough event correlates with porosity development at North Sioux Pass Field. A map of relative amplitude from the Ratcliffe trough event overlain on the Ratcliffe depth structure is shown in figure 52. This attribute appears to correlate with the geologic model for favorable Ratcliffe development. Across much of the North Sioux Pass Field the Ratcliffe trough amplitude is better developed on the northeast and southwest flanks of the platform. The coincidence of greater amplitude on the flanks of the North Sioux Pass platform is encouraging because it is consistent with observations at several larger Ratcliffe fields where better reservoir is preferentially developed on the flanks and not on crestal areas. Amplitude variation is very subtle, however. It appears that this attribute should be used as a final indication of better reservoir development within prospect areas delineated from isopach and lineament mapping.

Targeting Ratcliffe Drilling Locations

To demonstrate the methodology for targeting areas which are thought most prospective for Ratcliffe development, two prospects are described in the North Sioux Pass Field. These prospect areas are in sections 7 and 15 of T.26N., R.58E. and are shown in figures 53, 54 and 55. Both of these prospect areas have indications of Ratcliffe oil accumulations from nearby wells.

Prospect 1, located in section 15, is adjacent to Ratcliffe production established by two wells in section 16 which has been described in the section covering engineering characterizations of the Ratcliffe. These engineering characterizations suggest a large Ratcliffe reservoir has been contacted by the wells in section 16. Prospect 2, located in section 7, has a well which had relatively high pressure recorded by drill-stem test in the Ratcliffe. High-pressure gradients are indications of better production in the Ratcliffe.

Figure 53 shows the Ratcliffe trough amplitude overlain on the Ratcliffe to Bakken isopach. Each prospect area is associated with a thickening of the Ratcliffe to Bakken interval. The thick areas represented on this isopach are thought to most likely have thicker productive facies in the Ratcliffe because of compensating deposition. Geological characterizations at nearby Cattails and Nohly fields indicate a correlation of better reserves with a thick isopach of the Ratcliffe to Bakken interval.

Also shown on the map in figure 53 are two postulated lineaments which bound the thick areas. These lineaments may be scissor-like slip or wrench faults. These lineaments run northeast-southwest which is normal to the regional trends of basement lineaments. A strong response of the Ratcliffe trough amplitude is coincident with the Ratcliffe to Bakken isopach and is interpreted to indicate increased porosity development in thicker deposition of Ratcliffe sediments.

The Greenhorn to Ratcliffe isopach map is shown in figure 54 and is overlain with the Ratcliffe trough amplitude. The previously described lineaments associated with the Ratcliffe to Bakken isopach map are also shown. The contours suggest that these lineaments have undergone a reversal of movement during the time represented by this isopach. The lows areas during deposition of the Ratcliffe were uplifted after Ratcliffe time. The reversal of Ratcliffe to Bakken and Greenhorn to Ratcliffe isopach intervals is demonstrated at the Cattails and Nohly fields. It is thought that areas most likely to be fractured are adjacent to blocks with recurrent and reversal of movement. The greatest amplitude response of the Ratcliffe trough is coincident with areas adjacent to the interpreted lineaments.

The Ratcliffe structure map is shown in figure 55. Also overlain on the contours is the Ratcliffe trough amplitude. The map shows that the prospect areas are located with favorable amplitude response and are also associated with positive structural position.

Prospect 1, in section 15, would be best evaluated by a new well with a vertical hole drilled through the Ratcliffe interval. The Ratcliffe should be drill-stem tested and logged before a plugback and drilling laterally through Ratcliffe porosity. A formation micro-imaging log should be considered to help determine if there is a preferential fracture orientation which would guide the direction of the horizontal hole. Prospect 2, in section 7, would be best evaluated by a re-entry horizontal from the existing wellbore in the SESE quarter-quarter of section 7. The horizontal leg would be nearly flat and oriented due west toward the dry hole in the southwest quarter of section 7. The horizontal lateral would penetrate through the amplitude anomaly in the south-half of section 7. The stratigraphic and structural position of Ratcliffe porosity should be nearly constant across the traverse of the lateral as indicated by the well-log and seismic data.

Conclusions

It is concluded that oil accumulations in the Ratcliffe are developed as low-permeability reservoirs which do not require structural closure. Productive Ratcliffe intervals appear developed across large areas of the study area but average reserves from hydraulically fractured vertical completions have been insufficient to justify drilling new wells. Information from 3D seismic may be able to target better Ratcliffe development which would increase the probability of greater oil reserves. Primary factors controlling development of Ratcliffe reservoirs are dolomitization of certain facies and fracturing. Targeting the most prospective areas for Ratcliffe reserves involves integration of a multi-step process. This process first involves identification of areas which were most likely to have thicker Ratcliffe deposition through mapping the Ratcliffe to Bakken interval. The next step in the process is identification of areas which were uplifted after Ratcliffe time, as indicated from isopach mapping of the Greenhorn to Ratcliffe interval. Divergent trends of contours of these two maps are interpreted to indicate a change in location and direction of tectonic stress. Seismic modeling work indicates that increasing porosity development in the Ratcliffe is expressed as an observable amplitude change. However, the variation of amplitude is subtle and should be used only as a guide after targeting from isopach and structure mapping. Two locations for drilling are proposed from this work and have been shown as examples of targeting the Ratcliffe using seismic characterizations.

References

Hendricks, Michael L. 1988. "Shallowing-upward Cyclic Carbonate Reservoirs in the Lower Ratcliffe Interval (Mississippian), Williams and McKenzie Counties, North Dakota." In *Occurrence and Petrophysical Properties of Carbonate Reservoirs in the Rocky Mountain Region: Rocky Mountain Association of Geologists 1988 Guidebook*, eds. S.M. Goolsby and M.L. Longman, 371-380.

Longman, M.W. and K.H. Schmidtman. 1985. "Deposition and Diagenesis of the Mississippian Charles (Ratcliffe) Reservoir in Lustre Field, Valley County, Montana." In *Rocky Mountain Carbonate Reservoirs - A Core Workshop: SEPM Core Workshop No. 7*, eds. M.W. Longman, K.W. Shanley, H.F. Lindsay, and D.E. Eby, 265-310.

Table 5
Acquisition and Recording Parameters for Cattails 2D-3C Seismic

Recording Instruments:	DFSV	Shot Depth:	120 feet
Sample Rate:	2.0 msec	Data Channels/ Component:	120
Record Length:	6.0 msec	Group Interval:	88 ft
Format:	SEGB	Source Interval:	440 ft
Source:	dynamite	Recording Filter:	8/18 - 128/72 db per Octave
Charge Size:	10 lb	Sub-surface Coverage:	1200%

Table 6
Acquisition and Recording Parameters for North Sioux Pass 3D Seismic

Recording Instruments:	I/O System 2	Source Line Interval:	1320 feet
Sample Rate:	2.0 msec	Receiver Line Interval:	1320 feet
Record Length:	3.0 msec	Group Interval:	220 ft
Format:	SEGB	Source Interval:	220 ft
Source:	dynamite	Recording Filter:	12 - 128/72 db per Octave
Charge Size:	5 lb	Surface Area:	25 sq miles
Shot Depth:	60-80 feet	Sub-surface Coverage:	1500-2000%

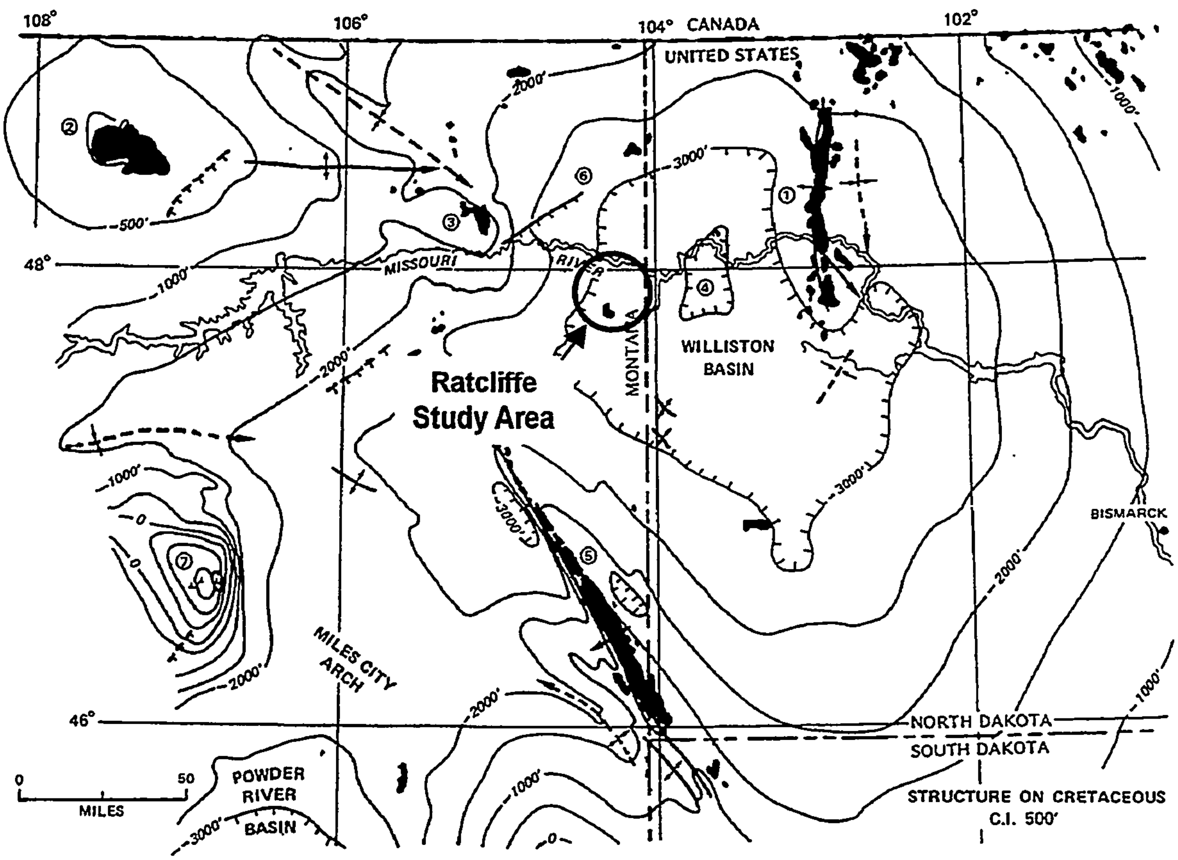


Figure 1: Map of the Williston Basin with Ratcliffe study area.

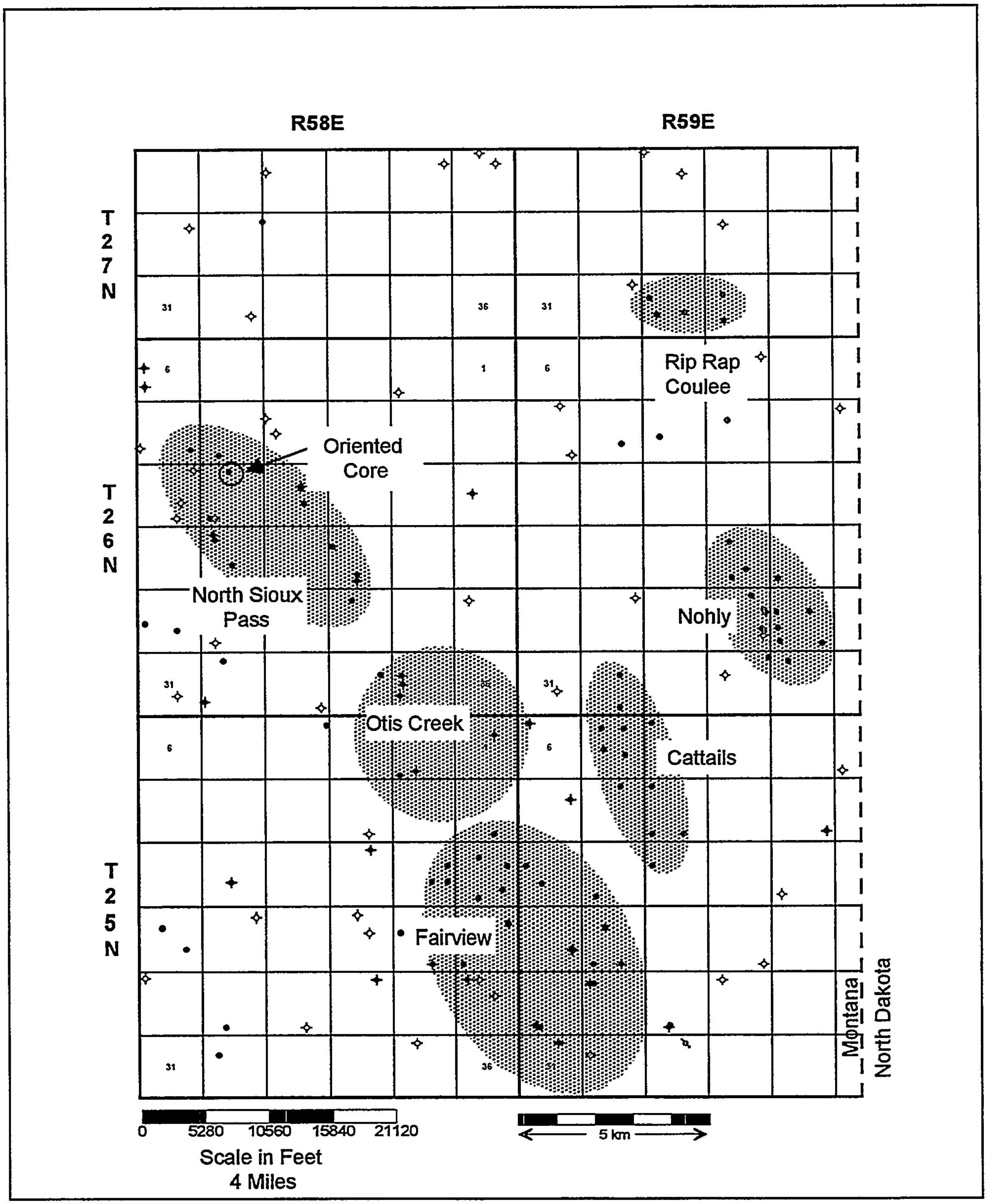


Figure 2: Map of Ratcliffe study area with fields annotated.

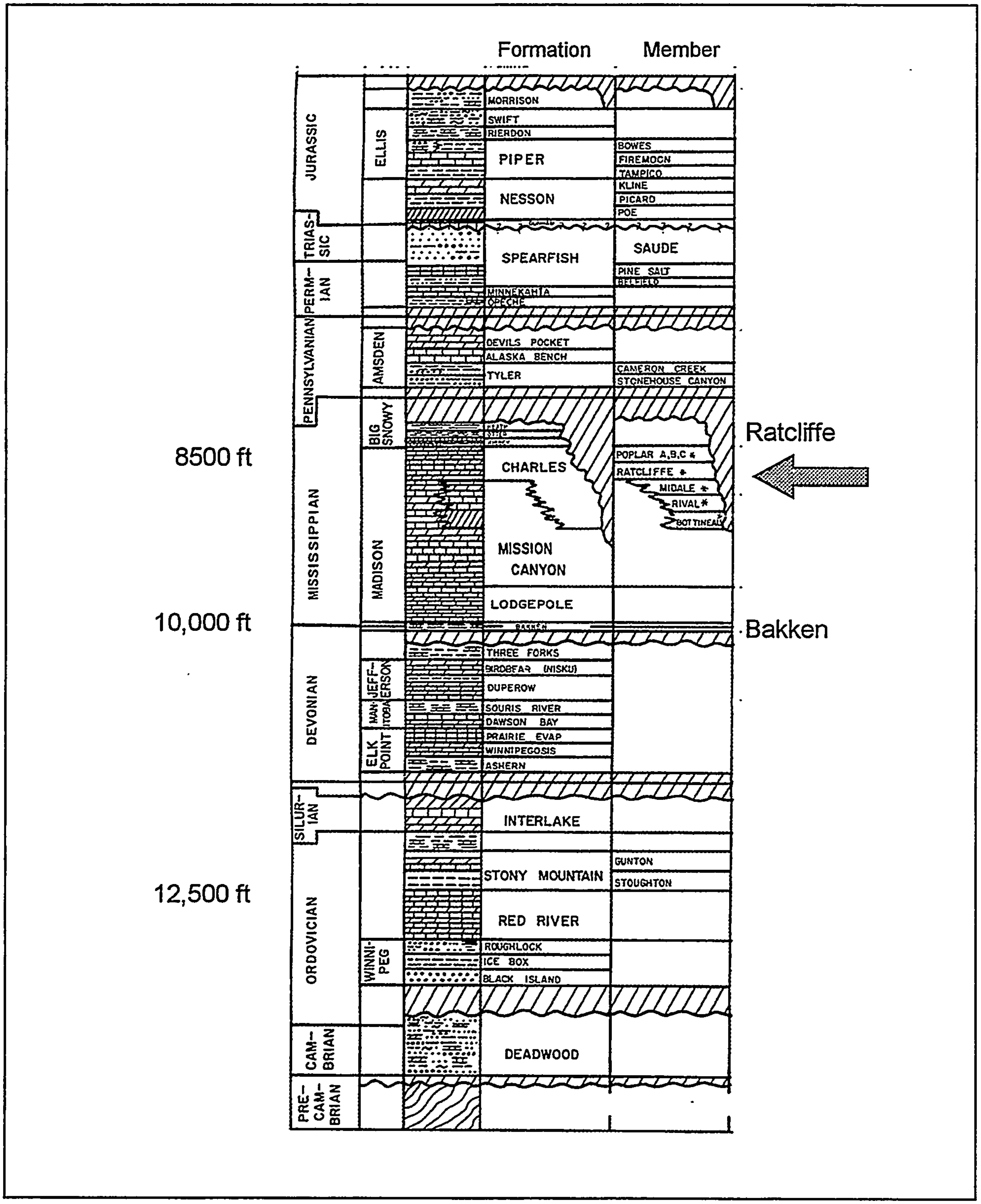


Figure 3: Stratigraphic column for the Ratcliffe study area. The Ratcliffe is a member of the Charles Formation of Mississippian age.

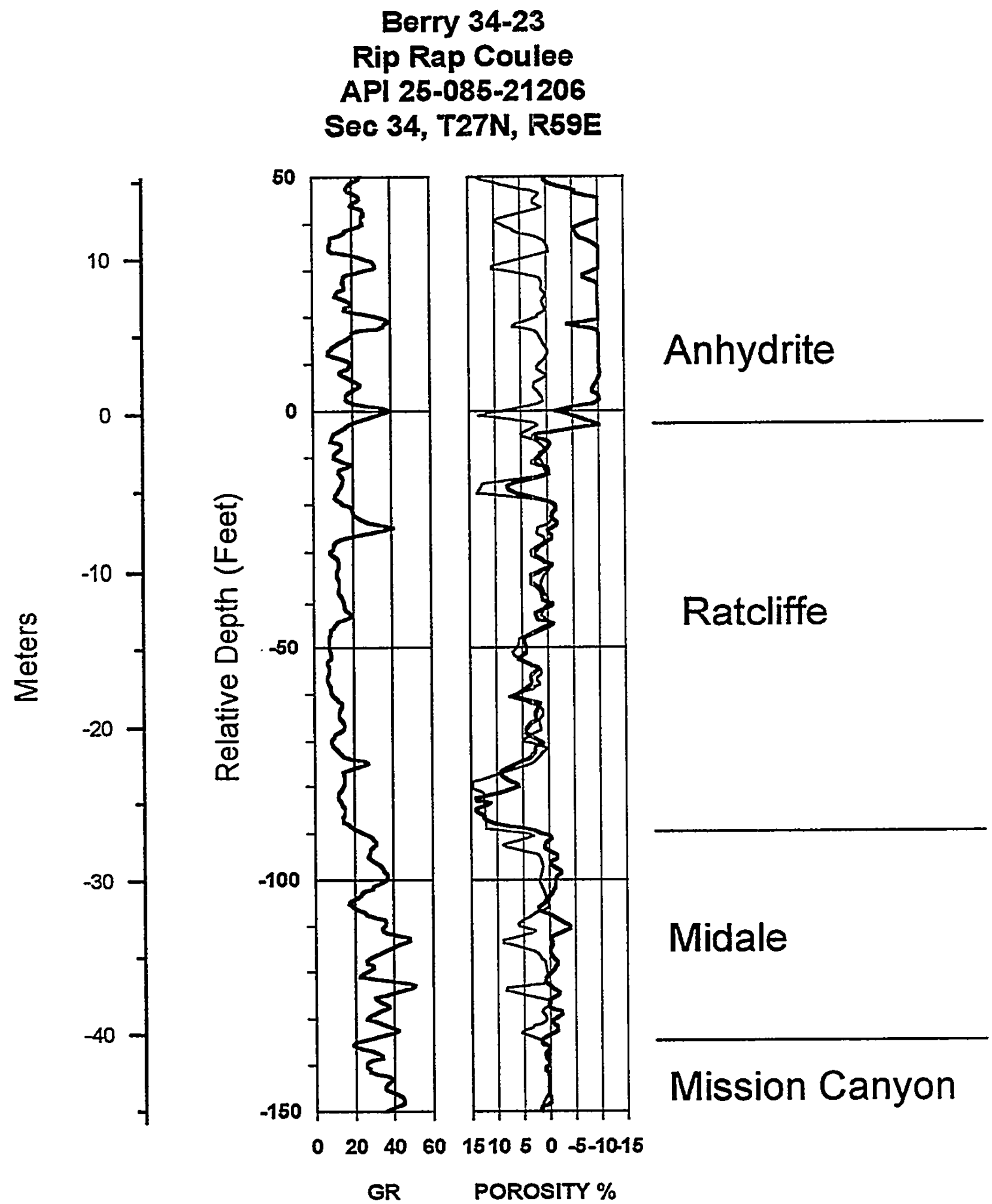


Figure 4: Type log from Rip Rap Coulee Field.

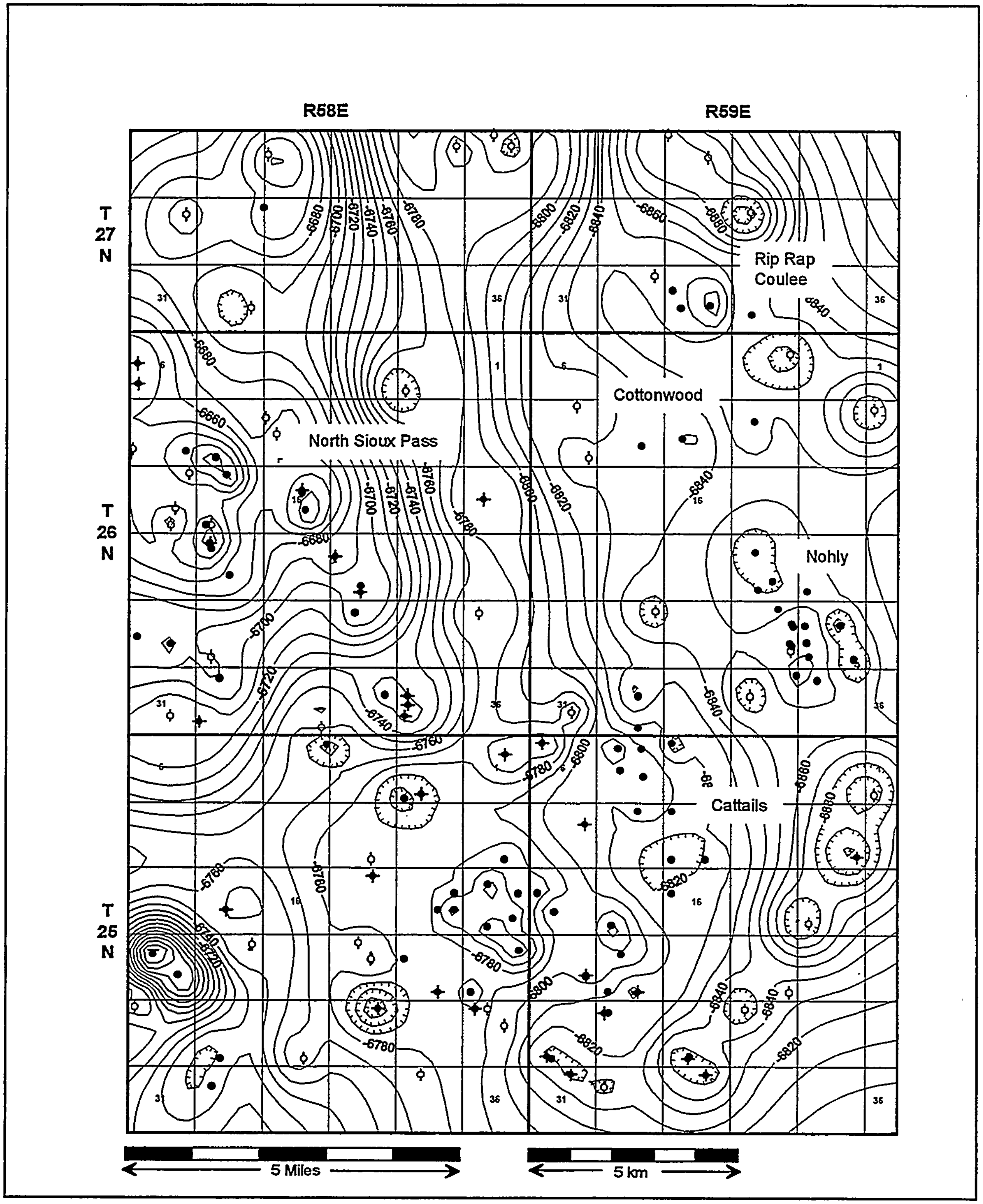


Figure 5: Structure map of Ratcliffe across study area. Present-day structural closure is subtle at several Ratcliffe fields with 10 to 20 ft maximum and is apparently not critical to reservoir development. C.I. = 10 ft.

