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3D SEISMIC ATTRIBUTE EXPRESSION OF THE ELLENBURGER GROUP
KARST-COLLAPSE FEATURES AND THEIR EFFECTS ON THE
PRODUCTION OF THE BARNETT SHALE, FORT WORTH BASIN, TEXAS

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3D SEISMIC ATTRIBUTE EXPRESSION OF THE ELLENBURGER GROUP
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OF THE BARNETT SHALE, FORT WORTH BASIN, TEXAS

A THESIS APPROVED FOR THE
CONOCOPHILLIPS SCHOOL OF GEOLOGY AND GEOPHYSICS

BY

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A mi familia por y mi mejor compañera y amiga Yoryenys.
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ABSTRACT

While karst-collapse features from the Ellenburger Group in the Permian Basin, similar features in Newark East Field in the Fort Worth Basin in north Texas produce water and are consider to be geohazards in completing the overlaying Barnett Shale gas reservoir. There are important stratigraphic differences within the Fort Worth Basin. West from the Newark East Field, the Viola and Simpson Formations thins out and the Barnett Shale lies directly over the top of the highly karsted Ellenburger Group. Hardage (1996) used pressure and production patterns from wells into two Ellenburger karst-collapse features to analyze how they affect the deposition, and hydrocarbon production potential of the overlaying Barnett Shale, as well as the shallower Atokan and Caddo Formations deposits.

This study shows how careful reprocessing of the 3D seismic data can better image the Mississippian and Ordovician targets, resulting in improved seismic attributes characterization of the internal architecture within the Ellenburger Group karst-collapse features. Exploratory data analysis using 3D seismic attributes including waveform similarity, reflector curvature, and shape indexes identify thicker areas of the Barnett Shale controlled by the karst collapses at the top of the Ellenburger Group.

The limited well control available indicates better production in thicker areas far from major faults, joints and karst and poor production in the more heavily karsted areas.
INTRODUCTION

The Barnett Shale in the Fort Worth Basin has seen more than 16,000 gas wells and 500 oil wells since the 1981. The Mississippian Lower Barnett is the source, reservoir, and trap for the production of more than 2.0 Tcf of gas. Horizontal drilling and hydraulic fracturing stimulation are necessary to increase the economic production from this tight formation, reactivating natural planes of weakness and generating and propagating new fractures that enhance the recovery of hydrocarbons. Ideally, these open fractures are confined to the Barnett Shale. Such confinement is the case of the hydraulic fracturing jobs in the Newark East Field, where the Barnett Shale is encased between the Viola/Simpson Groups and the Forestburg Limestone fracture barriers.

In the zone of this study, the Lower Barnett Shale sits right above the highly karst and diagenetically altered Ellenburger Group. Karst and joints in the Ellenburger are considered to be drilling hazards that serve as conduits into the Ellenburger aquifer. Given this recognition of “geohazards”, the western part of the Fort Worth Basin is less intensely drilled than the “core” area of the Newark East field. Then, is it possible to develop a workflow that quantitatively correlates water production to proximity to hypothesized “geohazards” seen on 3D seismic data?

This thesis starts with Chapter 1 general geological review of the zone of interest and how it differs from the Newark East field setting. Chapter 2 discusses the processing of a 3D prestack time migrated seismic data, the improvement of frequency spectrum, suppression of the groundroll, and general improvement of
the signal-to-noise ratio. Then, Chapter 3 shows the results of the migration algorithm and the comparison with the vintage-vendor's seismic processing. The Chapter 4 provides the interpretations and correlation of the hydrocarbon and water production from Lower Barnett Shale wells with the proximity of these karst-collapse fractures and faults using volumetric seismic attributes and production reports. Chapter 5 summarizes key observations and concludes with a recommendation for future work.
CHAPTER 1: GEOLOGY BACKGROUND

Province boundary, structural elements, and tectonic history:

The Fort Worth Basin, also known as Bend Arch-Fort Worth Basin, situated in North-central Texas and southwestern Oklahoma has a north-south orientation, is elongated in shape, relatively shallow in depth, and covers around 15,000 mi$^2$ (38,100 km$^2$) (Montgomery et al., 2005) (Figure 1). To the east and south are the Ouachita structural front and Llano uplift (Ball et al., 1996). The northern boundary follows Red river/Electra and the Muenster Archs (Thompson, 1982). The western boundary shallows against the Bend arch and Concho platform that separates the study area from the adjacent Permian Basin (Thompson, 1982; Ball et al., 1996).

The asymmetrical, wedge-shaped Fort Worth Basin consists of a marginal Paleozoic foreland Basin limited by the Muenster Arch to the east, and the Bend Arch to the west. In its deepest northeast portion close to the Ouachita structural belt and Muenster Arch, the Basin can reach depths of about 12,000ft (Pollastro et al., 2003). On the other side of the Basin, the Bend Arch is a broad positive subsurface structure, extending northward from the Llano Uplift. The Bend Arch was formed during the early stages of development of the Ouachita structural belt in the Late Mississippian, which formed a down-warping due to subsidence of the Fort Worth Basin of its eastern flank, and westward sloping, which formed the Midland Basin to the west during the late Paleozoic (Pollastro et al., 2003). Periodic upwarp of the Bend Arch resulted in several erosional unconformities between middle Ordovician to Early Pennsylvanian (Barnes and Cloud, 1946).
Principal structures in the Fort Worth Basin include folding, important karst-related collapse features, and major and minor faulting with possible associated fracturing patterns (Montgomery et al., 2005). An important structural feature is the prominent 65 mi long northeast-southwest Mineral Wells fault (Figure 2) splits the Newark East field (Montgomery et al., 2005). The origin of the Mineral Wells fault does not appear directly related to either the Muenster–Red River arch or the Ouachita front (Montgomery et al., 2005), but rather to a basement feature that underwent periodic rejuvenation, particularly during the late Paleozoic. This fault directly influenced the depositional patterns and thermal history of the Barnett Shale as well as hydrocarbon migration in the northern part of the Fort Worth Basin (Pollastro, 2003; Montgomery et al., 2005).

It is possible to identify different graben-type features and minor-angle normal faults related with several major tectonic elements in the Basin (Montgomery et al., 2005). In the northern part of the Basin, and close to Newark East field, it is been possible to interpret many normal faults trending northeast-southwest, parallel or subparallel to the Mineral Wells fault system. In the central of the area, Ouachita structural front to the east appears to be the responsible for the north-south fault trends. The Llano Uplift affected the southern half of the Basin and is probably responsible for the horst-like arches and northeast-trending normal faults (Browning, 1982; Montgomery et al., 2005).

There are macroscopic natural fractures related to fault trends in conventional cores taken from wells that penetrate the Barnett Shale near the Newark East field (Montgomery et al., 2005). These natural fractures, as observed in core, are
nearly always healed with carbonate cement (Montgomery et al., 2005; Gale et al., 2007). Previous work at the northern part of the Basin has shown small-scale faulting and local subsidence related to karst-collapse features in the Ordovician Ellenburger Group (Hardage et al., 1996; Jyosyula, 2003), which affects the overlaying Mississippian to middle Pennsylvanian formations (Montgomery et al., 2005; Jyosyula, 2003).

**General stratigraphy of the Fort Worth Basin:**

Montgomery and others (2005) divided the Paleozoic section of the Fort Worth Basin into three main intervals in the northeast corner close to the Muenster Arch, where it reaches its maximum depth (about 12,000 ft):

- Cambrian-Upper Ordovician platform strata: (Riley-Wilberns, Ellenburger, Viola, Simpson carbonates) deposited on a passive continental margin,
- Middle-upper Mississippian strata: (Chappel Formation, Barnett Shale, and lower Marble Falls Formation), controlled by the early phases of subsidence related to the Oklahoma Aulacogen, and
- Pennsylvanian strata (upper Marble Falls Formation, Atoka, etc.), that occurred due to the advancing Ouachita structural front and represents the most abrupt phase of subsidence and Basin filling (Montgomery et al., 2005).

