STRUCTURAL GEOLOGY AND HYDROCARBON PRODUCTION, BARNETT SHALE (MISSISSIPPIAN), FORT WORTH BASIN, NORTHWESTERN JOHNSON COUNTY, TEXAS

by

AMY ATAMANCZUK PATTERSON

Bachelor of Science, 2002
Texas Christian University
Fort Worth, Texas

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INTRODUCTION

The Barnett Shale (Mississippian) is the source rock for conventional reservoirs in north-central Texas and as an unconventional shale gas system is the source, seal, and reservoir for the largest gas field in the United States (Pollastro et al., 2007). In past decades, hydrocarbons sourced from the Barnett were produced from Pennsylvanian clastics within the Fort Worth basin, and also from Ordovician, Mississippian, and Pennsylvanian carbonates. Since the early 1980s, this black, organic-rich, petroliferous, siliceous mudrock has been developed into a world-class unconventional reservoir in Newark East field (Montgomery et al., 2005). Following the initial discovery of Newark East field in Wise County in 1981 by Mitchell Energy Corporation production from the Barnett expanded into Hill, Johnson, Tarrant, Denton, Wise, Young, Archer, Clay, Parker, Jack, Hood, Palo Pinto, Somervell, Ellis, and Montague counties (Montgomery et al., 2005) (Fig. 1).

In the initial development of the field it was thought that fractures and faults would provide natural conduits for moving natural gas from the shale to the wellbore (Bowker, 2007). However, after drilling and completing several wells, Mitchell Energy realized their best producers were located in unfaulted areas. In developing the field, the company implemented a policy of placing wells at least 5,000 ft or more from known major faults (Steward, 2007). In 1983, core analysis revealed that the dominant fracture system in the northern portion of the basin consists of a N-S trending set and a NW-SE trending set. However, most of the fractures are completely healed with calcite. Open fractures are rare in the Barnett and contribute little or nothing to well productivity (Bowker, 2007). With the introduction of horizontal drilling in 1998, Mitchell Energy found drilling and completing wells perpendicular to the NW-SE oriented fractures yielded the best production (Steward, 2007). The shift to horizontal drilling also

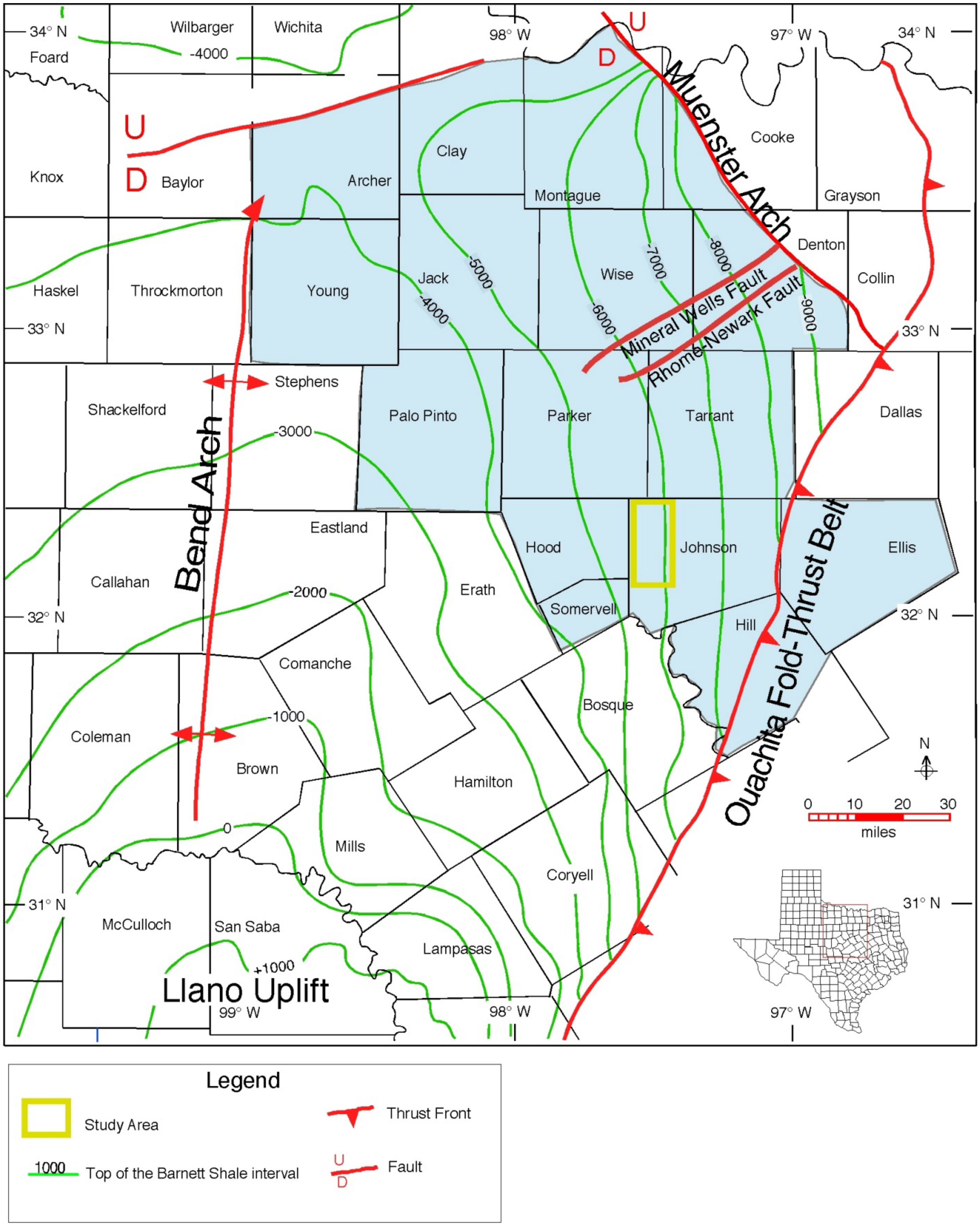


Figure 1: Map showing extent of Fort Worth basin. Shaded counties have Barnett Shale production.

highlighted the need for 3D seismic data to avoid collapse features and locally faulted areas in the Barnett associated with karsting of the underlying carbonates in the Ellenburger Group.

The location and orientation of tectonic structures and the size and distribution of karst-related disturbances in the Barnett must be known in order to maximize production of natural gas from the reservoir. Knowledge of these features has already been utilized in developing the Barnett Shale, both in selecting well sites and in choosing the direction to drill horizontal wells. In this study, I identify and map the faults and fractures in northwestern Johnson County (see Figs. 1 and 2 for location of the study area), establish their relative ages, and determine their origins. Also, I relate well productivity to the detailed structural setting with the goal of establishing guidelines for selecting well sites and orienting horizontals.

THE FORT WORTH BASIN

Basin Geometry and Bounding Structural Features

The Fort Worth basin is an elongated N-S trending, asymmetric trough covering approximately 15,000 mi^2 (Fig. 1). The deepest part of the basin is in the northeast corner where more than 12,000 ft of mainly Paleozoic strata are present. The basin shallows to the east, west and south. The northern margin of the basin is formed by the fault-bounded basement uplifts of the Red River and Muenster arches. The Bend arch forms the western edge of the basin. The Llano uplift—a domal feature that exposes Paleozoic and Precambrian rocks—lies to the south. The Ouachita thrust front forms the eastern edge of the basin.

Stratigraphy

The basin fill reaches a maximum thickness of approximately 12,000 ft in the northeastern corner adjacent the Muenster arch. The stratigraphic units that comprise the basin fill in that area include 4,000-5,000 ft of Ordovician-Mississippian carbonates and shales, 6,000-7,000 ft of Pennsylvanian clastics and carbonates, and a thin cover of Cretaceous rock in the

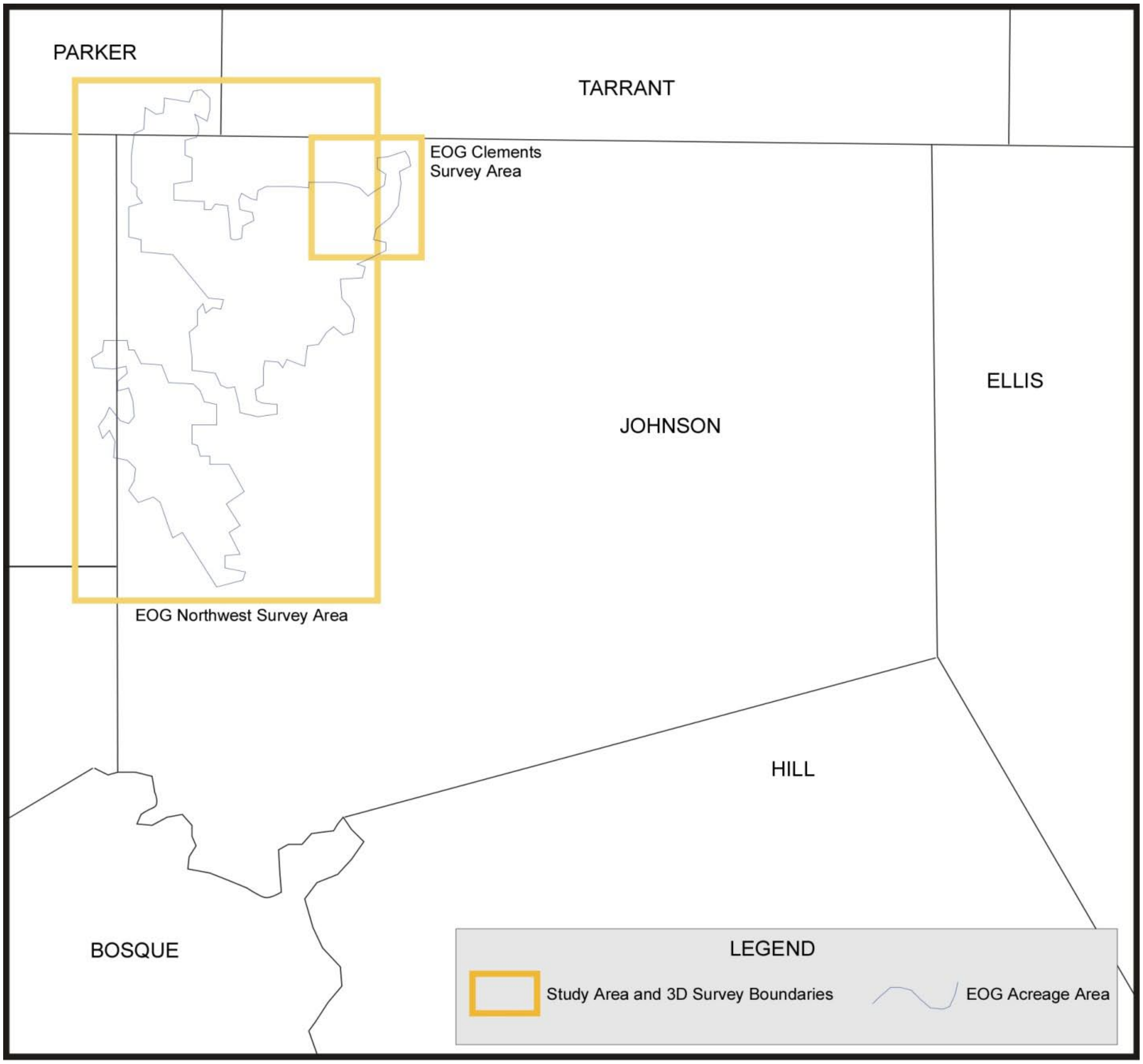


Figure 2: Map showing Northwestern Johnson County study area.

eastern part of the basin (Flawn, 1961). Within the Fort Worth basin, the Barnett Shale ranges in thickness from 300 to 1,000 ft with the thickest portions being in the northeastern part of the basin (Montgomery et al., 2005). It is found at depths of 6,900-7,500 ft in the subsurface in north-central Texas.

The fill of the basin consists mostly of Paleozoic strata (Fig. 3). Cambrian-Upper Ordovician strata include the Riley and Wilberns formations, the Ellenburger Group and the Viola-Simpson Group. Silurian and Devonian strata are not present in the basin (Flippin, 1982; Henry, 1982). The Middle to Upper Mississippian section includes the Chappel Limestone and the Barnett Shale. The Barnett lies unconformably on the Ellenburger or Viola-Simpson. Karst features, including collapse structures, are commonly present at the top of the Ellenburger Group. A slight angular unconformity separates the Mississippian strata from overlying Pennsylvanian strata, which include the Marble Falls, the Smithwick, and Atokan conglomerates, which are part of the Bend Group. The Pennsylvanian sequence represents the main phase of infilling in the basin related to the approach of the Ouachita structural front (Flippin, 1982; Henry, 1982).

The Viola-Simpson Group (Upper Ordovician) is found only in the northeastern part of the basin. These rocks are dense crystalline limestones and dolomitic limestones, respectively, that dip to the east beneath Mississippian units and thin to a zero edge in the central part of the basin. The Viola-Simpson pinches out to the south and west of the basin causing Mississippian rocks to lie directly above the Ellenburger Group (Flippin, 1982; Henry, 1982).

The Mississippian strata reach their maximum thickness along the southern edge of the Muenster arch. Here, the Barnett is approximately 1,000 ft thick and contains proportionally more limestone than elsewhere in the basin. Limestones in the Barnett decrease sharply to the south and west away from the Muenster arch (Bowker, 2002). In Newark East field, the

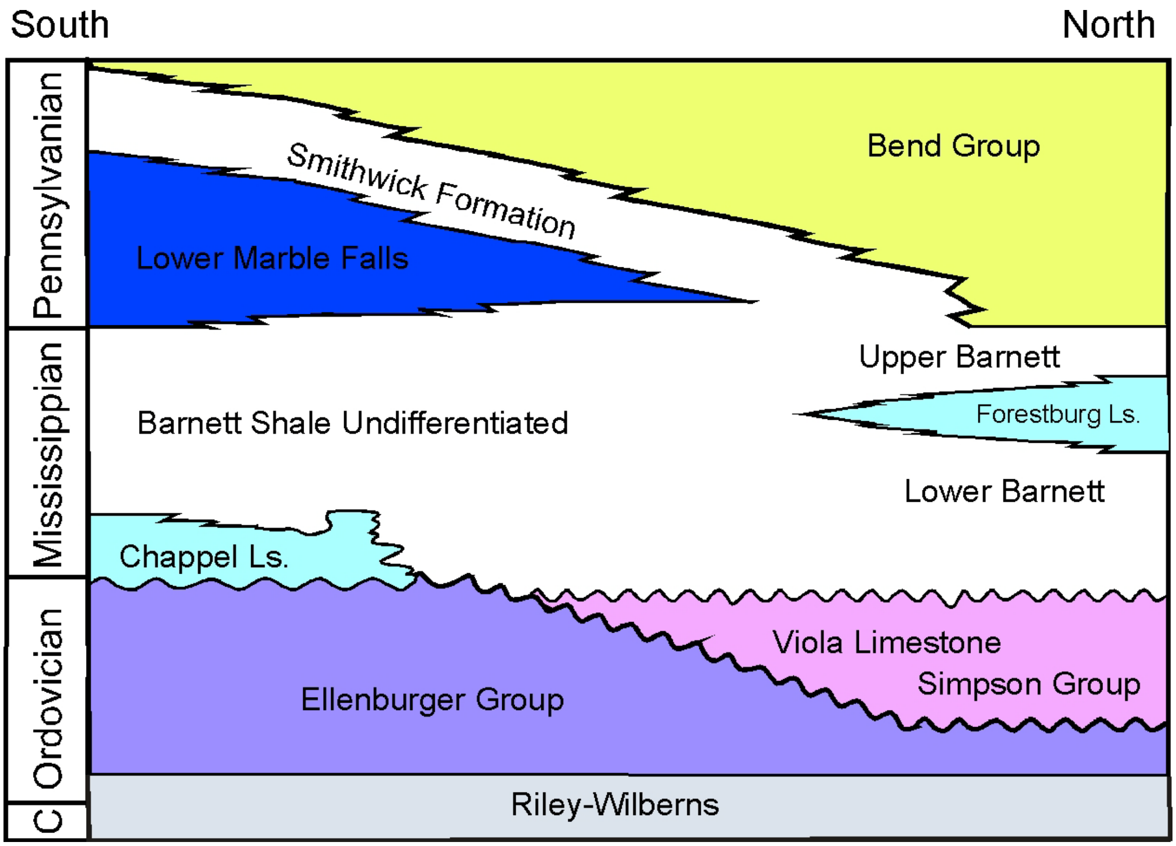


Figure 3: Paleozoic stratigraphy of the northern Fort Worth basin. C= Cambrian

Forestburg limestone divides the upper and lower shale members of the Barnett, but thins rapidly to the south and west to a zero edge in southern Wise and Denton counties. In the western part of the basin, the Barnett Shale interfingers with and thins over the top of the Chappel Limestone. To the south the Barnett thins over the Llano uplift and southern extension of the Bend arch.

Tectonic History

Tectonism affected north-central Texas from the late Precambrian through the Permian (Fig. 4). Reconstructing the Precambrian history on the southern margin of the United States is difficult because outcrops are sparse and few wells penetrate basement rock (Walper, 1977). Basement rocks from New Mexico, West Texas, and Central Texas date from 1,050 to 1,350 Ma (Denison et al., 1970). Extensive intrusive activity and granitic emplacement occurred approximately 1,150 Ma. The Llano region of central Texas experienced intrusive activity and metamorphism at 1,020 Ma (Denison et al., 1970). Serpentinite in the region has been interpreted as obducted oceanic crust and mantle from the closing of a Proterozoic ocean (Sengor and Butler, 1970). Between 900 and 1,000 Ma the North American plate was sutured with a proto-Afro-South American plate to form the Precambrian supercontinent Rodinia (Walper, 1977). Following this, tectonic activity shifted to the rifting of this Precambrian supercontinent.

The late Precambrian rifting event (Fig. 4A) that caused the breakup of the Rodinian supercontinent created the Iapetus Ocean. Aulacogens along the southern margin of North America (e.g. Southern Oklahoma aulacogen) provide evidence for the Proterozoic rifting event (Walper, 1975). Aulacogens extend deep into the continental interior at high angles to rifted plate margins. If the rifted margin is subsequently involved in episodes of convergence and continental collision—as the Southern Oklahoma aulacogen was—the compressive stresses often reactivate faults created during the rifting event. This inheritance of tectonic features can lead to complex relationships within the basin (Hoffman, 1973).