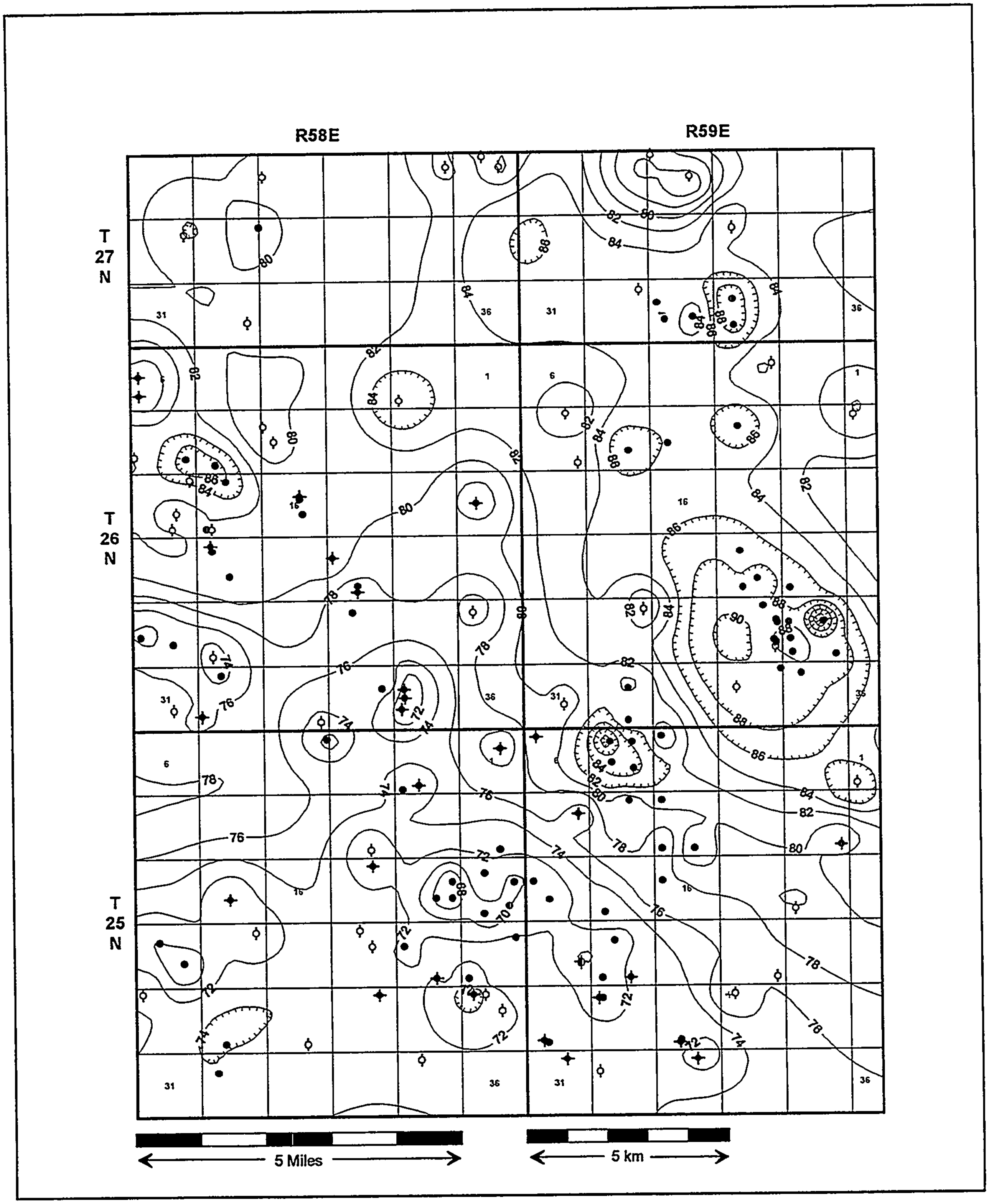


Figure 6: Isopach map of Ratcliffe interval. Hachured lines indicate thickening direction. C.I. = 2 ft.

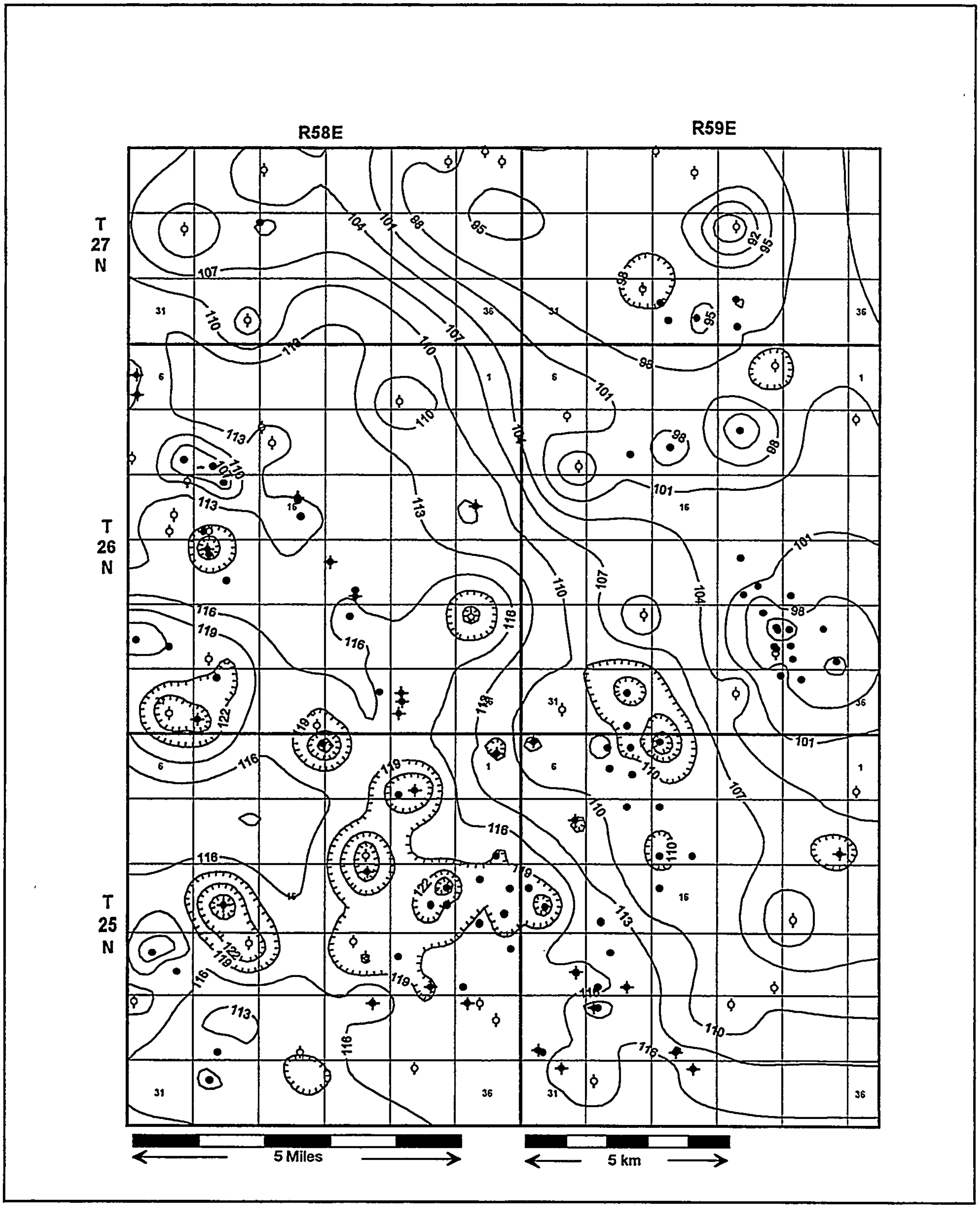


Figure 7: Isopach map of anhydrite and salt sections above Ratcliffe interval. Hachured lines indicate thickening direction. C.I. = 2 ft.

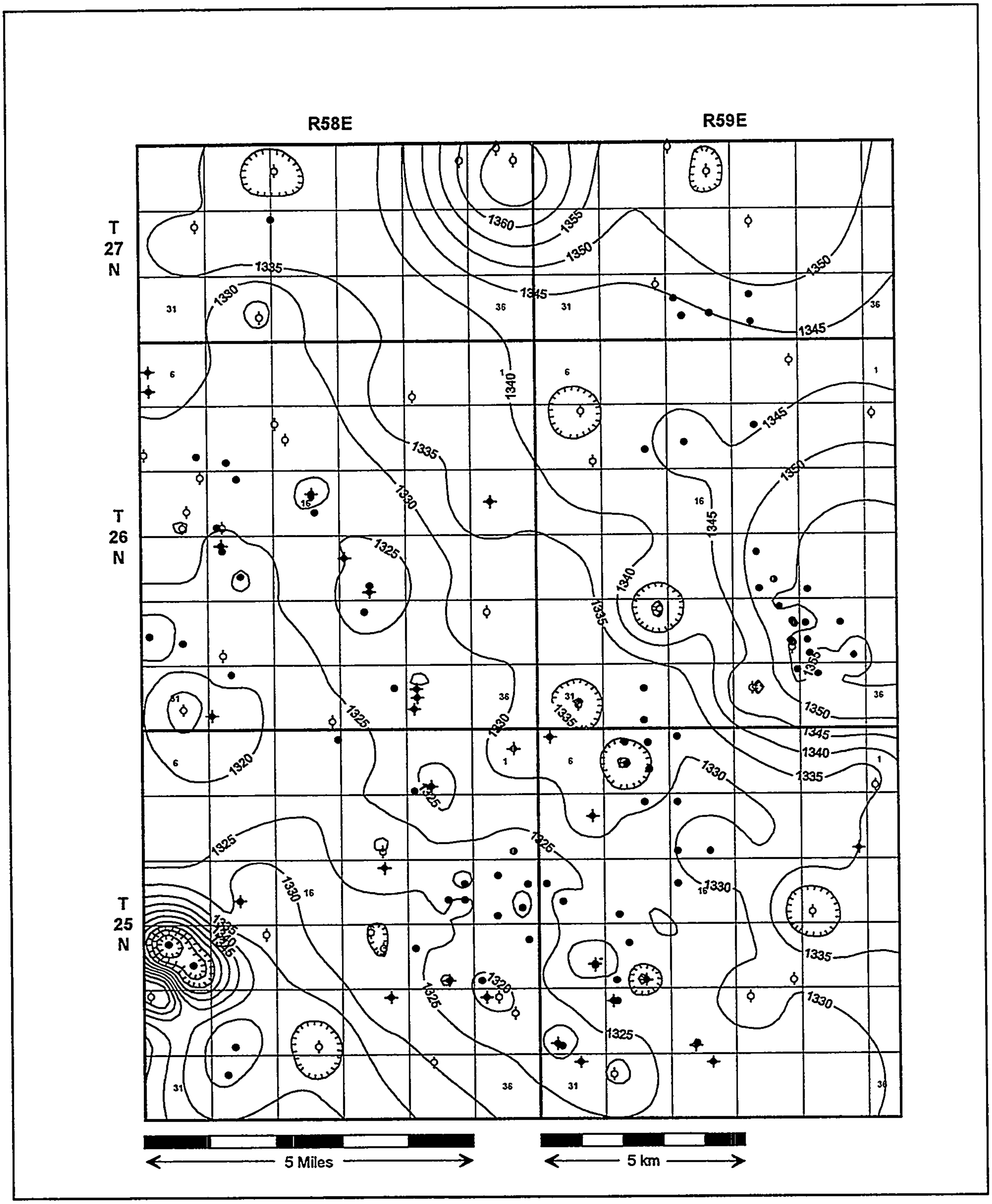


Figure 8: Isopach map of base Ratcliffe (Midale) to Bakken interval below the Ratcliffe. Isopach thicks suggest structurally low areas before Ratcliffe deposition. C.I. = 5 ft.

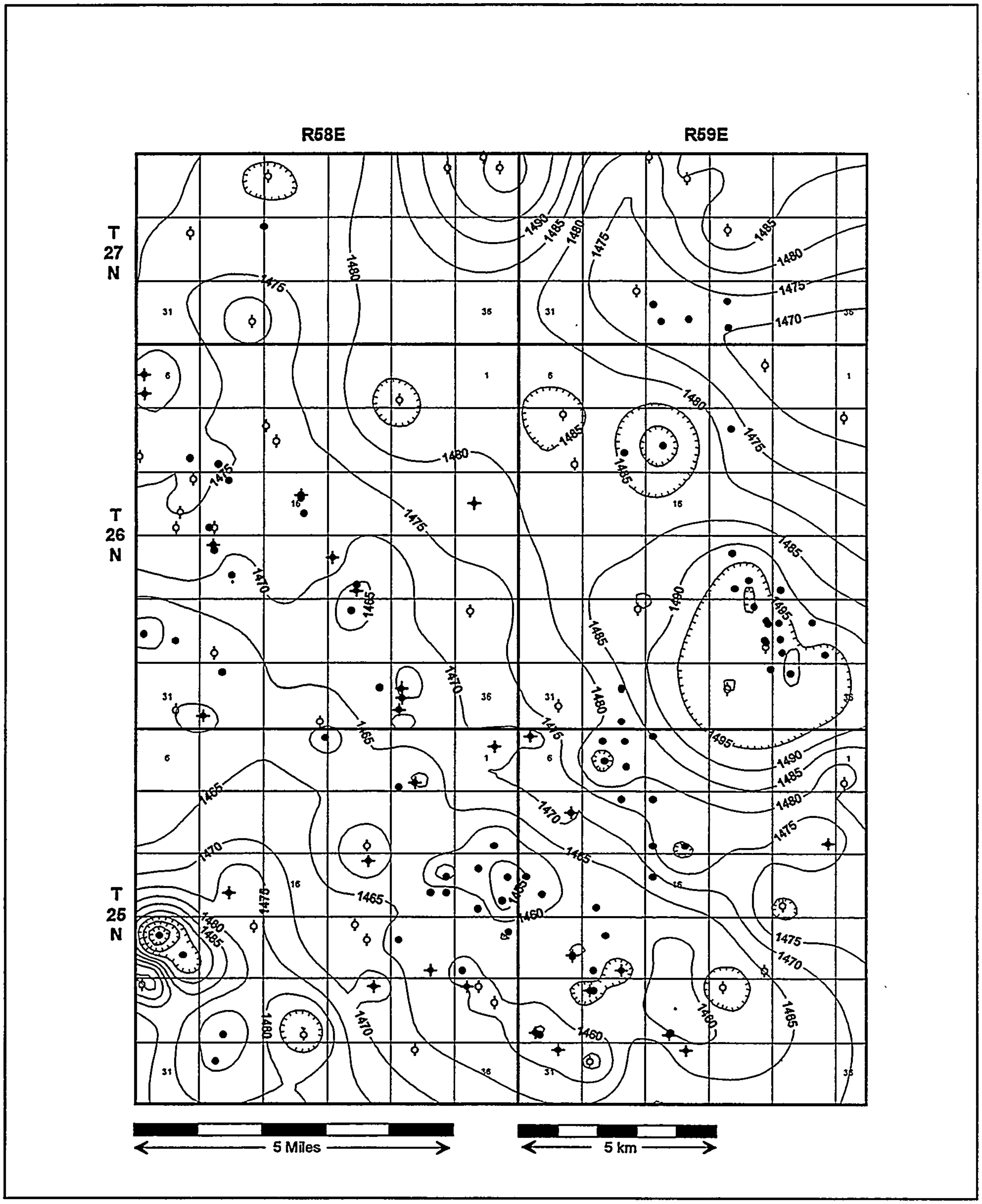


Figure 9: Isopach map of Base of Last Charles Salt to Bakken. C.I. = 5 ft.

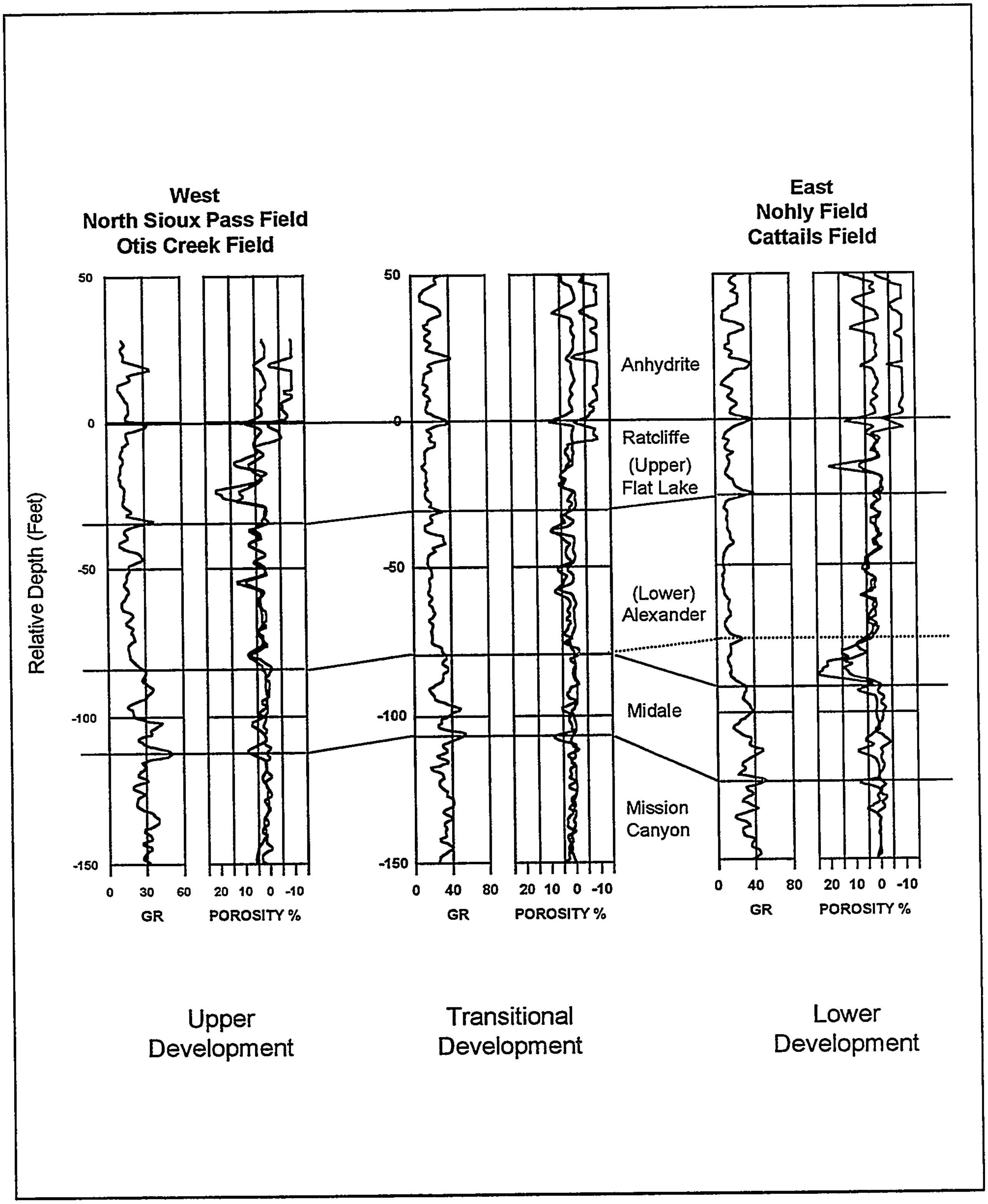


Figure 10: Cross-section of Ratcliffe type-logs showing variability of porosity development in study area.

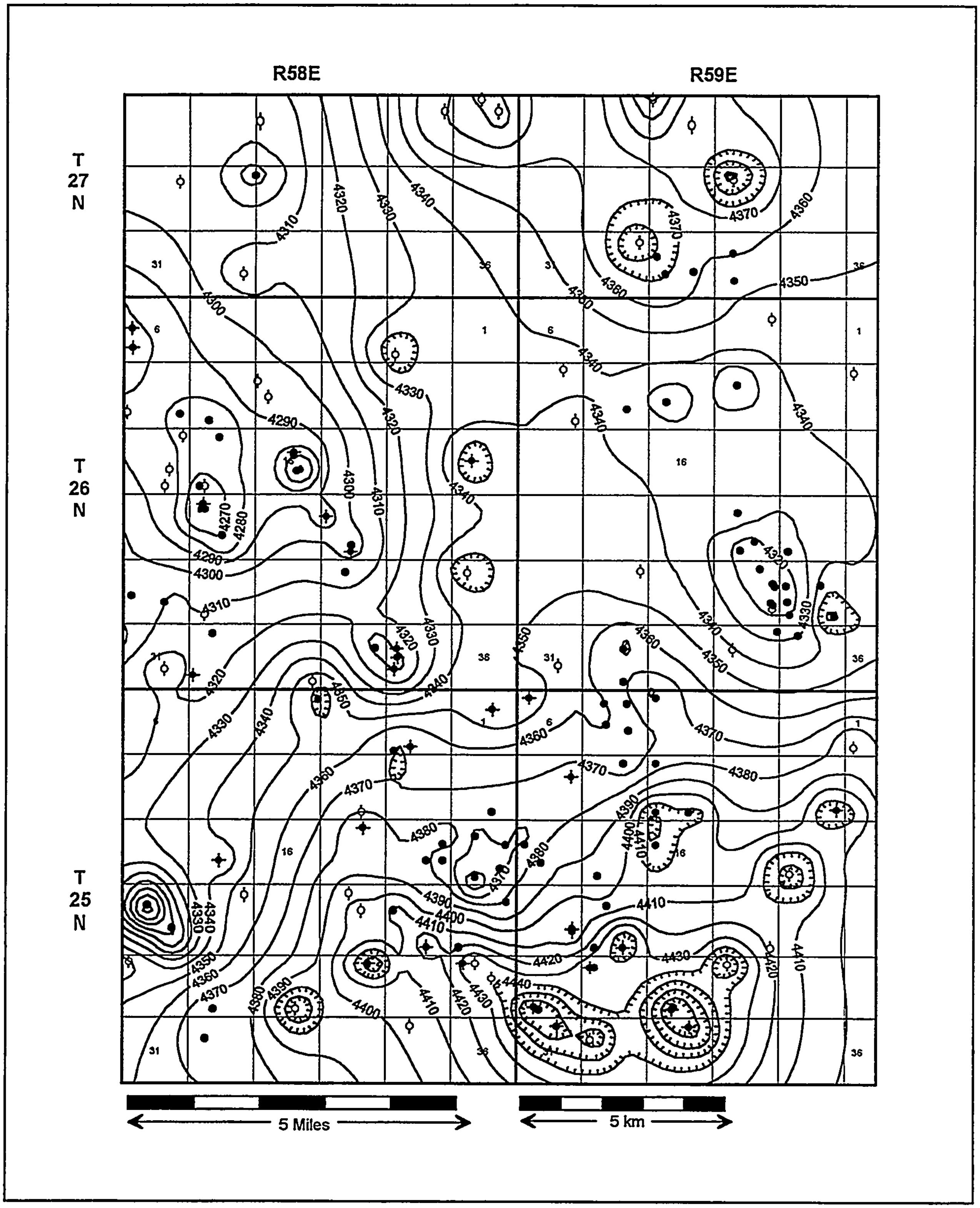


Figure 11: Isopach map of Greenhorn to Base Last Salt. C.I. = 10 ft.

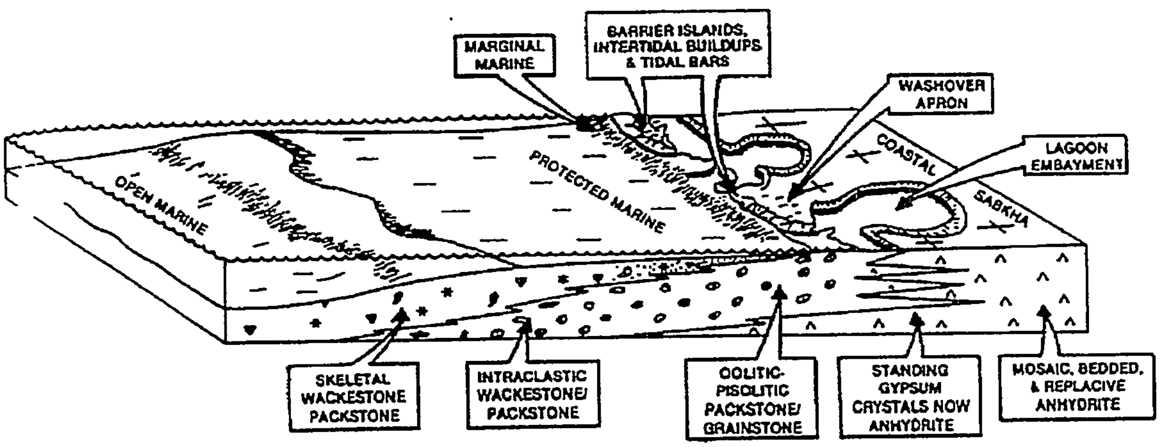


Figure 12: Block diagram of Ratcliffe depositional model.

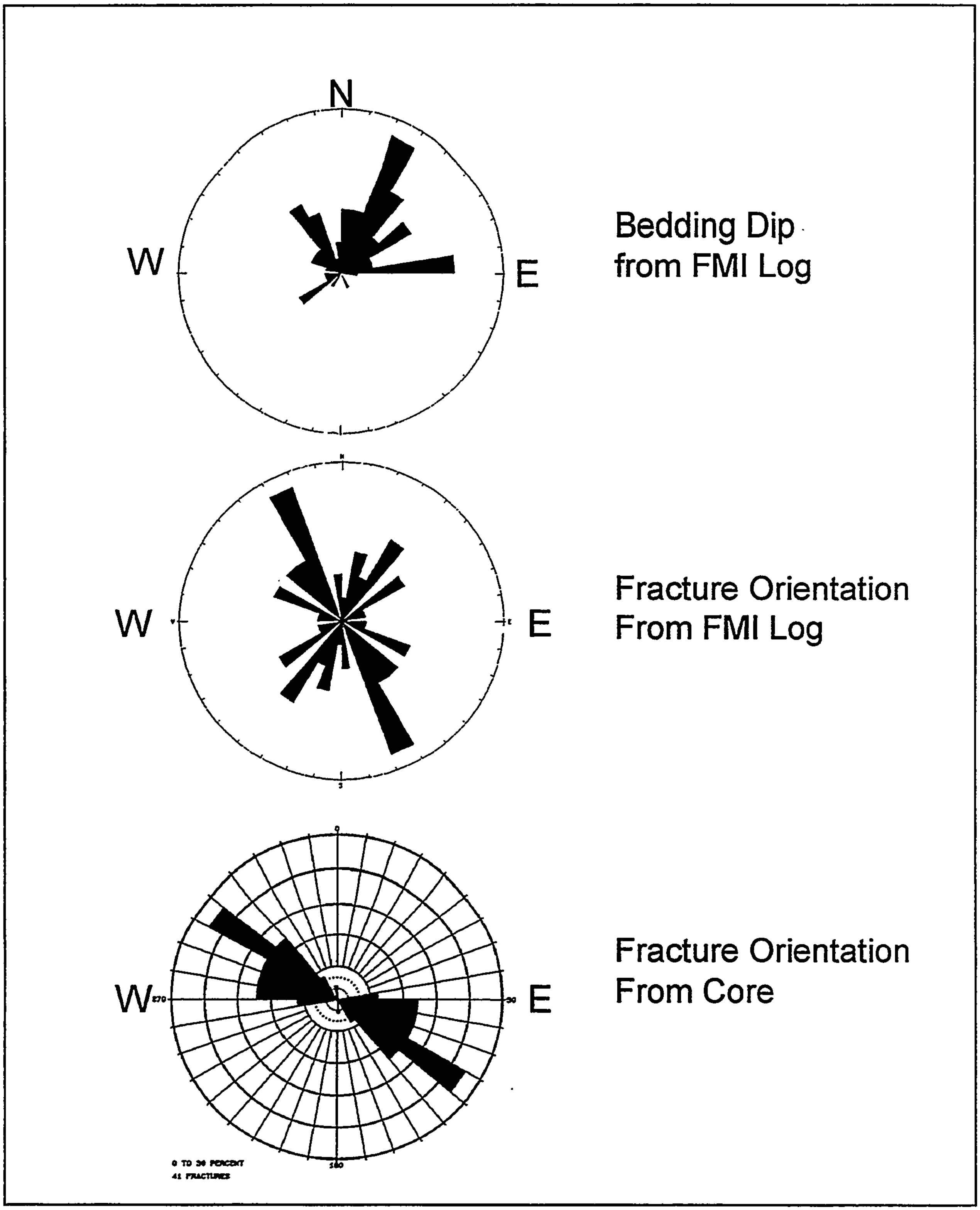


Figure 13: Fracture orientation from the Ratcliffe at the No. 1-17R Federal, North Sioux Pass Field.