The shelf limestones and dolomites from the Wilberns Formation were deposited during the Upper Cambrian and subtly merged with the overlying Ellenburger Formation by an uncertain process (Turner, 1957). However, the Wilberns Formation is differentiated from the overlying Ellenburger Group by an
unusual network of clear, rodlike silica crystals or spicules (Cheney, 1940). Insoluble residues are composed of siliceous oolites, green shales, rounded and frosted sand grains, and various types of unfossiliferous chert (Cheney, 1940). Just above the Wilberns Formation, Hendricks (1952) observed a significant decrease in the amount of silty and argillaceous materials in the Ellenburger. In addition, he recognized the Wilberns Formation to be richer in glauconite than the Ellenburger Group.

The Ellenburger Group represents part of a carbonate platform that was deposited over a stable cratonic shelf in the Fort Worth Basin that covered almost all Texas State during the Early Ordovician (Pollastro et al., 2003). Hendricks (1952) divided the gray to dark gray dolomitic Ellenburger into three formations (from youngest to oldest):

- The Tanyard Formation: predominance of granular chert, glauconite rare, drusy quartz is fairly common with absence of sand grains,
- The Gorman Formation: mainly non-granular chert with some frosted quartz sand grains. The sand occurs as scattered, individual grains and as sandy zones with poor sorting. Finally,
- The Honeycut Formation: mainly non-granular chert, absence of sand, and this formation contain most of the microgranular dolomite of the Ellenburger Group.

Although the important weathering process that marked the top of the Tanyard Formation, most of the interstitial chert and quartz occurred below this weathered surface (Hendricks, 1952).
Periodic upwarping of the Bend flexure from Mid-Ordovician through lower Pennsylvanian time resulted in at least seven significant erosional unconformities (Cloud and Barnes, 1946); with the most important one occurring during a low sea level period at the ending of the Lower Ordovician. This event created the karst-collapsed features observed at the top of the Honeycut Formation in the Ellenburger Group (Cloud and Barnes, 1946; Sloss, 1976; Kerans, 1988). (Figure 4).

Overlying the Ellenburger Group, the Upper Ordovician Viola and Simpson rocks are only found in the northeastern part of the Basin and consist mainly of dense, crystalline limestone and dolomitic limestone. These strata dip eastward beneath the sub-Mississippian unconformity and disappear along a northwest-southeast line through Wise, Tarrant, and Johnson counties (Bowker, 2007). This wedge of the Viola–Simpson Formations establishes an essential stratigraphic boundary because south and west of it, Mississippian rocks are in unconformable contact over the highly karsted and potentially water-bearing Ellenburger carbonates (Herkommer and Denke, 1982; Montgomery et al., 2005) (Figures 5 and 6).

Any Silurian and Devonian deposits in the area where removed by an important erosional event known as the post Viola Limestone unconformity (Henry, 1982).

The Mississippian deposits consist of alternating shallow-marine limestones of the Osagean age Chappel Formation and black, organic-rich shales of the Barnett Formation during the Chesterian-Meremecian. The total Mississippian
section reaches its most thick intervals south from the Muenster arch, where the Barnett Shale Formation is more than 1000 ft. thick and contains significant limestone (Pollastro, 2003). The Newark East Field falls inside the limits of this core producer area. West of the Basin axis, along the flanks of the Bend arch, the Barnett Shale thins over the Chappel platform, which consists of crinoidal limestone and local pinnacle reefs up to 300 ft. in height (Montgomery et al., 2005) (Figures 6 and 7).

The Marble Falls Formation differs from the Barnett Shale because it is less radioactive and has less organic matter. The top of the Marble Falls formation consists of a limestone interval (Montgomery et al., 2005), thins abruptly south of Newark East field, and is absent in the east-central part of the Fort Worth Basin (Bowker, 2003; Pollastro, 2003) (Figure 4).

Above the Marble Falls Formation lays the Pennsylvanian age Atokan Bend’s transgressive carbonate bank deposits (Cleaves, 1982; Thompson, 1988). The main phase of the Ouachita orogeny took place during the Lower Pennsylvanian, and is considered to be responsible for the Muenster arch and Ouachita fold-thrust belt. Giving rise to the marine, marginal-marine, and continental settings for the deposition of the Lower Pennsylvanian Atokan conglomerates, sandstones, shales, and thin limestones (Thompson, 1982) (Figure 6 and 7). Traditional oil and gas production in the Fort Worth Basin is associated with deltaic, fluvial, and carbonate bank deposits of these Pennsylvanian age intervals.
The Barnett Shale Formation in details:

The Barnett Shale source rock covered large parts of North-Central Texas during its deposition. However, because of post-depositional erosion due to several uplifting episodes, most of the Barnett Shale limited to the Bend Arch-Fort Worth Basin Province (Maple et al., 1979; Pollastro et al., 2003).

Important changes in the stratigraphy and lithology of the Barnett Shale occur through the Basin. In the northeast, the Barnett Shale is thickest and consists mainly of limestone rocks. The amount of shale increases quickly to the south and west directions (Montgomery et al., 2005). The origin of these limestones deposits seems to be from a source to the north of the Basin and been deposited by a succession of debris flows into the deeper part of the Basin (Bowker, 2002). The Barnett Shale is interpreted to be an undifferentiated interval across the Basin, except in the Newark East field and its surroundings, where a carbonate unit, informally known as the Forestburg Limestone, separates the shale into lower and upper intervals. The Forestburg Limestone reaches 200ft close to the Muenster arch, and thins westward to a feather edge in the southeast (Figures 4 and 5).

In general, the Barnett Shale formation is relatively rich in silica (35 – 50%, by volume) and poor in clay minerals (< 35%) (Montgomery et al., 2005). To the north, the Barnett Shale increases in thickness progressively and reaches around 400ft in thickness in the area of study (Singh, 2008).

Singh (2008) conducted a detailed study in four wells within the Fort Worth Basin, one of them, Adams Southwest #7 (Adams SW#7) inside the area of this
study. On this well, she interpreted 13 Gamma Ray parasequences, a relative sea level curve, and the position of the systems tracts using well core observations (Figure 8).

Pollastro et al. (2003) associated clay rich minerals intervals (3 – 13%) in the Barnett Shale to be those with the highest organic content (average 3.2% in weight in cuttings). Generally, these sections are located in the lower Barnett interval but can also be present in the upper Barnett Shale as well (Pollastro et al., 2003).

The Barnett Shale distinctive type log shows a high radioactivity and high resistivity, compared with the overlaying Marble Falls, the underlying Viola-Simpson Formations, the Ellenburger Group, and the dividing Forestburg limestone (Montgomery et al., 2005).

Summary of the Barnett-Paleozoic Total Petroleum System

Montgomery et al. (2005) considered the Barnett Shale to be unconventional hydrocarbon play, where petroleum system elements such as source, reservoir, and seal correspond to the same formation. Hydrocarbon saturation levels, distribution, and productivity in the Barnett Shale are complex and depend on geochemical elements such as original organic matter amounts, phases of thermal maturity, and burial history (Montgomery et al., 2005) (Figure 9).

Source rock: Using finger-printing, carbon isotope, and biomarker data (Pollastro et al., 2003; Jarvie et al., 2001) showed that oil and gas produced from Ordovician (Ellenburger Group and Viola Limestone), Mississippian (Chappel
Formation and Barnett Shale), and Pennsylvanian (Atokan) reservoirs, in the Fort Worth Basin, were derived from a single source rock, the Barnett Shale.

The Barnett Shale is similar to other Devonian-Mississippian black shales such as the Woodford and Bakken shales because they all contain oil-prone organic matter (Type II kerogen) and generated similar type of high quality oil (low sulfur, >30 API gravity) (Pollastro et al., 2003). The decomposition of kerogen controls the important amounts of oil and gas from the Barnett Shale (Jarvie et al., 2001; Pollastro et al., 2003).