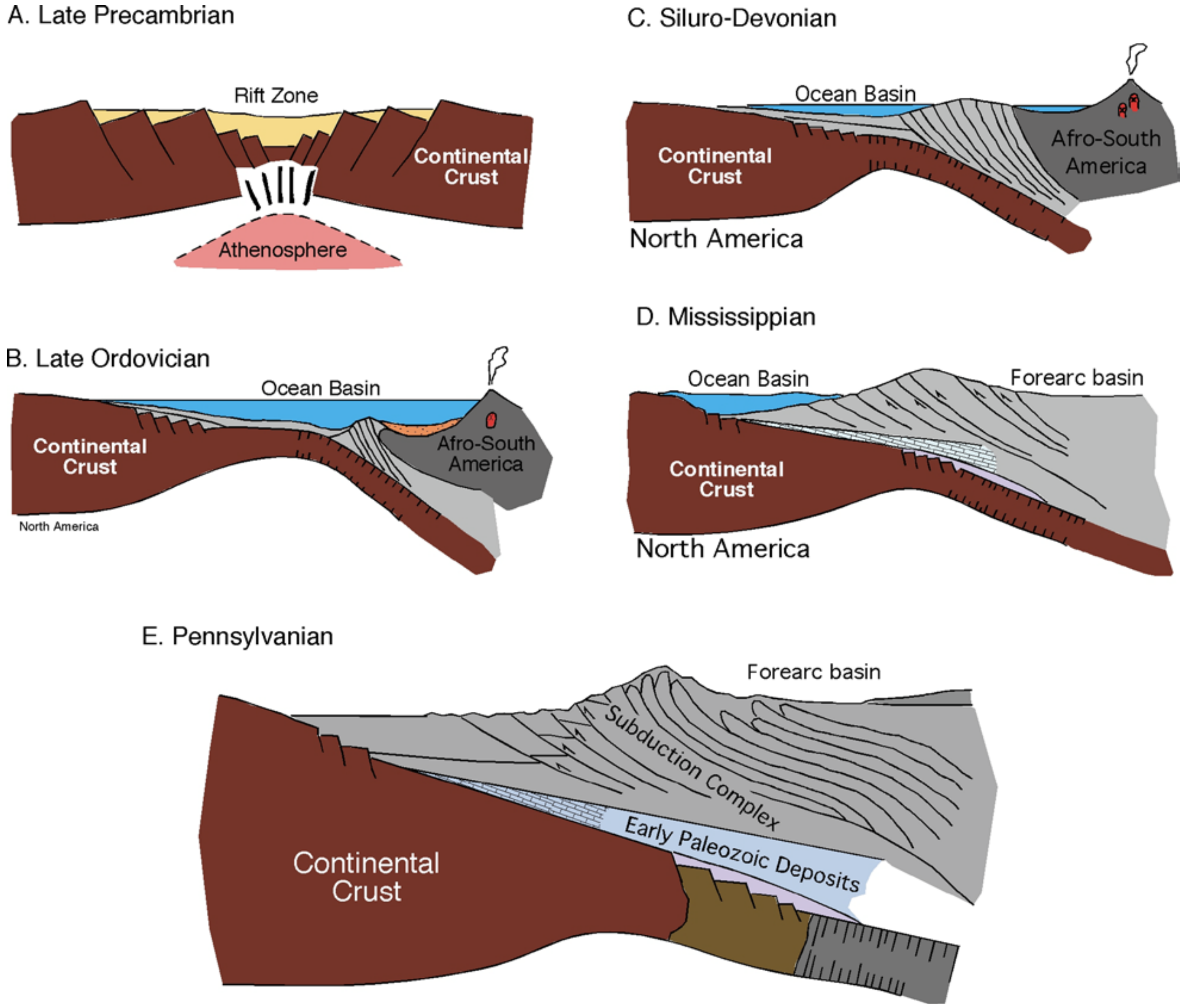


Figure 4: Schematic showing the tectonic evolution of North-Central Texas. See text for explanation. Modified from Walper (1977).

By the late Ordovician, plate motion reversed and the North American plate started to converge and subduct under the Afro-South American plate (Fig. 4B), forming an arc-trench system adjacent the southern continental margin of North America. An accretionary wedge complex formed of early Paleozoic strata. It developed on the overriding plate as material from the down-going oceanic plate scraped off during subduction. Continued subduction resulted in the growth of the accretionary complex during the Siluro-Devonian (Fig. 4C) (Dickinson, 1976).

In the late Mississippian, the southern continental margin of North America was drawn into the trench (Fig. 4D). This resulted in the uplift of the subduction complex and the erosion of sediment, which filled foreland basins associated with and adjacent to the Ouachita thrust belt. Convergence continued and the wedge of folded strata was thrust over the plate margin (Walper, 1977). In the Texas area of the North American craton, where the landmass was rigid and stable, the collision formed the highly metamorphosed interior zone of the Ouachita belt (Rozendal and Erskine, 1971). In the Fort Worth basin, the Bend arch marks the forebulge. As the thrust front advanced, the Bend arch migrated westward in response to the compressive stresses of the orogeny (Walper, 1975: DeCelles and Giles, 1996). The compressive stresses of this event also reactivated older faults associated with the aulacogens and this caused both vertical and transcurrent movement within the basin (Walper, 1977).

Basin Fault and Fracture Patterns

Several documented fault patterns are present in the Fort Worth basin. Thrusting on the eastern edge of the basin during the Ouachita orogeny created a fault system trending parallel to the thrust front, in approximately a NE-SW direction, perpendicular to principal stress (Gale et al., 2007). These faults extend through Wise and Denton counties, and exhibited normal and reverse fault characteristics (Steward, 2007). Also in the northern portion of the basin, there are N-S and NW-SE fracture trends that were documented by Mitchell Energy (Steward, 2007). The southern portion of the basin contains roughly E-W trending minor (100-1,000 feet long) normal faults caused by the opening of the Gulf of Mexico (Browning, 1982).

Basin Karsting

Strata in the Fort Worth basin above the Ellenburger Group were also affected by karst collapses occurring before, during and after the deposition of the Barnett Shale (Ruppel and Loucks, 2008). The Ellenburger was affected by at least five karsting events ranging in age from late Ordovician to early Pennsylvanian (Canter et al., 1993). Prior to the deposition of the Barnett Shale, the upper part of the Ellenburger and any Silurian or Devonian strata that may have been present were removed by erosion. Extended subaerial exposure allowed for near-surface processes including dissolution excavation to create void spaces in the carbonates of the Ellenburger group (Loucks, 1999). Multiple cave-forming episodes took place producing composite unconformities with different levels and stages of dissolution and collapse (Loucks, 1999). When the seas returned, waters invaded existing voids and tunnels and further developed an interconnected cave system at various levels.

Most cave systems form three dimensional megapore complexes in distinct geometric patterns (Loucks, 1999). The Ellenburger cave system displays a rectilinear pattern. Canter et al. (1993) attributed this pattern to solution enhancement (cave development) of orthogonal NE-SW and NW-SE trending joint systems that formed during the Early Ordovician. The caves within the Ellenburger seem to be concentrated at the points of intersection of the two joint systems (Canter et al., 1993). From the Ordovician through the Pennsylvanian, the caves developed, collapsed, and filled with chaotic breccia derived from ceiling and wall rock. Sags and faults may form as predominant features over the collapsed passages and, depending on the timing of karst-forming events, the formations deposited pre-, syn-, or post-collapse are variably affected (Fig. 5).

HISTORY OF NEWARK EAST FIELD

George Mitchell became active in the Fort Worth basin in the early 1950's as the owner of Oil Drilling, Inc. The company's primary target was the Bend Conglomerate (Steward, 2007). The company and subsequent companies that followed eventually became Mitchell Energy, which went public in 1972 on the American Stock Exchange (Steward, 2007). In the 1970s, Mitchell Energy gained expertise in unconventional, tight-gas reservoirs in North Personville field in Limestone County, Texas. In 1981, Mitchell drilled the C.W. Slay No. 1 in southeast Wise County, Texas. The well was drilled for a shallow target but was approved to drill deeper to test the Viola Limestone and the lower shale member of the Barnett (Steward, 2007). Only minimal natural gas shows were seen in the Barnett, but another operator documented significant gas shows while drilling a well in the same interval south of the Mitchell well. George Mitchell looked to the Barnett Shale to replace declining production from the Bend Conglomerate to fulfill natural gas pipeline capacity contracts (Steward, 2007).

Mitchell Energy opted to use the Austin Chalk play as a geologic model for the Barnett because not much information was available on the Barnett as a reservoir. Open, natural fractures resulting from faults and flexure zones within the basin were assumed to be essential for economic production from the Barnett. Tectonically quiet areas would be avoided because these areas would lack the production-enhancing fractures and faults (Steward, 2007). In 1982, Mitchell Energy filed for a field discovery in the Barnett Shale as a tight gas reservoir. The field was eventually named the Newark East (Barnett Shale) gas field. The "tight gas" designation gave the company tax savings on pricing of the gas. The designation was approved in 1985 at

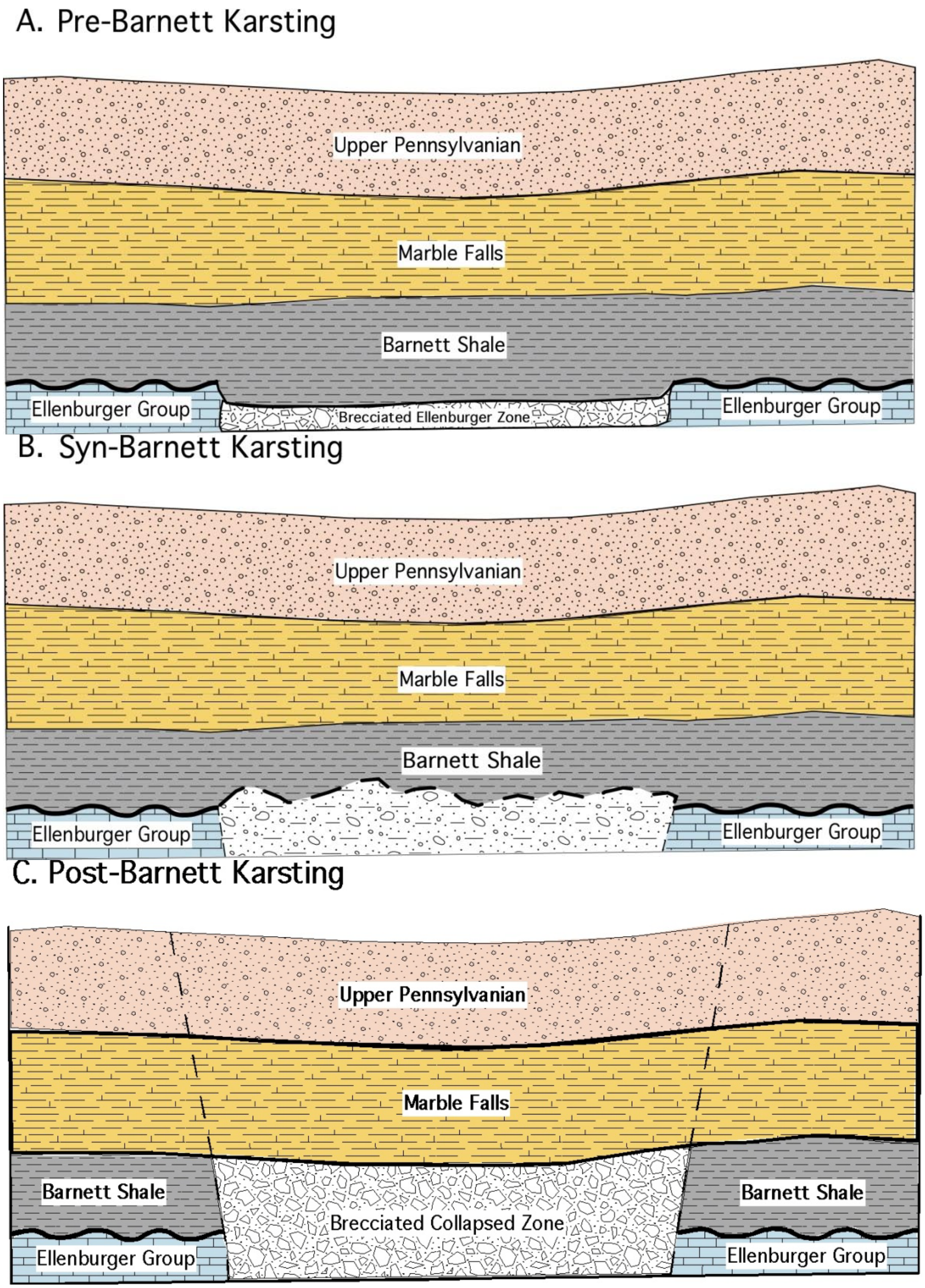


Figure 5: Cartoon showing effect of karst timing on strata in the Fort Worth basin.

the Federal Energy Regulatory Commission hearing. The field covered Wise County, the western half of Denton County, and the northwest corner of Tarrant County (Steward, 2007).

The first wells in the field were vertical wells drilled in areas where the Barnett had both upper and lower fracture barriers. The barriers were necessary to prevent hydraulic fracturing from going outside of the intended lower Barnett zone. Economics required that the wells be completed in shallower reservoirs as well as the Barnett. Mitchell Energy began taking core and running extensive geological analyses, initially in the lower Barnett (below the Forestburg limestone) and later in the upper Barnett. The search for the most productive zone in the shale took place from 1983 through 2000. Mitchell found that the Barnett Shale was unique compared to other shale gas systems, such as Devonian shales in the northeastern US, because it produced from greater depths and at higher pressures. The origin of the hydrocarbons was entirely thermogenic and both gas and liquids were produced (Montgomery et al., 2005).

The Fort Worth basin has a complex thermal history. Thermal maturity varies irregularly across the basin. The gas window occurs in the southeastern portion of the basin and grades through to the oil window in the northwestern extent of the basin. In Newark East field, the wells produce from 7,500 ft from an average formation thickness of 500 feet. Total Organic Carbon (TOC) values in the central and northern areas of the basin range from 3-13% (averaging 3.3% TOC per weight) (Jarvie et al., 2001; 2007). Core analysis indicates porosities of 5-6% and permeabilities of less than 0.01 millidarcies in the shale (Bowker, 2003). The water saturation of 35% in the Barnett represents bound-water in clay minerals. Free water appears to be absent in the reservoir (Johnston, 2004). The US Geological Survey estimated the technically recoverable gas in the basin to be approximately 26.2 tcf in 2003 (USGS, 2003). However, the estimated ultimate recoverable reserves increase year after year due to increased efficiencies of natural gas extraction driven by advances in technology. Texas Railroad Commission production data for the Barnett Shale indicate 7.0 tcf of gas was produced from 1993 to 2009 (Fig. 6).

Knowledge of fractures and faults in the basin was a major factor changing the way the Barnett Shale was exploited as the field developed. Core taken by Mitchell Energy in 1983 showed the dominant fracture system in the northern portion basin trended N-S. A NW-SE trending set of complementary fractures was also present in the northern portion of the basin (Steward, 2007). A majority of the fractures in the core were completely healed with calcite. The shale was not a fractured reservoir play like the Austin Chalk. In addition, after drilling and completing several wells, Mitchell Energy realized that the best producers were actually in tectonically quiet areas some distance removed from major regional faults in Wise and Denton counties (Steward, 2007).

Most operators were not aware of major fault systems in Wise County before the onset of drilling in Newark East field (Steward, 2007). Two major fault systems are present in the northern part of the basin. The Mineral Wells fault system and the Rhome-Newark fault system are en-echelon, almost vertical faults in central and southeastern Wise County, respectively. These fault systems trend NE-SW. Faults in each system show both normal and reverse movements along their length and both fault systems are believed to belong to a strike-slip wrench fault regime (Steward, 2007). In 1993, a 3D seismic survey, revealed additional faults in southeast Wise County and a number of karst collapse features where the Viola Limestone was not present. The karst features range from 20 to 200 acres in size and are detrimental to well productivity by establishing connectivity to the underlying water-bearing Ellenburger (Steward, 2007).

In 1998, with the help of microseismic technology, Mitchell Energy saw evidence that horizontal completions were opening the NW-SE oriented healed fractures within the northern

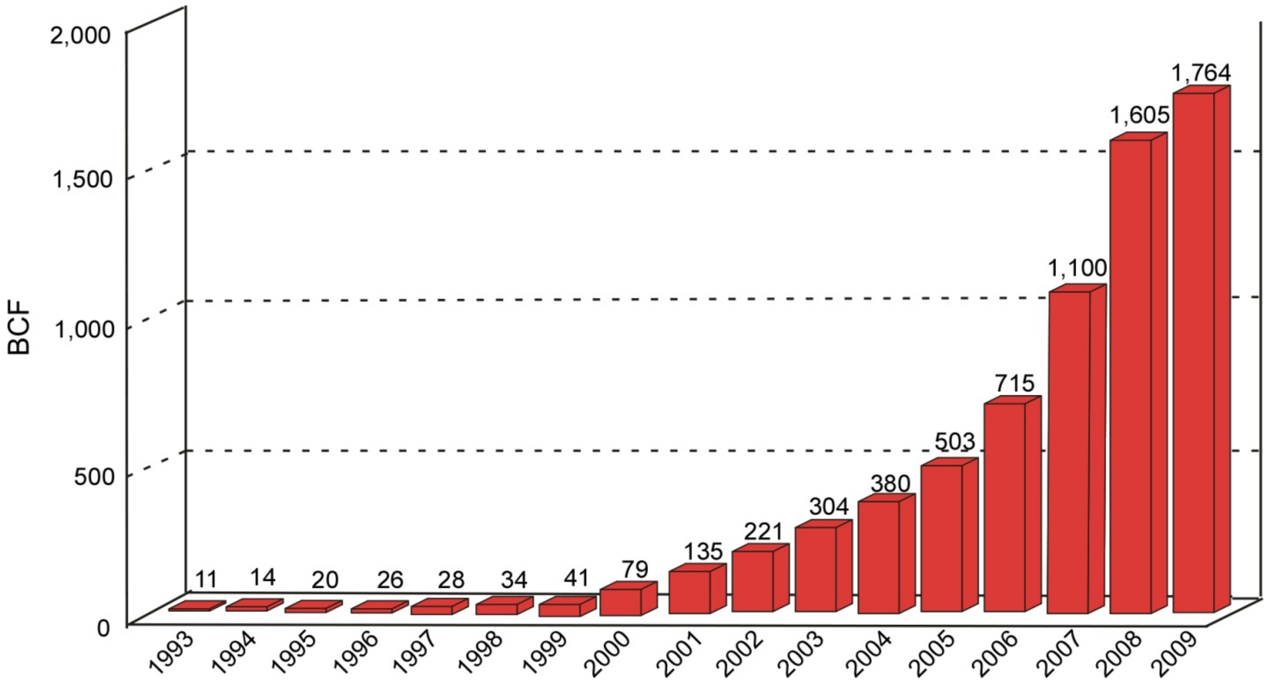


Figure 6: Table showing annual production for the Fort Worth basin Barnett Shale (source: Texas Railroad Commission).

basin of the Barnett Shale. Drilling and completing horizontal wells perpendicular to healed fractures yielded the best production (Steward, 2007). Mitchell's efforts to make the Barnett economic showed other operators that natural fractures need to be exploited, that major faults needed to be avoided, and that 3D seismic was essential to steering horizontal wells between karsted and locally faulted areas. With this knowledge and fueled by an increase in gas prices operators expanded the play across the northern and central part of the basin into 15 counties (Montgomery et al., 2005).

STUDY AREA

The study area in northwestern Johnson County, TX covers approximately 220 square miles (Fig. 2). The study area is west of the pinch outs of the Viola-Simpson and the Forestburg. The Barnett rests directly on the Ellenburger throughout the entire study area. The regional dip is to the northeast. The Ellenburger is at approximately -5400 ft subsea in the southwest part of the study area and at subsea depths of -6200 ft in the northeast. Wells drilled in northwestern Johnson County penetrate upper Pennsylvanian strata, the Marble Falls, the Barnett Shale and the Ellenburger Group before reaching basement rock. The Chappel Limestone, Viola Limestone and Forestburg limestone are not present in the subsurface in the study area. Few wells in the study area penetrate entirely through the Ellenburger. The top of the Ellenburger shows karst features such as sinkholes and collapsed caves and non-karst related topographic relief.