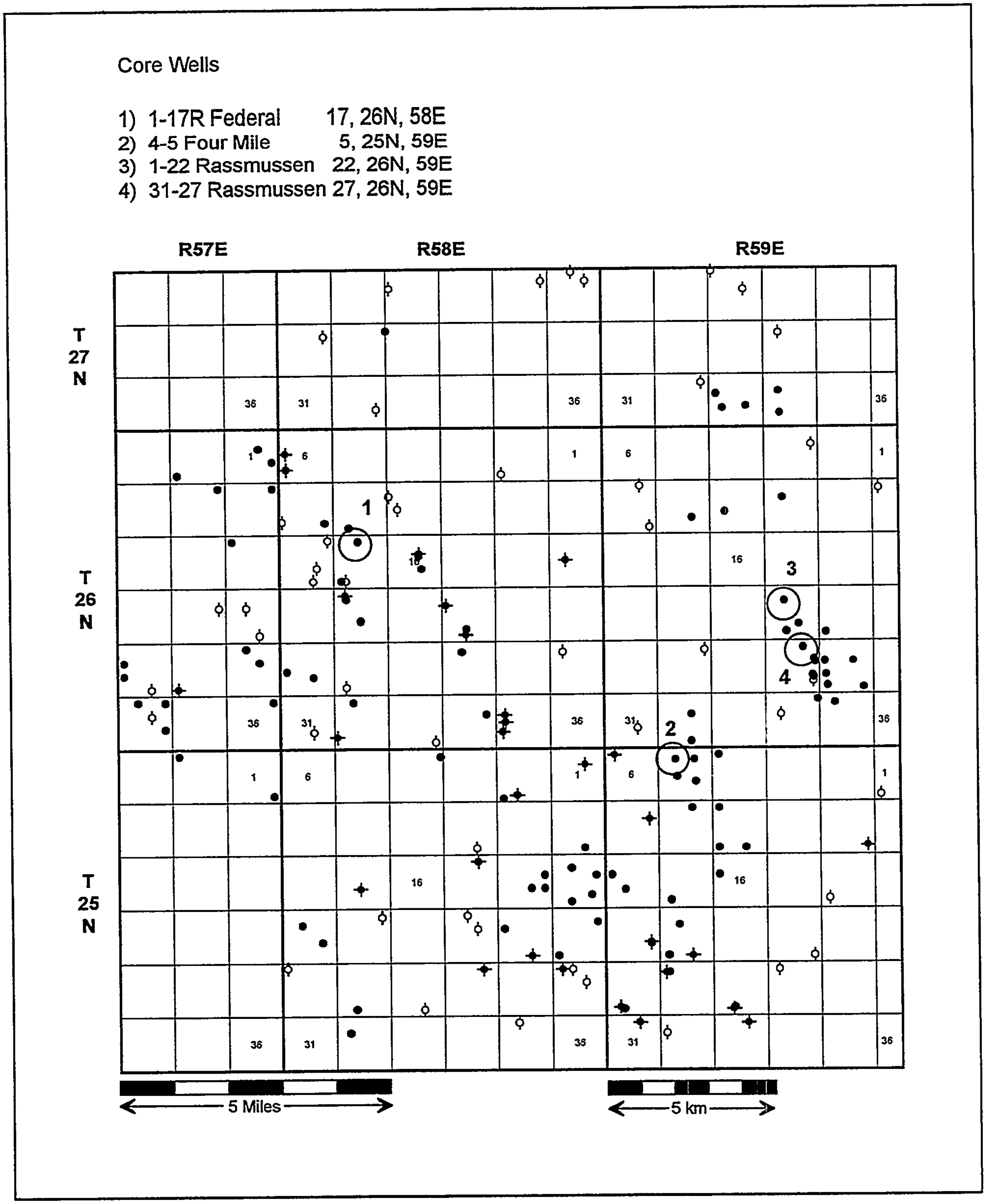


Figure 14: Map showing location of cored wells in the study area.

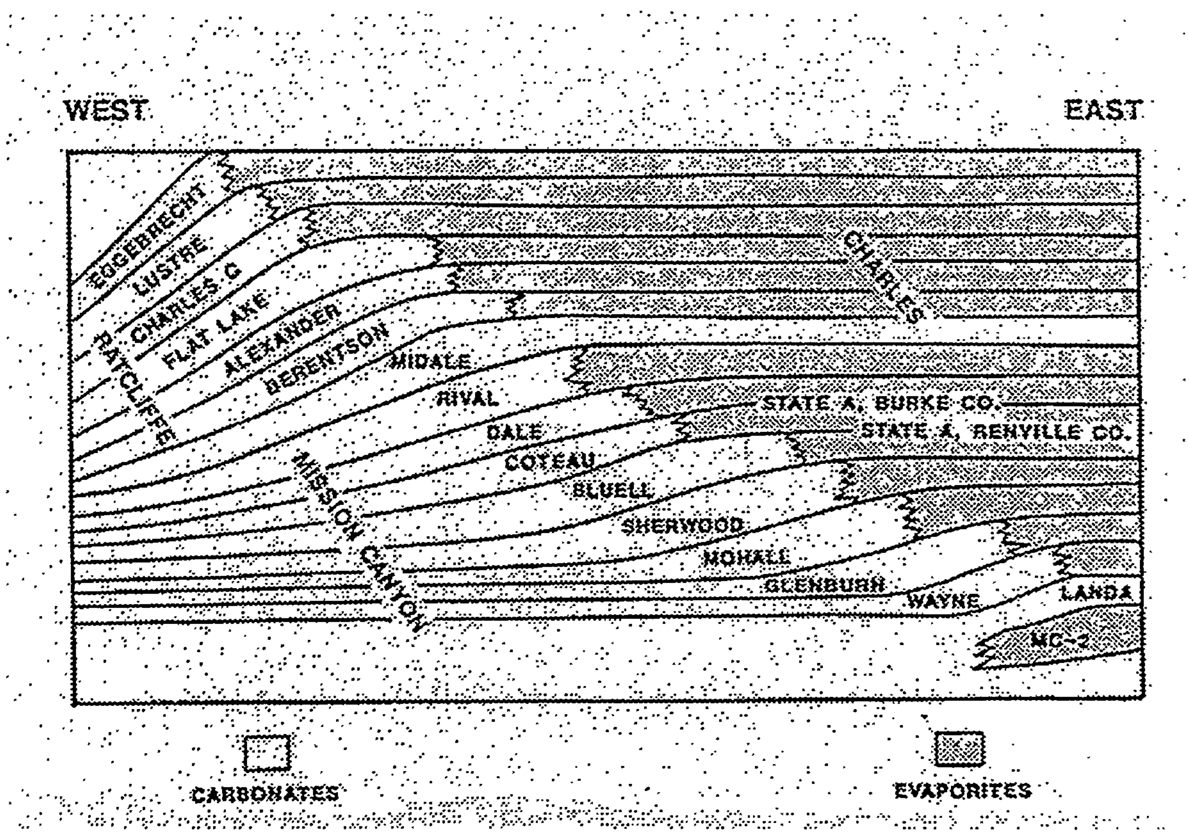


Figure 15: Diagrammatic cross-section showing progradational nature of Ratcliffe beds. Ratcliffe reservoir beds in the study area include the Alexander and Flat Lake subintervals.

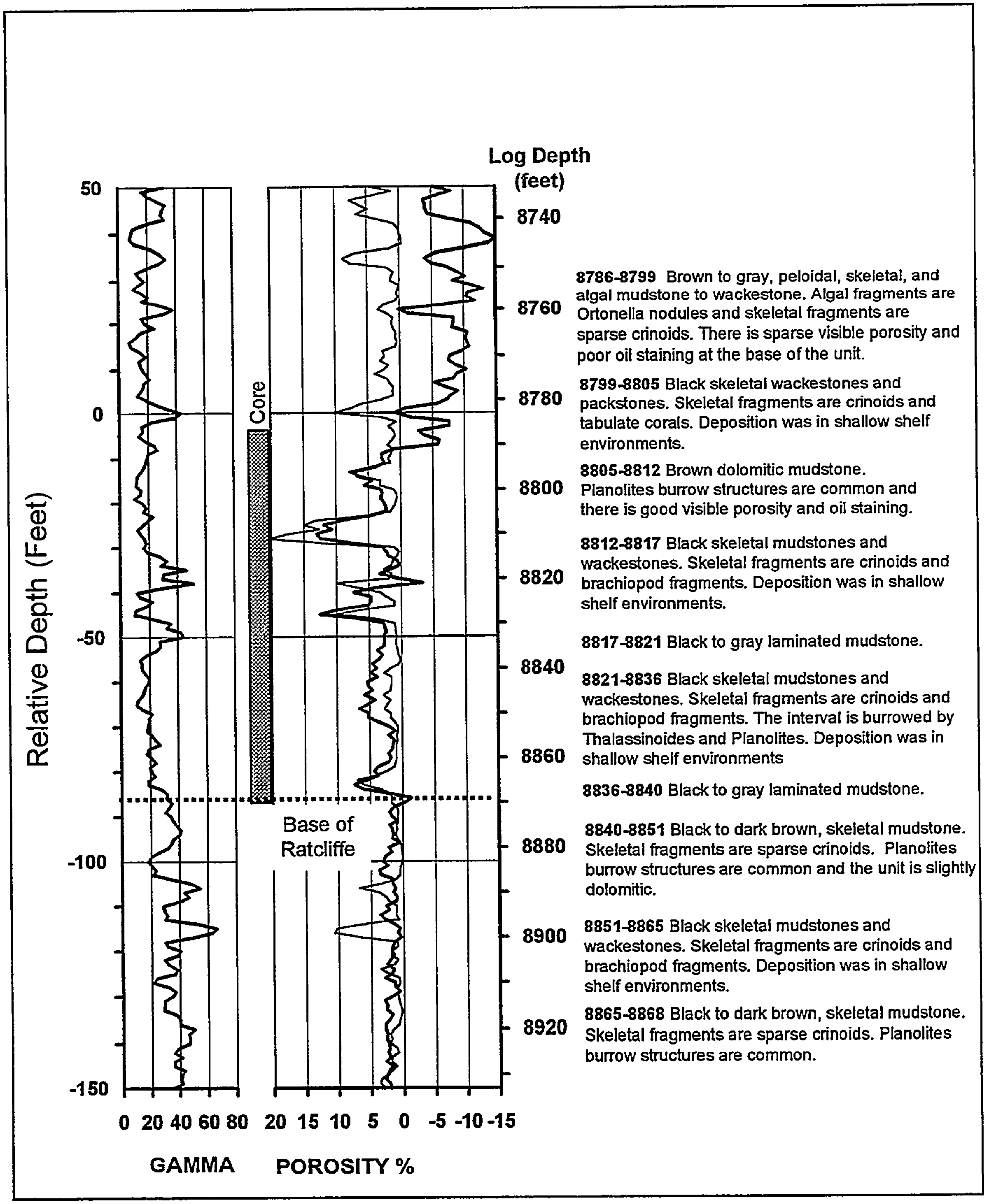
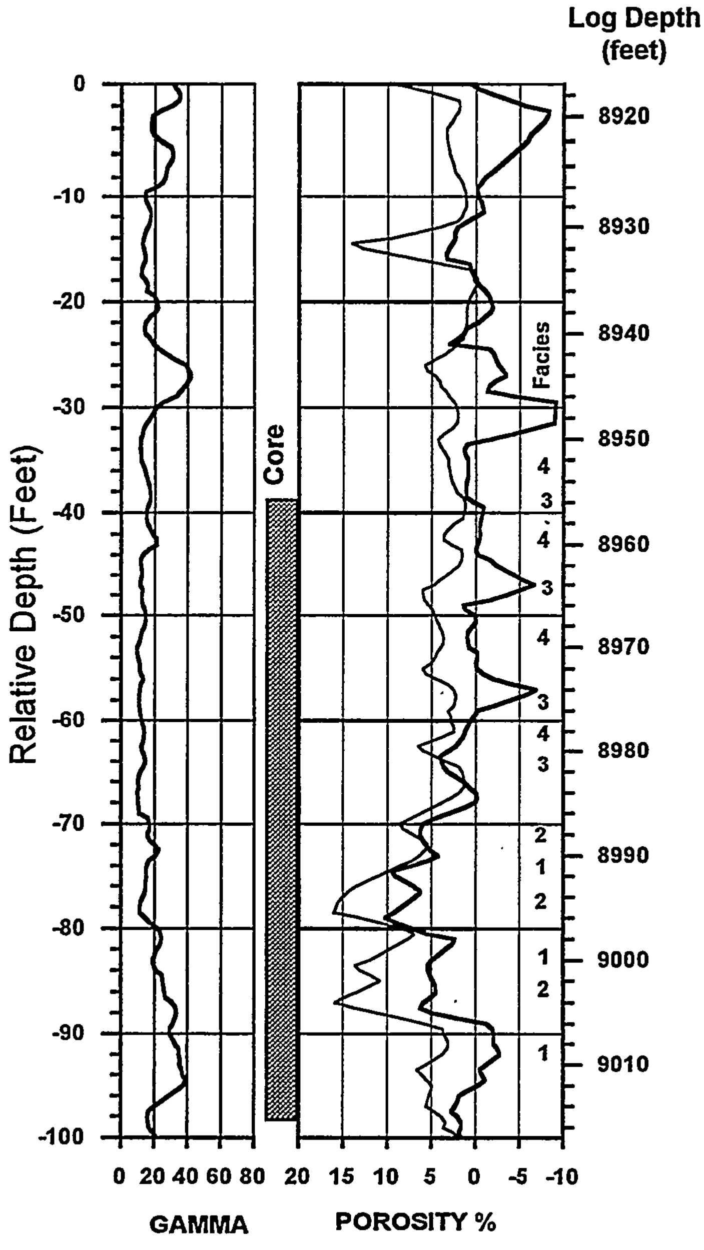


Figure 16: Core description from Federal No. 1-17R, North Sioux Pass Field shown with density-neutron porosity log.



8955-8975 Brown, peloidal, algal, and skeletal mudstones and wackestones. Skeletal fragments are ostracods and sparse crinoids. Algal fragments are Ortonella nodules and calcispheres. Deposition was principally in shallow shoal environments.

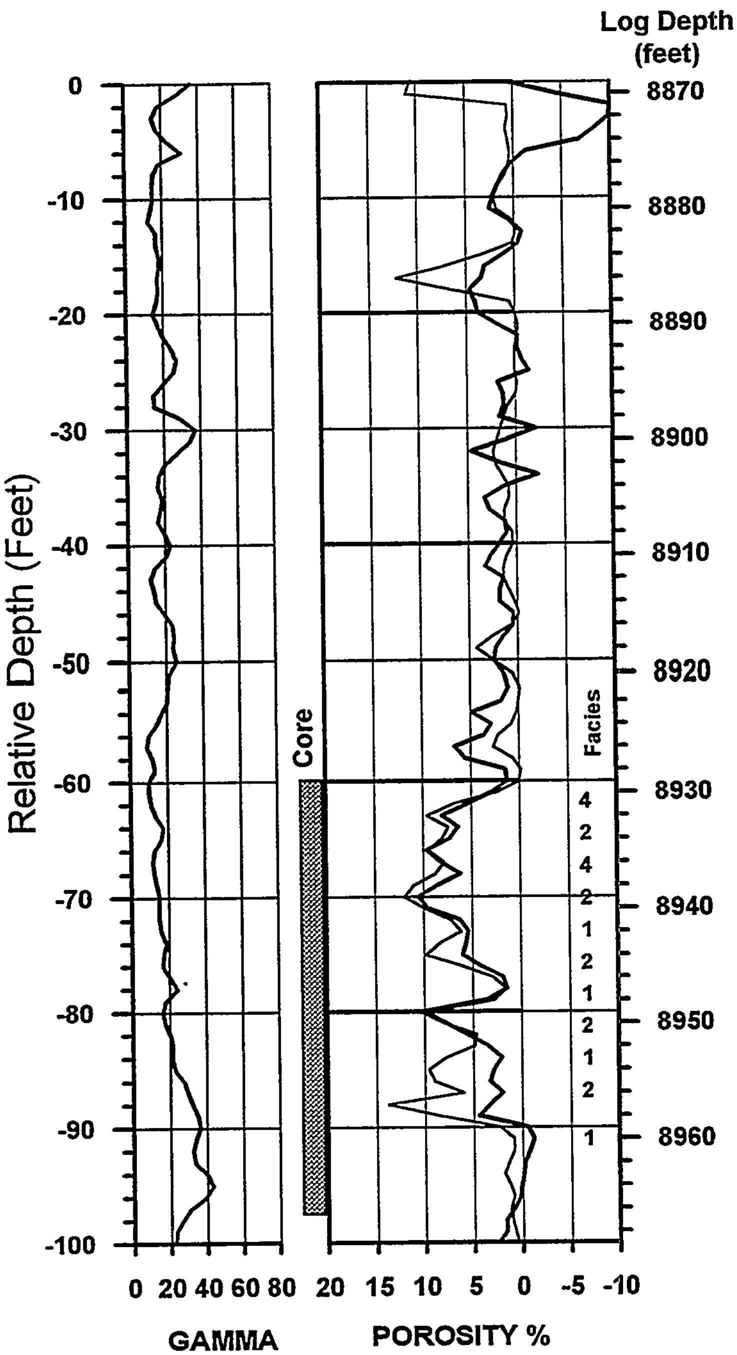
8975-8977 White peloidal and algal packstones and displacive nodules of anhydrite.

8977-8986 Brown peloidal and algal mudstone to wackestone. Calcispheres are common at the base of the unit. Fractures are present in the middle and lower portion of the unit. Deposition was in shoaling environments along a low energy shelf.

8986-9007 Brown skeletal and dolomitic mudstones and interbeds of black skeletal wackestones. The skeletal wackestones contain crinoid debris. The dolomitic mudstones are burrowed, in part, by Planolites and Chondrites. The upper portion of the interval is fractured. There is fair to good oil staining in the upper half of the interval and poor staining at the base.

9007-9015 Black skeletal mudstones and wackestones. Skeletal fragments are crinoids and tabulate corals. The unit is burrowed, but there is no visible porosity or oil staining.

Figure 17: Core description from Rassmussen 31-27, Nohly Field, shown with density-neutron log.



8929-8931 Dark brown, peloidal, algal and skeletal wackestone. Algal fragments are Ortonella nodules, and skeletal fragments are ostracod carapaces. There is no visible porosity or oil show.

8931-8941 Brown dolomitic mudstone to wackestone. The unit is burrowed by Planolites. There are thin wispy shale laminations and sparse ostracod fragments. A thin, Ortonella wackestone bed is present within the middle of the unit. There is poor to fair visible porosity and fair oil staining. *The interval is extensively fractured.* Deposition was in protected shelf environments.

8941-8944 Dark brown to black skeletal wackestone. Skeletal fragments are crinoids and rugose and tabulate corals. Deposition was in shallow shelf environments.

8944-8960 Brown dolomitic mudstone to wackestone. The unit is burrowed by Planolites. There are thin wispy shale laminations and sparse crinoid fragments. There is poor visible porosity and poor oil staining in the upper portion of the unit. Thin interbeds of black skeletal wackestones are common. Deposition was in protected shelf to shallow shelf environments.

8960-8967 Black skeletal mudstones to wackestones. Skeletal fragments are principally crinoids and sparse rugose corals. There is no visible porosity or oil stain.

Figure 18: Core description from Four Mile No. 4-5, Cattails Field, shown with density-neutron log.

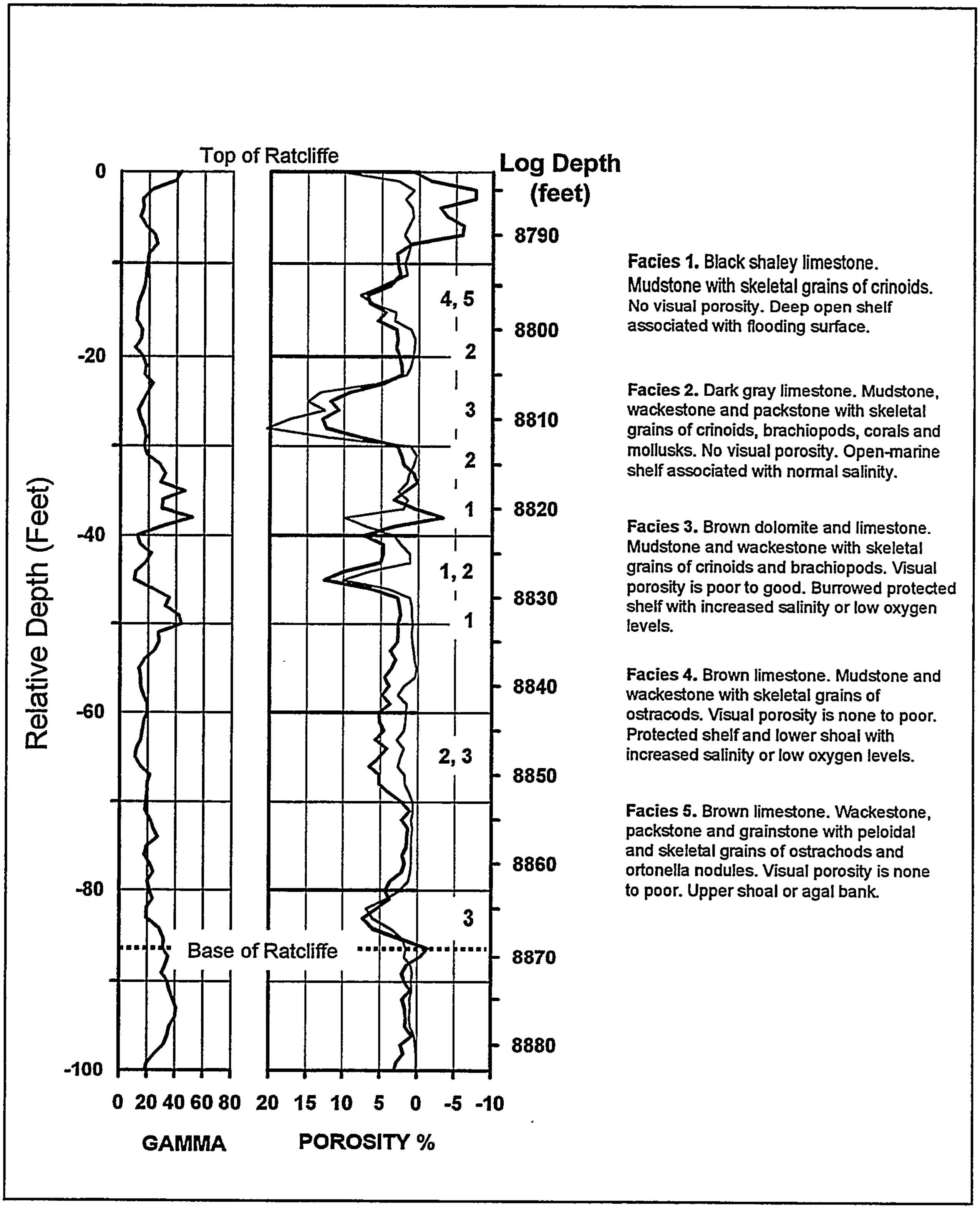


Figure 19: Stratal occurrence of Ratcliffe facies shown with porosity log at Federal No. 1-17R, North Sioux Pass Field.