There is a relationship between the several production patterns of Barnett-sourced hydrocarbons and the differences in maturation from east to west across the Fort Worth Basin (Montgomery et al., 2005). Present downhole temperatures are much lower than paleotemperatures in the Fort Worth Basin. Thermal history was influenced by the hydrothermal heating associated with the Ouachita thrust front (Bowker, 2003; Pollastro et al., 2007a) and movement along the Mineral Wells fault (Montgomery et al., 2005). Hot fluids generated by Ouachita thrusting could have been forced through karsted, porous Ellenburger Group carbonates into the overlying Mississippian section (Montgomery et al., 2005), probably causing the presence of saddle dolomites in both the Ellenburger Group and Chappel Formation, and also exotic minerals, including native copper in some core samples from Barnett in the southeastern Fort Worth Basin (Eastland County) (Montgomery et al., 2005).
Maturation, Timing, and Migration: Burial-history reconstructions suggest three main stages in the thermal history of the Barnett Shale (Montgomery et al., 2005):

1. Rapid subsidence and burial state in the Pennsylvanian–Permian period,
2. Elevated temperatures stage during the Late Permian–Early Cretaceous, followed by a short increase in the burial process during the middle–late Cretaceous, and
3. Uplift and removal of overburden in the Late Cretaceous–Tertiary (giving rise to the Ouachita thrust belt).

Jarvie et al. (2001) proposed two main phases of maturation of the Barnett Shale source beds. The first phase generated oil and gas due to high paleotemperatures due to subsidence of the Basin. The second phase of mainly gas generation from oil cracking (Montgomery et al., 2005). This secondary hydrocarbon generation phase, combined with leaking seals including the Barnett Shale itself, is thought to be responsible of the wide distribution of Barnett-hydrocarbons in overlying and underlying formations (Montgomery et al., 2005). These hydrocarbon expulsion phases may be responsible for some microfracture fabrics in the Barnett Shale rocks (Montgomery et al., 2005).

Reservoir: Conventional reservoir production is associated with the overlying Pennsylvanian age formations (Atokan), while unconventional production is associated directly with the source rock (Pollastro et al., 2003).
Seal rocks consist of dense shale units distributed in regional and local scales (Pollastro et al., 2003). The Barnett Shale is considered the regional seal for the underlying carbonate rocks of the Ellenburger Group (Pollastro et al., 2003). More important is the direct dependency of the production from the Barnett Shale itself on the presence the Marble Falls and Viola limestones. These formations act as barriers that keep hydraulic-induced fracturing to propagate beyond the Barnett Shale formation and keep the original formation pressures when it is artificially stimulated (Bowker, 2002; Shirley, 2002; Pollastro et al., 2003).

Traps: For the Barnett Shale reservoir, the hydrocarbon traps are mainly stratigraphic. These stratigraphic traps can be associated with combination of facies and depositional topography, erosional surfaces, facies thinning or pinchouts, and differences in permeability and porosity due to the diagenesis action (Pollastro et al., 2003).

Petrophysical properties of the Barnett Shale:

Petrophysical analysis shows that the organic-rich and more productive sections of the Barnett Shale have average porosities around 5-6% and permeabilities of less than 0.01 mD and in the nanodarcy range (Montgomery et al., 2005). The pore-throat radii for this facies are less than 0.0005 mm in average (Bowker, 2003). Water saturations, is around 25% but increases abruptly when carbonate components increase, which suggest that expulsion of hydrocarbons from these organically rich facies cause the drying of the reservoir (Bowker, 2003; Montgomery et al., 2005).
The regional stress field in the area of study has a similar northeast-southwest orientation to that on the Newark East Field (Figure 10), and is consistent with the known dominant hydrofracture propagation trend (Gale et al., 2008; Heidbach et al., 2008).

Gale and others (2008) analyzed a core from the Mitchell Energy 2 T. P. well in Wise County. They observed that all natural fractures were sealed with calcite and they described at least two sets of echelon fractures: an older north-south-trending set; and a younger, dominant west-northwest-east-southeast trending. They concluded that the fractures in the Barnett Shale are strongly clustered, and their filling cement minerals are not recrystallized with the grains in the wall rock. Moreover, reactivation of these planes of weakness is possible with hydraulic fracture procedures and they can open up to extend and connect more formation to the wellbore (Gale et al., 2008).

Gale et al. (2008) did not directly observe large open fractures. However, they infer that when hydraulically stimulated possible open natural fractures could be problematic because they could capture treatment fluids and prevent new fractures from forming. Moreover, open fractures could represent a problem if they connect the Barnett Shale with the underlying Ellenburger Group. The risk of this happening depends on the height of the fracture system and the preexisting connection of the open, natural fracture cluster and water from the Ellenberger Group (Gale et al., 2008).

The Barnett itself could behave as a barrier for some of these fractures. Internal carbonate-rich interbeded layers could provide smaller scale mechanical
boundaries for propagation of some fractures, but not for other, as demonstrated by Gale and others (2008).

Understanding the in-situ stress is critical to successful hydraulic-fracture procedures. In the area of study, Elibiju (2009) correlated the orientation of deeper Precambrian structures with the overlying Ordovician sedimentary features such as faults and collapse terrains using seismic attributes and anomalies displayed on high-resolution aeromagnetic data (HRAM). Thomas (2003) postulated that unexplored Barnett Shale “sweet spots” are correlated to fracture patterns associated with in-situ stresses and karst-collapse in the underlying Ellenburger Group.

**Production in the Bend Arch-Fort Worth Basin Province.**

The first shows of oil and gas were within Bend Arch-Fort Worth Basin during the mid-nineteenth century while drilling wells for water extraction (Pollastro et al., 2003). The first official exploration for petroleum began when the United States Civil War was finishing, and the first important commercial oil discoveries occurred at the beginning of the twentieth century (Ball and Perry, 1996; Pollastro et al., 2003). The Bend the Bend Arch-Fort Worth Basin Province reached a mature stage of exploration and development by 1960, demonstrated by the density of well perforations and production wells (Pollastro et al., 2003, Railroad Commission of Texas, 2013) (Figure 11).

Starting in the late 1990s, vertical drilling to the Barnett in Newark East Field grew rapidly, on 55-ac, 27-ac, and possibly closer spacing in some areas of the field (Montgomery et al., 2005, Energy Information Administration, 2012). Initial
rates of production in this field for these vertical wells ranged from 0.5 to more than 2.0 mmcf/day (Montgomery et al., 2005). Estimated ultimate reserves for these wells were typically about 1.0 – 2.5 bcf with some reaching 7.0 bcf. Artificial stimulations added an average of 0.5 bcf of reserves per well (Montgomery et al., 2005).

By the late 1990s, completions using water (1 million gallons) and small amounts of sand as proppant (50,000 lb. sand) showed reduced cost, better production performance, and increased estimated ultimate reserves around 25%, than completions using energized foam and gel fluids (Pollastro et al., 2003; Montgomery et al., 2005). Bowker (2007) indicates that the operators added no clay stabilizers to the water since the Barnett Shale reacts favorable in presence water because of the extremely low permeability (Warpinski et al., 2005).

Cumulative up to, and including 2007, the number of producing horizontal wells surpassed the number of vertical wells. In 2006, the annual total production of the horizontal wells exceeded the vertical wells, which currently accounts for more than 10,000 producing horizontal wells (about 90%) of total Barnett Shale natural gas production (Energy Information Administration, 2012) (Figure 12). Horizontal wells have exhibited initial rates of production ranging from 1.5 to 8.1 mmcf/day in the Newark East Field, and rates varying from 1.0 to 3.0 mmcf/day outside the field. Reserves for these wells range widely, but average about 2.5 bcf (Montgomery et al., 2005).

These horizontal wells will not produce unless they are fractured-stimulated and they are expected to produce from several parallel sections of reservoir, by
expanding the overall drainage area (3000 x 500 ft. in vertical wells; Fisher et al., 2002) and drilling perpendicular to the induced fracture direction (Montgomery et al., 2005). Initial rates of gas flow from the lower Barnett interval in Newark East field can be two to three times those of vertical wells.

Horizontal drilling techniques also represent an advantage in zones where lithological barriers for induced fractures growth are thin or absent, such in the case of this study where the Viola-Simpson Formations below are absent and the Barnett overlays directly the Ellenburger Group. Ideally, hydraulic-fractures from horizontal wells tend to stay inside the thick target zone of the Barnett Shale reservoir than vertical wells (Montgomery et al., 2005).