METHODOLOGY

Using SMT/Kingdom seismic interpretation software, two 3D seismic volumes were analyzed in northwestern Johnson County (Fig. 2). Sidney Bjorlie and Brian Murphy, geophysicists with EOG Resources, tied sonic logs to the 3D data, and generated time horizons on the top Ellenburger, Barnett and Marble Falls. Faults were then picked on vertical seismic sections through the data. Six groups of faults were recognized based on which strata and/or time horizons were cut (Fig. 7).

The fault groups are:

- Deep Ellenburger faults (blue) are faults occurring solely in the Ellenburger Group.
- Barnett/Ellenburger faults (red) cross cut both the Ellenburger and the Barnett Shale.
- Through-going faults (black) cross cut the Ellenburger, the Barnett, and the Marble Falls.
- The three other groups of faults are Marble Falls-only faults, Barnett Shale-only faults, and Marble Falls-Barnett Shale faults. These three sets of faults were mapped but were not considered in the subsequent analysis of production data. This approach is justified because these faults do not extend into water-bearing zones in the Ellenburger and, therefore, do not have a large impact on well productivity.

The faults groups were next placed into related fault polygons and surfaces. Each type of fault was classified according to the surfaces it cuts. Trends of karst features and fault surfaces were delineated from maps showing the distribution of karsts and faults.

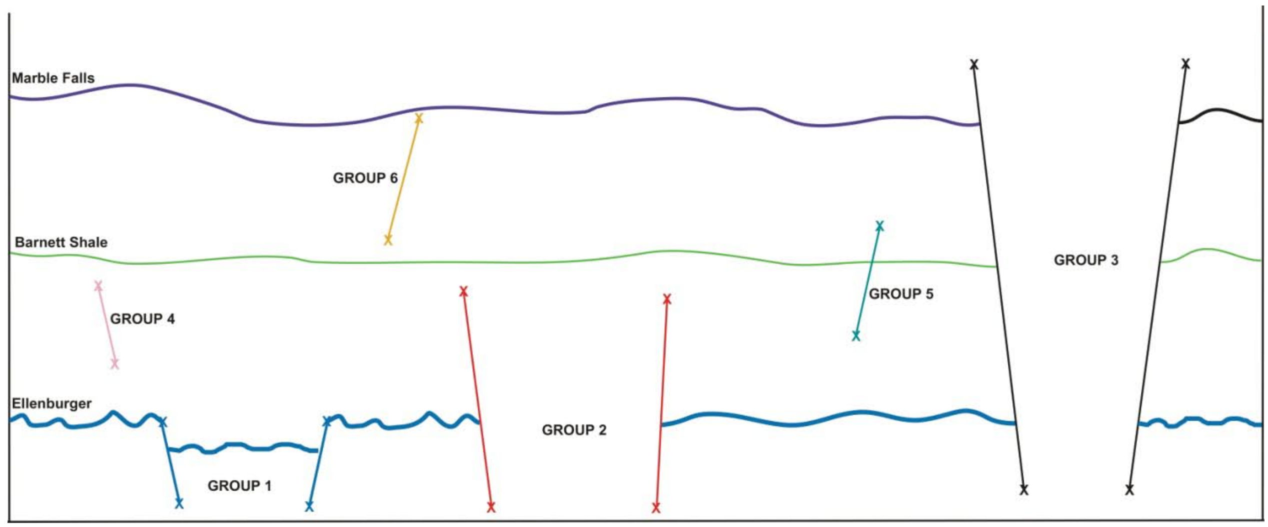


Figure 7: Schematic cross-section showing formation tops cut by each group of faults identified in study area.

The seismic data were converted from time to depth to allow structure maps to be made for the features in the study area. Subsea structure maps were made on the tops of the Ellenburger Group, Barnett Shale and Marble Falls interval. Dip curvature maps were made to illuminate faults not seen in the vertical seismic displays. A regional lineament was traced and mapped using dip curvature and SMT VuPak, which allows for the data to be viewed in three dimensions and rotated at the will of the user.

Orientations of fractures within wells were made from Schlumberger's Formation Micro-Imaging (FMI) logs, then plotted on rosettes (Plate 1 in pocket). Trends were quantitatively derived from the orientations of open, healed, partially healed, and drilling induced fractures. FMI logs were taken from both vertical pilot wells and horizontal wells. Production data for selected wells in the study area were gathered and analyzed to see if a relationship exists between well productivity and proximity to specific fault groups.

RESULTS

Faults

Six groups of faults were recognized on 3D seismic data based on which formations were cut (Fig. 7). Group 1 consists of faults that affect only the Ellenburger. These faults show up as either circular to semicircular clusters or as linear features on a structure map on the Ellenburger (Fig. 8). The faults are much more common in the northwestern and southwestern (shallower) portions of the study area than in the northeastern (deeper) portion. The semi-circular faults range from 460–1,000 ft in diameter. The linear faults follow NW-SE and NE-SW trends.

Group 2 consists of faults that cut the top of the Ellenburger and all or part of the Barnett, but none of the Marble Falls. This group includes faults formed both during and after the deposition of the Barnett (see below). Like the faults in group 1, the faults appear as both

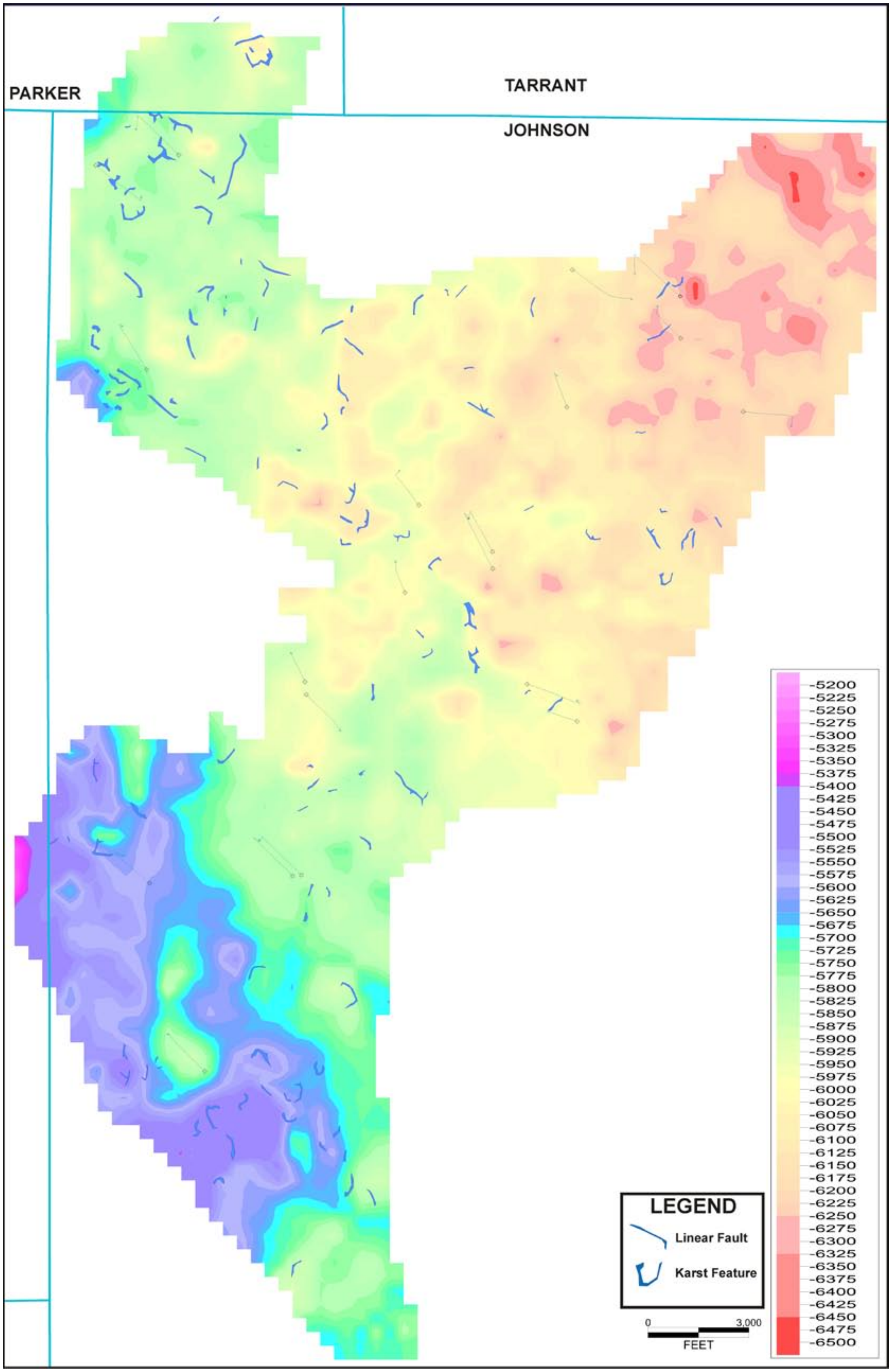


Figure 8: Time-structure map on the top of Ellenburger showing group 1 karsts and linear faults.

circular and linear features. The distribution of these faults is nearly opposite that of the faults in group 1 (Fig. 9). The faults are more abundant in the central portion of the study area than in the northwestern and southwestern portions. The semi-circular faults range from 450–1,800 ft in diameter. The faults in group 2 follow the same NE-SW and NW-SE trends as those in group 1.

Faults in group 3 cut the Ellenburger, Barnett and Marble Falls. Circular clusters of faults are more abundant than linear faults in group 3 than in the other two groups. The semi-circular faults range from 700–4,000 ft in diameter. The clusters are concentrated in the northern portion of the study area and coincide with lows on a time-structure map of the top of the Marble Falls interval. Group 3 faults show a strong northeast-southwest trend and a weak NW-SE trend (Fig. 10).

A large strike-slip fault runs NE-SW in the northern portion of the study area and N-S in the southern portion, where the fault steps over to the west at a bend (Fig. 11A-11F). The strike-slip fault is undetected on seismic cross sections but is apparent on a seismic attribute map (dip curvature) (Fig. 11G-H) and in SMT/Kingdom 3D application VuPak. The fault produces a linear sag on time-structure maps that is more apparent in the north than in the south. In the southern portion of the study area, there is a topographic high on the east side of the fault that is juxtaposed to a topographic low on the west side of the fault, which may indicate lateral movement.

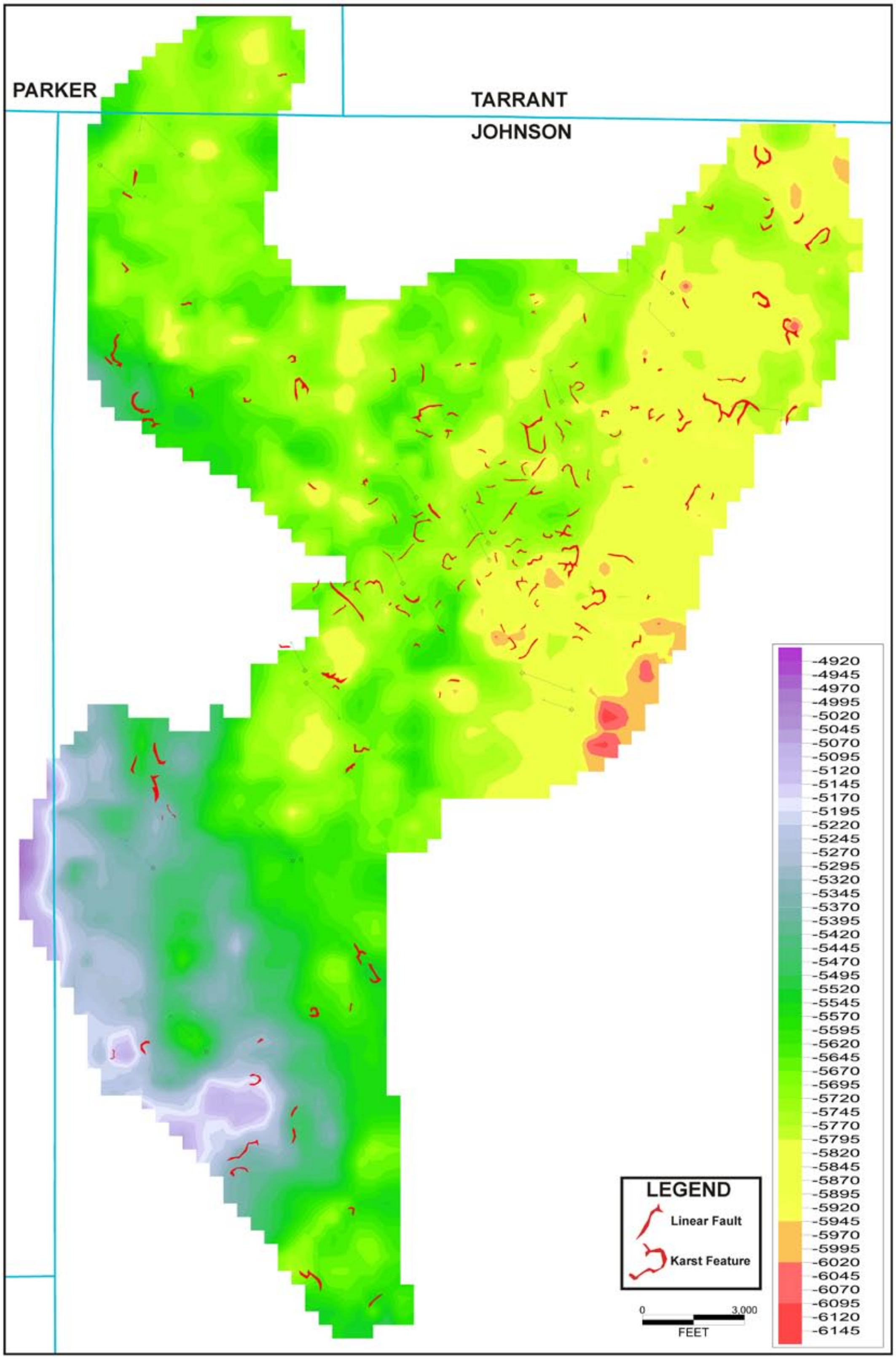


Figure 9: Time-structure map on the top of the Barnett Shale showing group 2 faults and karsts affecting only Barnett Shale.

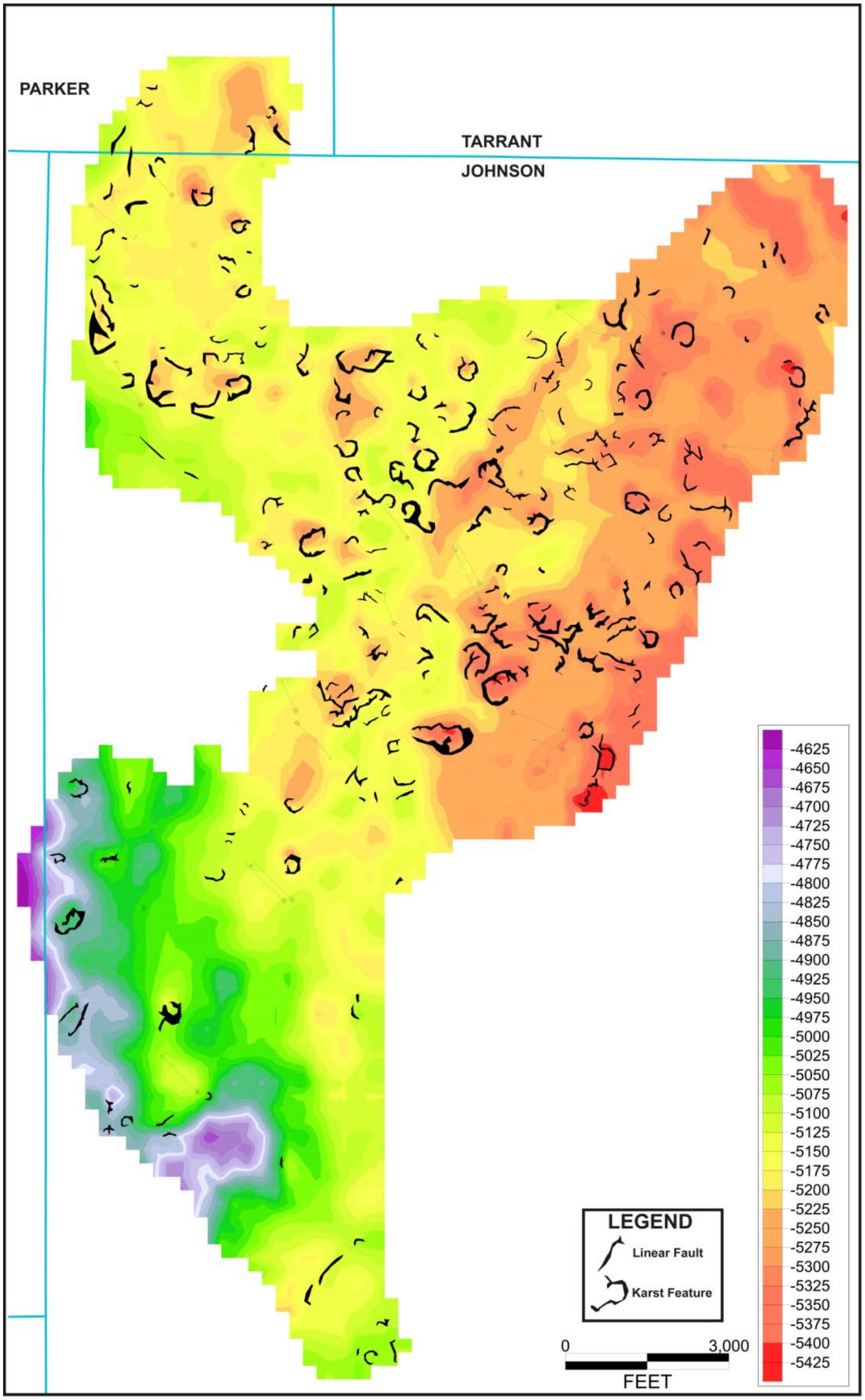


Figure 10: Time-structure map on top of the Marble Falls showing group 3 through-going faults and karsts.