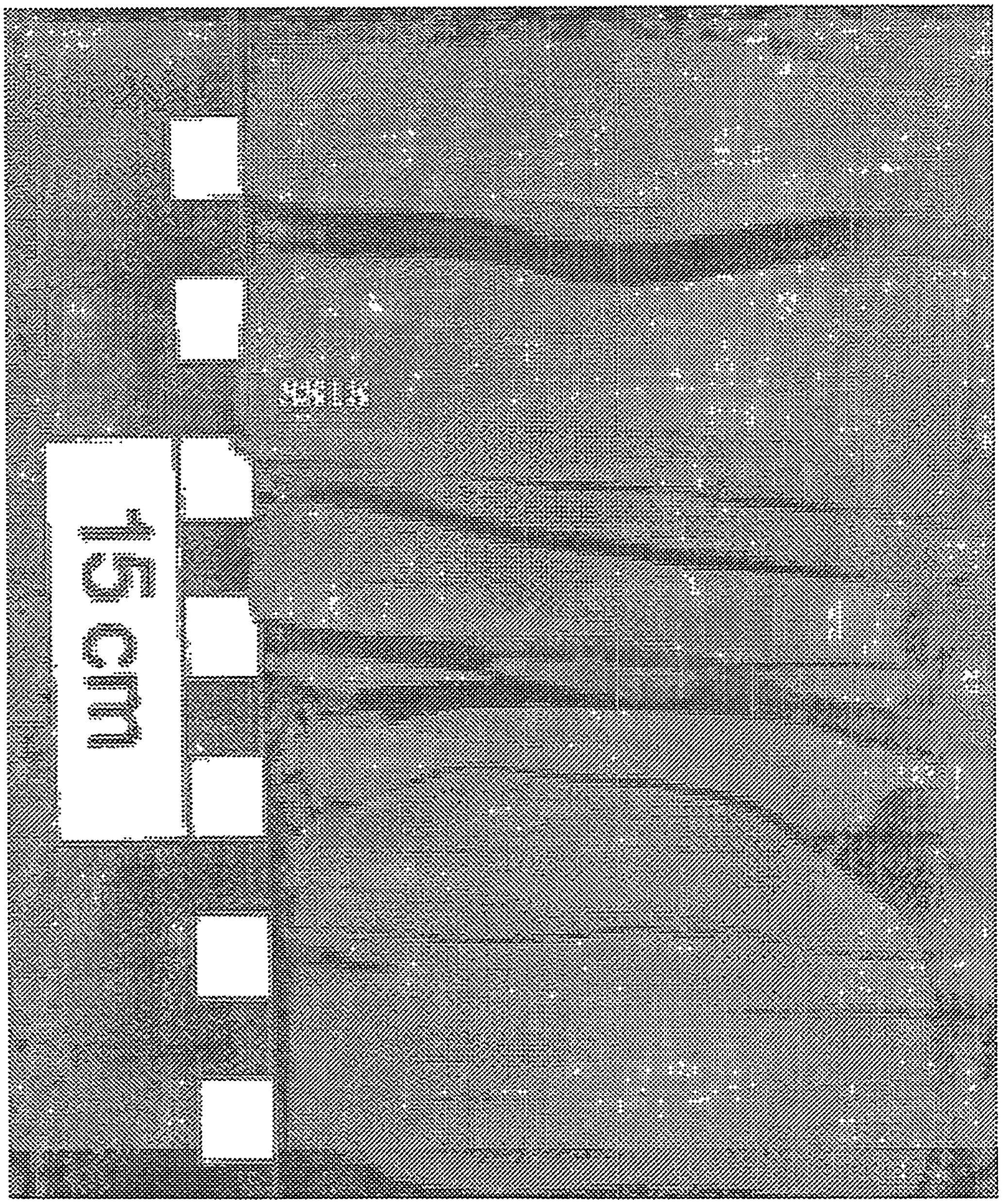


Figure 20: Core photo of Facies 1. Shaley lime mudstone beds occur within the middle and upper portions of Ratcliffe productive intervals and are associated with deepening events. Luff Federal No. 1-17R, 8818 ft.

Figure 21: Core photo of Facies 2. Skeletal fragments dominated by crinoids (white specks) are common within Facies 2. These sediments were deposited in open marine, shallow shelf environments. Luff Federal No. 1-17R, 8828 ft

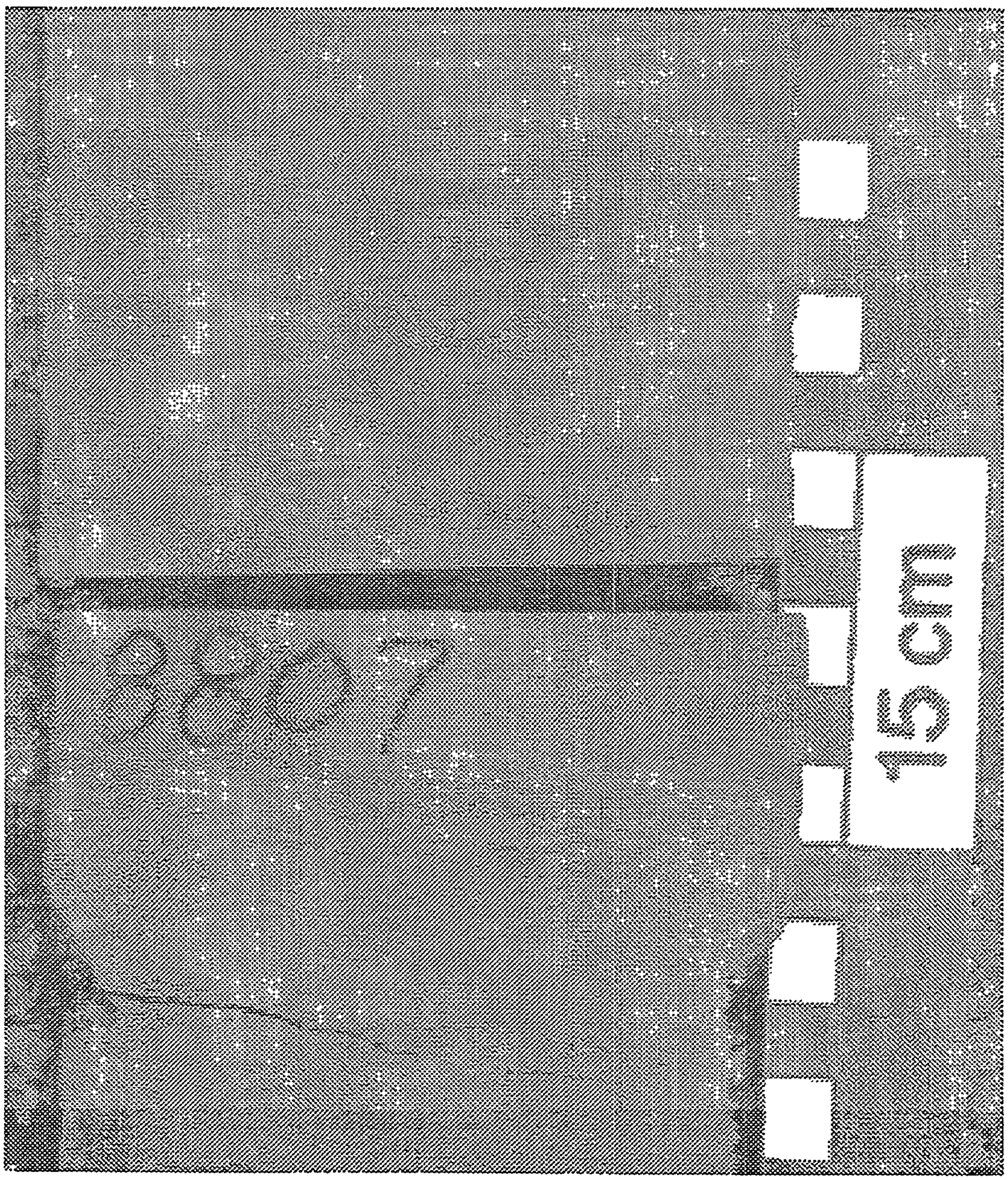


Figure 22: Core photo of Facies 3. Burrowed dolomudstones are reservoirs in the project area. These sediments were deposited in protected shelf environments where burrowing organisms created subhorizontal Planolites structures. Luff Federal No. 1-17R, 8807 ft.

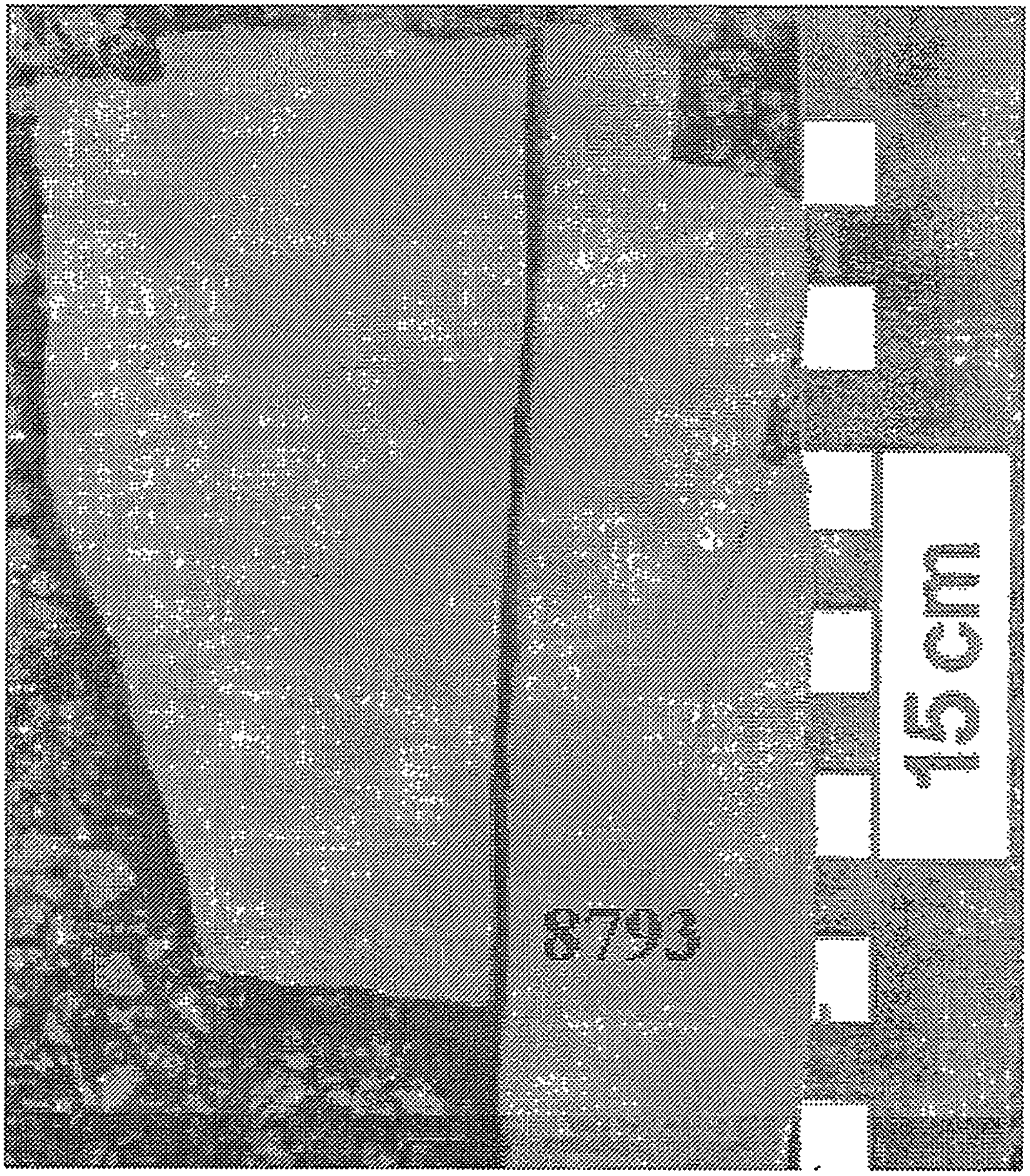


Figure 23: Core photo of Facies 4. Slightly laminated skeletal and peloidal mudstones were deposited in protected shelf and lower shoal environments. Luff Federal No. 1-17R, 8793 ft.

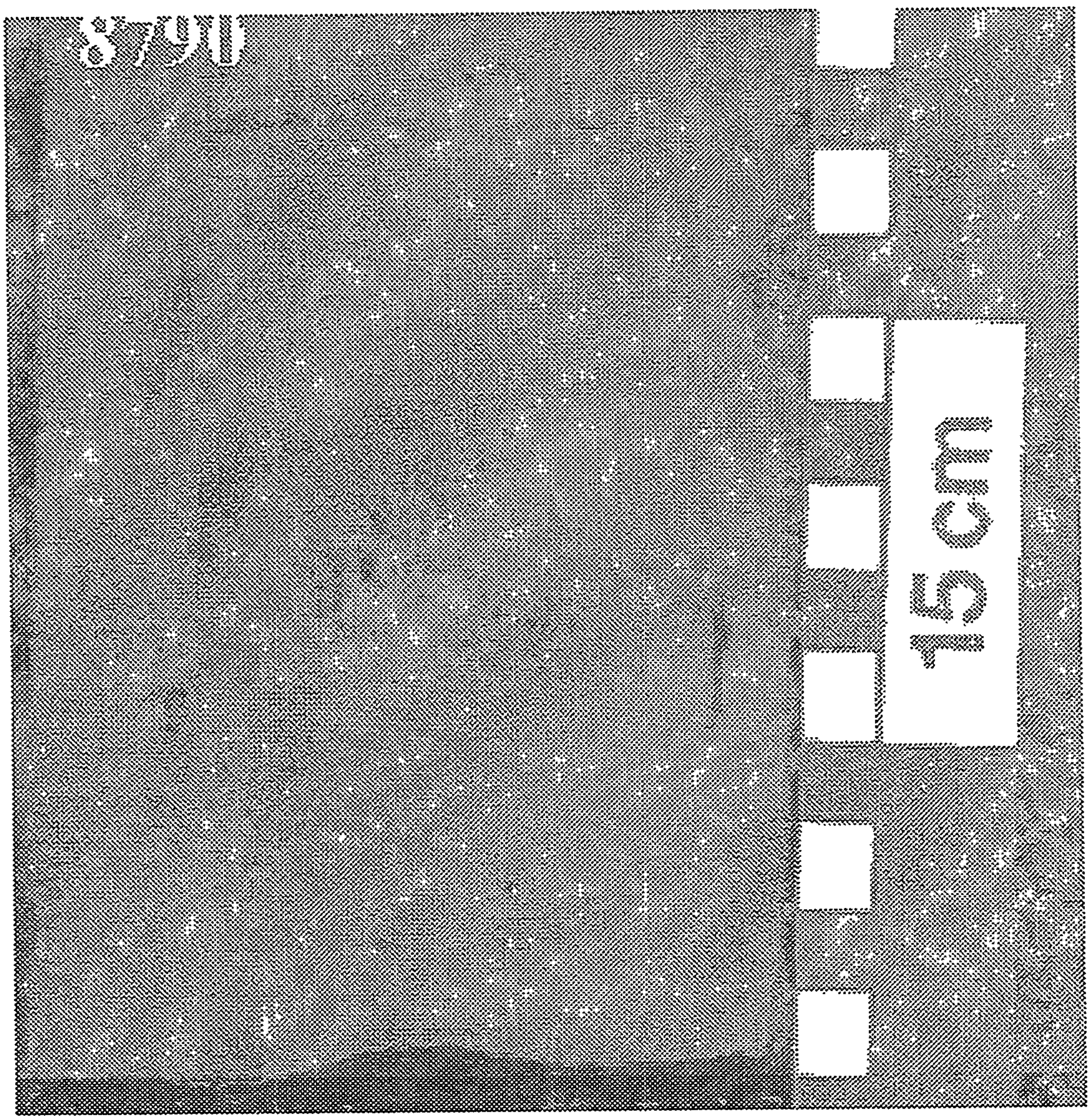


Figure 24: Core photo of Facies 5. Algal and peloidal wackestone and packstone beds are associated with shoaling environments along the ancient Ratcliffe shelf. The codiacean alga Ortonella commonly occurred within these shoal environments. Luff Federal 1-17R, 8790 ft.

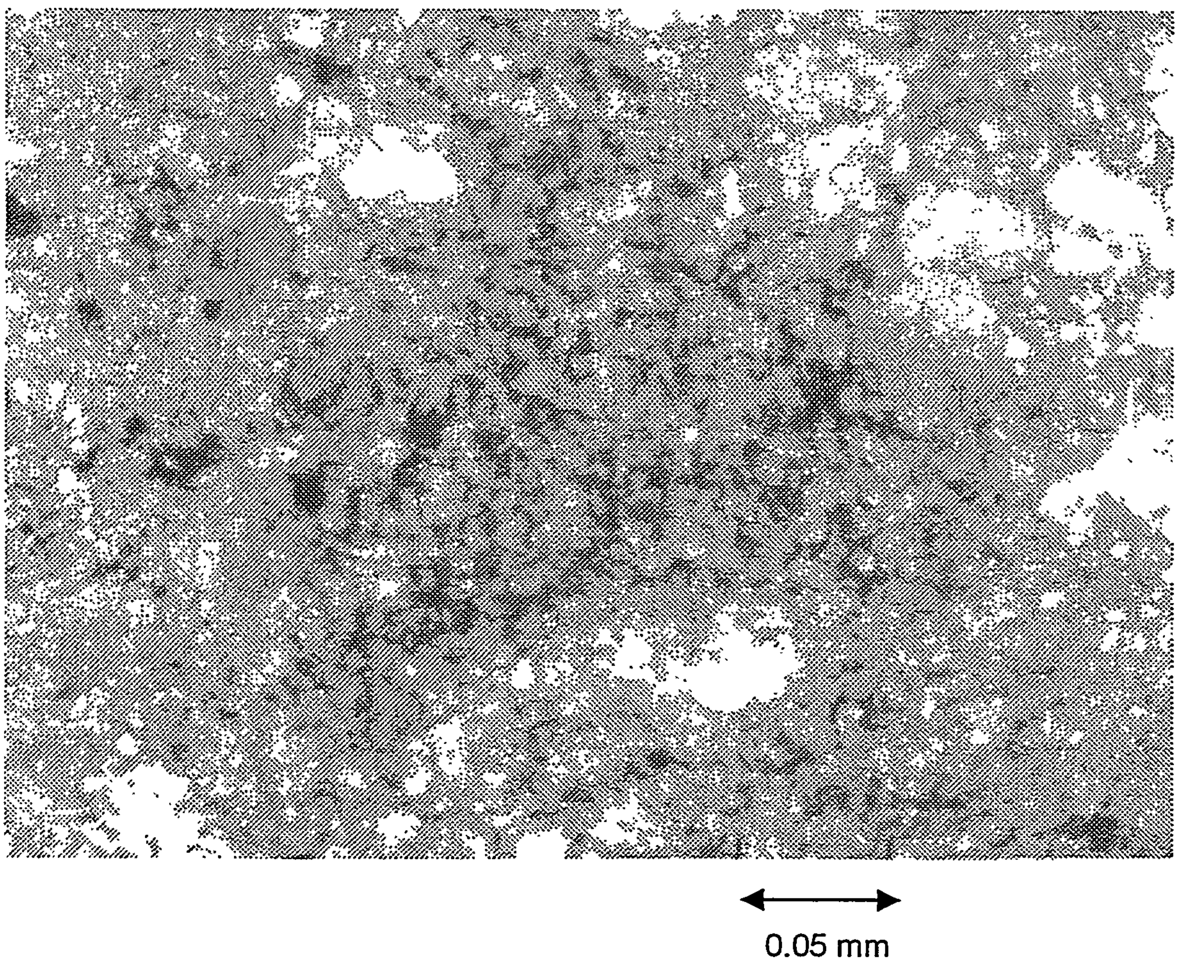


Figure 25: Photo micrograph of finely crystalline dolomite. Reservoir rock is fine-crystalline dolomite with areas of anhydrite occlusion (white). The black crystals are pyrite framboids.

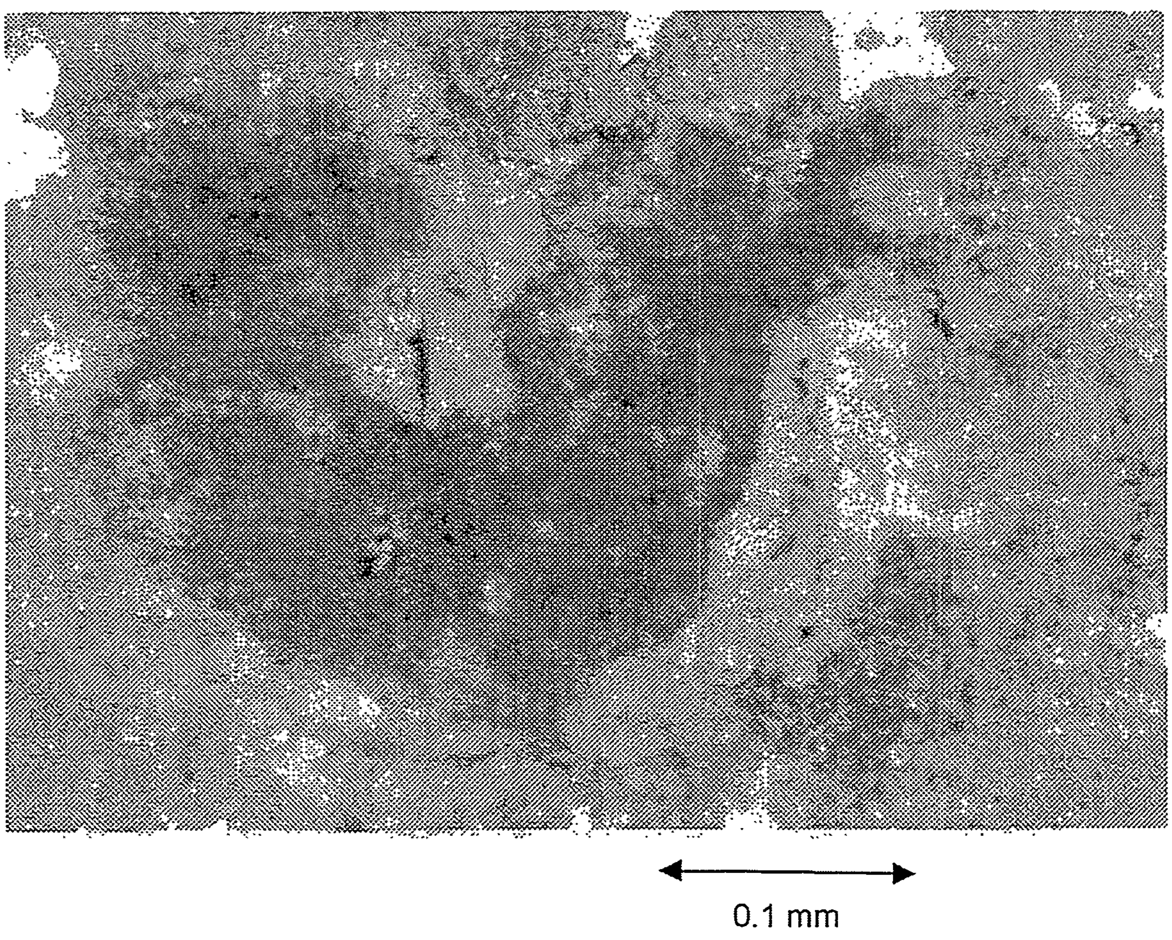


Figure 26: Photo micrograph of vuggy porosity. Leaching of micrite produced secondary vuggy porosity that was partly occluded by calcite spar and anhydrite cements (white). This vuggy porosity has poor interconnection which reduced overall permeability. Conquest Rasmussen No. 31-27, 8966.4 ft.

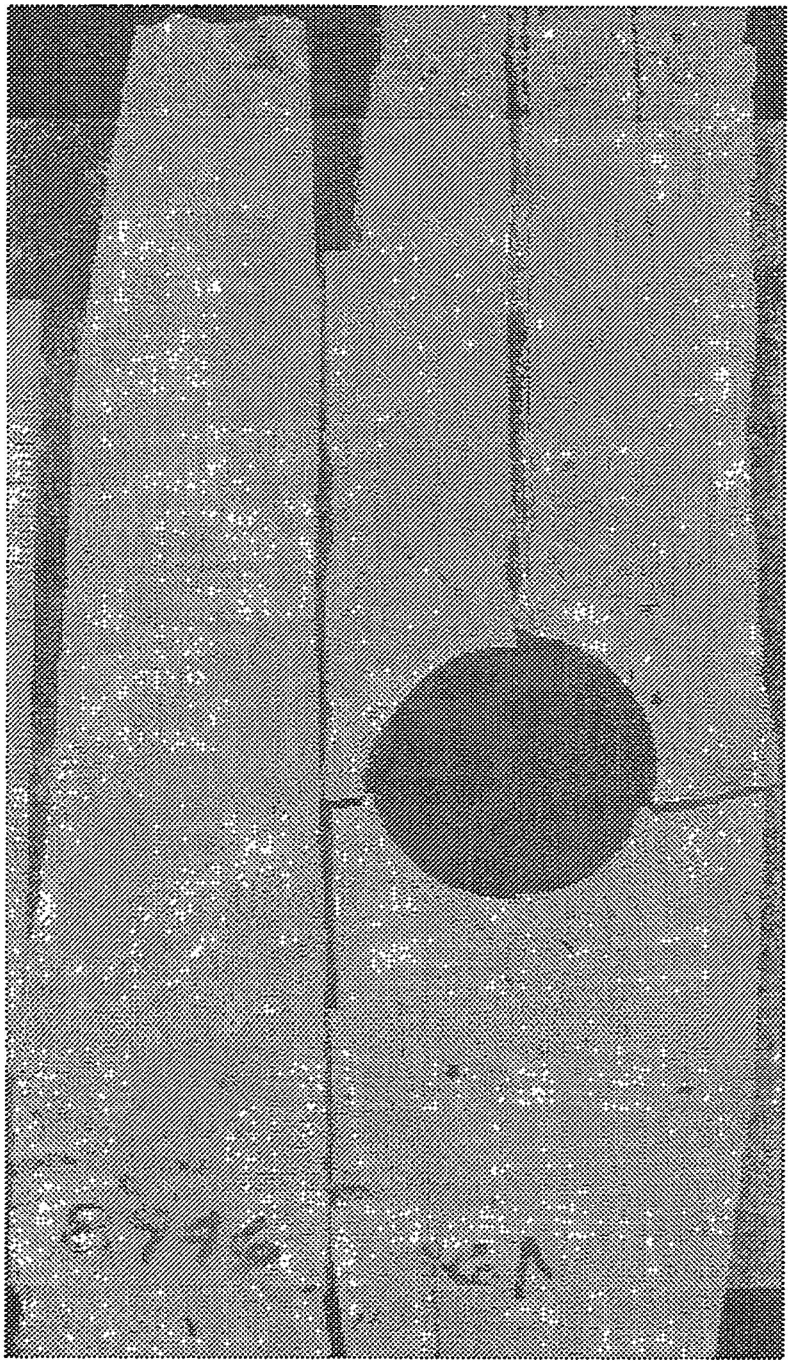


Figure 27: Core photo of fractured Ratcliffe from Four Mile No. 4-5, Cattails Field.