Bowker (2007) stated that microfractures are a key factor to the production from the overpressured and fully saturated Barnett Shale (Bowker, 2007). This formation stays at capillary pressure equilibrium (about 0.52 psi/ft, in the gas-saturated portion of the play) until it is drilled and hydraulically fractured. When it is fractured, the equilibrium is broken and the hydrocarbons circulate from the matrix to the borehole by flowing through the hydraulic fractures. Although natural fractures are thought to contribute to the permeability, the increment in permeability due to the induced fractures is responsible for the increase in hydrocarbon production (Bowker, 2007).

Bowker (2007) hypothesizes that the best place to locate prospective targets in the Barnett Shale is where there are no important structural folds or faults of any kind where gas content is higher.
Summary of Factors contributing to productivity in the Newark East Field:

All factors except one described by Montgomery and others (2005) present in the Newark East Field necessary for good hydrocarbon production in the Bend Arch-Fort Worth Basin (Figure 12), are present in this study. Montgomery et al. (2005) state that any Barnett Shale gas production beyond the Newark East field limits in the Fort Worth Basin will have to overcome some geological and geochemical factors such as:

1. Presence of the Marble Falls Formation, necessary to form an upper barrier to hydraulic fracture growth in my area of study. There is no obvious risk of fracturing into overlying mixed gas-water-bearing Pennsylvanian clastics.

2. Maturity levels are close to the optimal point since the area of study is inside the gas with oil window.

3. Target depths in the area of study (6900 to 7500 ft.) are not as deep as in the easternmost part of the Basin (depocenter close to the Muenster Arch). This means that the drilling cost should be similar to the ones in the Newark East field, with similar bottomhole temperatures.

The main risk in my area is the erosional pinch-out of the Viola–Simpson section, representing the absence of the preferred lower barrier to hydraulic fracture growth. Instead, the lower Barnett Shale lays directly on the karsted, potentially water-bearing Ellenburger Group. This creates the potential for water invasion after fracking the reservoir.

Wells located adjacent to local faults or surrounded by karst-related collapses, commonly show low gas production compared to wells targeting
flatlying and undisturbed Barnett Shale zones (Montgomery et al., 2005). On the other hand, open microfractures caused by the maturation and expulsion of hydrocarbons (Jarvie et al., 2001; Adams, 2003; Jarvie et al.; 2003), could store important amounts of free gas and rise levels of productivity (Bowker, 2007).

The focus of this study is in the assessment unit known as “Ellenburger Subcrop Fractured Barnett Shale Gas” described by Pollastro and others (2003) as continuous accumulations (unconventional) of hydrocarbons at the Barnett Shale. The efficiency of the production from the Barnett Shale will depend on the fracture patterns and water production associated with the macro fractures related with the karst-collapsed features of the underlying Ellenburger Group limestones.

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<td>North Basin and Arch Fractured Shale Gas and Oil AU</td>
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Table 1. Plays identified in the 1995 USGS National Oil and Gas Assessment (after Ball and Perry, 1996) and proposed assessment units (AU) for 2003 USGS National Oil and Gas Assessment of the Barnett-Paleozoic Total Petroleum System, Bend Arch-Fort Worth Basin Province. Note the highlighted Ellenburger Subcrop Fractured Barnett Shale Gas assessment, which is the interest in this study (After Pollastro et al., 2003)
Figure 1. Bend Arch-Fort Worth Basin Province within the boundary outlined in red and primary structural elements of north-central Texas and the southwestern corner of Oklahoma. (After USGS, 2013)
Figure 2. Regional setting and structure contour map of the Fort Worth Basin, north-central Texas. Also shown the northeast-southwest Mineral Wells fault cutting the Newark East field (main producing area of the Barnett Shale gas play). Contours are drawn on top of the Ordovician Ellenburger Group (contour interval = 1000 ft.). The orange line indicates the A-A’ west-east crossection of Figure 5 over the study area in red box (After Montgomery et al., 2005).
Figure 3 Interaction of the second-order relative coastal and relative shoreline curves for the Ellenburger Group (Lower Ordovician in age) (After Kupecz, 1992).
Figure 4. Cross-section index map showing the location of Viola/Simpson erosional edge and the limit of the Barnett gas-window. The polygon in red defines the Newark East productive field. The orange line indicates the A-A’ west-east crosssection of Figure 5 over the study area in red box

(After Bowker, 2007)
Figure 5. West-east cross-section showing the current core area and economically-productive limit of Newark East field. The updip limit of the field is controlled by the position of the Viola/Simpson erosional edge. Downdip toward the Muenster arch, the Barnett contains a much higher concentration of carbonate and has much lower gas saturation (After Bowker, 2007).
Figure 6. Generalized columnar section of the Bend arch–Fort Worth Basin province showing the principal Groups and Formations with the corresponding petroleum system element (After Pollastro, 2003).
Figure 7. Columnar section of the study area showing the principal Groups and Formations with the corresponding petroleum system element. Note the Barnett Shale overlays directly over the Ellenburger Group due to the absence of the Chappel Limestone, Viola Limestone, and Simpson Group (After Pollastro, 2003).
Figure 8. Analysis of the Barnett Shale core sections from the well Adams SW#7 (Figure 4). Correlation between the Total Organic Carbon (TOC (wt%)), Relative Hydrocarbon Potential (RHP) from well core sample measurements and the parasequence, GRP depth assignment, relative sea level curve, and position of the systems tracts. The magnitude of changes of relative sea is not shown to scale. TSE refers to transgressive surface of erosion, MFS – Maximum flooding surface, SB – Sequence Boundary, LST – Lowstand systems tract, TST – transgressive systems tract, and HST – Highstand systems tract. Major shifts in geochemical parameters tend to occur at maximum flooding surfaces. (After Sigh, 2008).
Figure 9. Events chart for Mississippian-Pennsylvanian Barnett-Paleozoic Total Petroleum System (TPS) of the Bend Arch-Fort Worth Basin Province. It shows the Petroleum System elements and timing of trap formation and hydrocarbon generation. (After Pollastro et al., 2003)
Figure 10. Stress map over the zone of study. Note the regional and vertically constant northeast-southwest orientation of the maximum horizontal stress. To extract the stress information, Heidbach and others (2008) used the reported well breakouts (After Heidbach et al., 2008).
Figure 11. Map showing major structural elements (black lines), oil (green dots) and gas (red dots) well production, location of Newark East Field, and boundary of USGS Bend Arch-Fort Worth Basin Province (gray line). Red lines show present-day limit of Barnett Shale (Mapel et al., 1979) and purple lines are eastern limit of Woodford Shale (Comer, 1991). Blue line approximates the boundary of the Barnett-Paleozoic Total Petroleum System (After Pollastro et al., 2003)
Figure 12. Annual Barnet Shale natural gas production by well type. (After Energy Information Administration, 2012)
Figure 13. Map outlining high-potential areas for Barnett Shale gas production in the Fort Worth Basin and the Newark East field limits. It also shows an area interpreted to contain the larger portion of a continuous-type gas accumulation in the Barnett (Lighter shading). It also shows the limestone barriers limits that could contain stimulated fractures in the formation (Darker shading) (After Montgomery et al., 2005).
Data Available:

In 1999 Mitchell Energy acquired a wide azimuth, long offset 3D seismic survey in Wise County, TX, and merged it with two older (1995 and 1997) surveys. This chapter presents the most important results of the processing flows applied to the 1999 survey.

Figure 14 shows the location of the survey within Wise County, while Table 2 summarizes the acquisition parameters. The survey has a good variation in azimuths, with some locations having wide azimuth acquisition (Figure 15). The record length is 3 seconds at 2 ms sampling interval, with a relatively shallow Barnett Shale at 1.2 seconds. The overall quality of the data is very good with recorded frequencies ranging between 8 and 125 Hz. The dominant frequency at the target depth of 6700 ft (approximately 1.1 s) is 40 Hz with a velocity of approximately 3658 m/s (12,000 ft/s), resulting in a tuning thickness vertical resolution of about 75 ft. (22 m).