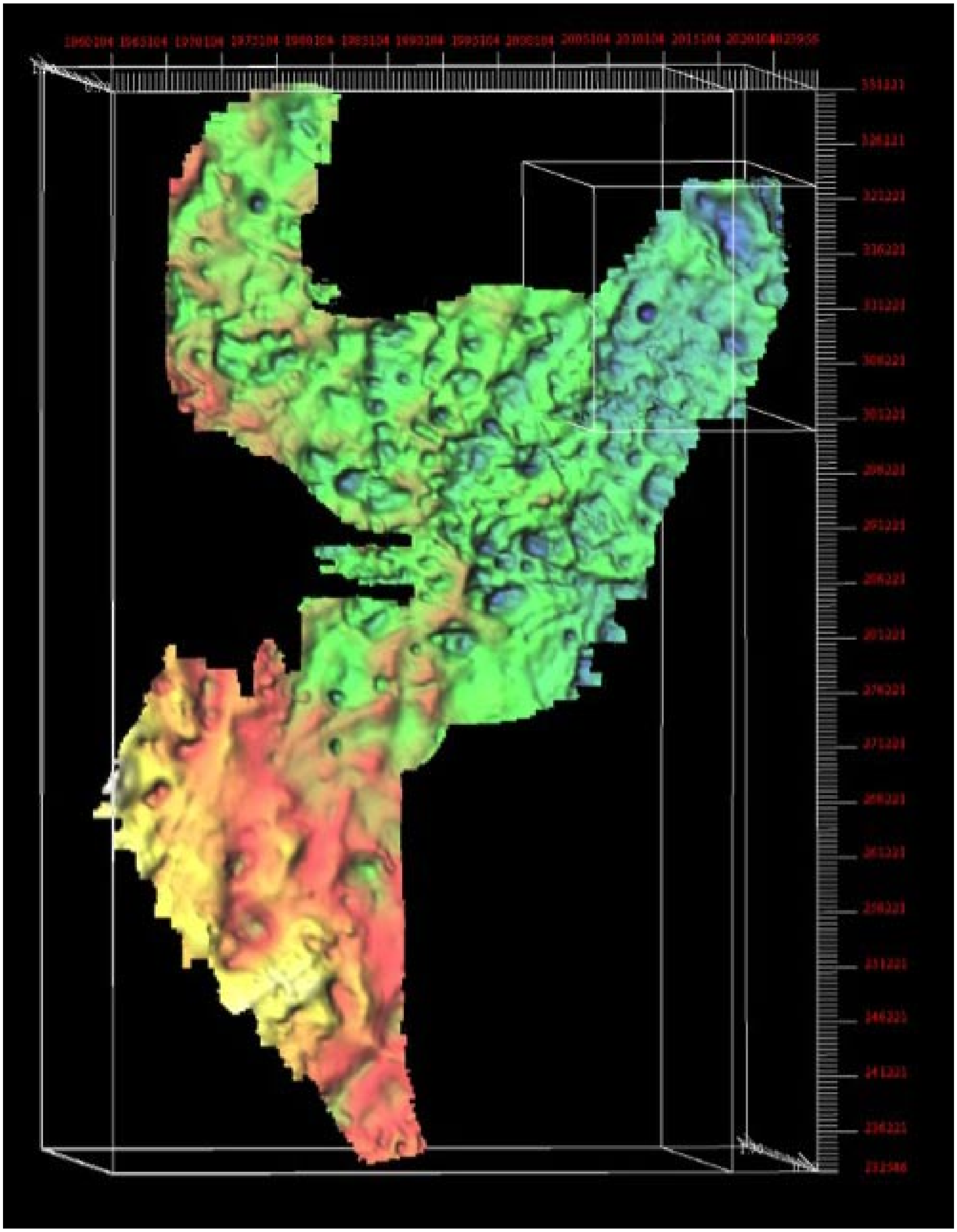


Figure 11A: 3D representation of time-structure map of the top of the Ellenburger. Yellow is the highest point and blue is the deepest.

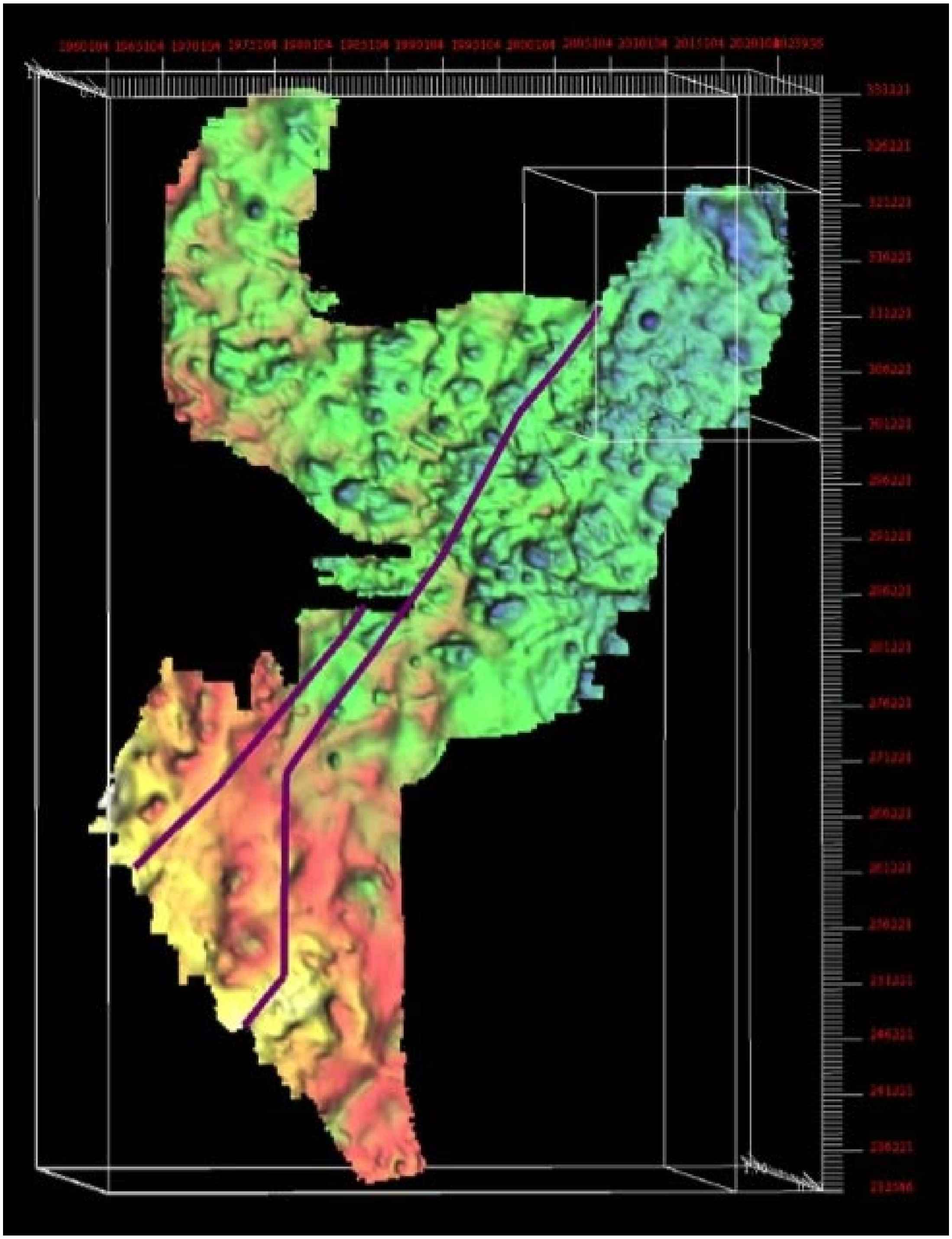


Figure 11B: 3D representation of time-structure map of the top of the Ellenburger showing strike-slip fault trace. Yellow is the highest point and blue is the deepest.

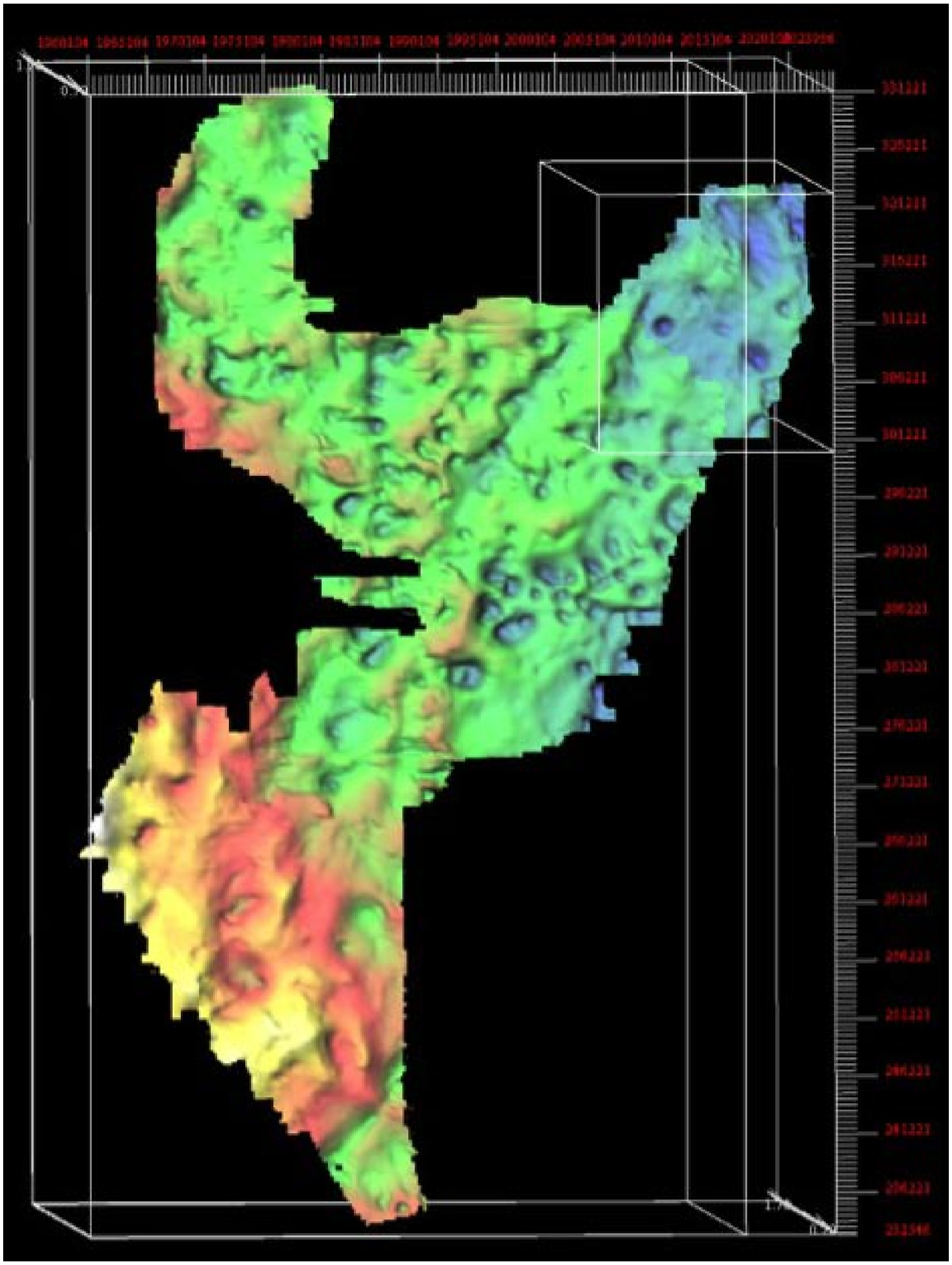


Figure 11C: 3D representation of time-structure map of the top of the Barnett Shale. Yellow is the highest point and blue is the deepest.

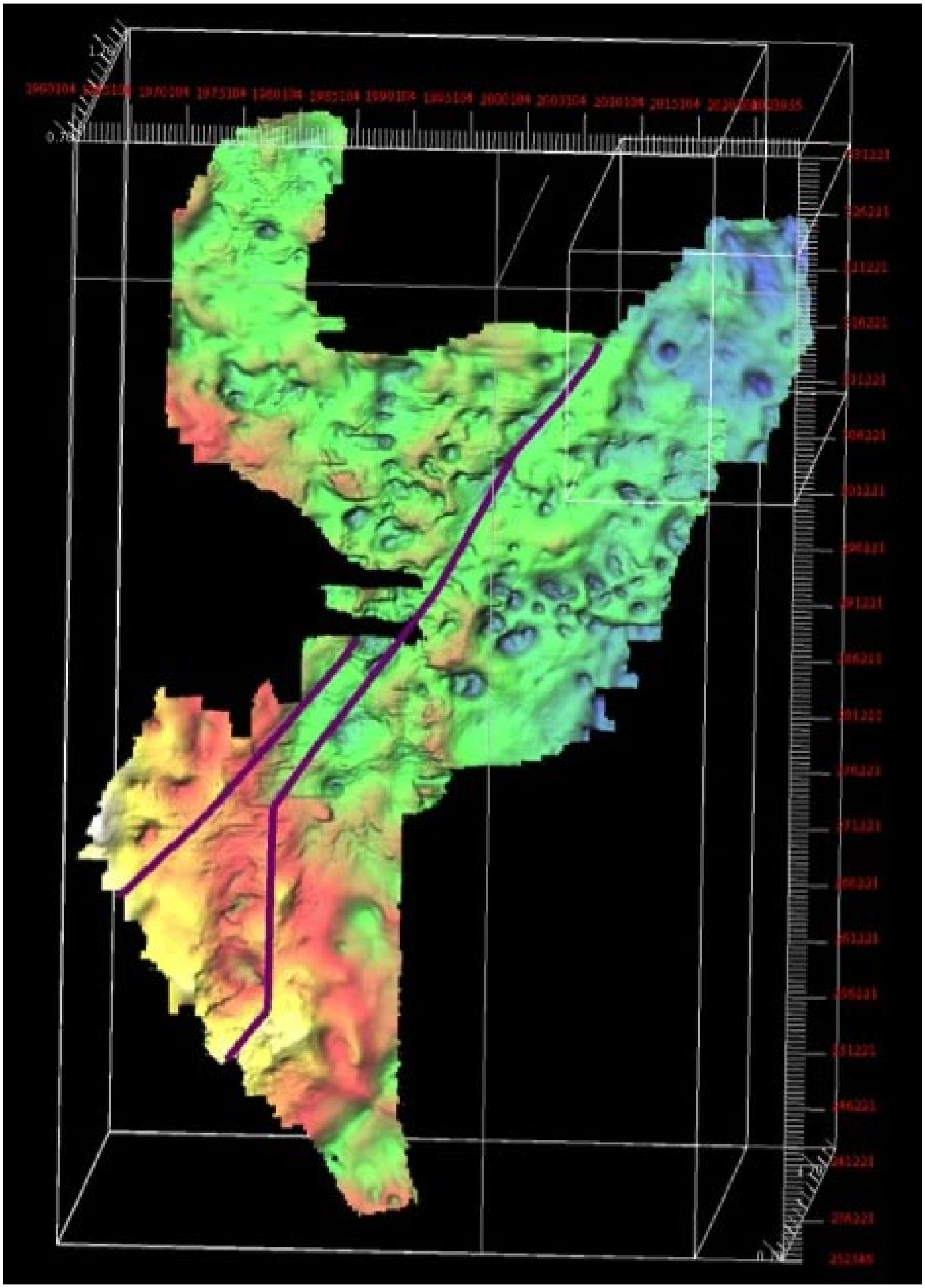


Figure 11D: 3D representation of time-structure map of the top of the Barnett Shale showing strike-slip fault trace. Yellow is the highest point and blue is the deepest.

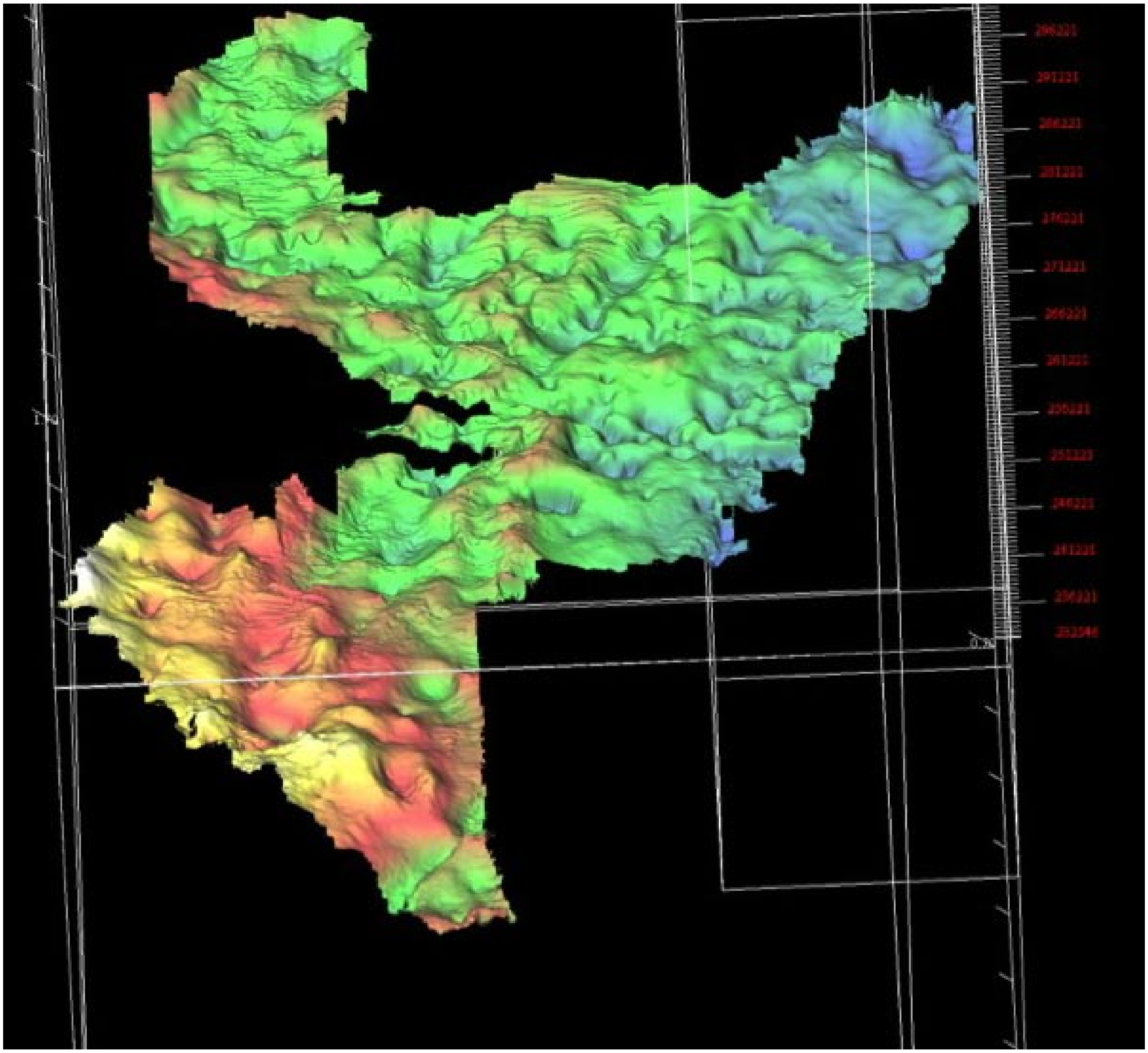


Figure 11E: 3D representation of Barnett time-structure map rotated to enhance strike-slip fault trace. Yellow is the highest point and blue is the deepest.