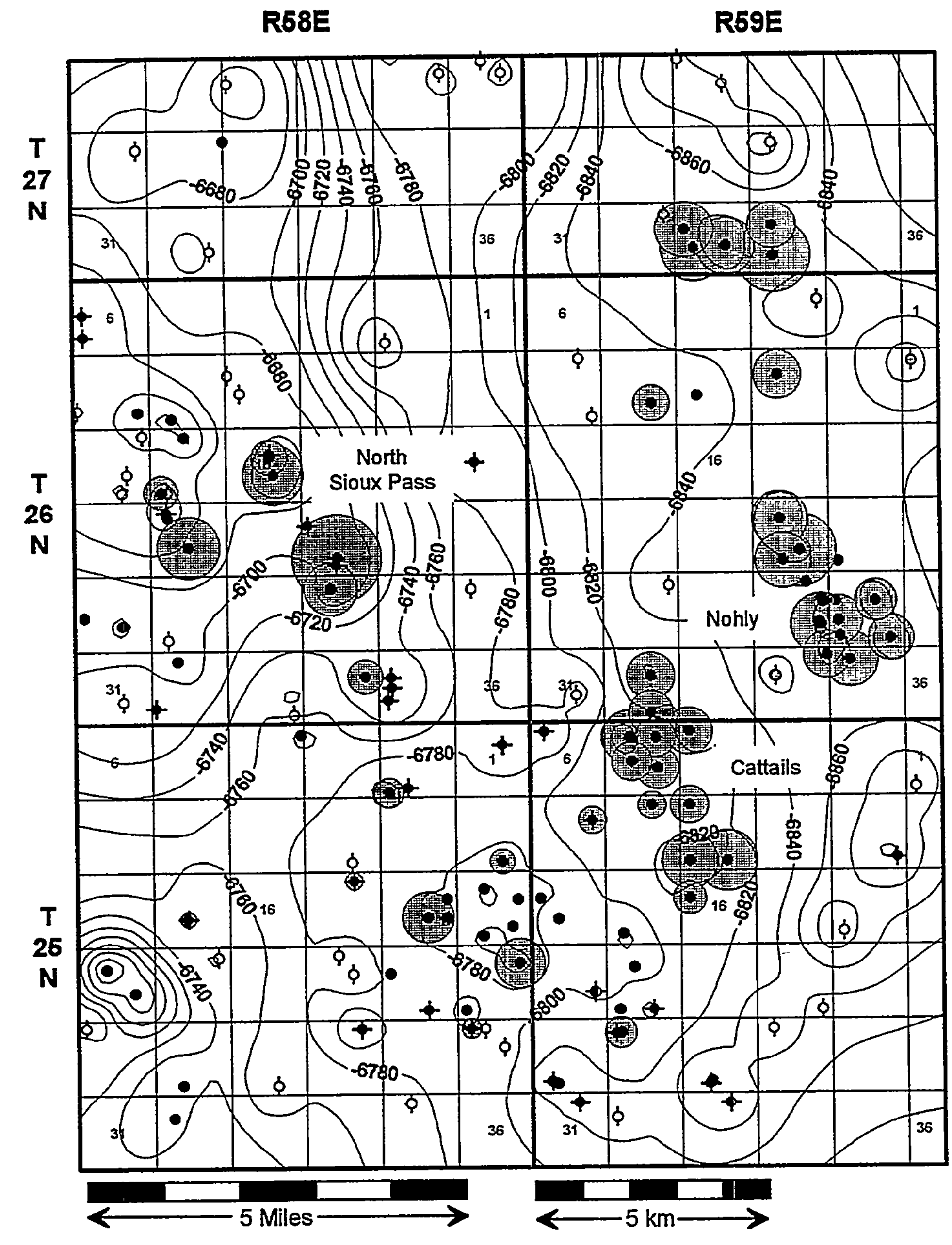
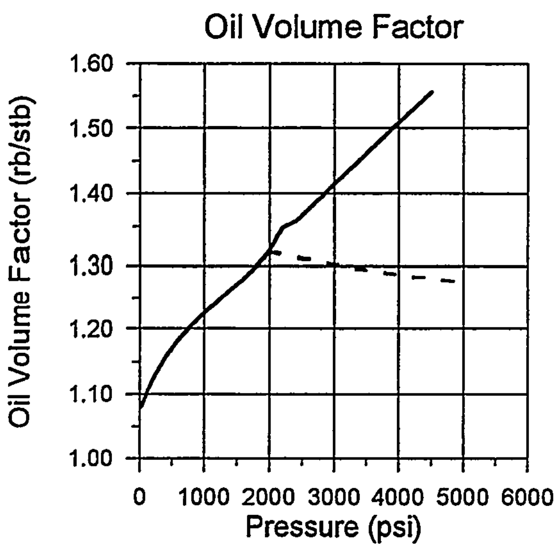
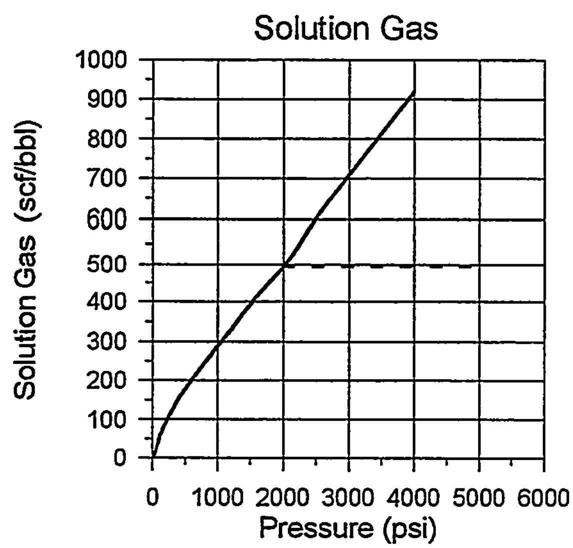
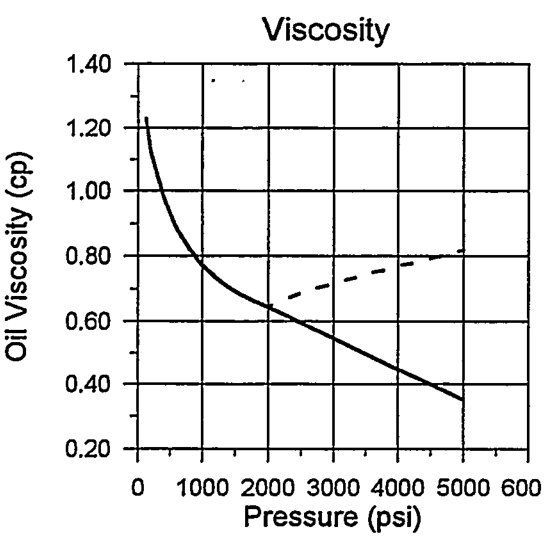


Figure 28: Map showing Ratcliffe completions and drainage areas with Ratcliffe structure for the study area.







PS	Muo	Bo	Rso	Muob	Bob	Rsob
15	1.910	1.080	1	1.910	1.080	1
115	1.230	1.106	59	1.230	1.106	59
202	1.120	1.126	94	1.120	1.126	94
400	0.977	1.159	153	0.977	1.159	153
600	0.886	1.184	202	0.886	1.184	202
800	0.822	1.205	246	0.822	1.205	246
1000	0.773	1.226	289	0.773	1.226	289
1200	0.735	1.245	330	0.735	1.245	330
1400	0.705	1.264	372	0.705	1.264	372
1600	0.681	1.282	414	0.681	1.282	414
1800	0.662	1.301	456	0.662	1.301	456
2000	0.644	1.320	495	0.644	1.318	495
2200	0.625	1.349	541	0.661	1.315	495
2400	0.605	1.358	583	0.678	1.311	495
2500	0.595	1.367	604	0.687	1.310	495
3000	0.547	1.415	709	0.717	1.302	495
3500	0.498	1.462	815	0.744	1.295	495
4000	0.449	1.509	920	0.769	1.288	495
4500	0.400	1.556	1026	0.794	1.282	495
5000	0.351	1.603	1131	0.818	1.275	495

Figure 29: Ratcliffe oil PVT properties.

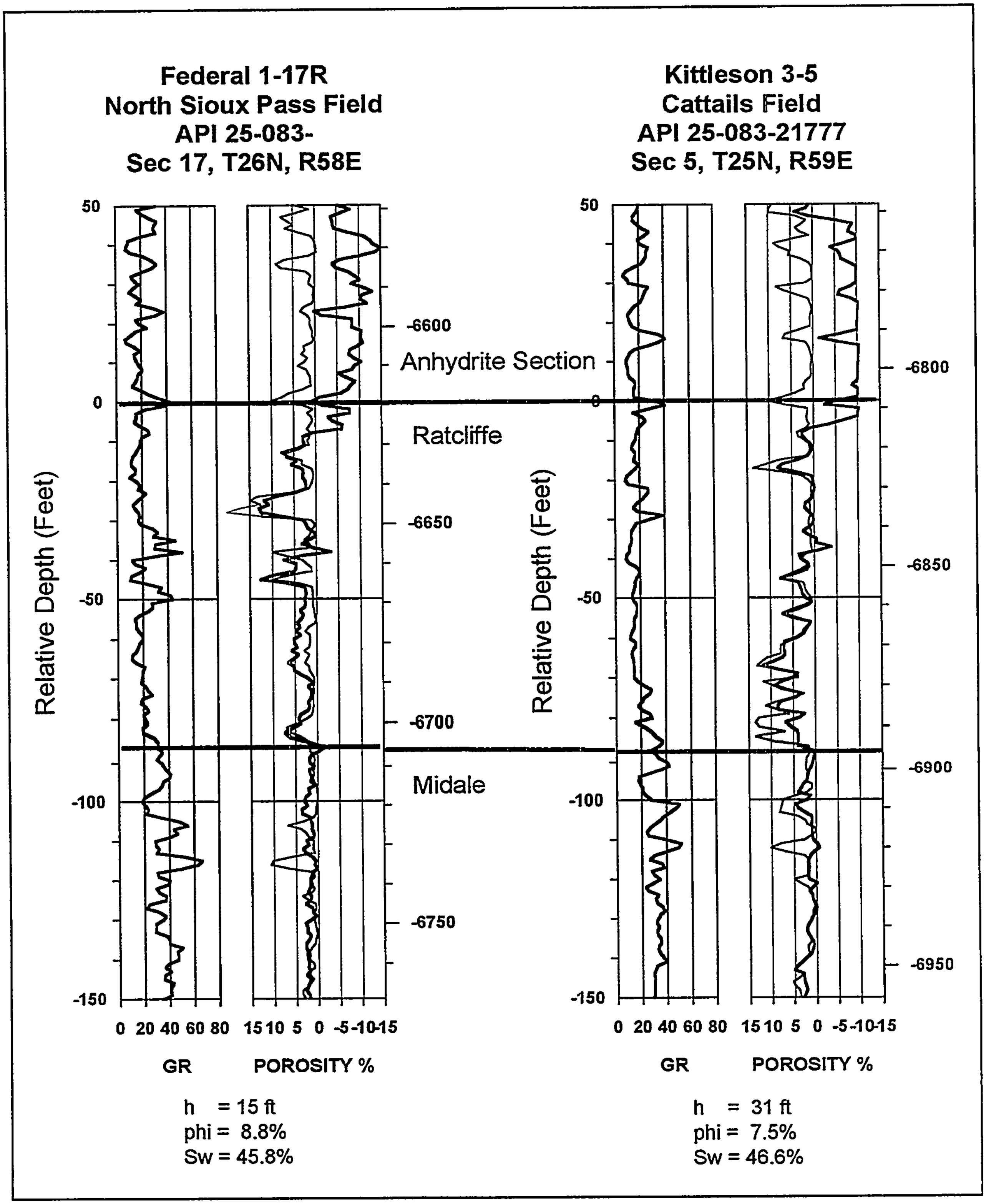


Figure 30: Ratcliffe type-logs with reservoir pay calculations.

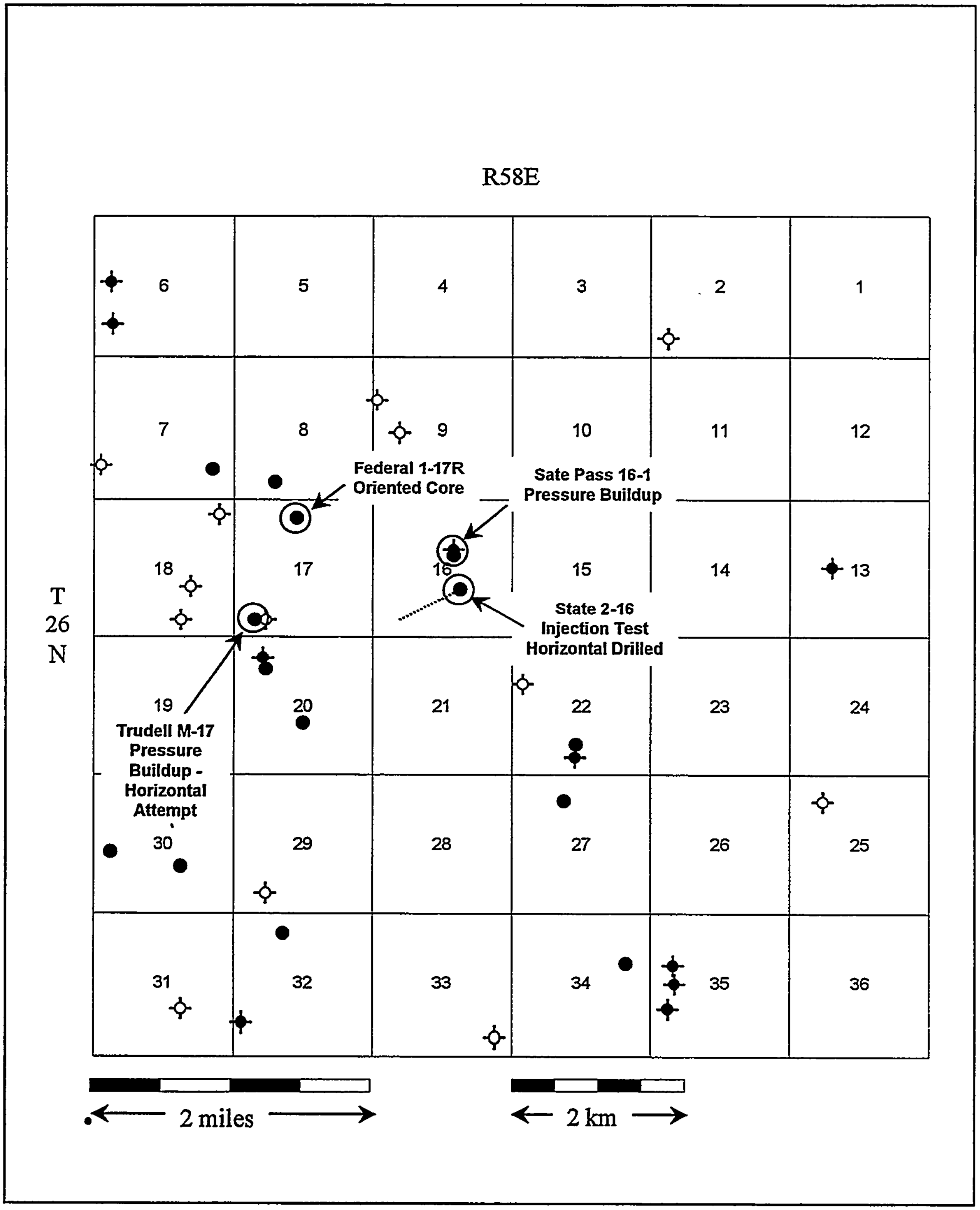


Figure 31: Map showing locations of wells used for data collection and demonstrations.

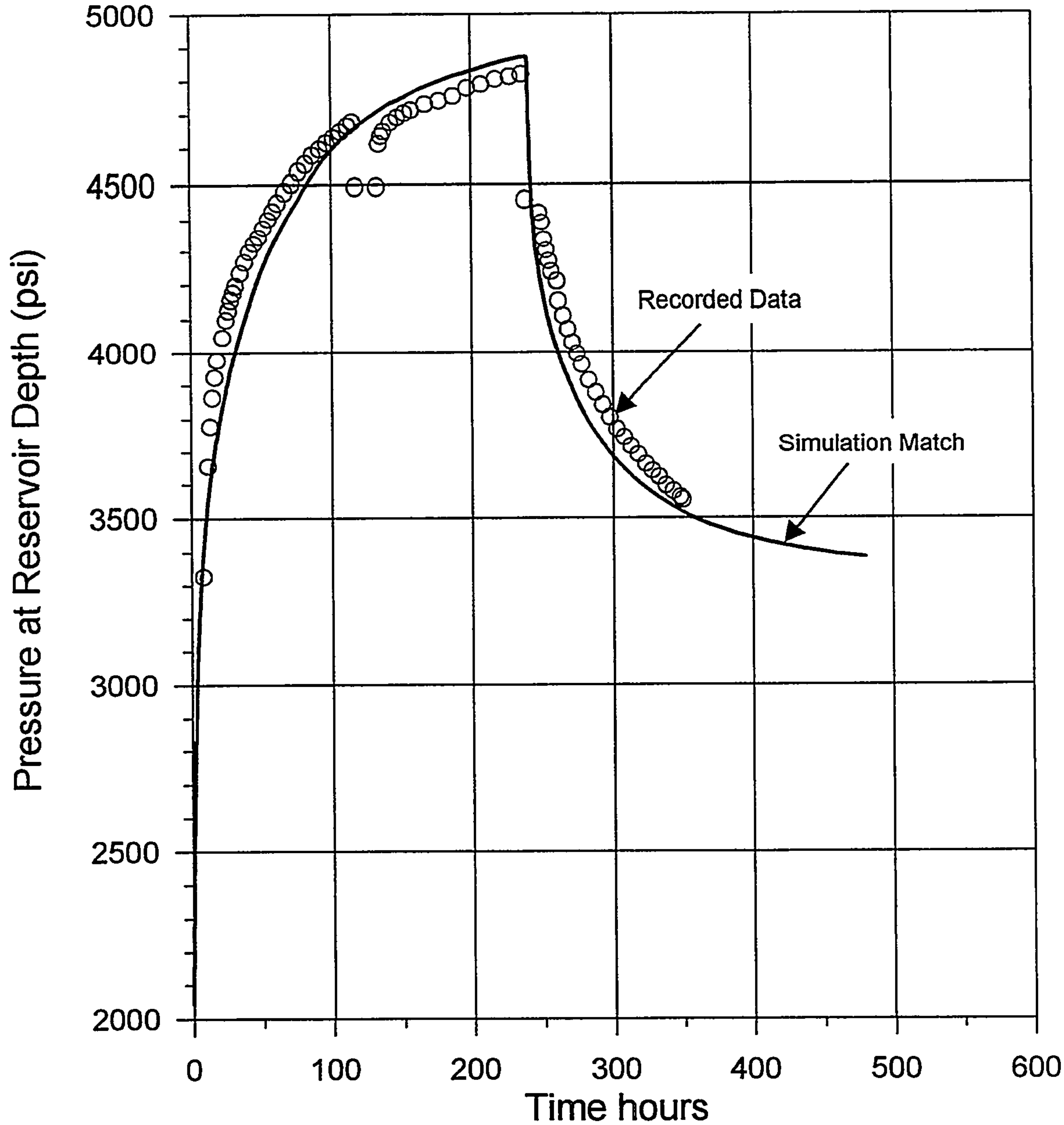


Figure 32: Graph of pressure data from the water injection test at the State No. 2-16 well.

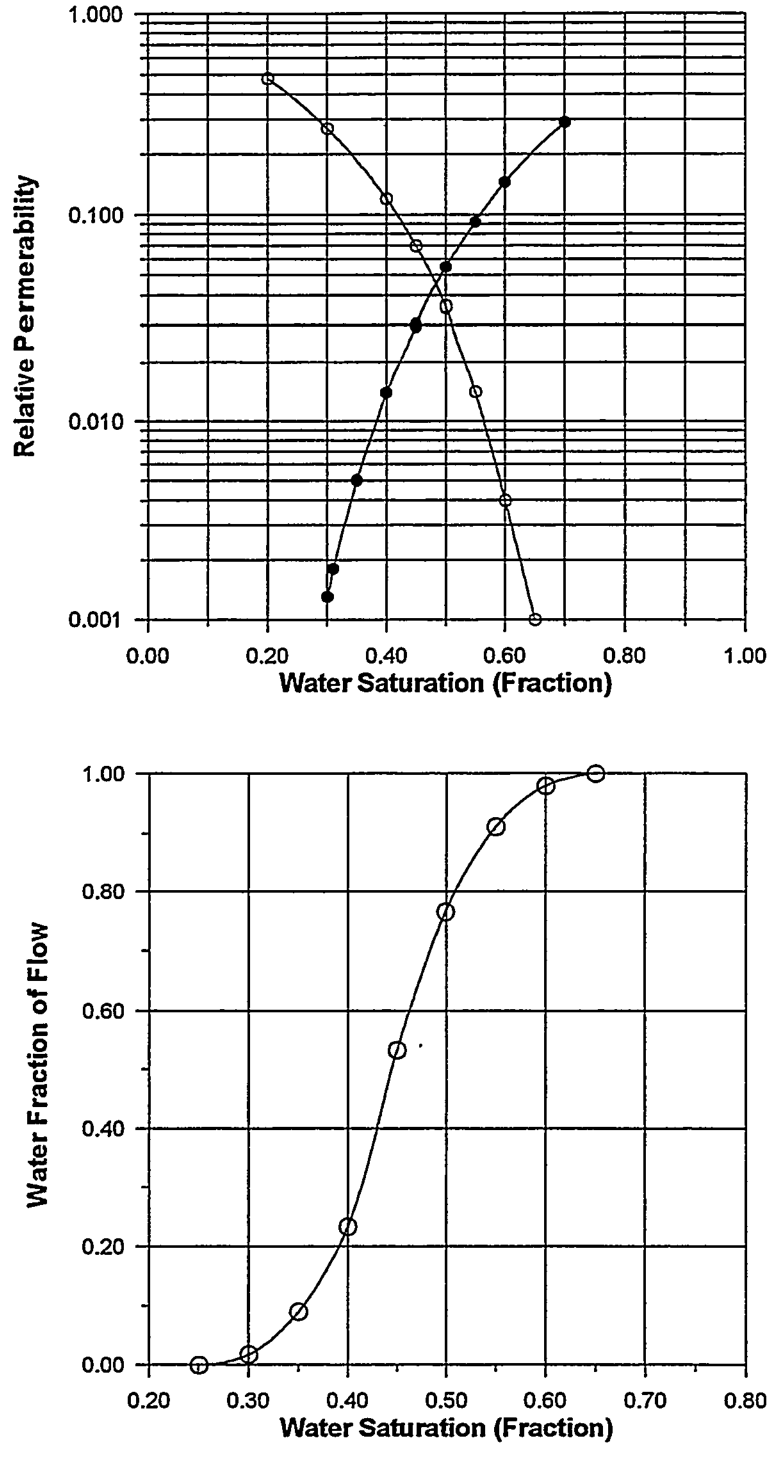


Figure 33: Oil-water relative permeability curves with resulting water production.

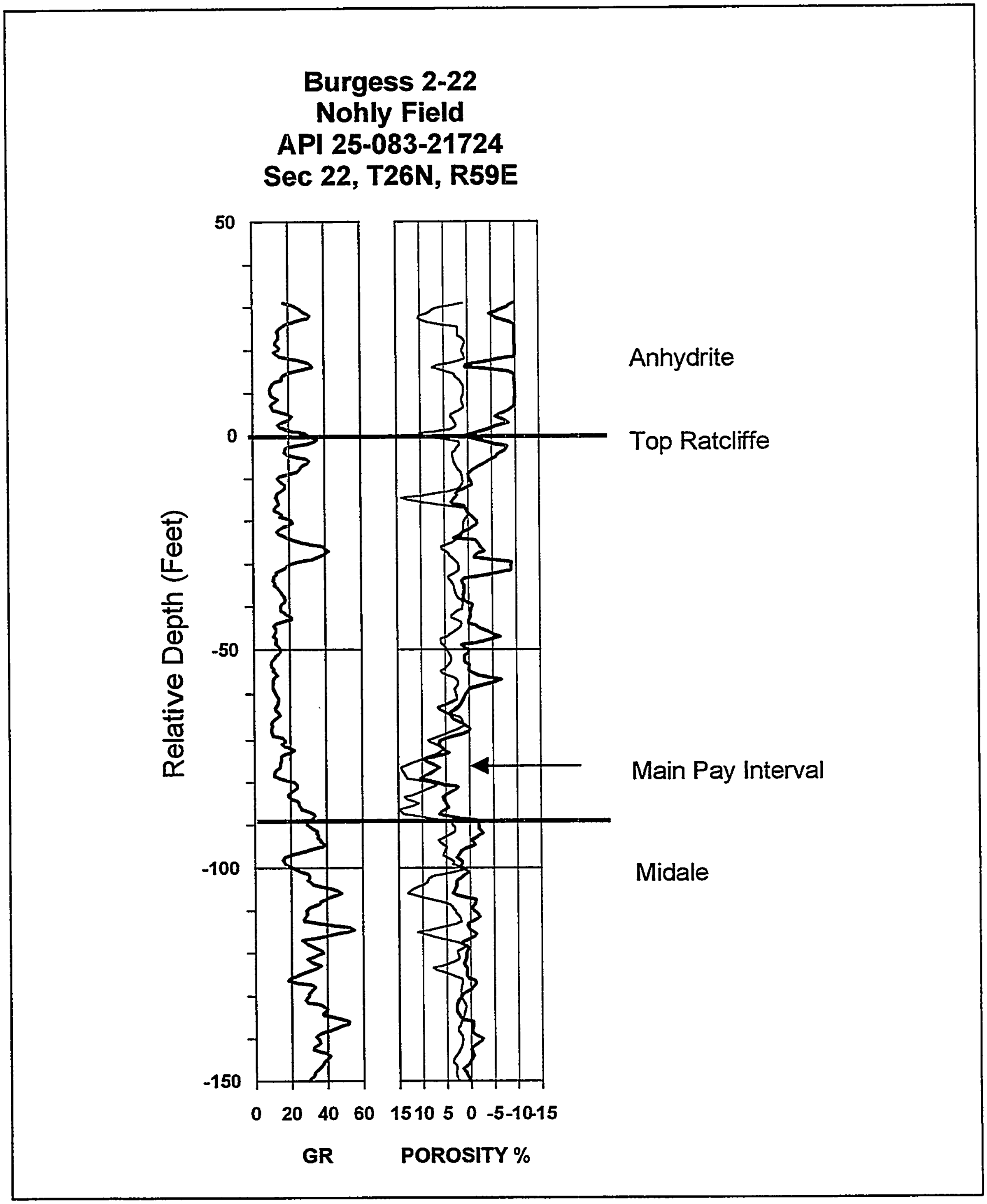


Figure 34: Ratcliffe type-log from Nohly Field.