Processing:

The workflow starts with 48 files containing a total of 28 GB of the 3D prestack seismic survey that contains raw shot records, retaining the contractor’s computed refraction and elevation statics. Jyosyula (2003) also found that the field data headers contained incorrect coordinate values. The problem was solved using the ProMAX data input tool and the calculator during the geometry definition. Each trace had to be verified with the correct receiver number, shot number, coordinates, and define the midpoint binning grid.
The objective was to attenuate the ground roll and coherent noise, and reduce the acquisition footprint to improve the resolution Ellenburger Group karst-collapse. Figure 16 shows the generalized processing workflow.

Figure 17 shows the source and receiver geometry for this survey. For each source, there were 12 live receiver lines with 71 geophones per line. The CMP fold map shows a maximum fold of 49 with the average fold being 26 (Figure 18). Figure 19 shows the offset distribution, with the maximum offset near 3,657m (13,000 ft), while the most commonly occurring offset is about 1,524m (5,000 ft).

The commercial processing company demultiplexed the data to create traces and applied refraction statics to remove the irregular terrain effects on the data. The groundroll is quite strong and overprints the near offset signal (Figure 20). Sorting the shot gather by offset shows how the groundroll covers the reflector signal at near offsets (Figure 21).

During the processing, it was possible to identify the different signal and noise frequency bands using different bandpass filters. After this analysis, the intermediate frequencies between 10Hz to 100Hz contain most of the geological signal. Even though some groundroll remains around 20 Hz, it is important to preserve low frequencies as much as possible for future seismic inversion (Figure 22).

Noise burst and bad coupling gave rise to high amplitude noisy traces in the data. It was possible to estimate the range of the desirable dominant frequency, the statistical frequency deviation, the average trace energy, and the spikiness of the signal in the traces, by an analysis of the amplitude statistics of the each
trace. Figure 23 shows the ranges of the original data and the ranges used to reject anomalous traces. Figure 24 shows a shot gather before and after applying this statistical trace analysis.

Four-component surface-consistent deconvolution was used because it not only uses the source and receivers spectral components, but also the offset and CDP spectral components based on the theory described by Gary and Lorentz (1993). For land seismic data, surface-consistent log-amplitude spectra are calculated for the “source component” which represents the source and near-source structural signal and the “receiver component” which represents the receiver and near-receiver structural effects. In the case of four-component surface-consistent spiking deconvolution, the log-amplitude spectrum also includes the offset and CDP spectral components (Gary and Lorentz, 1993). The offset component represents the average reflectivity and is highly affected by groundroll, while the CDP component will represent some geological signal when smoothed. This methodology requires two steps. First, the method calculates and solves for the four components using spectral decomposition. Then, it designs and applies the deconvolution operator to all four components. Based on Gary and Lorentz’s (1993) observations, the deconvolution window’s average spectrum was designed from the middle (4900 ft.) to far (7900 ft.) offsets so that the traces contaminated by near offset (<4900 ft.) groundroll and noisier far offset (>7900 ft.) would not affect the deconvolution process.

Conventional spiking surface-consistent deconvolution using a zero phase 220 ms operator with 0.1% white noise was applied for the preliminary velocity
analysis. A top mute, air blast attenuation, true amplitude recovery, time-variant spectral whitening, and time-variant amplitude scaling processes were applied to the data. Figure 25 shows a representative CMP before and after surface-consistent spiking deconvolution for the velocity picking, the four-component surface-consistent spiking deconvolution, and finally after applying prestack structural oriented filters (PSSOF). Note the improvement of the geologic reflectors using the four-component surface-consistent spiking deconvolution, and how the reflectors are notably improved using the PSSOF.

Deconvolution and noise attenuation parameters eliminated much of the groundroll and air blast, and retained coherent reflector events visible down to almost 1700 ms at the far offsets. Figure 26 shows the corresponding frequency spectrum before and after four-component surface-consistent spiking deconvolution.

Figure 16 describes the iterative process of velocity analysis and residual statics calculation, by picking velocities using progressively denser analysis grids. The data was normal move-out (NMO) corrected, so new statics were calculated and applied, to then stack the gathers and generate a brute stack. Every analysis time a velocity cycle started, residual statics from the previous iteration were applied, and, for each finer grid, previously generated velocity field were used as a guide function. This process resulted in a reduction of the standard deviation of the residuals statics from 4.2 ms to 1.67 ms for the receivers, and 3.39 ms to 1.36 for the sources to the designated elevation datum.
(Figure 27). This iterative process used velocity analysis grids of 80x80, 40x40, and 20x20.

Figure 28 shows the representative CDP gather with NMO correction after each velocity analysis pass. As the velocity analysis becomes finer, events are better flattened and, in the case of the velocity picking after PSSOF, the events are best flattened and better resolved. Figures 29 to 33 show the stacked version of the vertical slice A-A’ after each iteration of velocity analysis, where the best quality image corresponds to the data after four-component surface-consistent deconvolution and prestack structural oriented filtering.

Applying a prestack structure-oriented filter not only attenuates groundroll and coherent noise, it also improves the semblance calculations for velocity analysis. This facilitates velocity picking, increasing both the accuracy of the picks and the number of reflectors resolved. Figure 34 shows a semblance panel from velocity analysis prior to applying the prestack structure-oriented filter, while Figure 35 shows a semblance panel from velocity analysis after applying the four-component surface consistent spiking deconvolution and prestack structural oriented filtered.

For the initial migration, the files is exported after applying the four-component surface-consistent spiking deconvolution, structural oriented filters, and applying the residual statics after velocity analysis of 80x80, 40x40, 20x20, and 20x20 after structural oriented filters.

While the previous amplitude equalization facilitated velocity analysis, prestack inversion will require an “amplitude friendly” workflow, including a
1/distance spherical divergence, followed by time-variant spectral whitening. The final velocity field is exported to SEGY, first interpolating it to a 1x1 grid so there is a pick at every CMP, and smoothing with a 10x10 increment. Resampling the velocity field to a 2.0 ms sample interval matches it to the seismic data. Figure 36 shows A-A’ line through the final velocity field that for prestack time migration.

Note that while the specular reflections in Figure 33 are more continuous that those with PSSOF in Figure 32, important diffraction events (blue ellipses) have been attenuated.

Reflectors are better focused when migrating the PSSOF filtered data using the current velocity model (Figure 36). This facilitates a final iteration of velocity analysis as described in the next chapter.
Figure 14. Regional map of the top of the Ellenburger Gr. in the Fort Worth Basin over Texas.

The star indicates the location of the 3D seismic survey used in this thesis which is located to the west of the Newark East Field and is intersected by the Mineral Wells fault (After Montgomery et al., 2005).
Table 2. 3D Seismic survey acquisition parameters.

<table>
<thead>
<tr>
<th>Acquisition Parameters</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Receiver spacing</td>
<td>220 ft.</td>
</tr>
<tr>
<td>Receiver line space</td>
<td>880 ft.</td>
</tr>
<tr>
<td>Active receiver lines per shot</td>
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</tr>
<tr>
<td>Live channels per receiver line</td>
<td>71</td>
</tr>
<tr>
<td>Shot spacing</td>
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</tr>
<tr>
<td>Source Description</td>
<td>Single hole 5 lbs. 60 ft. and 80 ft. depths</td>
</tr>
<tr>
<td>Record Length</td>
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</tr>
<tr>
<td>Sample Interval</td>
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</tr>
<tr>
<td>CMP Bin size</td>
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</tr>
<tr>
<td>Maximum CMP Fold</td>
<td>49</td>
</tr>
<tr>
<td>Average CMP Fold</td>
<td>26</td>
</tr>
</tbody>
</table>
Figure 15. a) Offset distribution, with the most common being around 5,000ft. From b) to g) show azimuth displays or “spider diagrams” from different CMPs in the area.
Figure 16. Generalize processing workflow.
Figure 17. Source and receiver geometry. Red lines indicate the live receivers lines for a particular shot.
Figure 18. a) Bin fold map and b) bin fold distribution, with 26 being the most common. The black circle highlights the location of the shot shown on Figure 20. The white circle denotes the location of the CDP display in subsequent figures.
Figure 19. Offset distribution of the 3D prestack seismic survey.
Figure 20. (a) Raw shot record after applying geometry, sorted by source station number and recording channel showing the twelve live receiver lines in the patch shown in Figure 17. The yellow explosion symbol indicates the source location. Seismic reflections (green arrows) are overprinted by groundroll (red arrows). Orange arrows indicate noise bursts or poor coupling. (b) Spectral content for the same raw shot showing that the frequencies range between 18-110 Hz.
Figure 21. The same raw shot record shown in Figure 20 but now sorted by offset. Green arrows indicate reflector signal, red arrows indicate groundroll, and orange arrows indicate bad traces.