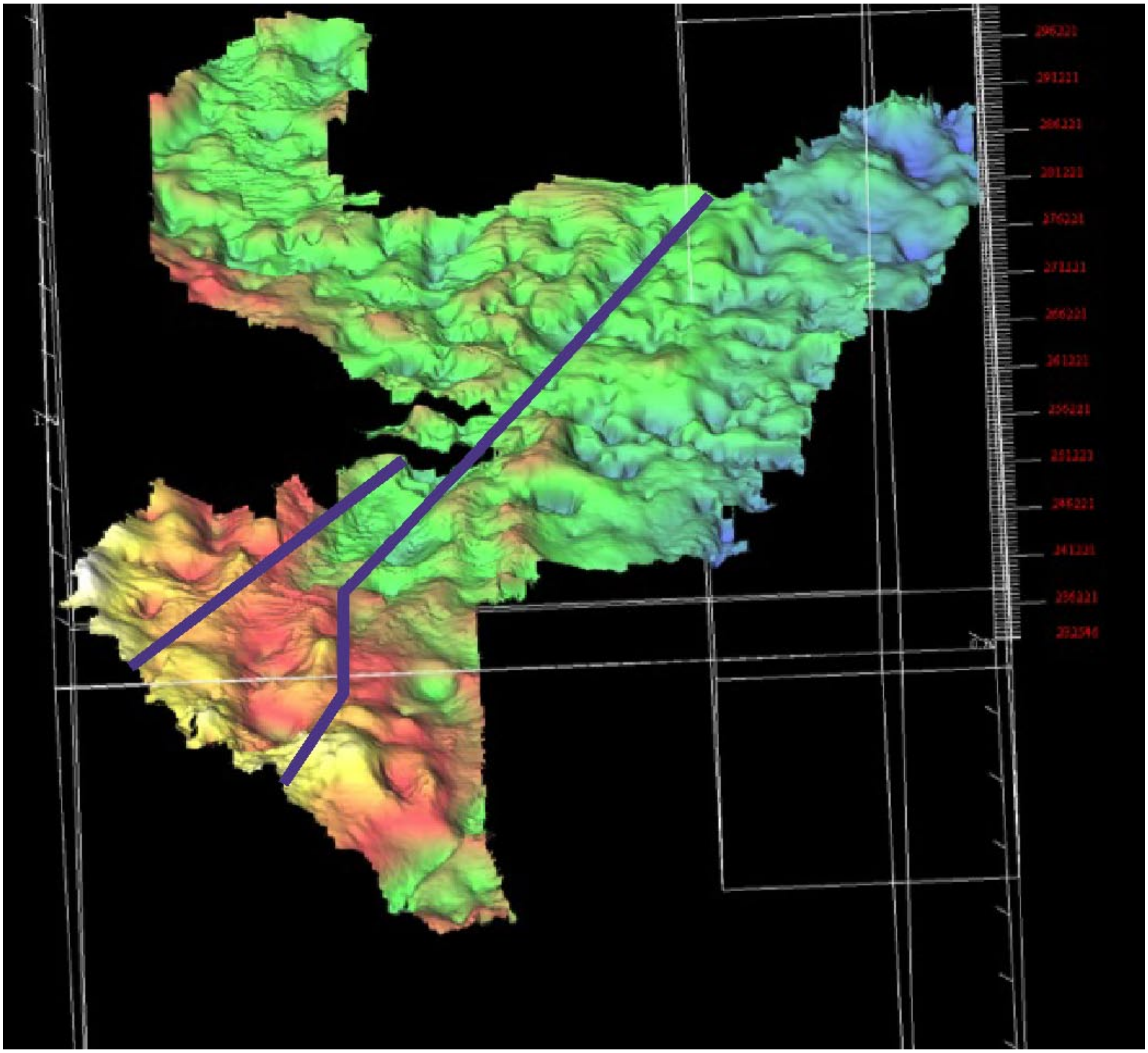


Figure 11F: 3D representation of Barnett time-structure map rotated showing strike-slip fault trace. Yellow is the highest point and blue is the deepest.

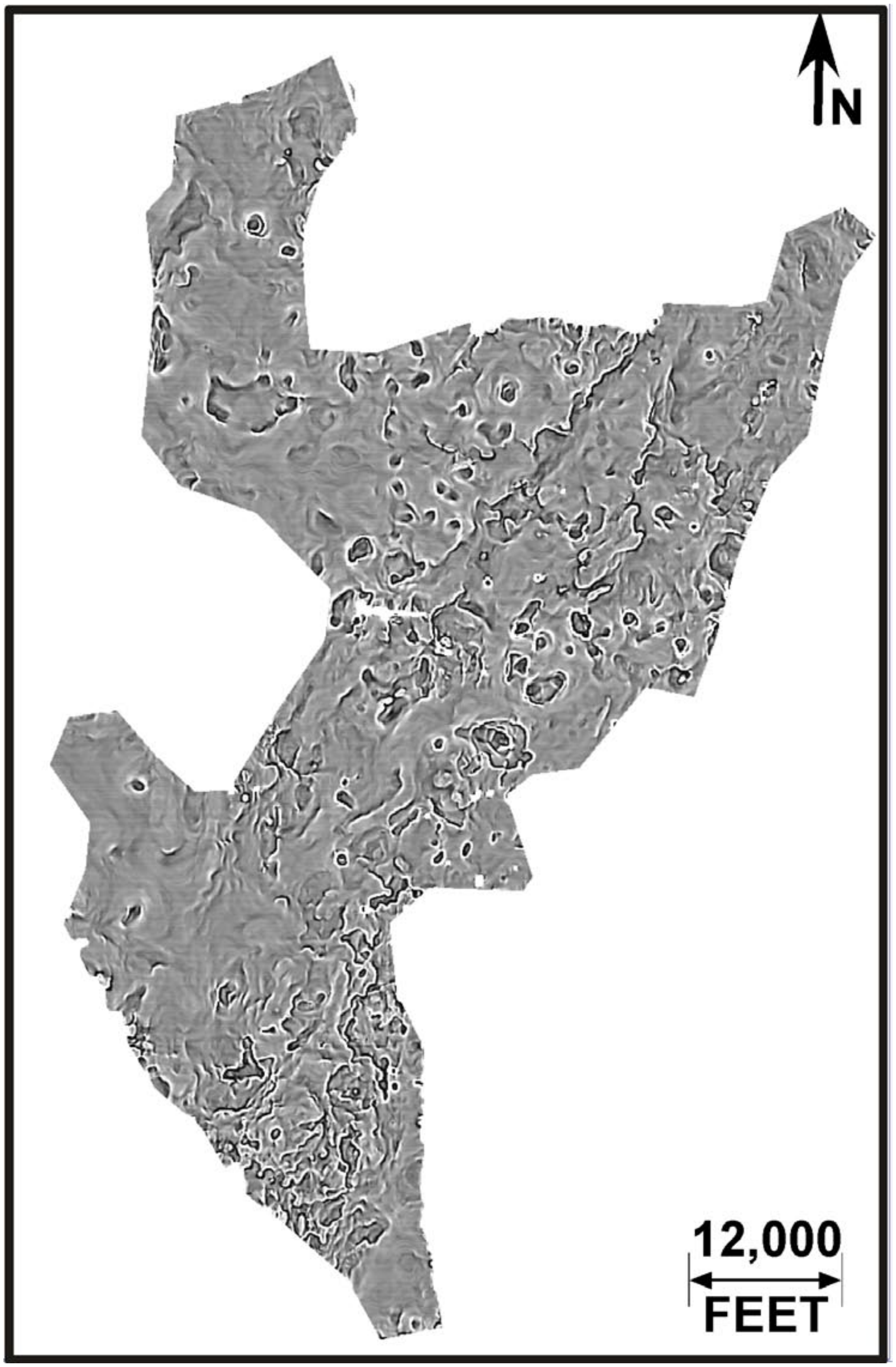


Figure 11G: Seismic dip curvature map of the Marble Falls Formation

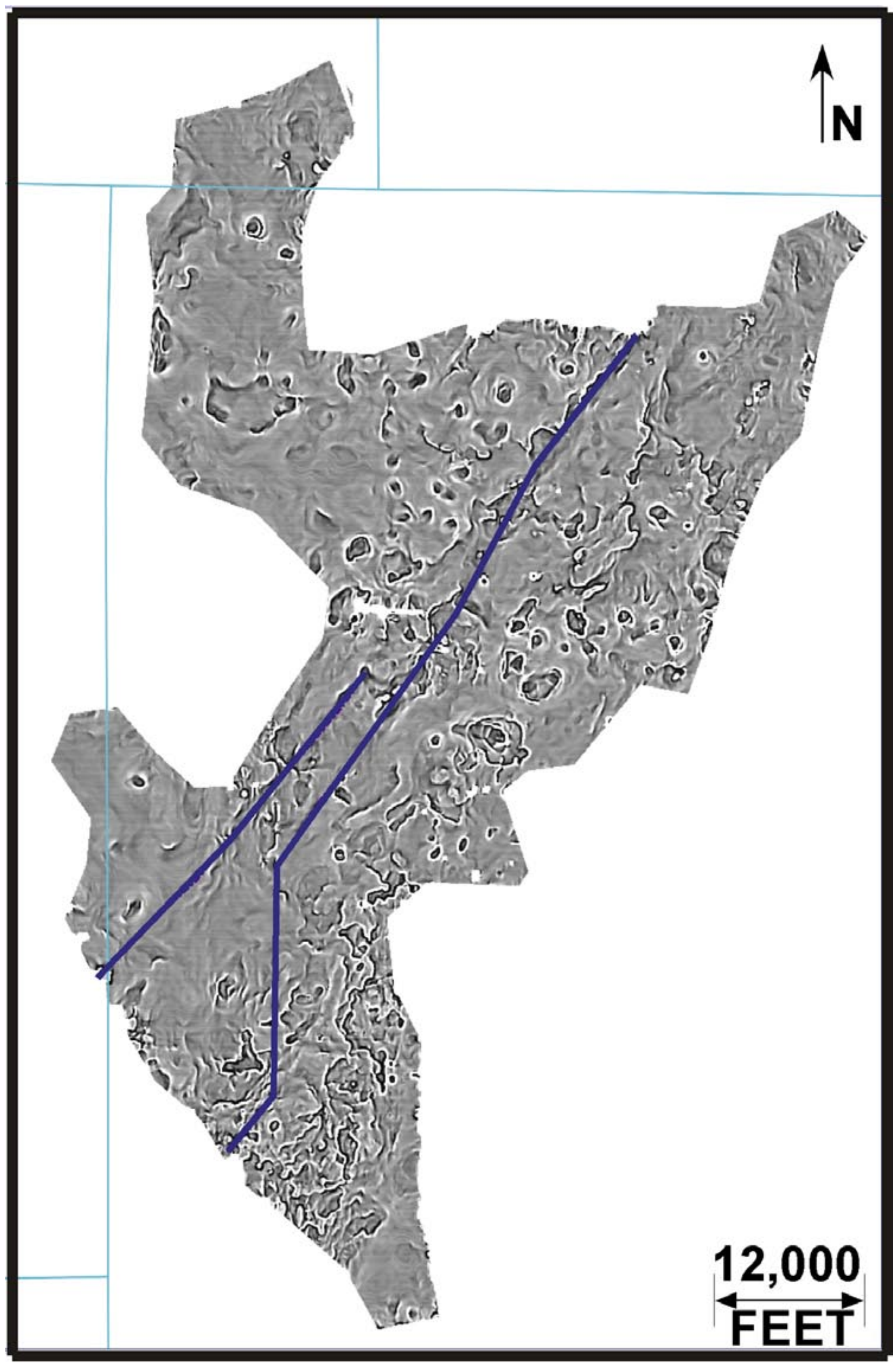


Figure 11H: Seismic dip curvature with strike-slip fault shown.

FMI Data

FMI data confirm the fault trends recognized on the seismic data (Plate 1 in pocket). Stress orientations of fractures taken from wells through and near the strike-slip fault show a local anomaly when compared to wells some distance from the strike-slip fault. In the Teich area to the northwest, the FMI data shows conductive fractures trending NE-SW. Resistive calcite-healed fractures in the area trend in an east-west direction. Drilling induced fractures, most likely indicating modern day stresses, show a strong NE-SW trend.

In the northeast Clements part of the study area, the conductive fractures show a weak N-S to NE-SW orientation. The calcite healed resistive fractures and the drilling induced fractures are oriented NE-SW.

In the central study area, the River Hills well is approximately 2 miles from the strike-slip fault. The rosettes for this well show conductive fracture trends occurring in the NE-SW direction. The resistive healed fractures show a strong NW-SE trend but also a very weak NE-SW trend. Drilling induced fractures trend NNE-SSW.

In the southern study area, the Geren area shows similar trends. The conductive fractures trend along a NE-SW direction. The healed fractures have an orientation that is roughly E-W. The drilling induced fractures trend in a NE-SW orientation.

The Rice University #3H and Jernigan #1H were drilled through the strike-slip fault and FMI data were obtained. The conductive fracture trends in these two wells are different. The Rice University well has strong NE-SW and E-W orientation for its conductive fractures. The Jernigan trend is more E-W in orientation. The resistive fracture orientations are both E-W. The drilling induced fractures vary greatly, i.e. Rice University fractures trended ENE-WSW, while the Jernigan trends NNE-SSW.

Well Productivity

Several wells in the northwestern and east-central parts of the study area were drilled near faults that cut only the Ellenburger (group 1). Among these were the EOG Carolyn Teich Unit #2H, Ken Teich Unit #3H, River Hills #5H, River Hills #8H, Hoffman #3H, Richard Crider Unit #3H, and Ellis Unit #2H. In these wells the well bore passed directly over or within 1,000 feet of the faults in the Ellenburger Group (Fig. 12 and Appendix I). Production from these wells was higher than production from wells in unfaulted areas. These wells drilled over or near the group 1 faults averaged approximately 2.68 million cubic feet per day (mmcfd) compared to the production from wells in unfaulted areas of 2.11 mmcfd (Table 1). Production from wells drilled within 1,600 ft of group 1 faults was equal to that from wells much further away. Group 1 faults did not adversely affect well productivity.

The Carrell #1H, KTV Caddo Unit #5H, Godley Minerals Unit #5H and Godley Minerals Unit #6H were drilled near, through or above group 2 faults (Fig. 13 and Appendix I). These faults cut the base of the Barnett and penetrate varying distances into the formation. Production from wells drilled either through these faults or within 1,900 ft of them is equal to production from wells drilled even farther away. Group 2 wells averaged 2.23 mmcfd while the wells in unfaulted Barnett averaged 2.11 mmcfd (Table 1).

Group 3 faults cut from the Marble Falls through the Barnett and into the Ellenburger. Reflectors in the Barnett section penetrated by these wells are chaotic indicating brecciation of the strata due to karst collapse (Fig. 14 and Appendix I). Initial production from the Beasley Unit #2H drilled near a group 3 fault was 1.004 mmcfd. Production from the Geren #12H drilled near a group 3 fault was 1.672 mmcfd (gel job done after completion). The Bowerman A Unit #1H was drilled through a through-going karst and its average initial production over its first two weeks was 1.5 mmcfd. The average production from wells near or through the group 3 faults is

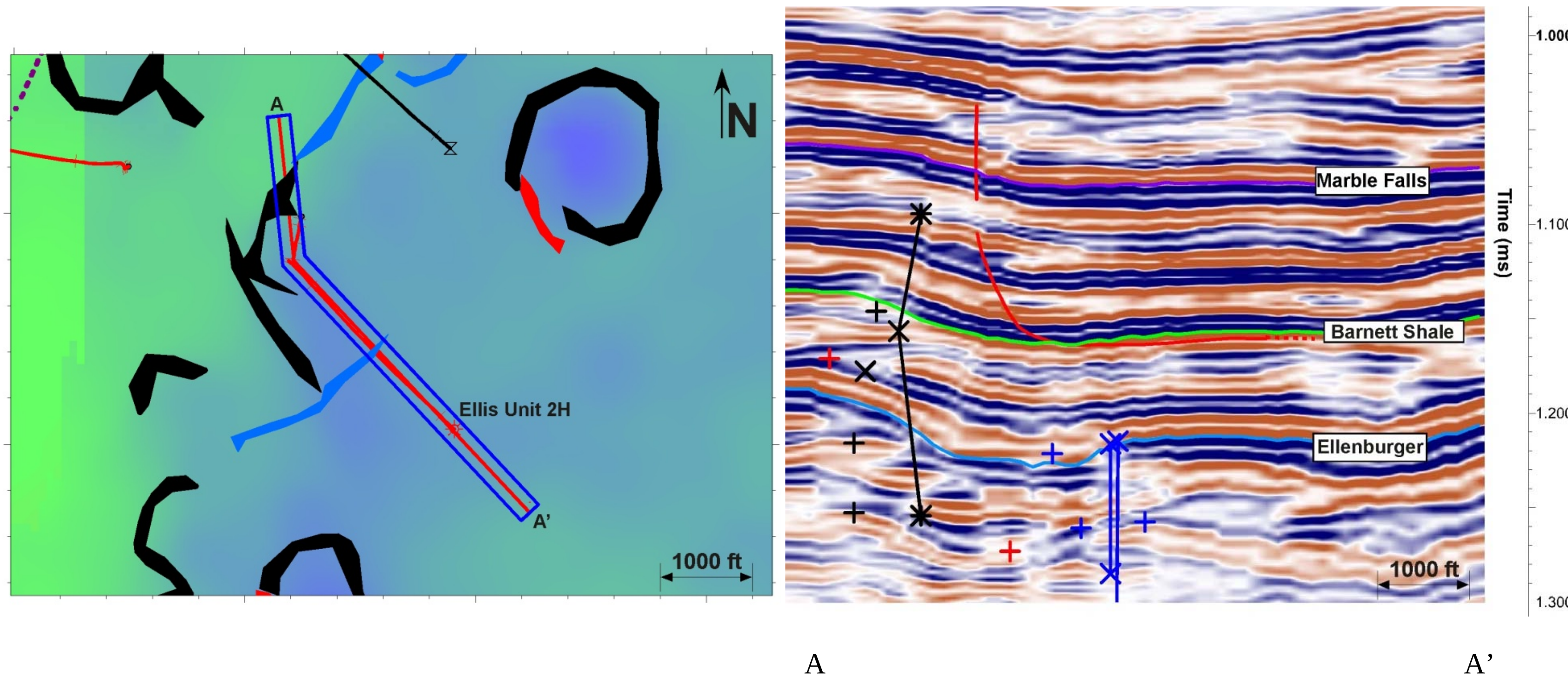


Figure 12: The Ellis Unit 2H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults.

Table 1: Production from Selected Wells in the Study Area[1]

A. Group 1 Wells

Well Name	IP[1]
CRIDER RICHARD UNIT 3H	3376
ELLIS UNIT 2H	1691
HOFFMAN 3H	not completed[2]
RIVER HILLS 5H	2802
RIVER HILLS 8H	3617
TEICH CAROLYN UNIT 2H	2327
TEICH KEN UNIT 3H	2258
Faulted well average (mcfd):	2678.5
Unfaulted well average (mcfd):	2108

B. Group 2 Wells

Well Name	IP
CARRELL 1H	438
GODLEY MINERALS UNIT 5H	2776
GODLEY MINERALS UNIT 6H	3204
KTV CADDO UNIT 5H	2504
Faulted well average (mcfd):	2230.5
Unfaulted well average (mcfd):	2108

C. Group 3 Wells

Well Name	IP
BEASLEY UNIT 2H	1004
BOWERMAN A UNIT 1H	1499
GEREN 12H (Gel Job)	1672
Faulted well average (mcfd):	1391.67
Unfaulted well average (mcfd):	2108

D. Lineament Wells

Well Name	IP
BEASLEY UNIT 2H	1004
CHRISTOFFERSON UNIT 3H	1216
CRIDER RICHARD UNIT 2H	3656
GODLEY MINERALS UNIT 5H	2776
GODLEY MINERALS UNIT 6H	3204
JERNIGAN 1H	659
KNAPP UNIT 2H	125
RICE UNIVERSITY UNIT 3H	1045
Lineament well average (mcfd):	1710.625
Unfaulted well average (mcfd):	2108

[1] IP- Initial Production on 2nd week daily average
[2] Well was not completed as of November 1, 2010.