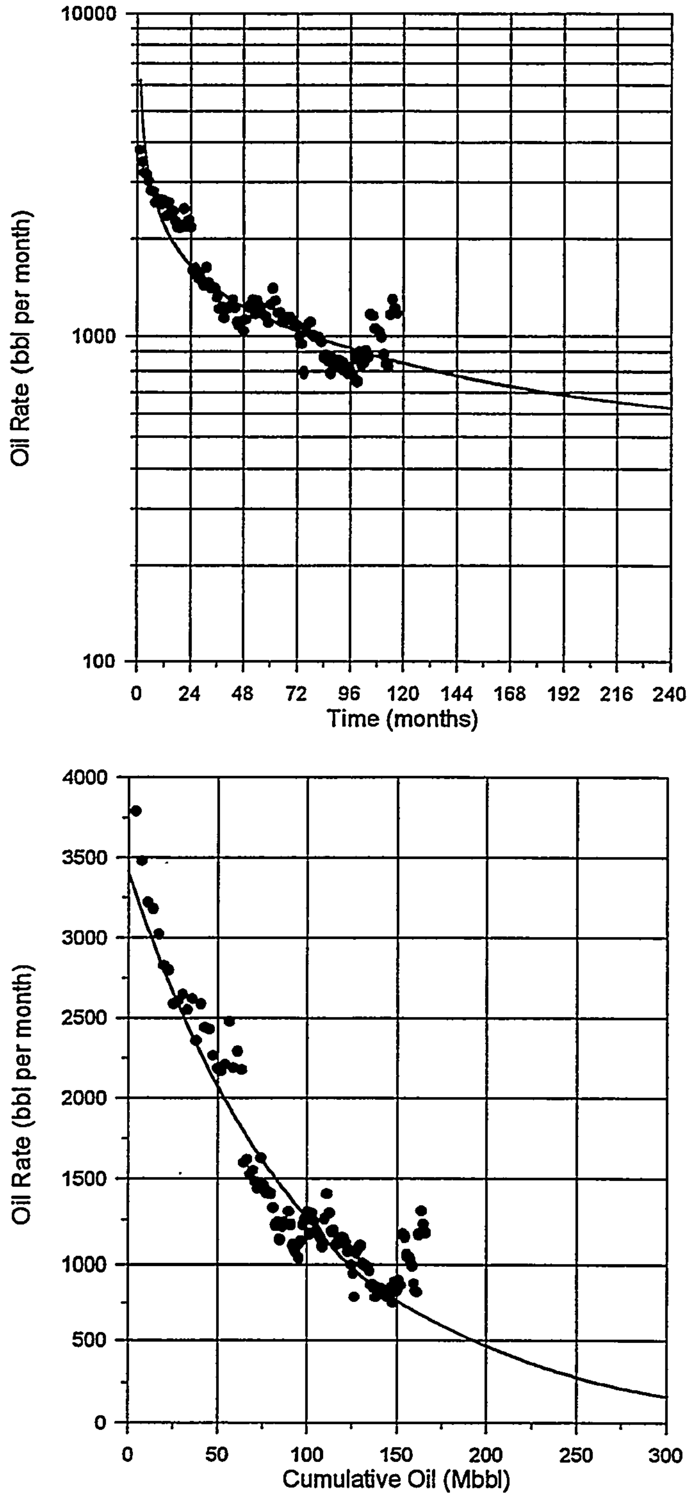


Figure 35: Normalized production curves from Nohly Field.

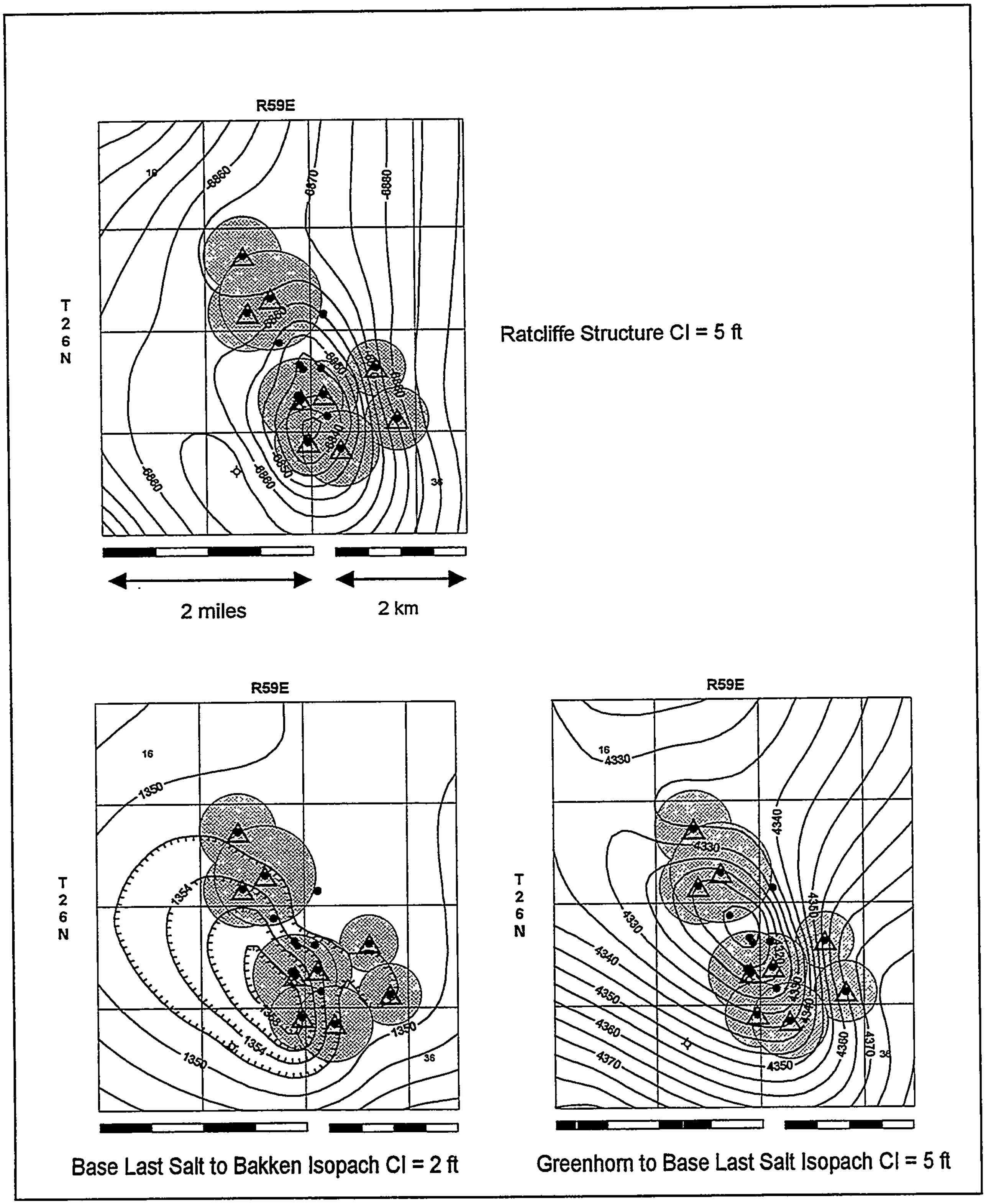


Figure 36: Relevant maps for the Ratcliffe at Nohly Field. Effective drainage areas are shown as shaded circles. Triangles indicate Ratcliffe wells.

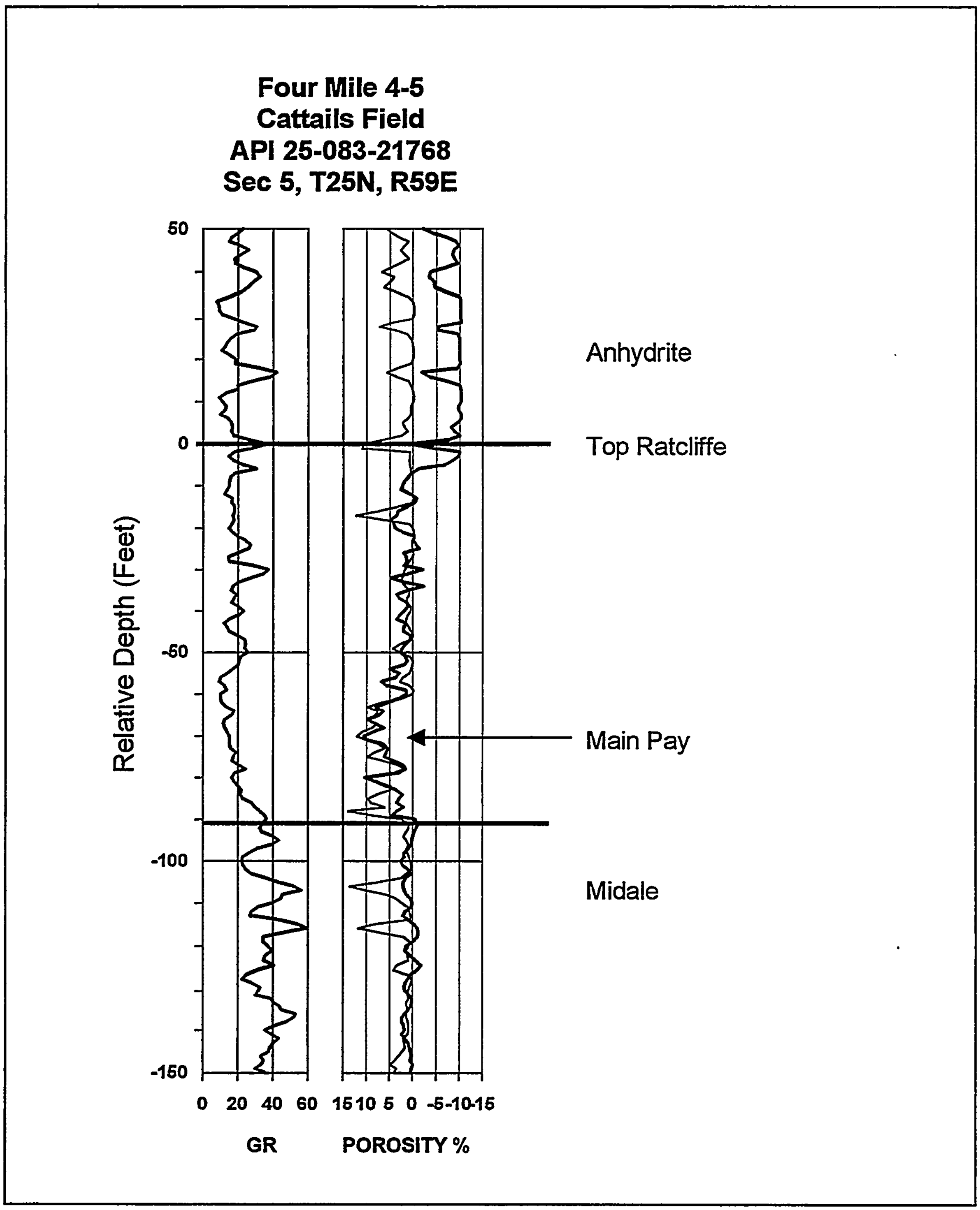


Figure 37: Ratcliffe type-log from Cattails Field.

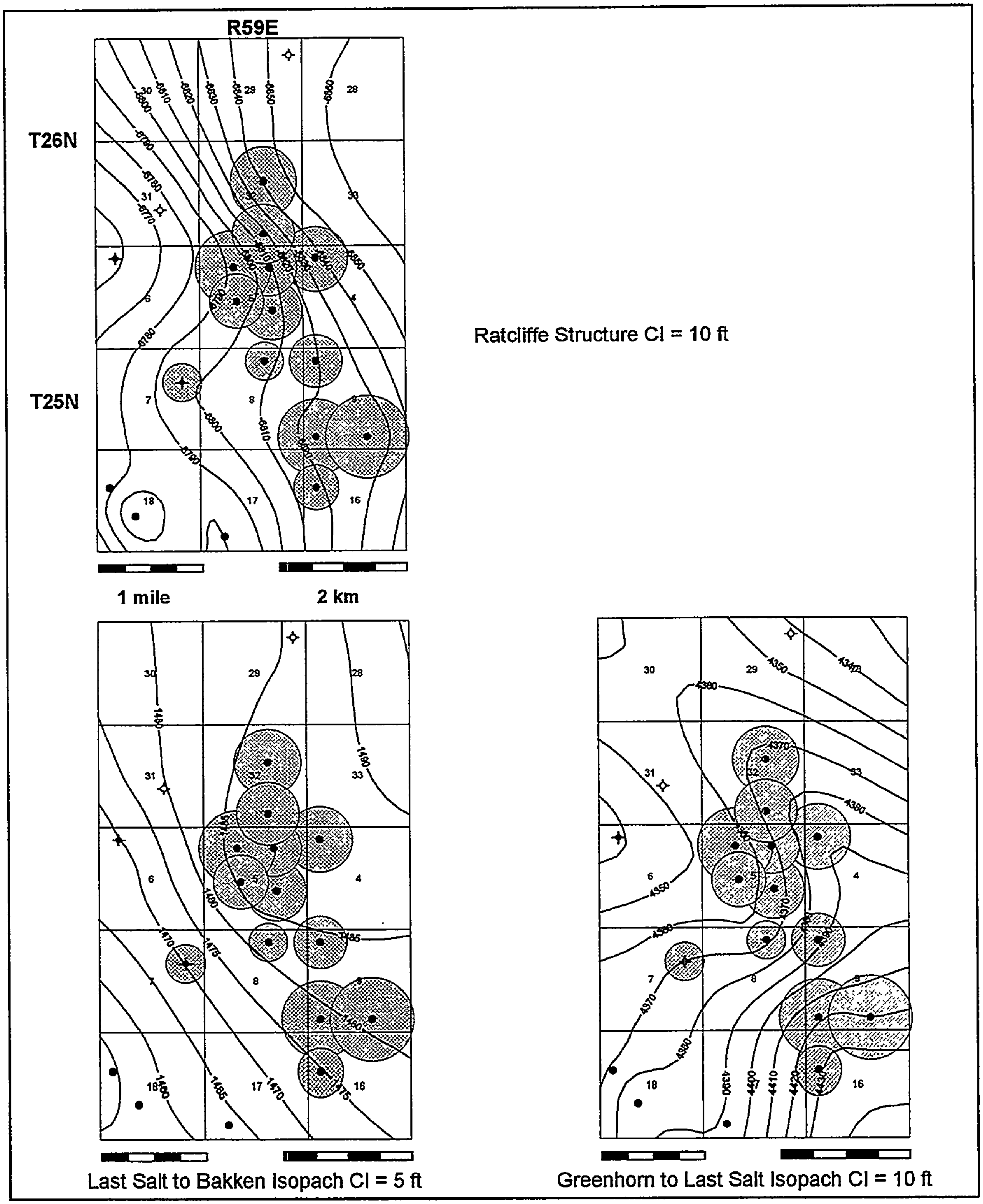


Figure 38: Relevant maps for the Ratcliffe at Cattails Field. Effective drainage areas are shown as shaded circles.

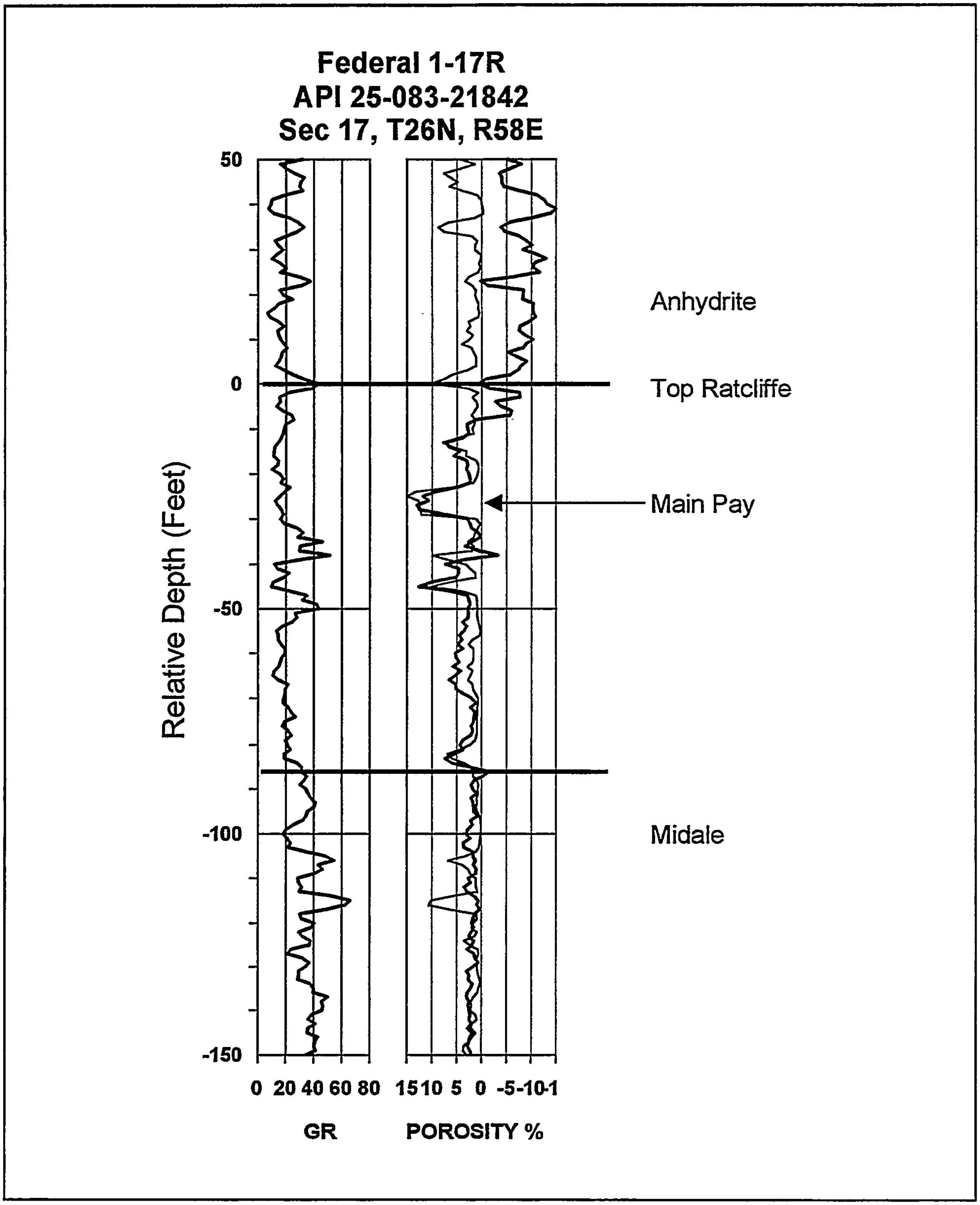


Figure 39: Ratcliffe type-log from North Sioux Pass Field.

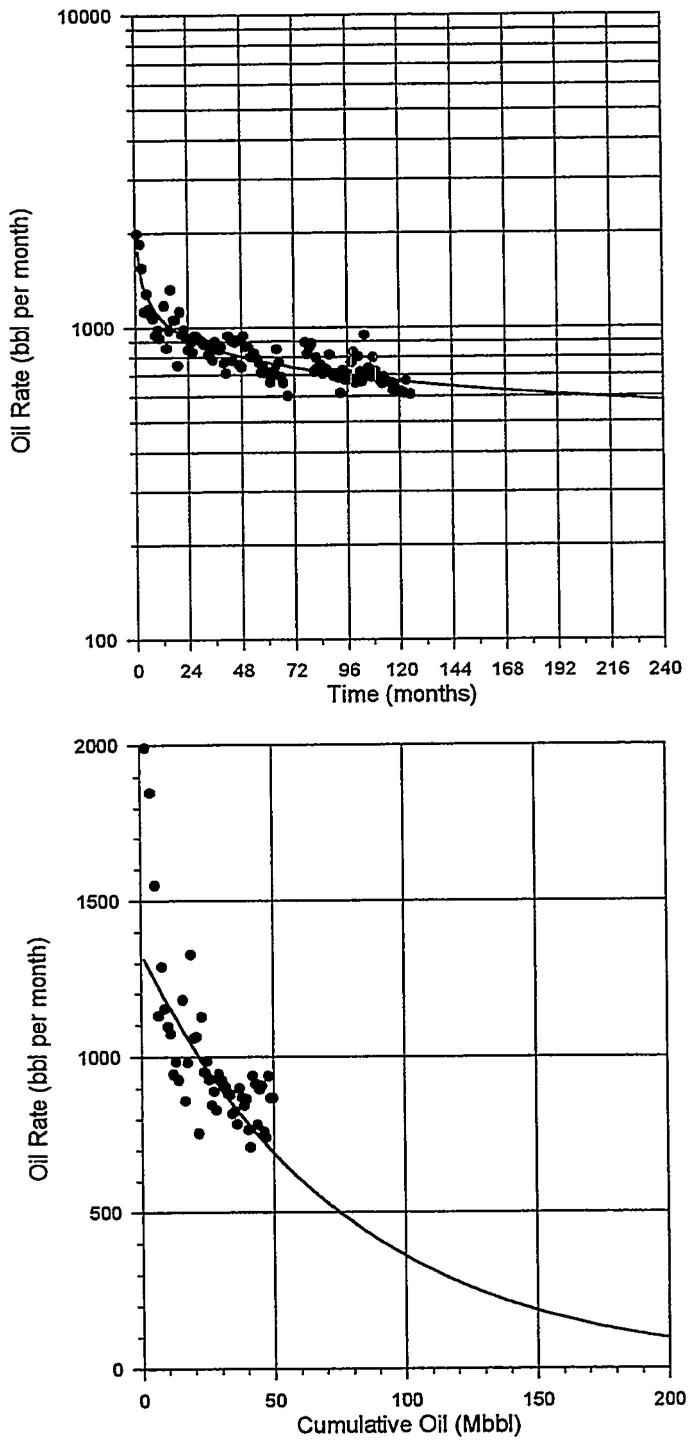


Figure 40: Normalized production curves from North Sioux Pass Field.

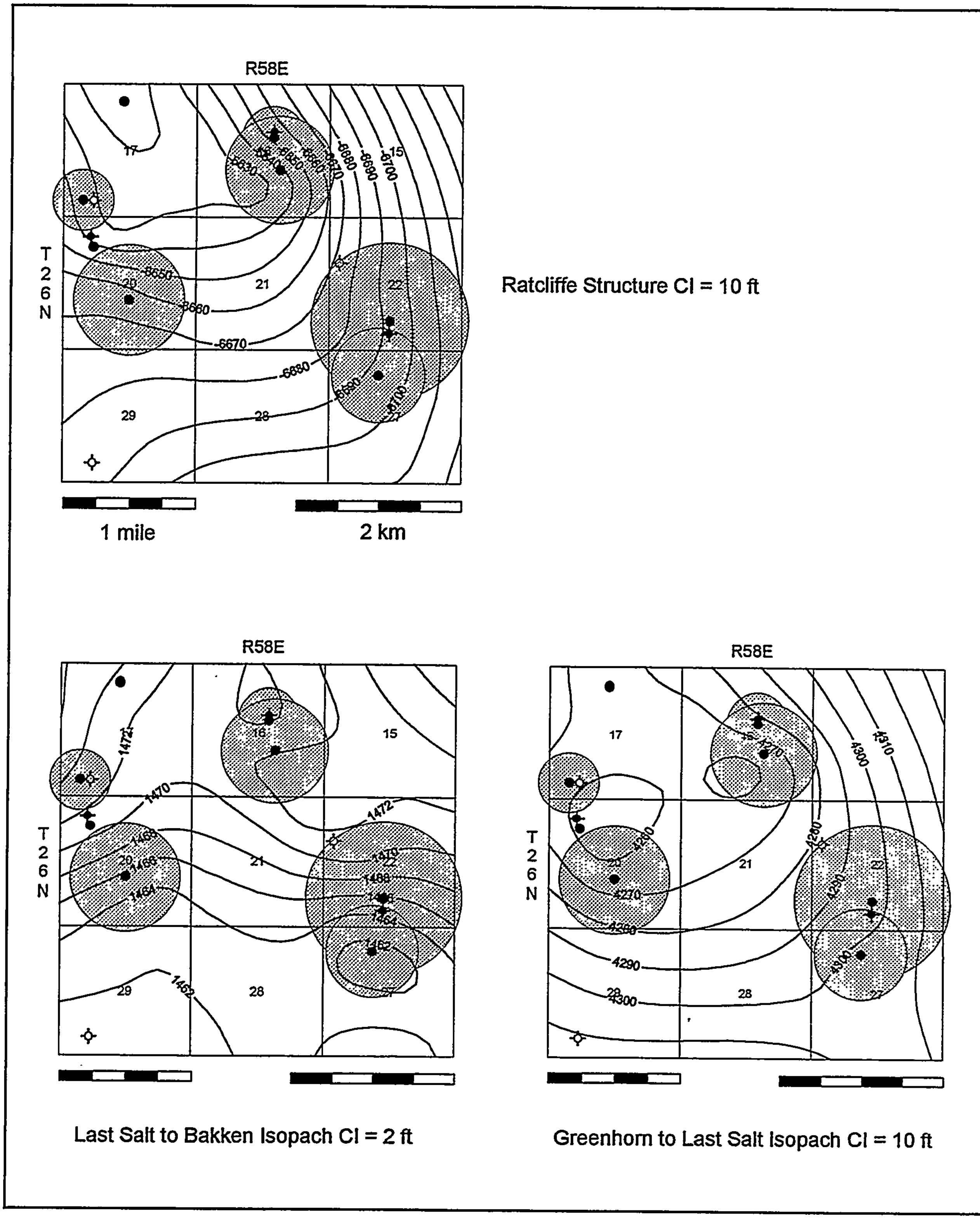


Figure 41: Relevant maps for the Ratcliffe at North Sioux Pass Field. Effective drainage areas are shown as shaded circles.