This kind of display accurately depicts the linear movement of the head wave and ground groundroll (red arrow) but interpolates the sparsely sampled near offset (<1000 ft.).
Figure 22. Ormsby bandpass filter 10-25-105-130 Hz over a raw shot gather used through the processing of the data.
Figure 23. Statistical trace analysis of the entire data and the ranges chosen for subsequent processing: (a) Statistical frequency deviation of the entire data and (b) chosen range between 8.0 and 29 Hz; (c) Dominant frequency of the entire data and (d) the chosen range below 60 Hz; and (e) the Spikiness measured by the maximum amplitude by the average amplitude of the entire trace, and (f) the chosen range below 110 Hz.
Figure 24. Shot gather (a) before and (b) after the statistical trace analysis. The green line indicates the top mute horizon used for the entire survey. Green arrows indicate geological reflections. Orange arrows indicate undesirable noise to be rejected.
Figure 25. CDP gather showing the frequency interval of interest between 10 and 100Hz over (a) original raw data, (b) preliminary surface consistent spiking deconvolution, (c) four-component surface-consistent spiking deconvolution, and (d) after applying prestack structural-oriented-filters that enhance the quality of the geological reflections.
Figure 26. Frequency spectrum of the CMP gather in Figure 25 (a) before and (b) after four-component surface consistent spiking deconvolution. The frequencies in (a) reach a maximum at 20 Hz and begin to fall off rapidly after 50 Hz. The spectrum in (b) is flatter and consistent after deconvolution.
Figure 27. Residual statics map and histogram of the original data (a) sources and (b) receivers; compared with the residual corrected statics of the (c) sources and (d) receivers after the smallest and finest supergather grid of 20x20. Note that the outlayer values in (c) and (d) are close to the edge of the survey and belong to the low fold areas shown in Figure 18.
Figure 28. NMO-corrected CMP gather shown in Figure 2.13 using velocities computed on (a) an 80x80, (b) a 40x40, (c) a 20x20 supergather grid after the conventional surface-consistent deconvolution. The data in (d) was subjected to four-component surface-consistent deconvolution and prestack structural oriented filtering.
Figure 29. Crossline A-A’ through the stack after conventional surface consistent spiking deconvolution, 80x80 grid velocity analysis, and one pass of residual statics. Reflectors between 800-1400ms are the objective interval. Note the diffractions associated with karst collapses on the right and to the wrench fault in the middle of the line.
Figure 30. Crossline A-A' through the stack after conventional surface consistent spiking deconvolution, 40x40 grid velocity analysis, and two passes of residual statics. Reflectors between 800-1400 ms are the objective interval. Note the diffractions associated with karst collapses on the right and to the wrench fault in the middle of the line.
Figure 31. Crossline A-A' through the stack after conventional surface consistent spiking deconvolution, 20x20 grid velocity analysis, and three passes of residual statics. Reflectors between 800-1400ms are the objective interval. Note the diffractions associated with karst collapses on the right and to the wrench fault in the middle of the line.
Figure 32. Crossline A-A’ through the stack after four-component surface consistent spiking deconvolution, 20x20 grid velocity analysis, and four passes of residual statics. Note how the reflectors are sharper and better resolve in zone of interest between 800-1400ms. Note the diffractions associated with karst collapses on the right (red circle) and to the wrench fault in the middle of the line (green oval).
Figure 33. Crossline A-A' through the stack after four-component surface consistent spiking deconvolution, prestack structure oriented filtering (PSOF), 20x20 grid velocity analysis, and four passes of residual statics. Note how the diffractions associated with karst collapses on the right (red circle) and to the wrench fault in the middle of the line (green oval) are not as sharp as on previous images, but the specular reflectors are better focused.
Figure 34. Representative velocity analysis panel after conventional surface-consistent spiking deconvolution. Note high values of semblance interpreted to be associated with the Caddo Fm. and Ellenburger Group. intervals. It is possible to infer some high semblance intervals below the Ellenburger Group that are probably related to intra-basement reflectors.
Figure 35. Representative velocity analysis panel after four-component surface-consistent spiking deconvolution and prestack structural oriented filtering. Note high amplitude and localized values of semblance interpreted to be associated with the Caddo Fm., Ellenburger Group intervals, and to intra-basement reflectors.
Figure 36. Crossline A-A' through the velocity cube overlying the stacked section. The velocities are interpolated for every CMP using a 10x10 grid, ideally smoothed using a 3x3 trace operator, and resampled to 2.0 ms to match the seismic data. This velocity field will be used for prestack time migration.
CHAPTER 3: PRESTACK TIME MIGRATION

Prestack Time Migration:

Two unmigrated data volumes had been obtained. One of these was subjected to Structural Oriented Filtering (SOF) and has more continuous specular reflectors. The other is unfiltered and somewhat noisier volume that better preserves the diffraction events that define the karst-collapsed features.

Using the velocity volume computed from unmigrated CMP velocity scans, both seismic gathers are migrated using a Kirchhoff prestack time migration (PSTM) algorithm described by Perez and Marfurt (2008) that sorts the data on the fly by offset and azimuth bins.

To reduce the amount of output data, my first migration used one azimuth and 60 offset bins, using the maximum offset at 4,267 m (14,000 ft) which corresponds to incident angles greater than 45° at the target depth of 2,050 m (6,700 ft) (Figure 37). These higher angles are critical for subsequent inversion to estimate S-impedance and density as well as P-impedance.

Comparing CRP gathers of both migrated volumes, note that the specular reflections are more continuous on the un-migrated prestack-SOF filtered CMP gather than on those without SOF filtering (Figure 38).

Those two volumes are stacked to calculate 3D geometric attributes and elicit the qualitative comparison. Again, discontinuities due to the karst-collapses and the fault are sharper on the volume without SOF than in the one with SOF. Moreover, the quality of the reprocessed volume without SOF is superior if compared with the vintage vendor-processed data (Figures 39 to 41).
The workflow is summarized in Figure 42, where the volume submitted to the pre-migrated-Prestack-SOF is used to obtain the new velocity field to migrate the unfiltered volume. This will ensure that the velocity field optimally focuses the specular reflectors seen on the filtered volume, while the diffractions are preserved on the unfiltered volume (Figures 43 and 44).

Migration focuses diffractors and reduces CDPs smear from dipping reflectors, facilitating subsequent velocity analysis. Following the Deregowski (1990) loop, the normal-moveout (NMO) will be removed using the first migration velocity field (Figure 45). A new velocity field can then be obtained for subsequent migration (Figure 46).