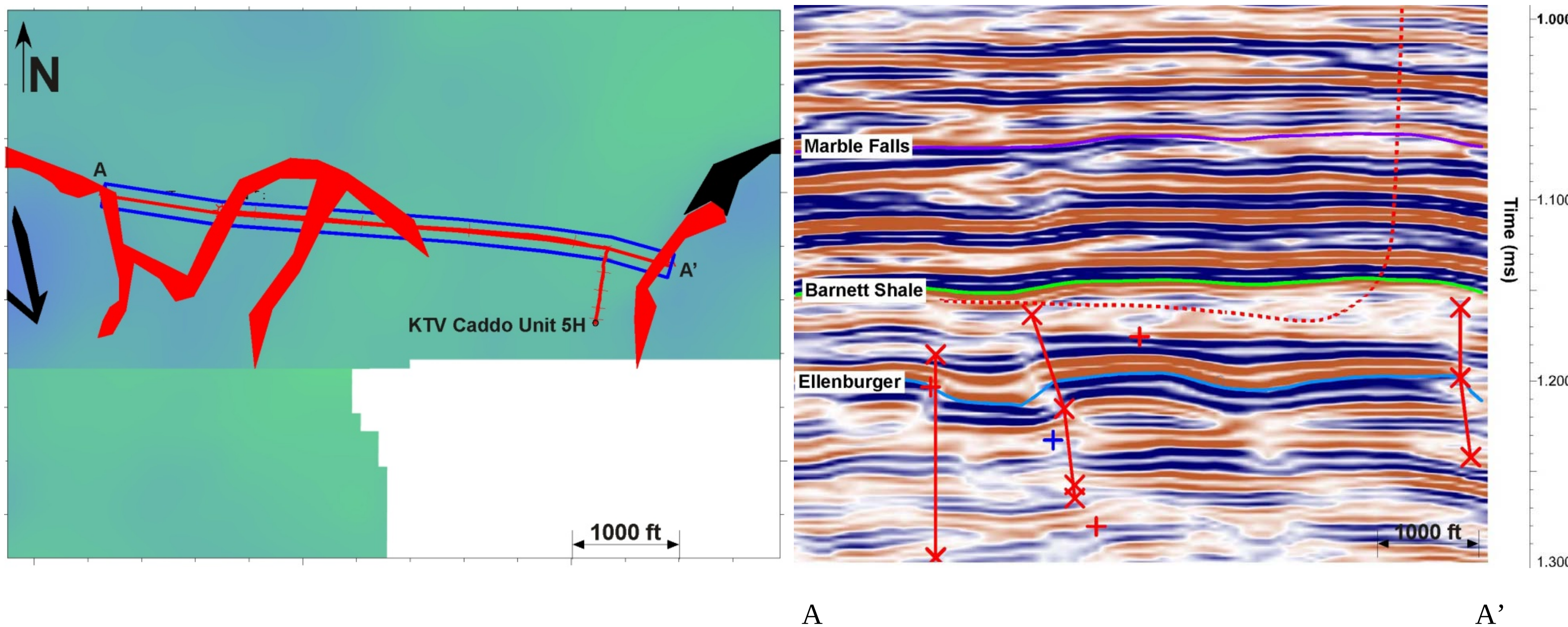


Figure 13: The KTV Caddo Unit 5H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in dashed red and its proximity to surrounding faults.

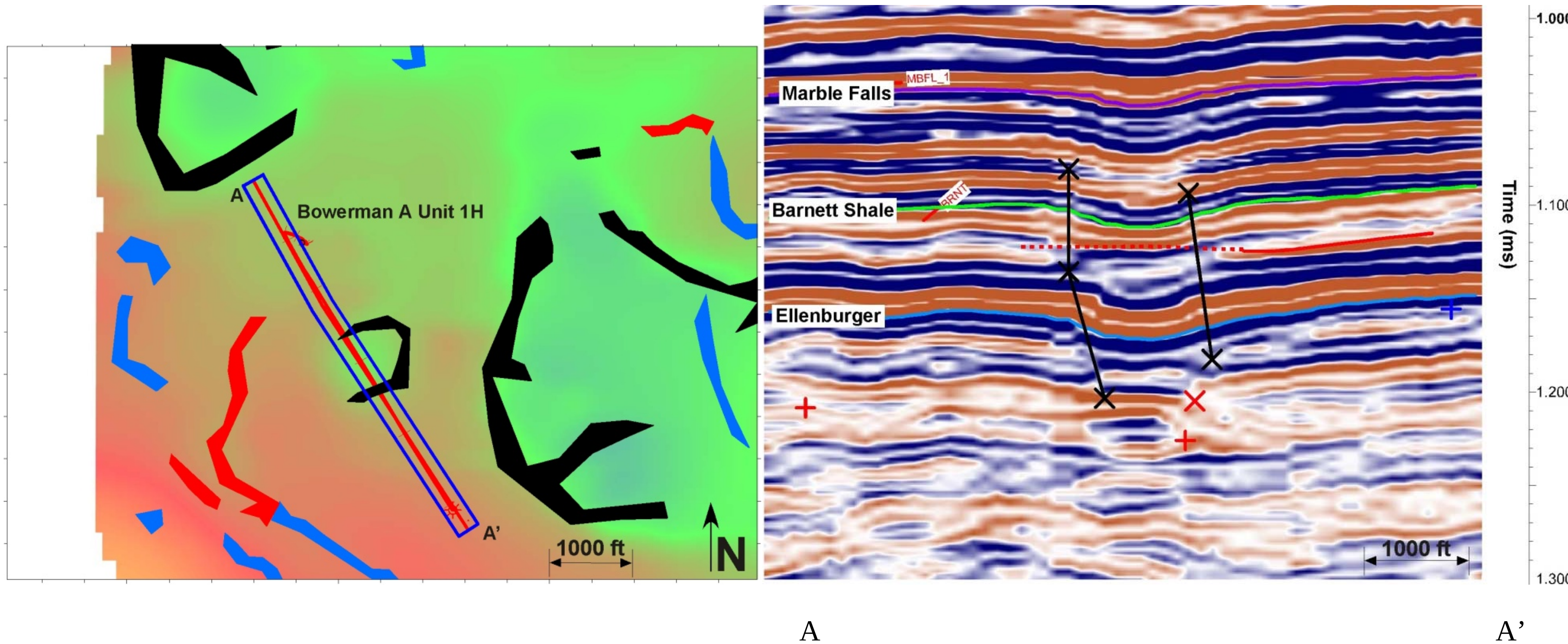


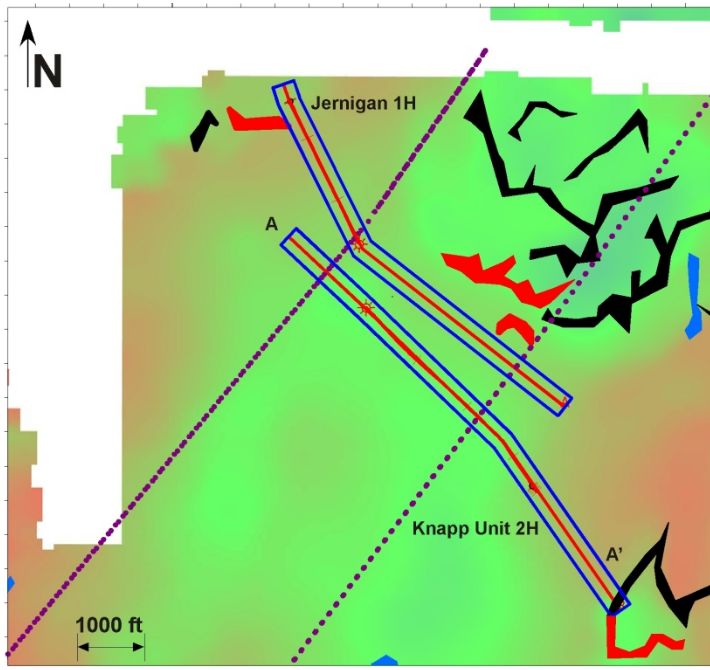
Figure 14: The Bowerman A Unit 1H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in dashed red and its proximity to surrounding faults.

1.39 mmcfd. The average production from wells drilled in unfaulted areas is 2.11 mmcfd (Table 1). Well production within 2,400 ft of the faults are negatively affected.

Production from wells drilled near or through the strike-slip fault is erratic (Table 1). Some of the wells are good producers, but others are marginal. The Beasley Unit #2H, Knapp Unit #2H, Jernigan #1H, Richard Crider Unit #2H, Rice University #3H, Christofferson Unit #3H, Godley Minerals Unit #5H and Godley Minerals Unit #6H were drilled near or through the fault (Fig. 15 and Appendix I). The seismic data do not reveal the strike-slip fault due to its subvertical orientation and lack of vertical displacement. However, the fault is apparent in three-dimensional plan-view viewing derived from the seismic data. FMI logs taken through the Rice University well show a swarm of healed fractures with a strong NE-SW trend possibly indicating development of a fault breccia.

DISCUSSION

Garrison (2007) attributed the orientation of the fractures and faults in the Fort Worth basin to the tectonic history of the basin. A surface fracture analysis that correlated faults and fractures to the subsurface, via FMI data, concluded that two prominent trends are present in the basin. Of the two wells studied by Garrison (2007), one is in Palo Pinto county in the western Fort Worth basin and the other well is in Erath county, which is in the southwestern Fort Worth basin. Garrison (2207) interpreted an overall E-W trending set was concluded to have been formed by the compressive stresses during the Ouachita orogeny and a younger NE-SW trending tensile set was to have formed by the opening of the Gulf of Mexico (Garrison, 2007). In my study area, the karst collapse features seen as circular clusters of faults and as linear faults on the time-structure and acreage maps developed at the intersections of NW-SE (and sometimes weak E-W trend) and NE-SW fracture and fault systems similar to those described by Loucks and Ruppel (2007). The faults in the study area are interpreted as caused by



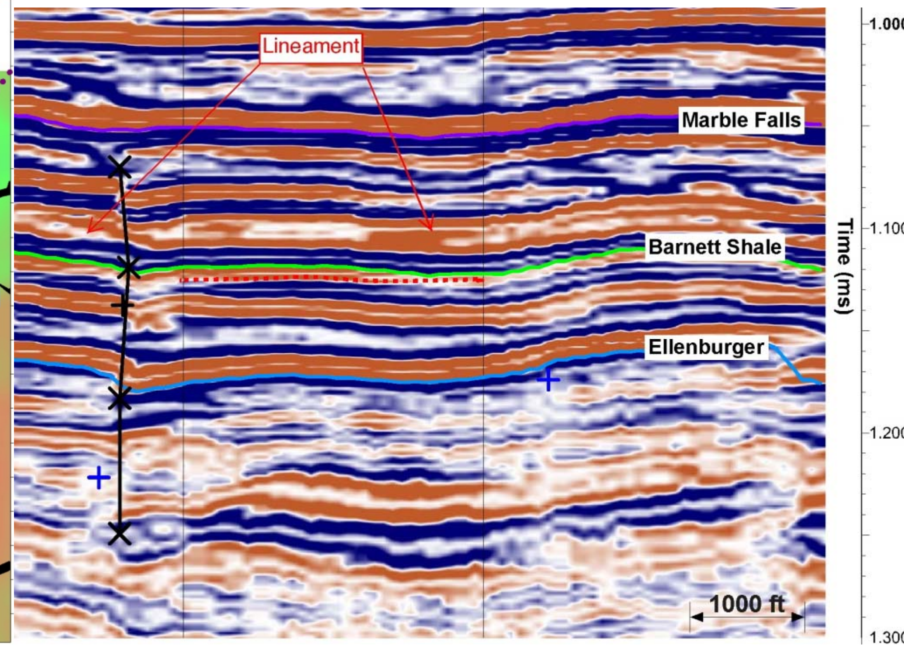


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Figure 15: The Knapp Unit 2H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the lateral portion of the wellbore in dashed red and its proximity to surrounding faults. The strike-slip fault is not seen on seismic but is noted with arrows.

dissolution and collapse of the Ellenburger formation at these fracture intersections. With the exception of the strike-slip fault, the difference between the different fault types in this study area is timing of karst formation. The linear faults in all groups could be the result of incomplete dissolution or the dissolution of better developed fractures with a particular trend. As seen on the FMI rosettes, fracture orientations show weak or strong trends.

Karst collapse features seen only in the Ellenburger (group 1) were formed before the deposition of the Barnett Shale, which thickens across these features (Fig. 16). These faults do not penetrate the Barnett. Wells can be drilled directly above them because no connectivity has been established with the water-bearing zones in the Ellenburger. The clay-rich, more ductile lower Barnett is thicker in the collapsed area, helping prevent hydraulic fractures from reaching down into the Ellenburger. Group 1 faults have little effect on the production of the well that was drilled near or above them.

Caves in the Ellenburger continued to collapse during the deposition of the Barnett in the Mississippian. Seismic sections through group 2 faults show down-dropping of the Barnett without any thickening of the strata indicating deposition of the Barnett *before* collapse (Fig. 17). The Barnett does thicken above some collapse features associated with group 2 faults, indicating collapse *during* deposition of the Barnett (Fig. 18). Caves continued to collapse after the deposition of the Barnett, because the karsts affect strata in the overlying Marble Falls interval. Group 2 faults also have little effect on production compared to the average production of unfaulted wells in the study area. For the same reasons stated in group 1, the scenarios where the Barnett thickens in group 2 wells may help prevent underlying Ellenburger water from invading into the Barnett Shale.

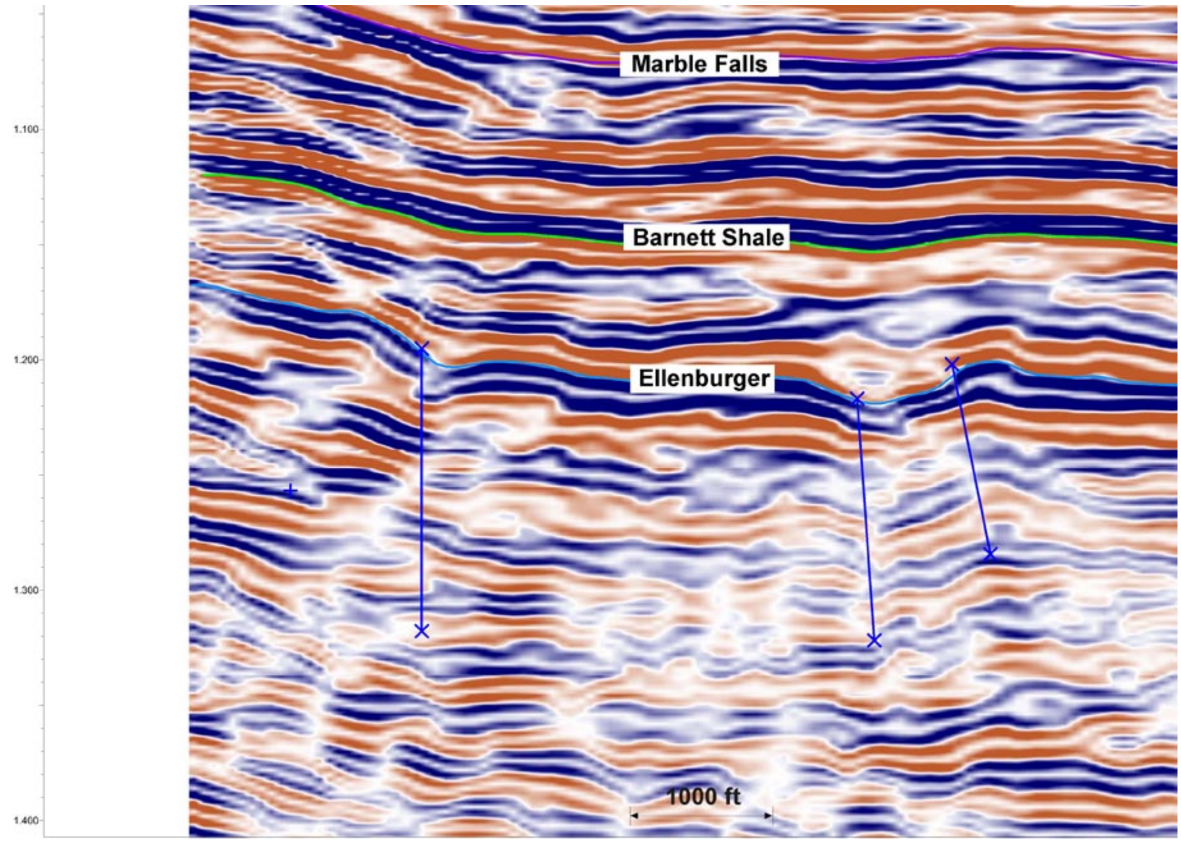


Figure 16: Vertical cross-section (y axis in milliseconds) of Group 1 type of faulting. Note the Barnett Shale thickens as it is deposited in the pre-existing karst.

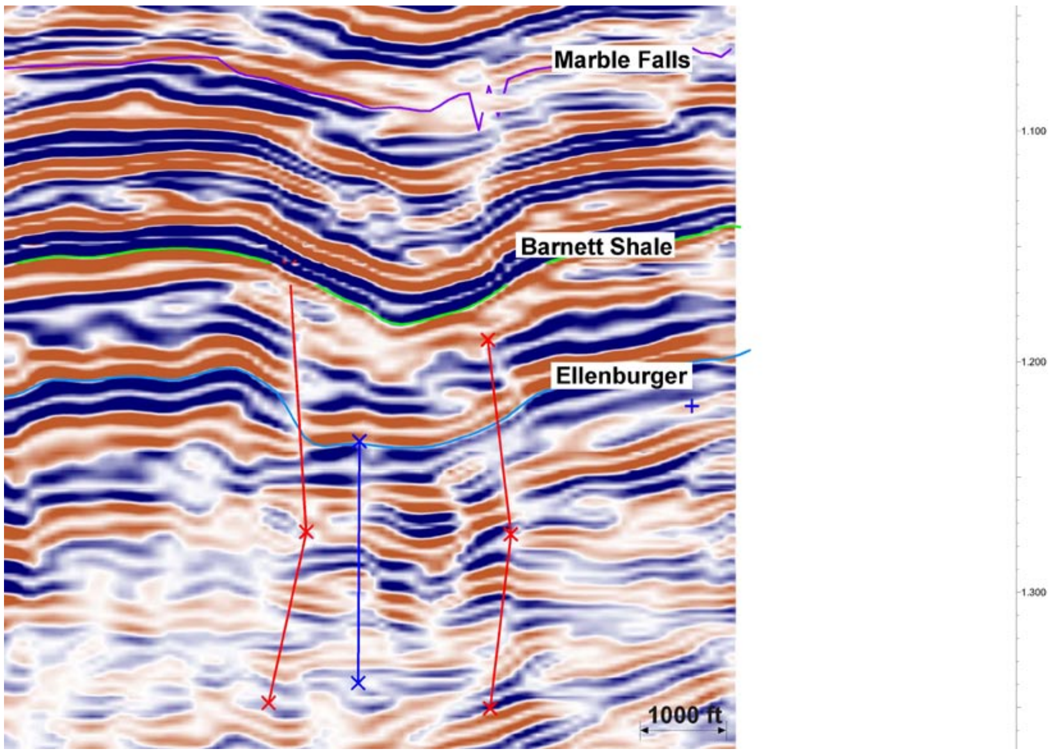


Figure 17: Vertical cross-section (y axis in milliseconds) of Group 2 type of faulting. Note the Barnett Shale section thickness is preserved in downthrown fault.