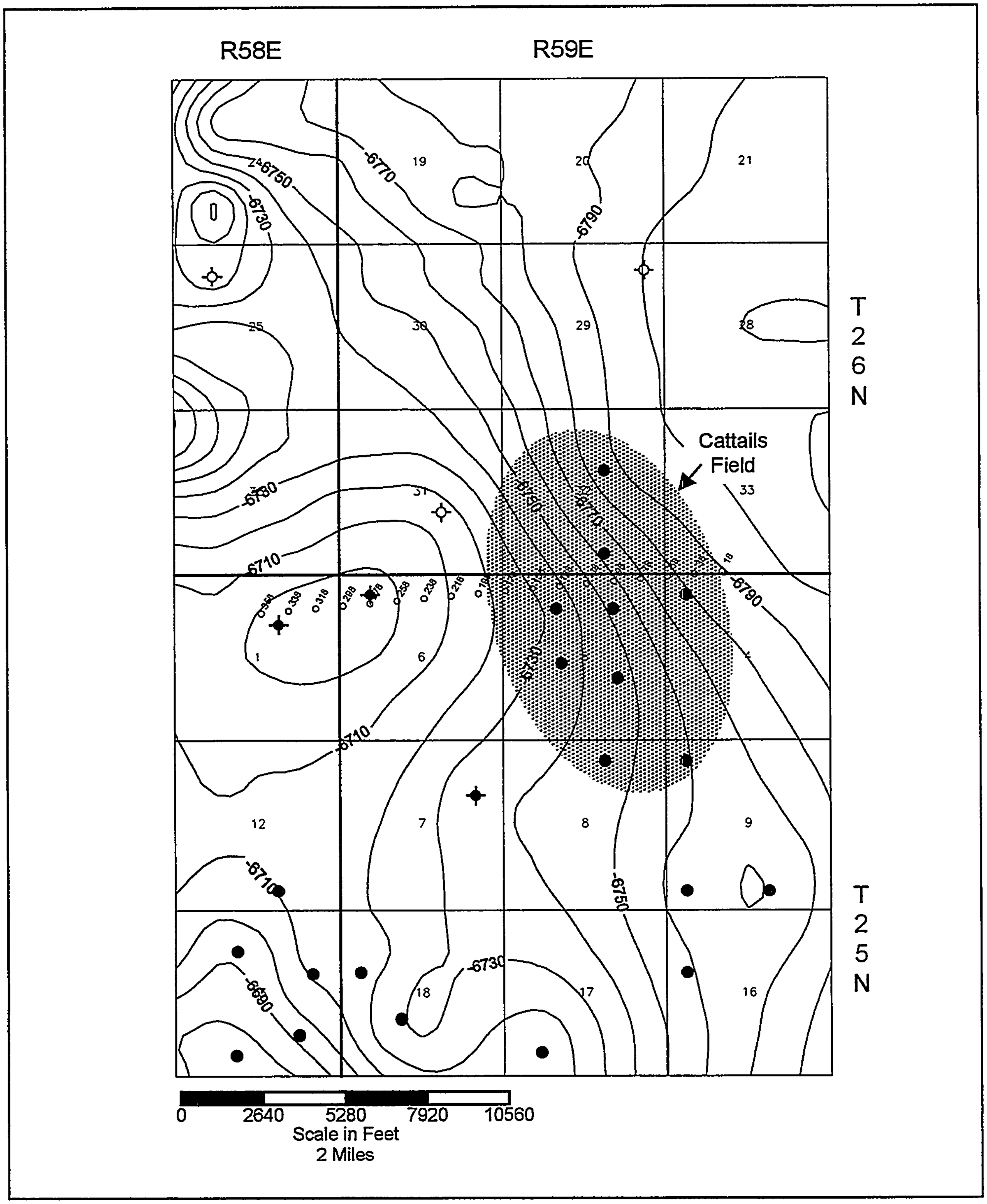


Figure 42: Location of multi-component 2D seismic line at Cattails Field. Contours are on the top of the Ratcliffe. C.I. = 10 ft.

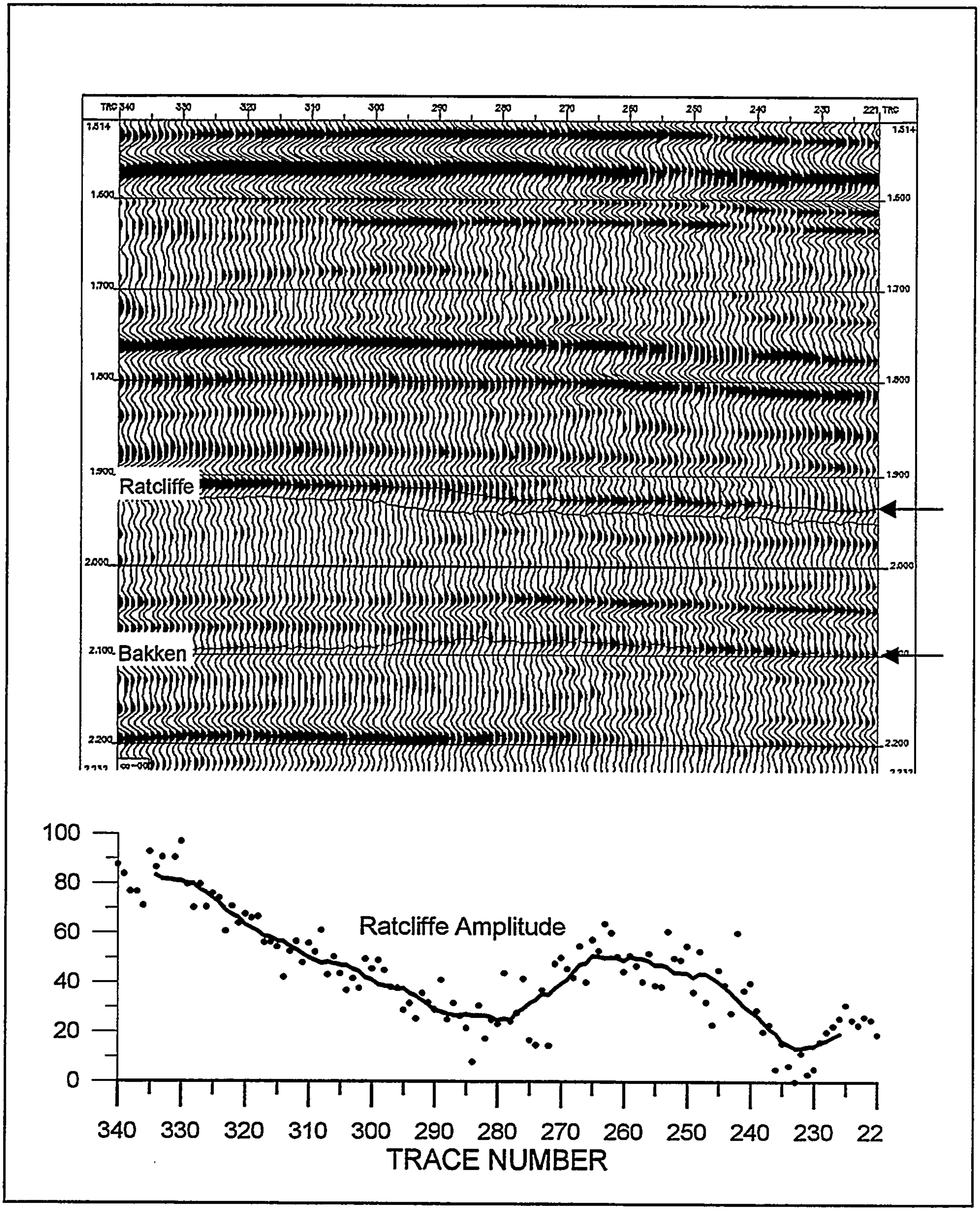


Figure 43: Seismic section with compressional data from Cattails test line. Relative amplitude is shown for Ratcliffe first-peak event.

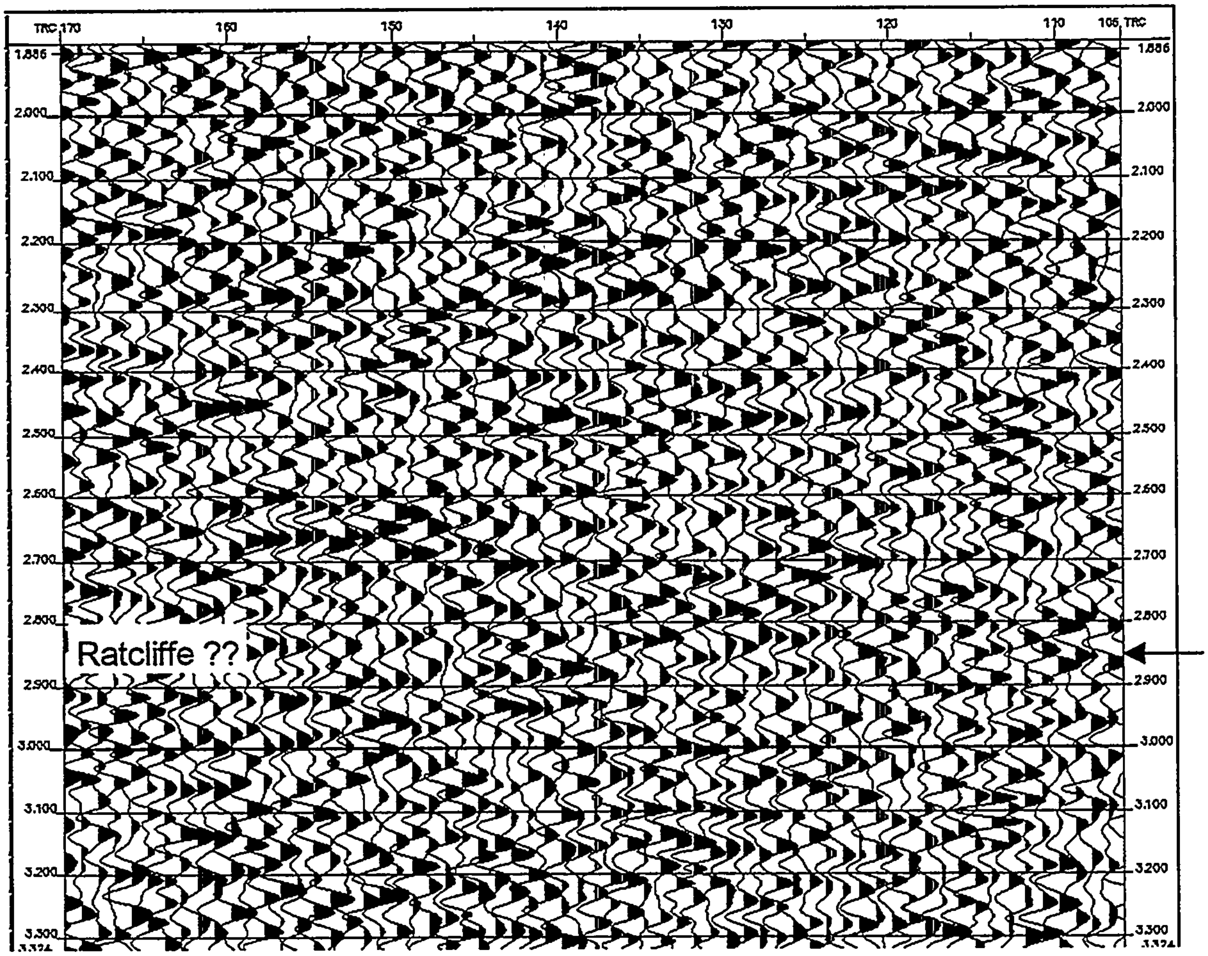


Figure 44: Seismic section with radial component of converted shear-wave data from Cattails test line. Coherent events are not observed.

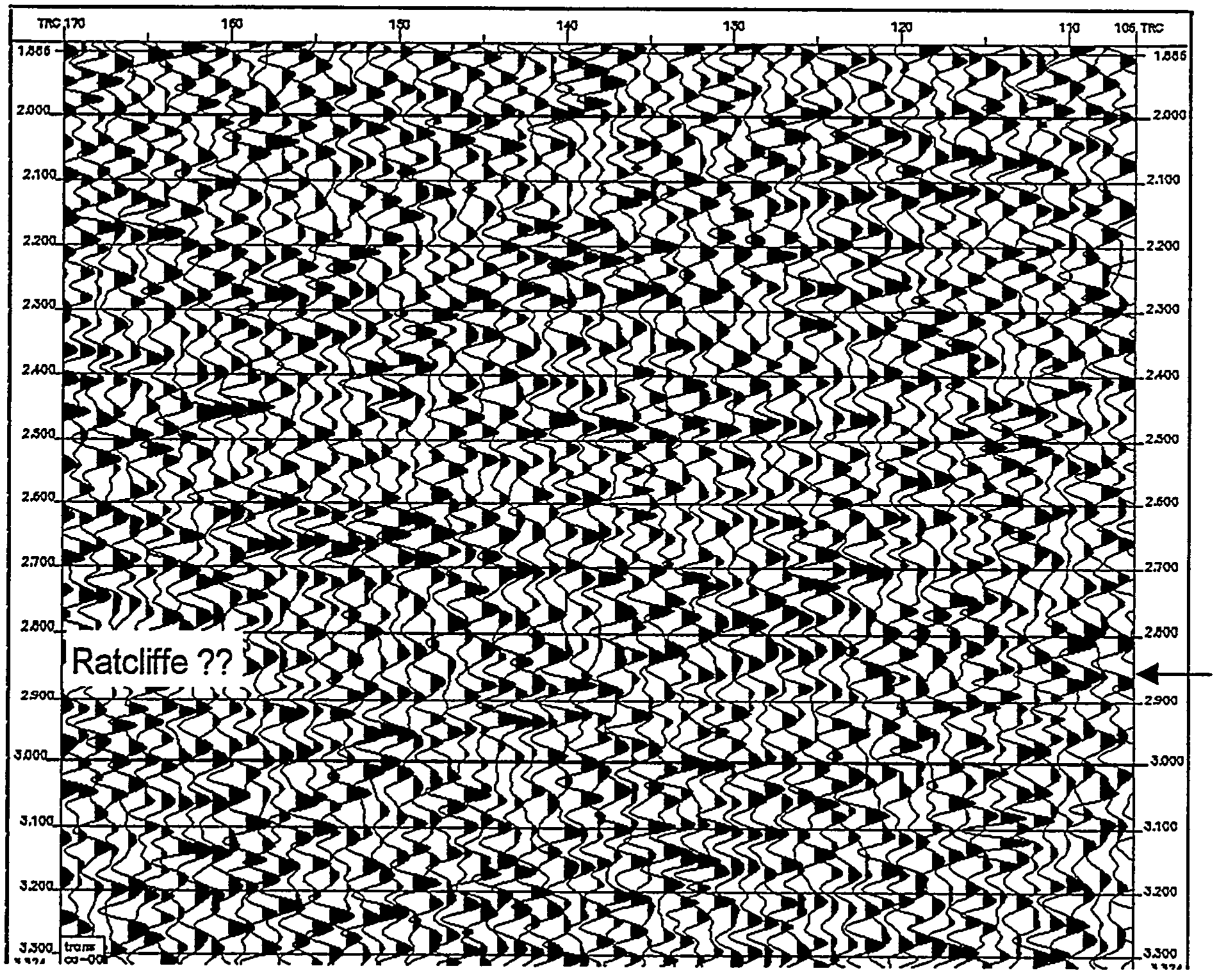


Figure 45: Seismic section with transverse component of converted shear-wave data from Cattails test line. Coherent events are not observed.

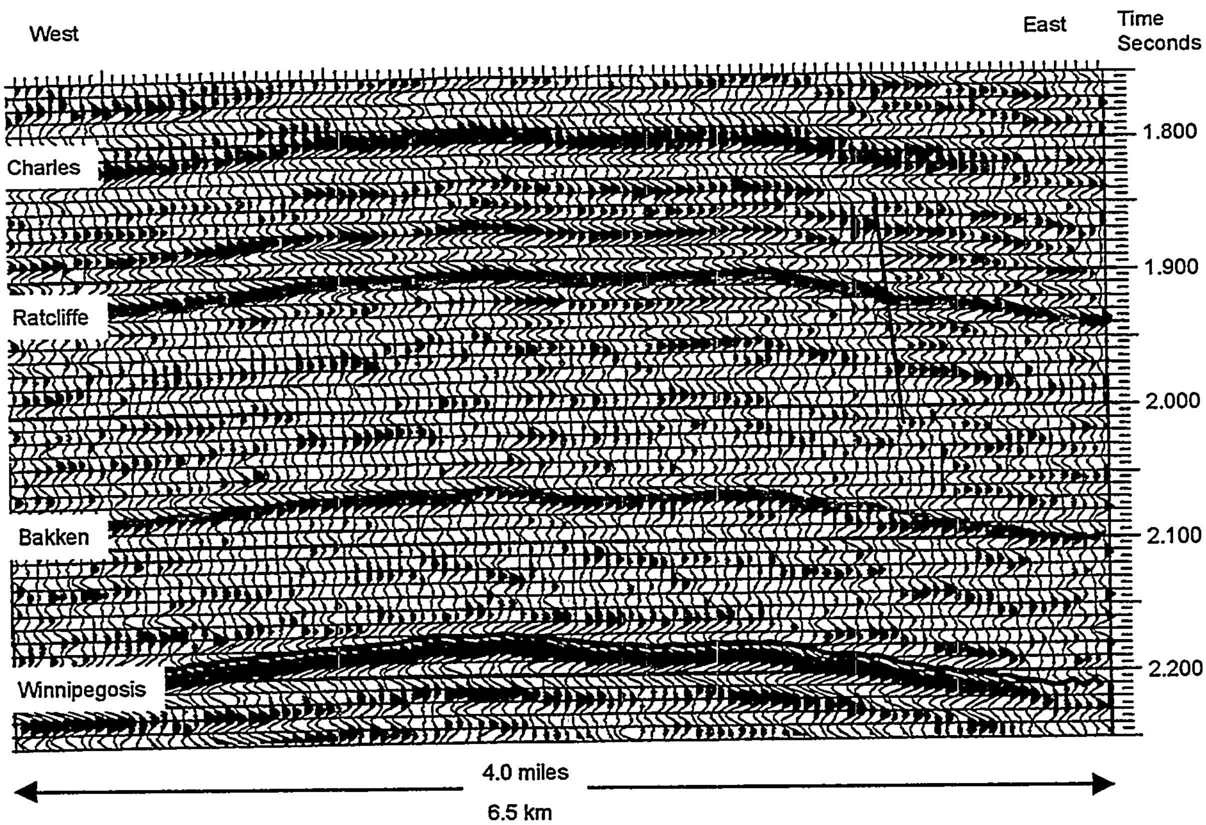


Figure 46: West-east seismic section (inline 229) across North Sioux Pass Field.

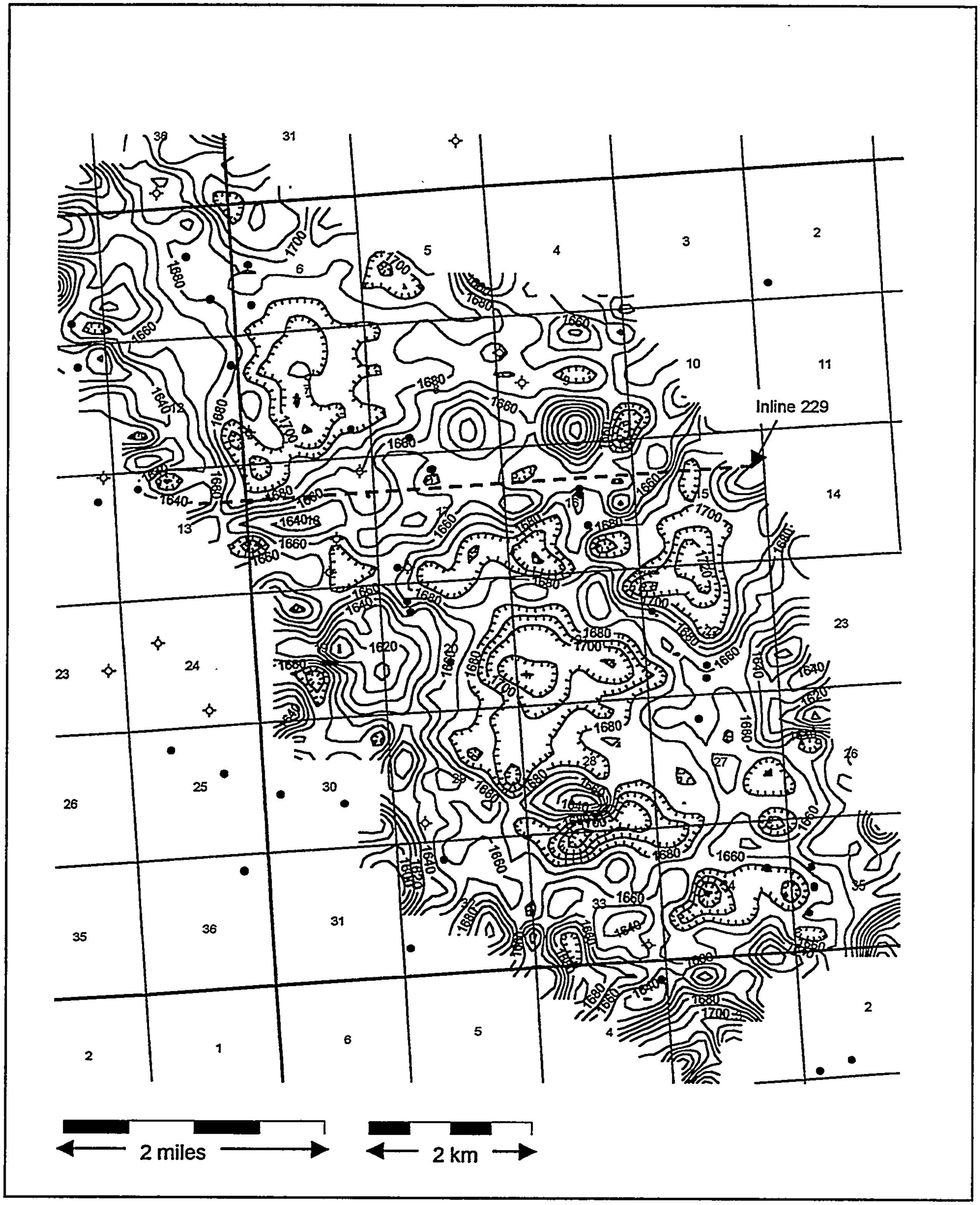


Figure 47: Map of Ratcliffe to Bakken isopach from 3D seismic at North Sioux Pass Field. Isopach values are computed from seismic interval time and velocity trends from well-log data. C.I. = 10 feet. Hachures indicate thickening direction.

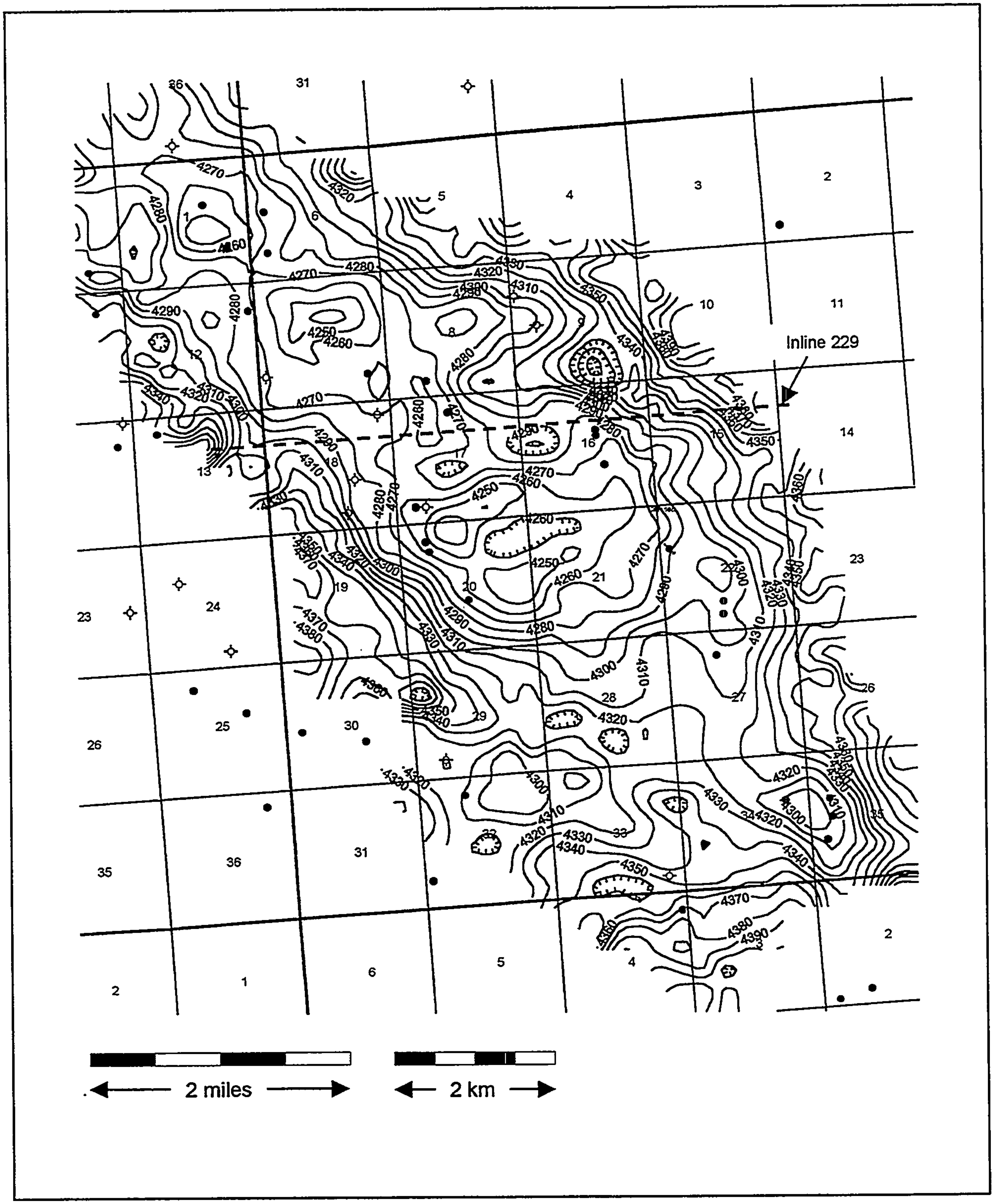


Figure 48: Map of Greenhorn to Ratcliffe isopach from 3D seismic at North Sioux Pass Field. Isopach values are computed from seismic interval time and velocity trends from well-log data. Hachures indicate thickening direction. C.I. = 10 feet.