In the future, a new velocity field will be used to migrate the unfiltered gathers into eight azimuths, such that the energy diffracted from the karst-collapse is preserved azimuthally. Furthermore, it will be possible to conduct a more detailed residual analysis and non-stretch NMO correction to invert for the elastic parameters and anisotropy parameters.
Figure 37. Illustration showing that for a target reflector a 6700 ft, with a maximum offset of 14,000 ft for migration will recover greater than 45° incident angle, which is required to invert for density in addition to P- and S- impedances.
Figure 38. Comparison between the prestack time migrated gathers of (a) without and (b) with PSOF filtering. Note how the reflections are more consistent and continuous on the filtered gathers. Note the farther offset in (b) are missing due to the NMO-stretch mute applied as part of the SOF process.
Figure 39. Vertical section through the 1999 vendor-processed amplitude volume, showing the principal seismic horizons corresponding to the Caddo Fm., Forestburg Fm., Ellenburger Group. Magenta arrows indicate collapse features with some migration artifacts associated. Light blue arrows indicate the fault a with strike-slip component associated with the Mineral Wells fault.
Figure 40. Vertical section through the processed seismic volume without prestack pre-migrated SOF. Note the rugosity of the Ellenburger horizon and the better definition of the intra Ellenburger reflectors.
Figure 41. Vertical section through the processed seismic volume with SOF applied to the un-migrated gathers. In general, the reflectors are more continuous with less cross cutting noise. However, since the prestack SOF suppressed nonspecular events, the diffractions (magenta arrows) and strike-slip faults (light blue arrows) are less well resolved.
Figure 42. Proposed workflow to use the pre-migrated-Prestack-SOF volume to be stacked and then filtered using principal components Prestack Structural Oriented Filters. A new velocity field is obtained from this volume where the reflectors are best focused. These velocities are used to migrate the un-filtered gathers. This will ensure that the energy of the reflectors is preserve and will be better focused, while the diffractions associated with the karst-collapses discontinuities are preserved.
Figure 43. Horizontal slice at 1160 ms through the Sobel filter similarity volume, where discontinuities related with karst-collapses display low values of similarity. Note how this poke-marks are more sharp and better focus than using the PSSOF volume.
Figure 44. Horizontal time slice at 1160 ms through the Sobel filter similarity volume obtained from the pre-migrated-prestack-SOF volume. Discontinuities related with karst-collapses display low values of similarity but also appear smoother than on the unfiltered cube on Figure 44.
Figure 43. The Prestack time migrated and Principal Component SOF filtered gathers before (a) and after (b) were reversely corrected for Normal Moveout (NMO) using the same migration velocity field.
Figure 44. Velocity analysis after removing the NMO correction using the migrated velocities. It is possible identify the flattened Caddo Fm., Ellenburger Group and basement reflectors. This is the new velocity field used for the migration of the un-filtered gathers.
CHAPTER 4: RESULTS AND INTERPRETATIONS

After migrating the unfiltered volume using the velocity field from the prestack SOF filtered volume, the final volume was stacked to generate a full suite of geometrical seismic attributes.

Based on the geology and in reports, the production in this area is controlled not only by the en echelon natural fractures in the Barnett Shale, but also due to the proximity to faults and planes of weakness that appear to control the karst features in the Ellenburger Group. Faulting and dissolution of the Ordovician Ellenburger Group, affects the overlaying Mississippian to middle Pennsylvanian formations (Hardage et al., 1996; Montgomery et al., 2005; Sullivan et al., 2006; Jyosyula, 2003) as seen in map views and vertical slices through the seismic amplitude volume (Figures 47 to 49).

After spectral balancing the amplitude spectrum of the data, a series of volumetric seismic attributes were generated to better characterize the karst-collapse in the area. The attributes that best displayed the effect of the karst were Sobel filter similarity (Figure 50 and 51), short and long wavelength most negative curvature (Figure 52 to 56), and the derived shape index attributes. Roberts (2001), Bergbauer et al. (2003), and Al-Dossary and Marfurt (2006) use the structural shape index that combines the principal components of curvature, $k1$ and $k2$, to calculate bowl, valley, saddle, ridge, and dome shapes. The aerial exposure of the Ellenburger Group during the late Ordovician, created the characteristic collapses exhibit bowl- and valley-shape forms (Figure 57).
Figure 58 is a cartoon showing the seismic expression of the faults and fractures associated with the karst and collapses in the Ellenburger Group. Figures 59 and 60 show the expression of the expected bowl-shape with the collapsed features and how they extend vertically through the Barnett Shale and overlaying formations, causing severe reservoir compartmentalization (Hardage, 1996). The short wavelength most-negative principal curvature best illuminates the valley expression of what is possible to hypothesize to be water-bearing fractures through the Ellenburger Group. These fractures continue into the overlaying Barnett Shale and affect the production from both vertical and horizontal wells.

Previous studies related the interpreted Ellenburger Group karsting with at least two subaerial exposures and how they could be associated with extensional basement faults. These multiple extensional processes created joints that reactivated during the deposition of overlying formations (Sullivan et al., 2006). Moreover, caverns and sinkholes preferentially form at the intersection of joints where diagenetical dissolution was more intense. The correlation of faulting to collapses features presents a “string of pearls” image (Schuelke, 2011). The collapse chimneys associated faults and fractures within the Ellenburger Group will present strong values of $k_2$ most-negative principal curvature and low coherence.

As explained by Guo (2010), it is possible to correlate the first 3 months scaled production from the Barnett Shale wells in the area with the intensity of the most-negative principal curvature and coherence. In this study, the scaled water
production of three wells is correlated with the weighted average values of the $k2$ most-negative principal curvature and Sobel filter similarity. This correlation is performed assuming that most of the reported production corresponds to the distance from the wellbore and will decay with a relation of $1/r$ perpendicular to the well. Figure 61 summarizes this computation. Using a value of 1100 feet measured by microseismic (Roth and Thompson 2011) as an estimate of hydraulically fractured rock, one simply sums the contribution from each perforation. The inputs are the structural 3D seismic attribute from which is going to be correlated with the production, the top and bottom horizons that from fracture barriers; the location of the wells, the heel and toe depths for horizontal wells, and their measured depths in feet or corresponding time. The output will be the extracted weighted average of the attribute based on the procedure explained in detail in Appendix A.

The first step for the correlation of production and seismic attributes is an interpretational one and requires applying a threshold to the range of values of the attributes in a process usually called “skeletonization”. Figure 62 shows the geometric attributes and their corresponding skeletonized image after applying a threshold. These limited images ensure that the weighted average extracted best represents the faults and fractures associated with the Ellenburger collapse features (Figure 62b)). Figure 62c) shows the color-coded well probe following the well path, in the case of the horizontal well, which indicates the contribution of the attribute for the weighted averaged extracted with a relation of $1/R$. 
Table 3 shows the correlation of the weighted average of the extracted attributes and the production of water. Well 1 is located in a zone highly affected by the karst-collapse features as observed on Figure 63b). This well reported the highest production of water, the lowest weighted average for the Sobel filter similarity and the intermediate correlation with the $k2$ most-negative principal curvature. The horizontal well 2 reported an intermediate water production and is located in a less affected zone than well 1; however, it is also closer to the karst-collapse features than well 3. Well 2 has an intermediate value for the weighted average correlation factor for the Sobel filter similarity and the $k2$ most-negative principal curvature. Finally, well 3 is the well with no water production reported for the first three months and is located in a zone with less presence of karst-collapses. Well 3 presents the highest weighted average for both Sobel filter similarity and $k2$ most-positive structural curvature weighted average.

Figure 63 describes the zones of interest based on the isochron map between the Forestburg and Ellenburger horizons and weighted average correlation of the Sobel Filter Similarity and $k2$ most-negative principal curvature. Well 3 has no water production and correlates with high similarity, but also presents strong most-negative curvature. Well 3 is also located where the Lower Barnett Shale is thickest and where the Viola Group fracture barrier could exist (Figure 63a)). As interpreted by Sullivan and others (2006), macrofractures plugged with calcite cement in the Mississippian Barnett Shale could represent a final stage of digenesis. Furthermore, most negative curvature is the attribute that best
represent the joint lineaments from the basement that controlled the orientation and intensity of the karst-collapses in the Ellenburger (Sullivan, 2006).

Table 3. Correlation between the gas and water production between the cigar_probe extracted values and the $k_1$ most-positive principal curvature azimuthal intensity. The correlation values are plotted on Figure 62.