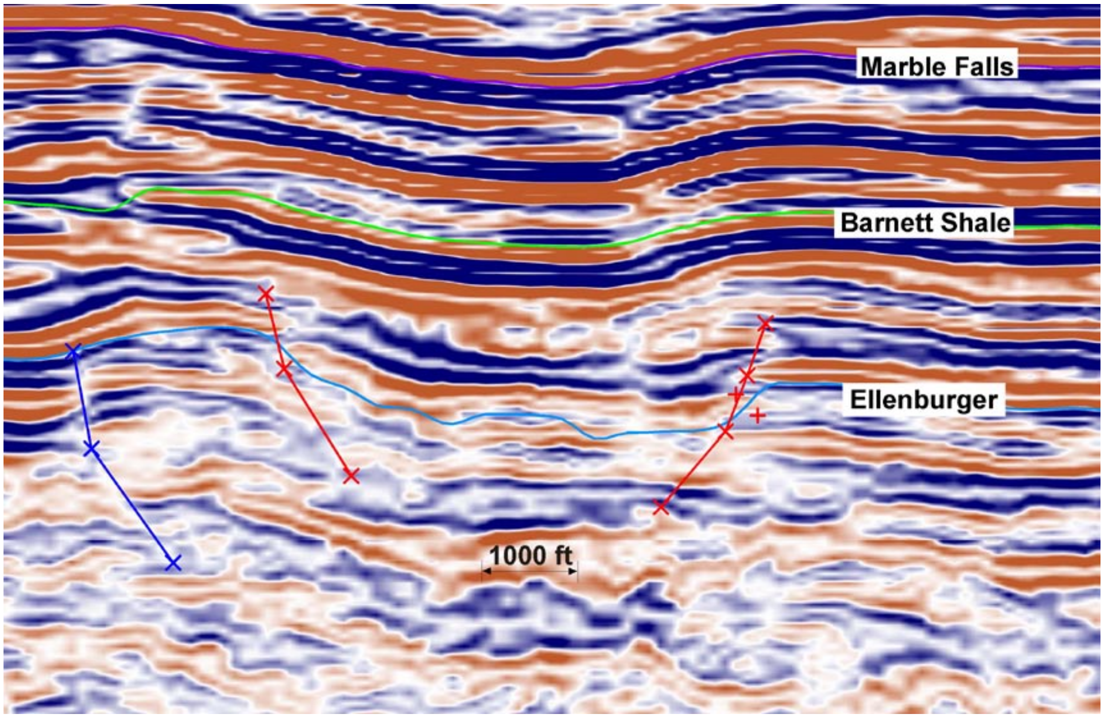


Figure 18: Vertical cross-section (y axis in milliseconds) of Group 2 faults where faulting occurred as Barnett Shale was being deposited. This resulted in the thickening of the Barnett Shale.

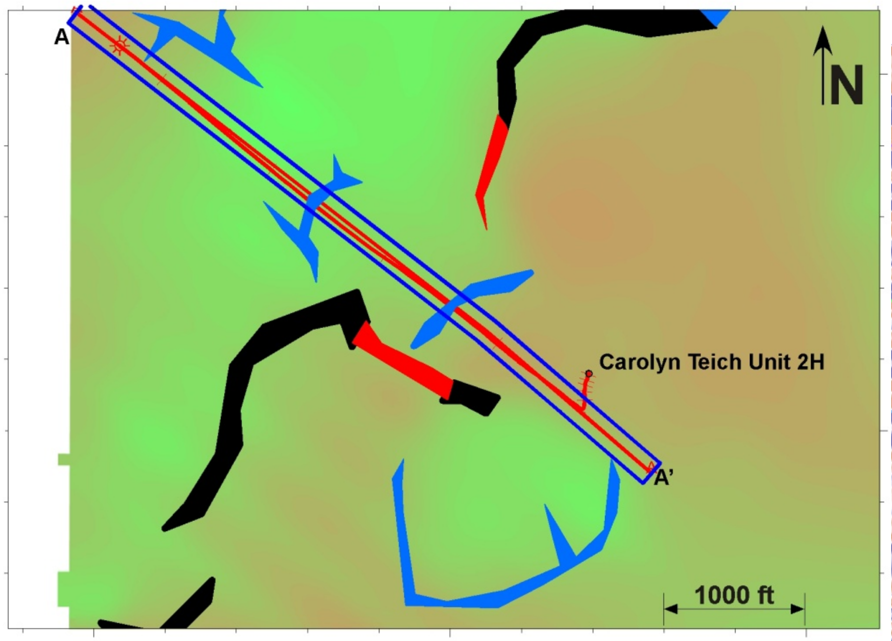
Group 3 faults indicate that cave collapse occurred through the early Pennsylvanian, after the deposition of the Barnett Shale. The Barnett and Ellenburger show brecciation in these faults, which one can infer that they are able to communicate water through these types of faults, unless the brecciation is not seen. These group 3 faults affect production from the Barnett Shale wells.

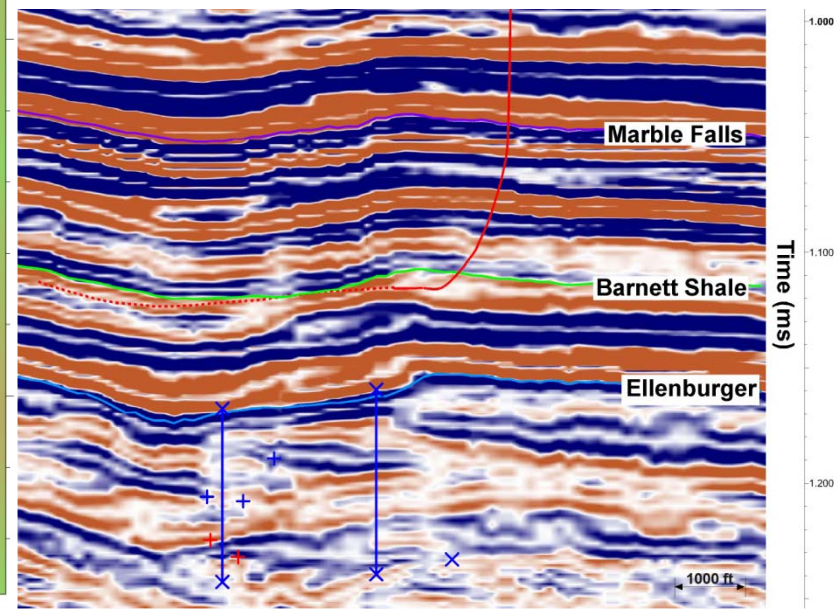
The strike-slip fault in the study area is interpreted to have formed as a result of the Ouachita orogeny. The NE-SW trending orientation of the fault coincides with the orogenic thrust front and with the Mineral Wells and Rhome-Newark fault systems in the northern portion of the basin. With the current data available, the strike-slip fault in the study area is assumed to be directly related to the faults in Wise and Denton counties. The strike-slip fault juxtaposes a topographic high and topographic low on the time-structure map of the southern portion of the study area. The relative position of the high and low suggests a left-lateral sense of displacement along the fault. The principal movement of the Ouachita thrust in central Texas near the Llano uplift was to the north and northwest (present-day directions) as North American and South America collided (Amsbury and Haenggi, 1993). Amsbury and Haennggi (1993) suggested that northward movement resulted in strike-slip deformation along the Llano uplift. Here, small horst blocks or pull-apart grabens develop at restraining or releasing bends, respectively, along strike-slip faults and at left or right stepover zones, much like in the southern portion of the study area. Thus, it is possible that observations from the Llano area can be expanded into the subsurface and is seen in the study area. No vertical displacement of reflectors was seen in seismic cross section through the feature suggesting strike-slip motion. Wells drilled near the feature have fair to good production, but wells drilled *through* the feature are poor producers. The reasons for these results include the fact that the Barnett Shale is of poor rock quality along this zone. Calicite (?) mineralization of the fracture swarms may have effects on gas in place volumes.

CONCLUSIONS

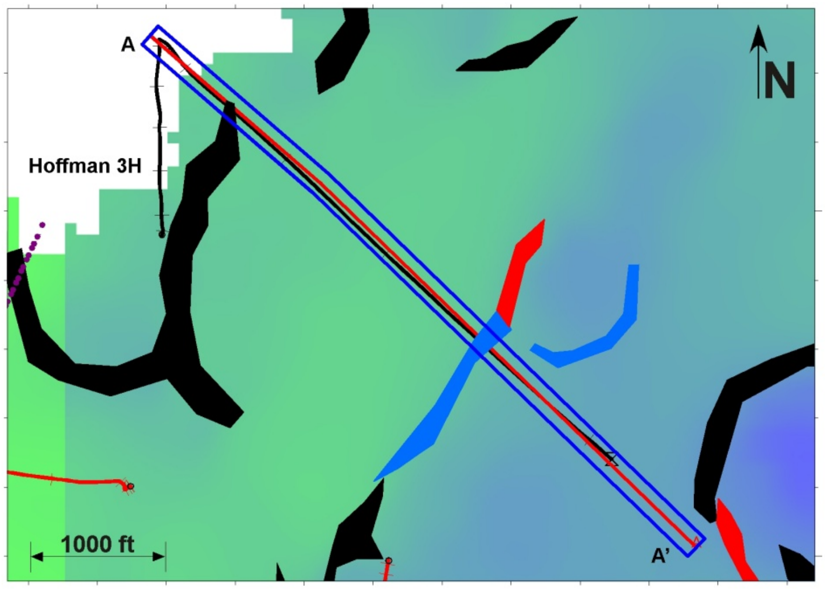
Faults in the study area are attributed to the dissolution and collapse of Ellenburger formation at the intersection of NE-SW and NNW-SSE fracture trends documented throughout the Fort Worth basin. The origin of the fractures and the NE-SW trending strike-slip fault is related to the tectonic history of the Fort Worth basin. The thrusting during the Ouachita orogeny and the opening of the Gulf of Mexico are two events that could have caused the fracture patterns. The strike-slip fault is comparable to the faulting in the Llano uplift area, which attributed the cause of the strike-slip motion to the Ouachita thrusting. The timing of formation of different types of collapse features and faults can be established relative to the deposition of the Barnett Shale. These faults may or may not affect production in the wells drilled in or near them.

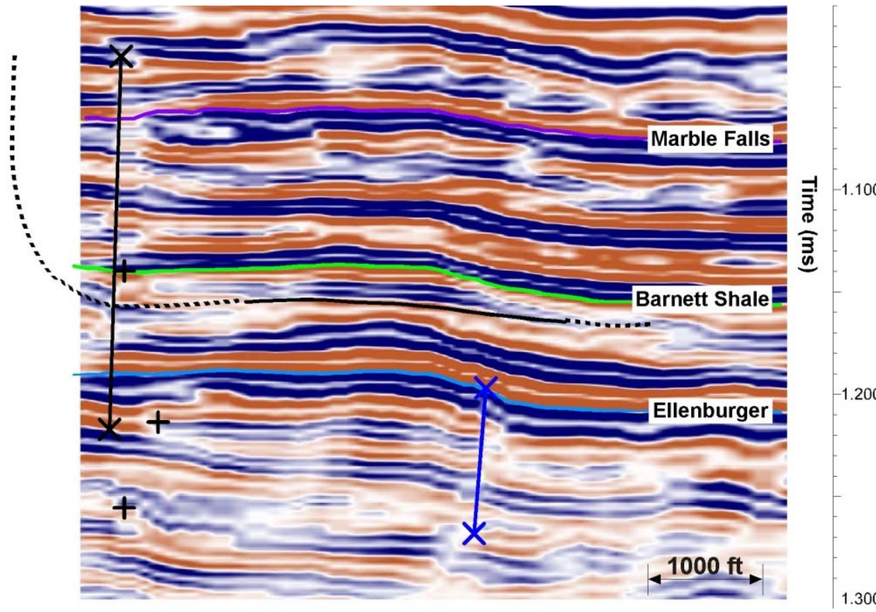
APPENDIX



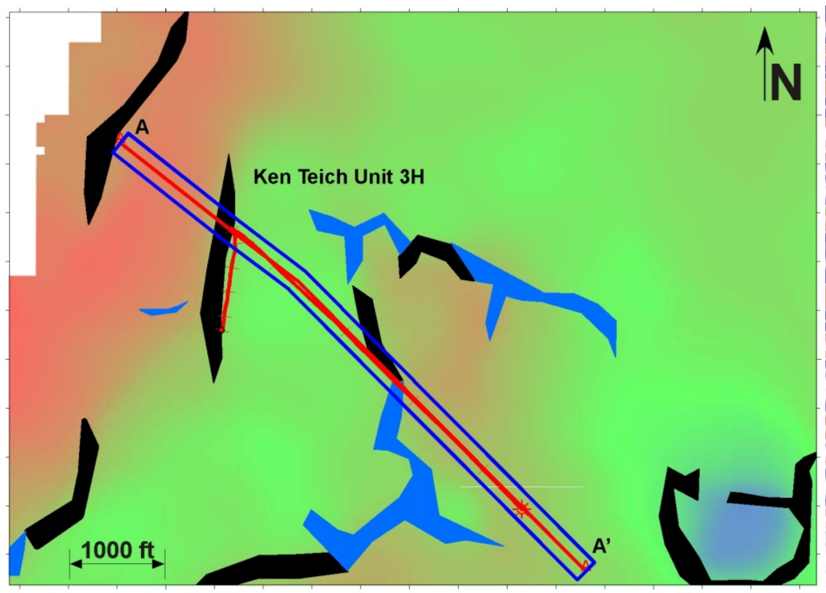


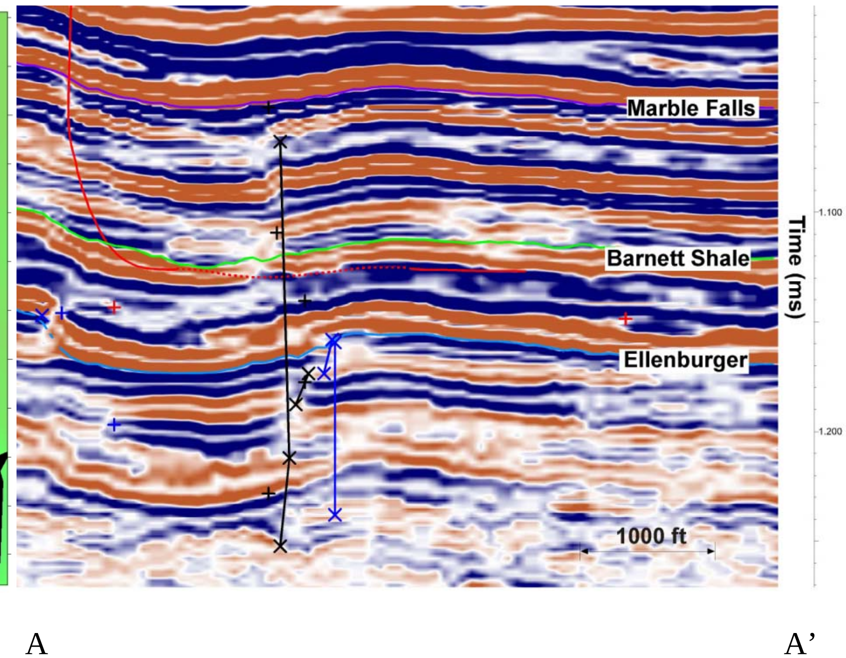
The Carolyn Teich Unit 2H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults.



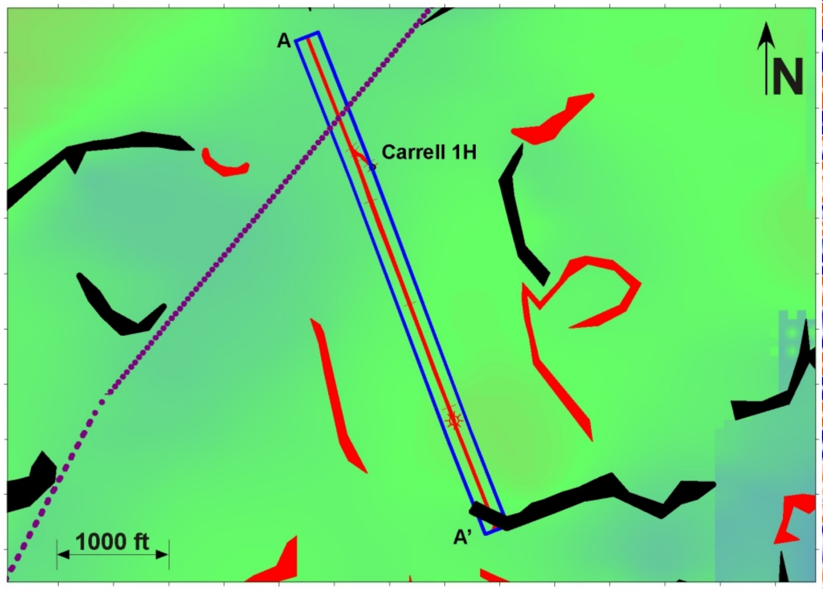


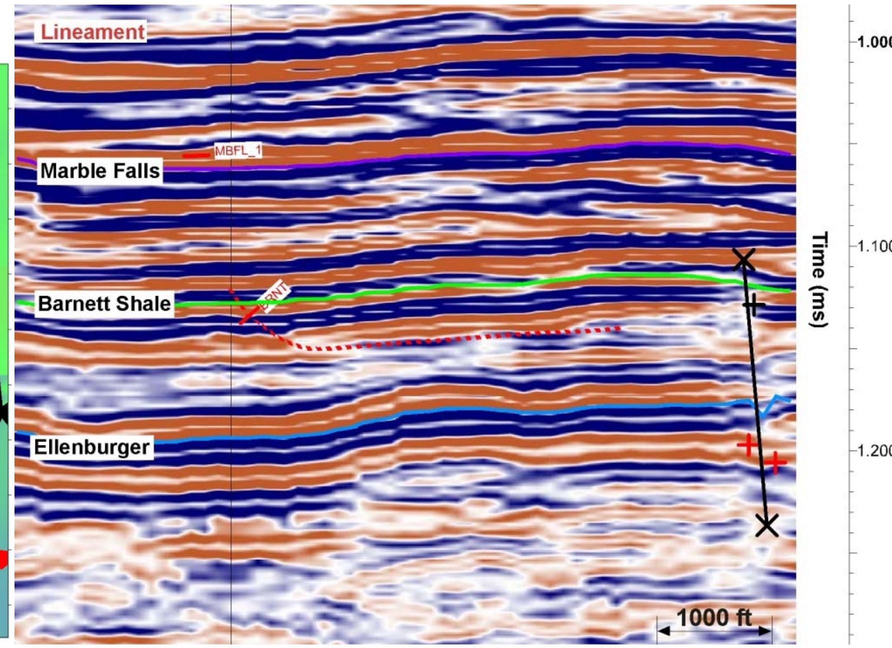
The Hoffman 3H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in dashed black and its proximity to surrounding faults.





The Ken Teich Unit 3H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults.