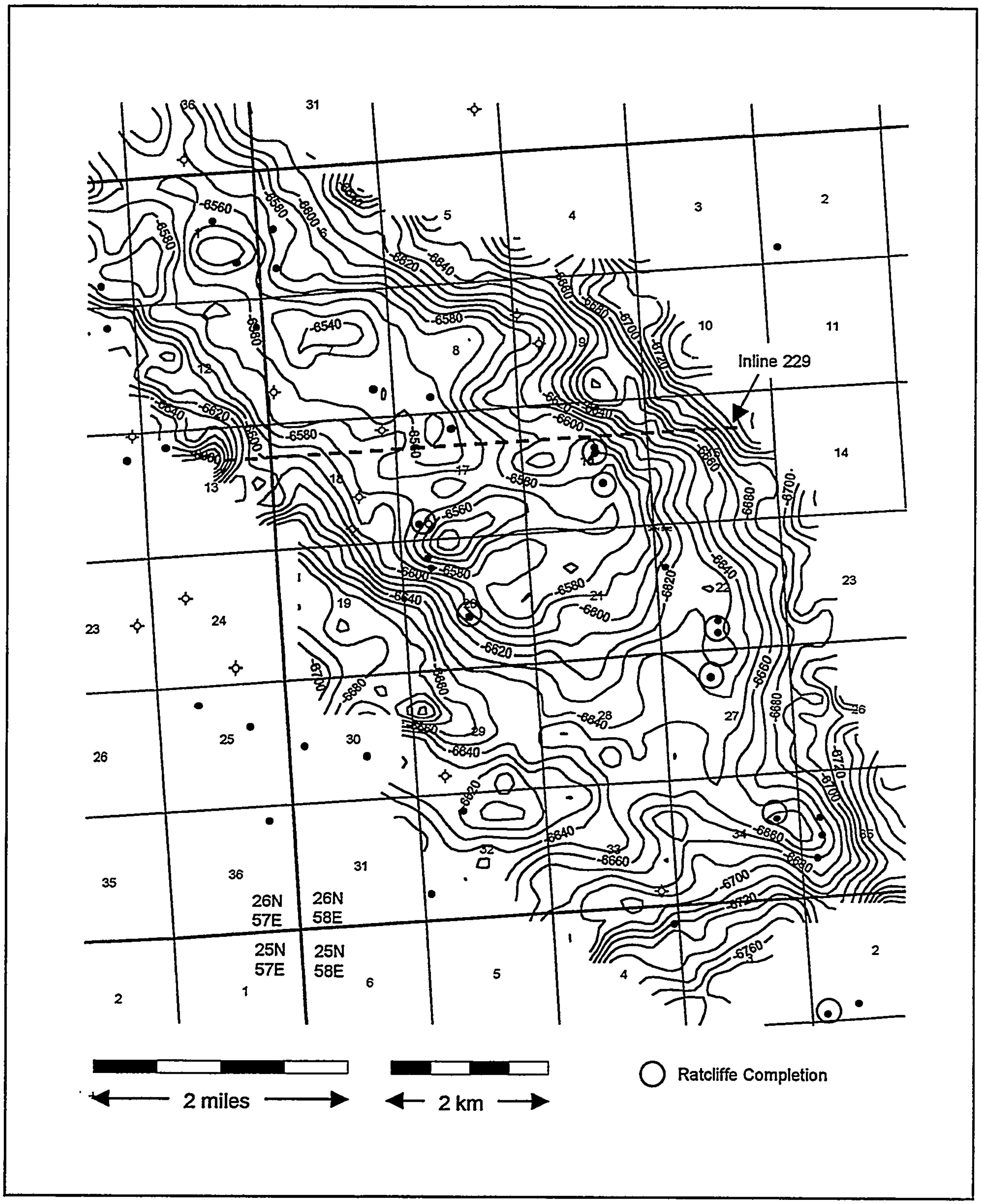


Figure 49: Map of Ratcliffe structure from 3D seismic at North Sioux Pass Field. Depth values are computed from seismic interval time and velocity trends from well-log data. C.I. = 10 feet.

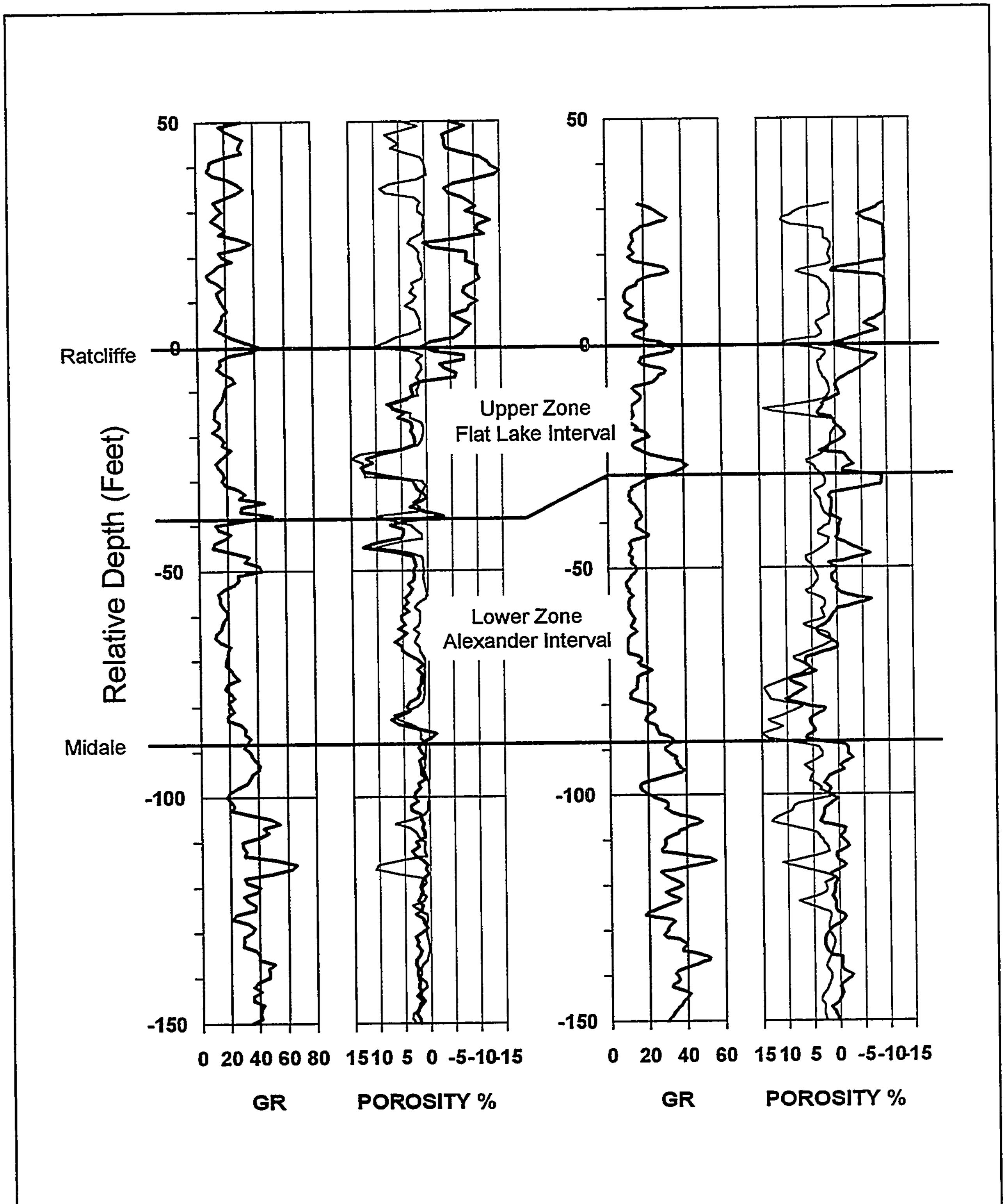


Figure 50: Ratcliffe type logs used for synthetic seismograms.

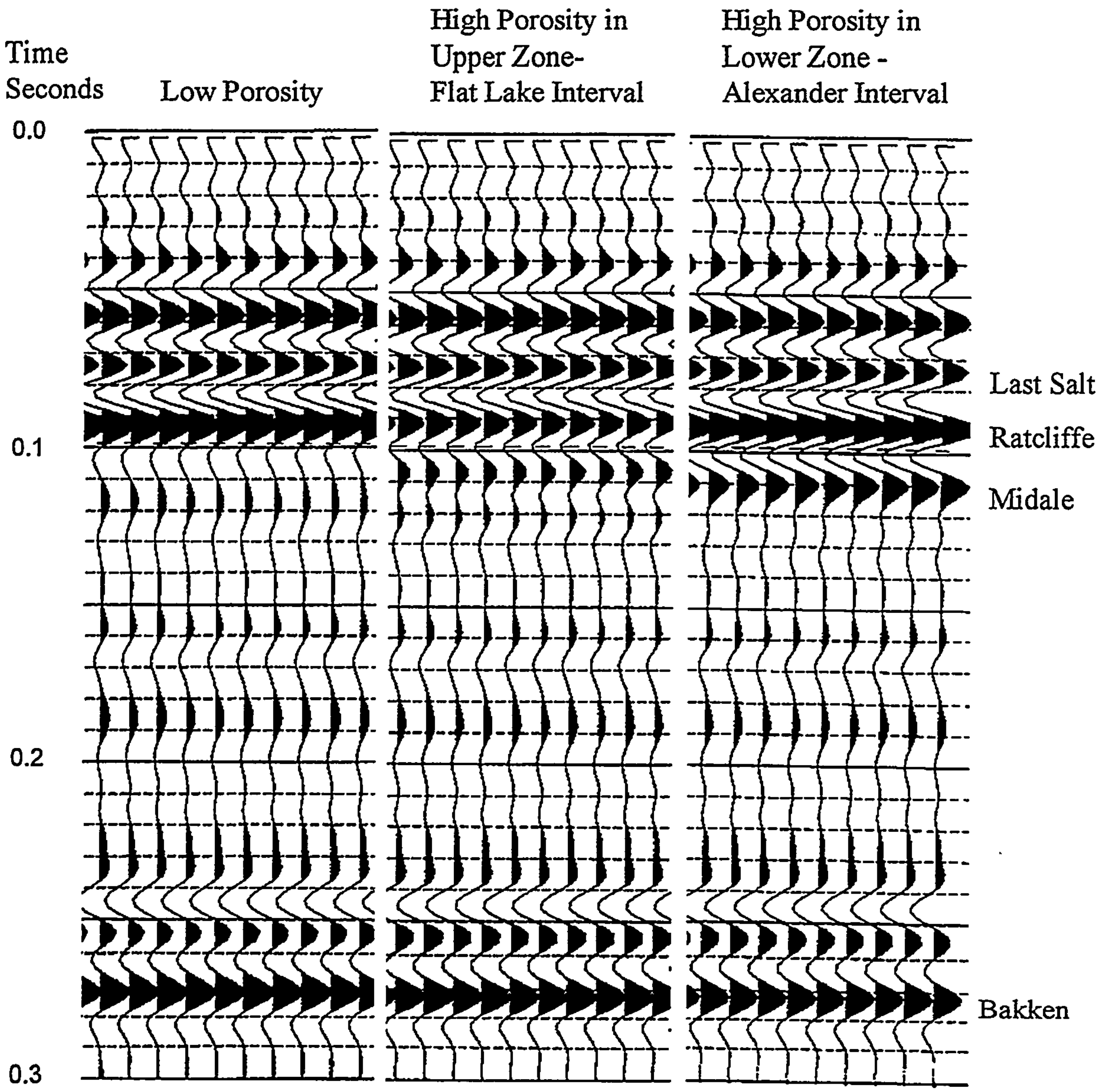


Figure 51: Synthetic seismograms of Ratcliffe variation. The top of Ratcliffe occurs approximately at 0.1 seconds. A greater negative response of the Ratcliffe trough amplitude corresponds to increasing porosity in either Flat Lake or Alexander intervals. A greater positive response of the underlying peak is associated with porosity development in the Alexander interval.

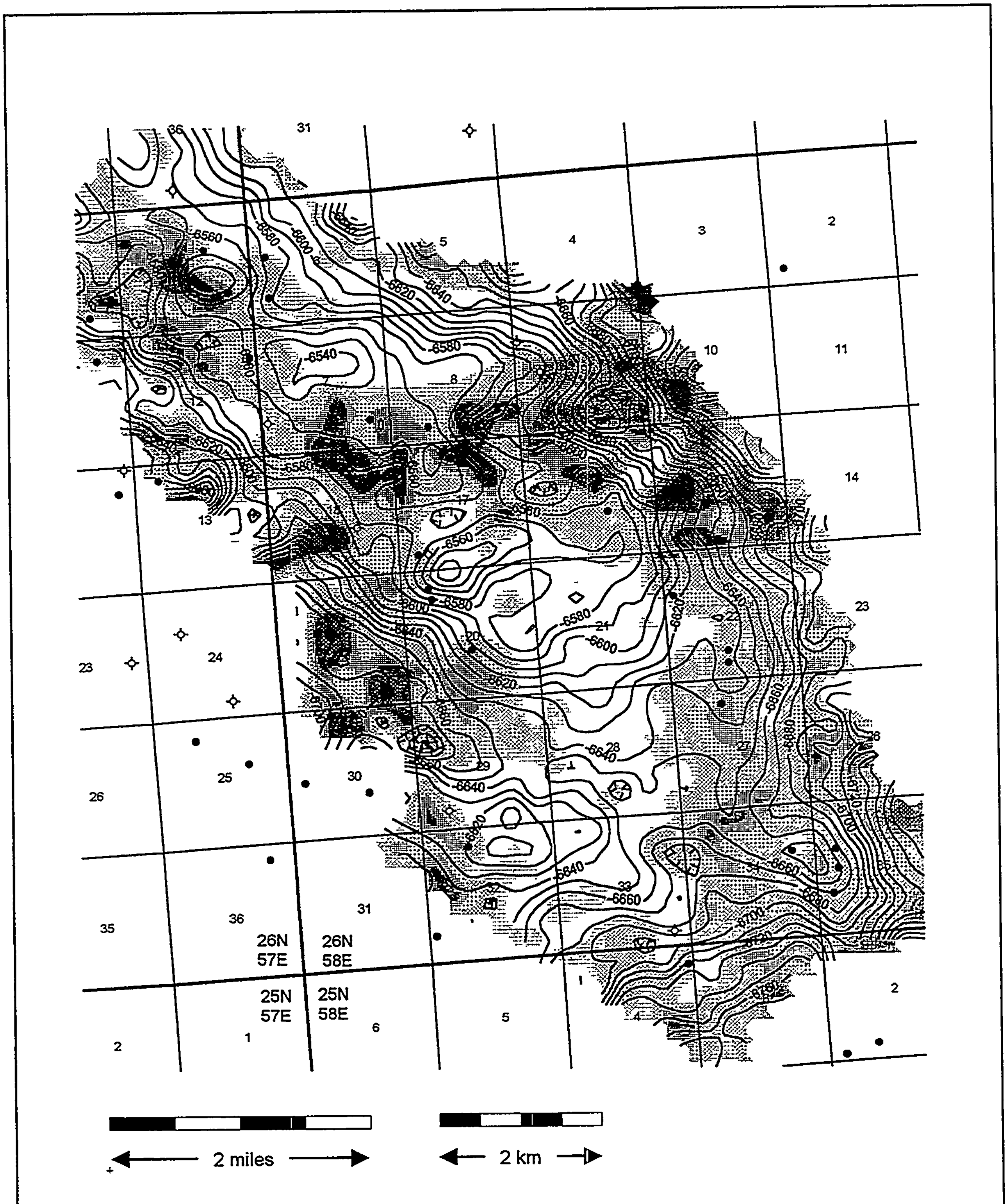


Figure 52: Map of Ratcliffe structure with seismic amplitude of Ratcliffe trough event. Darker shading indicates greater absolute amplitude response.

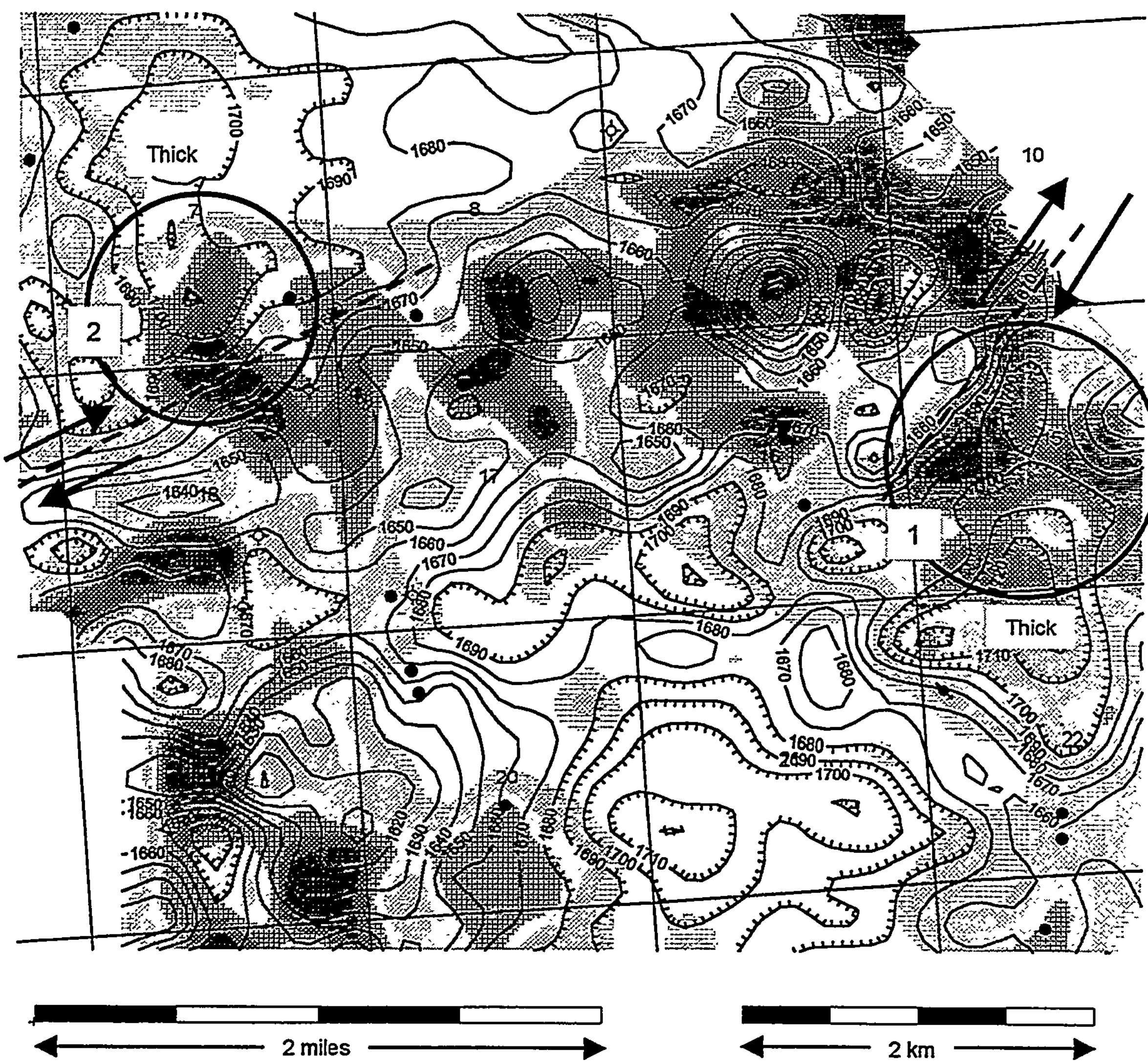


Figure 53: Map of Ratcliffe to Bakken isopach with Ratcliffe amplitude showing prospective areas for Ratcliffe drilling. Lineaments relating to recurrent movement are shown as dashed lines. Darker shading indicates stronger amplitude of trough event.

0

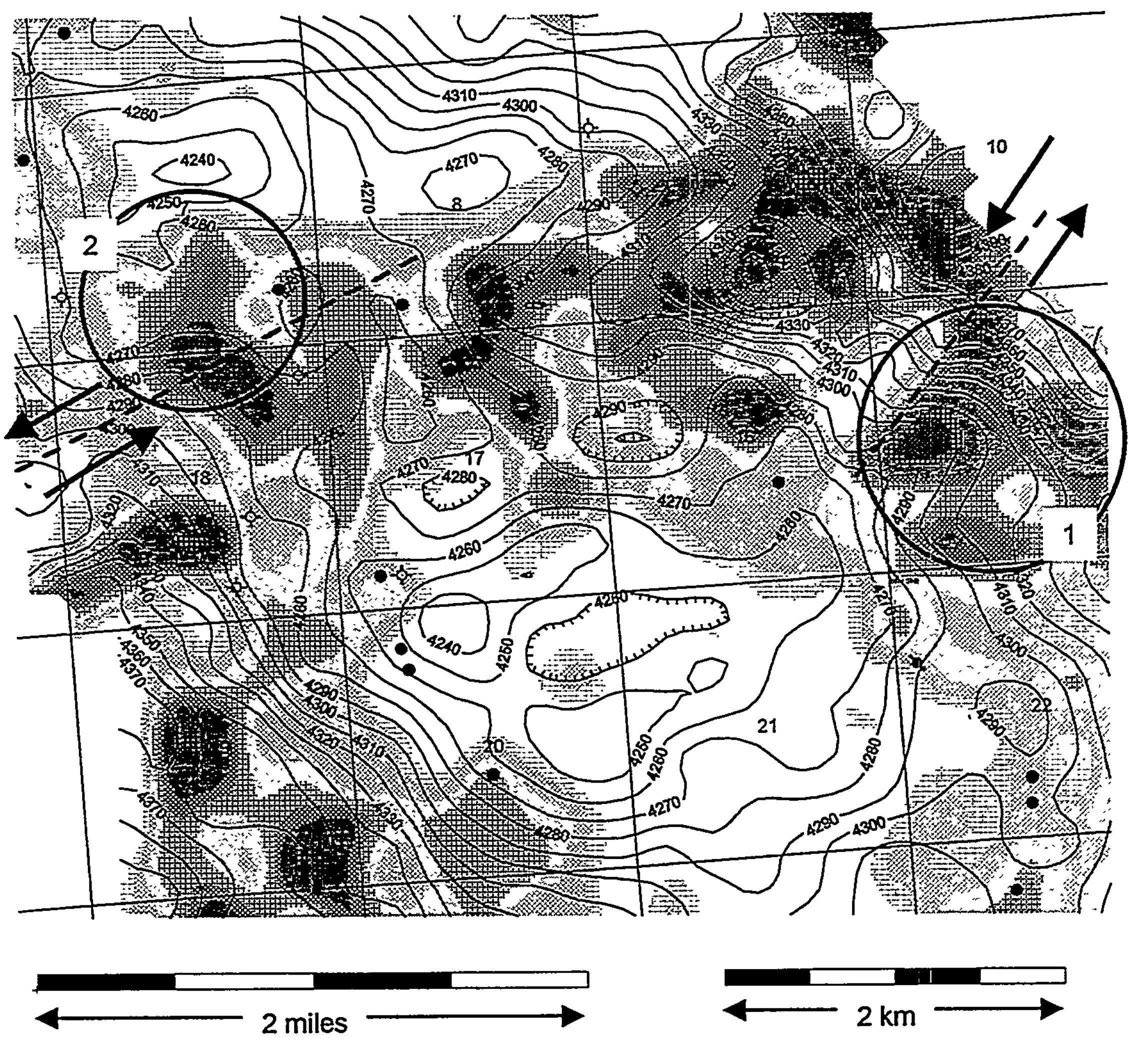


Figure 54: Map of Greenhorn to Ratcliffe isopach with Ratcliffe amplitude showing prospective areas for Ratcliffe drilling. Lineaments relating to recurrent movement are shown as dashed lines. Notice reversal of movement from figure 53. Darker shading indicates stronger amplitude of trough event.

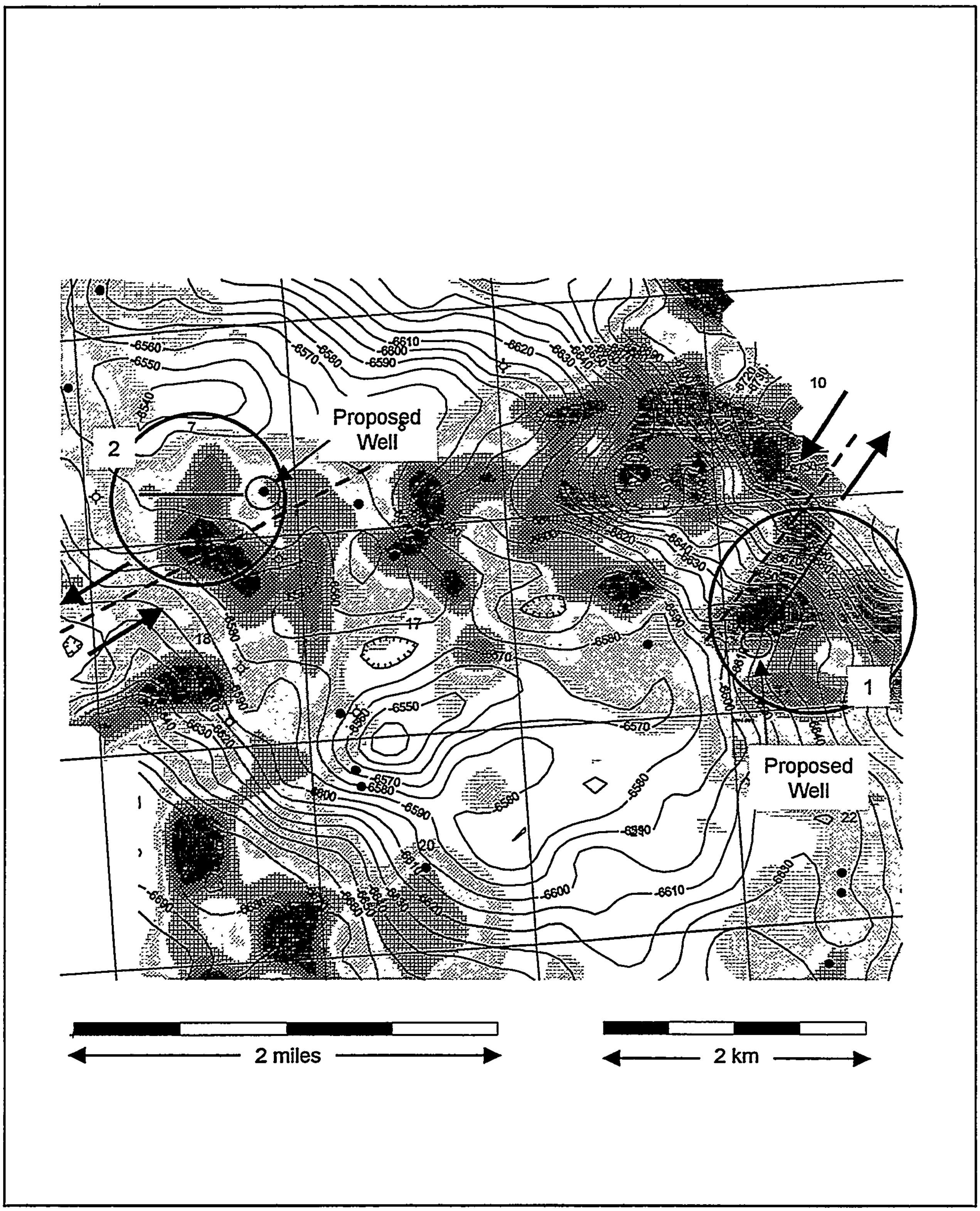


Figure 55: Map of Ratcliffe structure with Ratcliffe amplitude showing prospective areas for Ratcliffe drilling. Locations of proposed horizontal wells are shown. Lineaments relating to recurrent movement are indicated as dashed lines. Darker shading indicates stronger amplitude of trough event.