<table>
<thead>
<tr>
<th>Well</th>
<th>Sobel filter similarity weighted average</th>
<th>$k_2$ most-negative principal curvature weighted average</th>
<th>Scaled Water Production</th>
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<tr>
<td>1</td>
<td>0.675</td>
<td>0.612</td>
<td>10</td>
</tr>
<tr>
<td>2</td>
<td>0.861</td>
<td>0.488</td>
<td>6.2</td>
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<tr>
<td>3</td>
<td>0.871</td>
<td>0.867</td>
<td>0</td>
</tr>
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</table>
Figure 45. Vertical slice through the amplitude volume showing the reflectors associated with the Marble Falls, Forestburg, and Ellenburger and Basement. Magenta arrows indicate the karst surface and collapsed features on the Ellenburger Group top that are affect the overlying formations. Note the rugosity of the Ellenburger top surface and the inter-Ellenburger reflectors associated with the different unconformities episodes during the Ordovician. Light blue arrows indicate the normal and strike-slip fault that intersects the survey with West-East direction.
Figure 46. Structural map of the (a) thin Forestburg limestone horizon, which represents the top of the zone of interest, and (b) the top of the Ellenburger Group. Note the effect of the collapse features from the lower Ellenburger Group (one of which is indicated by the white arrow) over the overlaying Forestburg limestone. A wrench fault crosses the entire survey (light blue arrows).
Figure 47. Isochron map between the Forestburg and Ellenburger horizons and the location of the three wells with reported water and gas production used in further analysis. White and cyan arrows points to the location in the structural maps (Figure 49) of the collapsed feature and strike-slip fault respectively. Note how these features are not shown in this isochron, implying collapses in and faulting the Ellenburger Group occurred after deposition of the overlaying formations.
Figure 48. Vertical slice through the Sobel filter similarity volume. Magenta arrows indicate the karst surface and collapse features on the Ellenburger Group top that create small-scale faults propagating into the overlaying formations (red lines). Light blue arrows and dotted line indicate the EW strike-slip fault shown on the previous maps.
Figure 49. Vertical slice through the seismic amplitude co-rendered with Sobel filter similarity volume. Magenta arrows indicate the karst surface and collapsed features on the Ellenburger Group top that are creating small-scale faulting that affects the overlying formations (red lines). Light blue arrows and dotted line indicate the normal and strike-slip fault that intersects the survey with West-East direction.
Figure 50. Vertical and horizontal slices (1228 ms) through the long wavelength $k1$ most positive curvature volume. Bowl shapes will have a negative value and hence appear as blue. Note the karst-collapse features in the Ellenburger horizon (magenta arrows) and the negative values of positive curvature associated with the collapses and how the strong positive effect extends through Barnett Shale interval to upper Forestburg horizon. Blue arrows indicate the strike-slip fault, note the high values of positive curvature associated with the footwall block.
Figure 51. Vertical and time slices (1228 ms) through the long wavelength $k_2$ most negative curvature volume. Note the karst-collapse features in the Ellenburger horizon (magenta arrows), the negative values of most negative curvature associated with the collapses and how the effect extends through Barnett Shale interval to the upper Forestburg horizon. Blue arrows indicate the strike-slip fault shown in Figure 49. Note the strong negative values of most negative curvature associated with the hanging wall of the fault.
Figure 52. Vertical and horizontal sections (1228 ms) through the short wavelength $k_2$ most negative curvature co-rendered with the Sobel filter similarity. Note the karst-collapse features in the Ellenburger horizon (magenta arrows) are associated with low values of similarity and high values of most negative curvature. Light blue arrows indicate the strike-slip fault shown in Figure 48. Note the strong negative values of most negative curvature associated with the hanging wall of the fault.
Figure 53. Vertical and horizontal slices (1228 ms) through the short wavelength $k_2$ most-negative principal curvature volume co-rendered with the Sobel filter similarity. Note the karst-collapse features occur at intersections of most negative curvature valley (magenta arrows). Blue arrows indicate the strike-slip fault shown in Figure 48.
Figure 54. Vertical and horizontal sections (1228 ms) through the short wavelength $k_f$ most-positive principal curvature volume co-rendered with the Sobel filter similarity. Note the karst-collapse edges are associated with negative values of most-positive curvature and low similarity (magenta arrows). Blue arrows indicate the strike-slip fault shown in Figure 48.
Figure 55. Shape index classification in bowl, valley, saddle, ridge, and dome based on the most positive and negative principal curvatures and curvedness of the reflectors (After Mai, 1999). The karst-collapses will be associated with bowl shape in the bottom and ridges at the edges.
Figure 56. Karst-collapse cartoon showing the response to (a) most-positive and most-negative principal curvatures and to (b) shape index. Note how high values of most-positive principal curvature and ridge shape correspond to the steep edges of the karst-collapses; whereas the bottom of the karst-collapsed is associated with most-negative principal curvature and bowl shape index.
Figure 57. Vertical and time slices (1228 ms) through the shape index modulated by curvedness volume. Bowl (blue) and valley (cyan) shapes are associated with the karst-collapse features (magenta arrows), while (yellow) ridge shape is associated with the edges of the karst and the upthrow side of the strike-slip fault (light blue arrows). Again, note the occurrence of bowl collapses as the intersection of valley-shaped, diagenetically altered valleys.
Figure 58. Karst-collapse appear as bowl shapes on the shape index. These collapses propagate upward increasing the accommodation space for the shallower Bend conglomerates (Hardage, 1996).
Figure 59. Cartoon of the cigar_probe workflow: (a) for vertical and horizontal wells between the two horizons of interest, (b) The flow to each perforation is approximated by the impulse response on Green’s function $1/R$. (c) If the perforation are close (or unknown) each element of the well is assumed to be perforated. The result is a cigar-shaped volume with flow approximation $1/r$ perpendicular to the well bore. The fracture barriers (Forestburg and Ellenburger truncate the cigar).
Figure 60. a) Isochron map between the Forestburg and Ellenburger interpreted horizons and the wells with gas and water reported production. The black rectangle indicates the (b) zoomed area with the production wells through Sobel filter similarity and k2 most-principal negative curvature. (c) For the correlation between the production and the proximity of the collapses, it is necessary to skeletonize the image by interpreting the value ranges that best represent the collapses and associated faults and fractures. (d) After skeletonize the attribute volumes, is possible to calculate the weighted average of the attribute and its relation of $1/R$ from the wellbore, where the fattest distance corresponds to 1100 ft.
Figure 61. (a) Isochron map between the Forestburg and Ellenburger interpreted horizons and the wells with gas and water reported production. Red polygon delineates an area where the thickness exceeds 60 ms. (b) Time at t=1228 ms through the $k_2$ most-principal negative curvature volume. Red polygon delineates an area with lower intensity curvature. (c) Time at t=1228 ms through Sobel filter similarity. Red polygon delineates an area with high similarity and absence of karst-collapse features. (d) Finally, the most prospective zone (thickest, undeformed, high similarity) corresponds to the northeast corner of the survey.
CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

Careful reprocessing of 3D prestack seismic data provided high quality results. Higher frequency reflectors were obtained by applying four-component surface-consistent deconvolution, time-variant spectral whitening and scaling, and structure oriented filtering. Detailed iterative velocity analysis proved to be a key step to successively reduce the residual statics. Kirchhoff prestack time migration provided gathers with good offsets which will be used for prestack inversion.

Structural attributes such as Sobel filter similarity, and most positive and most negative principal curvatures assist in the characterization of the collapses in the Ellenburger Group. Shape index calculations explicitly define valleys and bowls of the karst-collapse features, which are related with the faults and fractures that could directly affect the hydrocarbon production in the Lower Barnett Shale.

The new “cigar probe” workflow proved to be a useful tool to quantitatively correlate water production with proximity to karst-collapse features of the Ellenburger Group and their effects through overlaying formations.

Azimuthal prestack time migration of the unfiltered volume, using the velocity field obtained from the prestack time migrated SOF filtered volume, results in focused specular reflectors and diffractions.

Isochron maps, structural seismic attributes, and the cigar probe workflow permits quantitatively correlate water production and proximity to “geohazards” associated with collapse features in the Ellenburger Group. This methodology allowed delineating a prospective zone in the northeast corner of the seismic survey.
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