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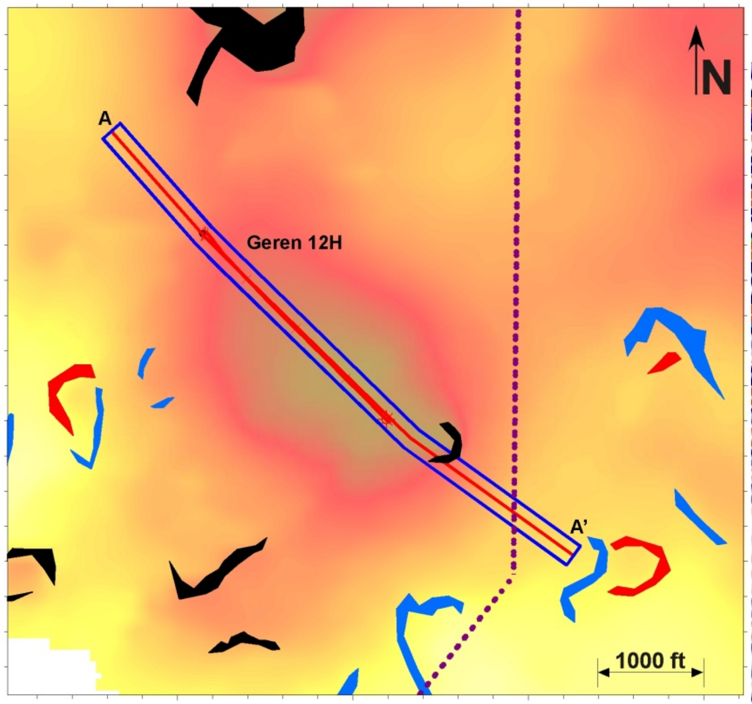
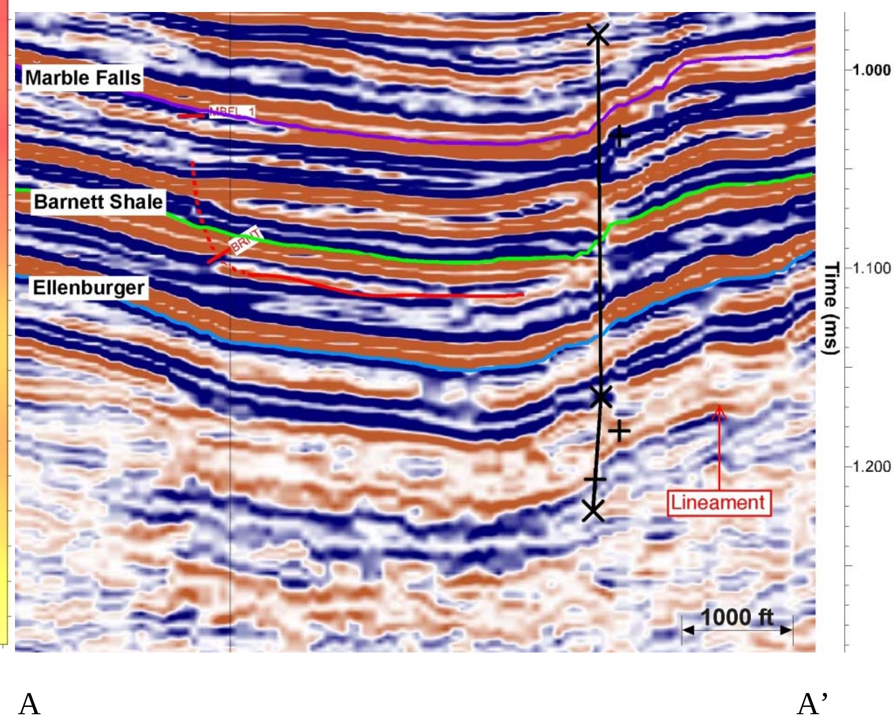
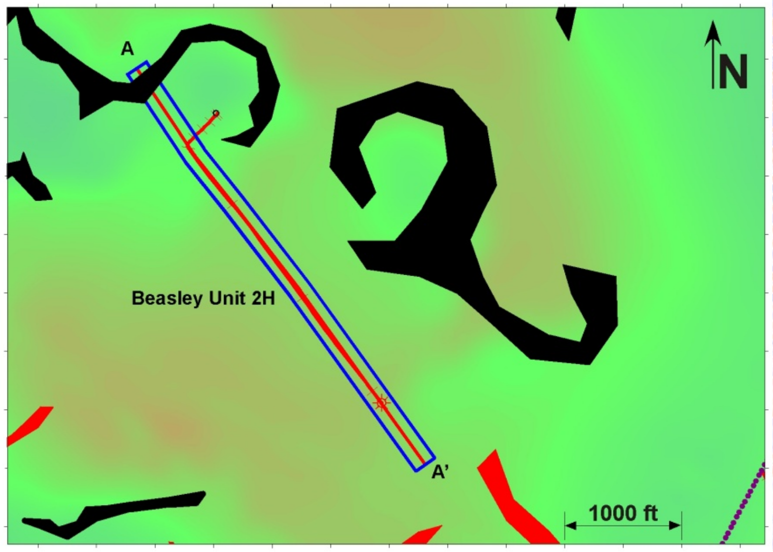
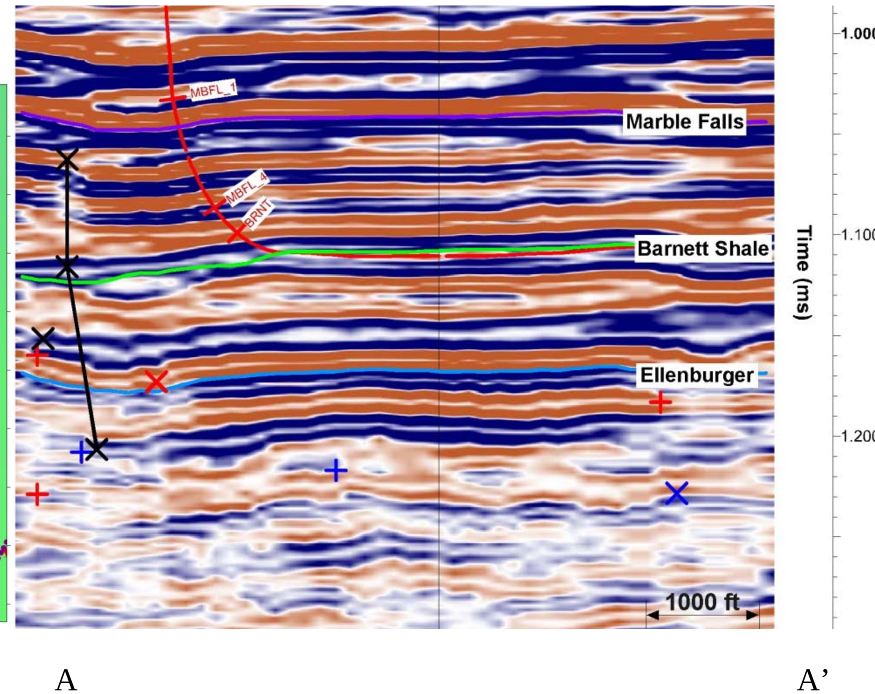
The Carrell 1H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults. The strike-slip fault is noted but not clearly seen.



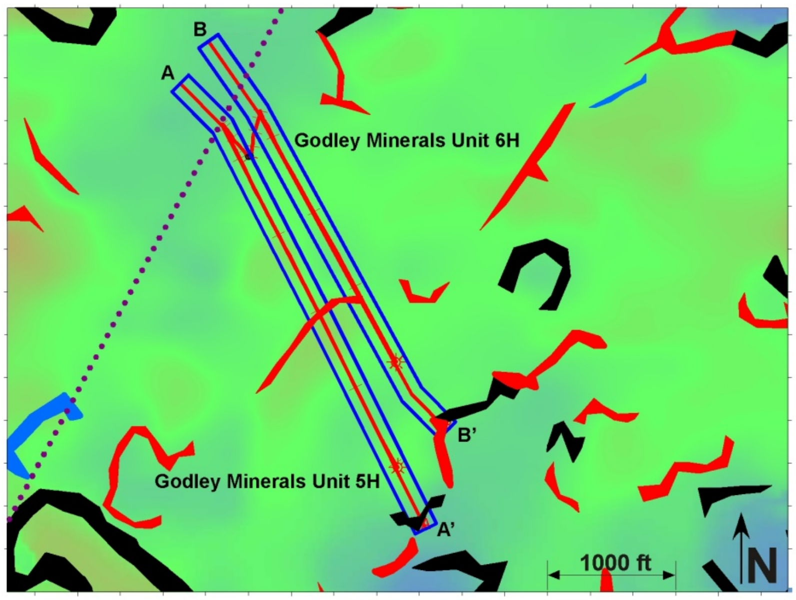


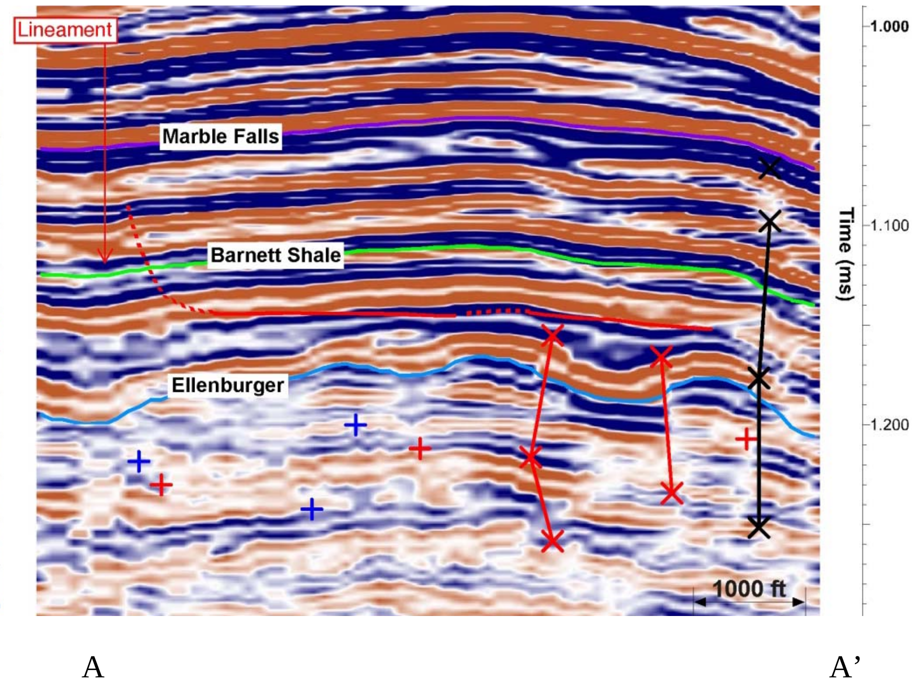
The Geren 12H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults. The strike-slip fault is noted but not clearly seen.



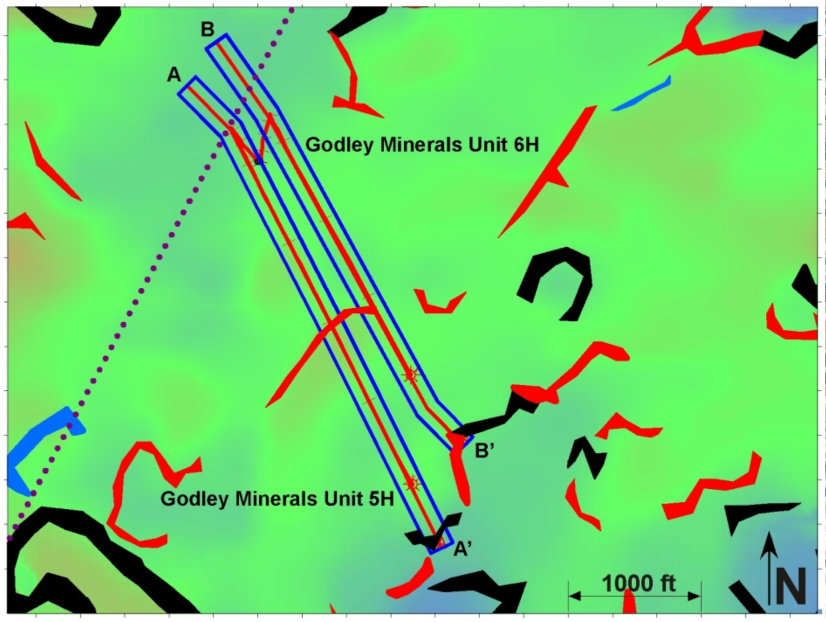


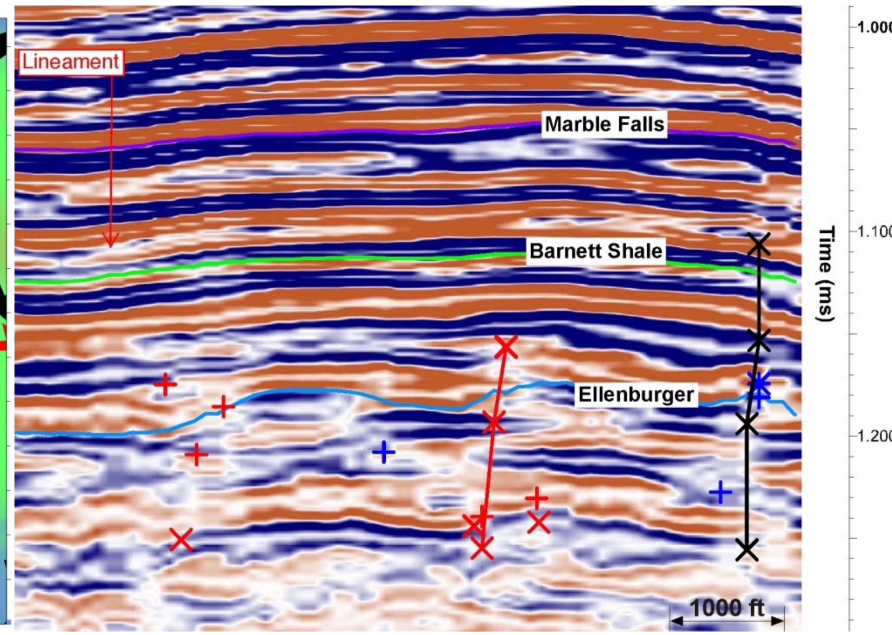
The Beasley Unit 2H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults.





The Godley Minerals Unit 5H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults. The strike-slip fault is noted but not clearly seen.





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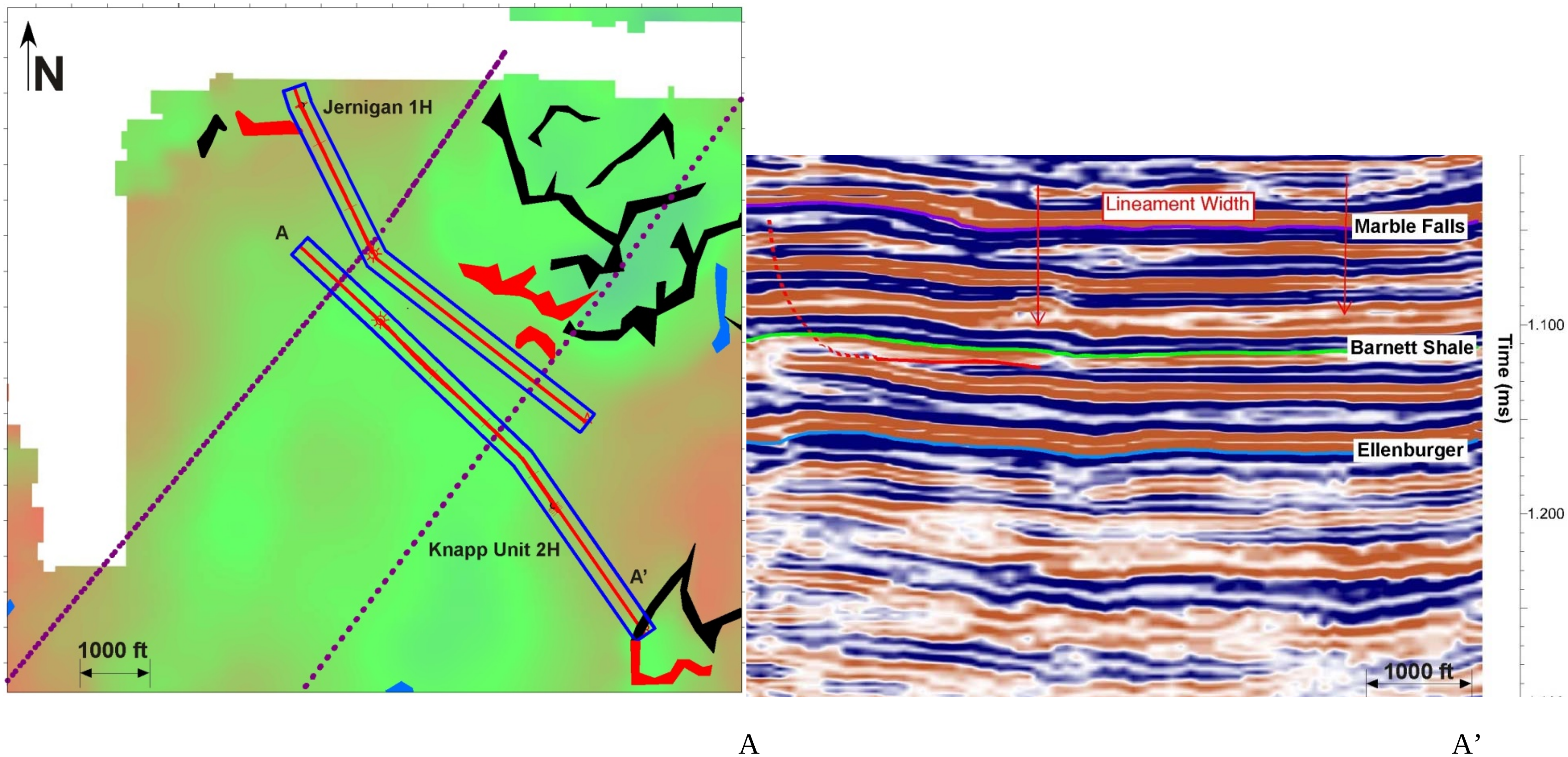
The Godley Minerals Unit 6H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults. The strike-slip fault is noted but not clearly seen.



The Jernigan 1H location map (left) is drawn on the top of the Barnett (time horizon). The vertical seismic cross section (right) shows the wellbore in red and its proximity to surrounding faults. The strike-slip fault is noted but not clearly seen.

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VITA

Amy Atamanczuk Patterson
Fort Worth, Texas
Daughter of Dan Atamanczuk and Wanda Burks
Married Casey Patterson, March 22, 2003

Diploma, R.L. Paschal High School, Fort Worth, Texas, 1997
Bachelor of Science, Environmental Earth Resources, TCU, 2002
Master of Science, Geology, TCU, 2010

ABSTRACT

STRUCTURAL GEOLOGY AND HYDROCARBON PRODUCTION,

BARNETT SHALE (MISSISSIPPIAN), FORT WORTH BASIN,

NORTHWESTERN JOHNSON COUNTY, TX

By Amy Atamanczuk Patterson
Department of Geology
Texas Christian University

Dr. John A. Breyer, Professor of Geology

The location and orientation of tectonic structures and the size and distribution of karst-related disturbances in the Barnett must be known in order to maximize production of natural gas from the reservoir. Knowledge of these features has already been utilized in developing the Barnett Shale, both in selecting well sites and in choosing the direction to drill horizontal wells. In this study, I identify and map the faults and fractures in northwestern Johnson County, establish their relative ages, and determine their origins. Also, I relate well productivity to the detailed structural setting with the goal of establishing guidelines for selecting well sites and orienting horizontals.