LITHOLOGIC AND GEOCHEMICAL ASSESMENT OF THE HYDROCARBON PRODUCING CAPABILITY OF THE WOODFORD SHALE IN SOUTHERN OKLAHOMA

By

JOE MARCUS WICKER

Bachelor of Science in Geology

Oklahoma State University

Stillwater, Oklahoma

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Thesis Approved:

Jim Puckette

Thesis Adviser

Alex Simms

Anna Cruse

A. Gordon Emslie

Dean of the Graduate College

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TABLE OF CONTENTS

LIST OF FIGURES

Figures Page

LIST OF TABLES

TABLE

LIST OF PLATES

PLATE

CHAPTER I

INTRODUCTION

Problem Statement

As a result of recent rises in oil and natural gas prices, the economics of producing domestic reserves have improved. This rise in price, coupled with new completion technology, has focused attention on reserves that in the past, were considered to be too low in volume to be produced profitably. Specifically, recent attention has focused on unconventional plays such as shale-gas plays. Shale gas plays are categorized as continuous gas accumulation reservoirs. A continuous gas accumulation is defined as a regionally pervasive and generally non-buoyancy driven accumulation, that is commonly independent of structural and stratigraphic traps (Cardott, 2004).

The three main variables that control the capability of shale-gas plays to produce natural gas are organic matter type, organic matter quantity, and the thermal maturity of the formation (Cardott, 2004). The organic matter type is broken down into four kerogen groups (Type I, II, III, and IV). Types I and II are both characterized as being of the Sapropelic maceral group meaning that the source material for the kerogen was most likely marine elements such as algae “Tasmanite’ or cerinite and will most likely produce oil. Type III kerogens are referred to as vitrinite macerals and belong to the Humic maceral group which indicates that type III source material is composed of terrestrial or reworked elements and will most likely to produce natural gas. Type IV kerogens are also under the Humic maceral group, but are classified as being inert, meaning that the kerogens of this type do not have the capability to produce hydrocarbons (Cardott, 2004 and Hunt, 1996).

The Woodford Shale located in the Ardmore Basin, southern Oklahoma, is a shale gas play that has only recently been drilled and produced. Exploitation of this resource was delayed in part because source rock studies indicated that the Woodford Shale is thermally immature and not expected to be capable of producing economic quantities of natural gas in the Ardmore Basin. The validity of these thermal maturity data is questionable because of current and historic production of gas from the Woodford Shale in the basin.

Gas-shale plays have always undergone scrutiny on their ability to produce economical amounts of natural gas and oil due to the low permeability and porosity of shales. It was not until the development of the Antrim Shale in the 1980's as a prolific gas shale play that interest and investment began into researching techniques to increase the recovery from these "tight" reservoirs. By the 1990's, the Antrim Shale of the Michigan Basin became the most active United States natural gas play (Curtis, 2002). The current outlook for the gas-shale plays is that they will become a gas supply on regional and global levels with proved reserves reaching as high as 783 trillion cubic feet(tcf) for the five major proven gas-shale resources (Curtis, 2002). This is the result of the success of plays like the Barnett Shale play in the Fort Worth Basin of northern Texas. The Barnett is the second largest-producing by volume, onshore, domestic gas field. The Woodford play could be of the same magnitude as the Barnett due to the high total organic content of the formation, which exceeds that of the Barnett. "The Woodford

Shale exceeds a commonly accepted shale source-rock minimum of 0.5 weight percent" (Hester T.C. and Schmoker J.W. et al p. D2 Tissot and Welte, 1984 p. 699).

The Woodford Shale is compared to the Barnett Shale because both are dark shales and thermal plays. A thermal play is a type of unconventional gas shale play in which primary maturation occurs due to the increase in temperature and pressure that the formation experiences during burial. This is in contrast to a biogenic play in which organisms consume the organic matter located in the formation and conversion to methane occurs as a waste product. Between 1961 and November 2006, the Woodford Shale produced 51.2 billion cubic feet (bcf) of gas from 169 wells located throughout southern Oklahoma (IHS, 2006). This production volume gives credibility to the Woodford Shale as a shale resource play whose production could prove to be as economically important as the Barnett Shale.

The purpose of this thesis is to examine variables that influence Woodford Shale productivity. It is hypothesized that the Woodford Shale is capable of economically viable gas production in the Ardmore Basin due to current production tests, the high amounts of organic matter, and depth of burial of the formation throughout the study area. The focus of this study is to examine thermal maturity, structural attitude, and the relationship between natural fracturing patterns and lithology. The end result is to determine which zones within the Woodford Shale should be considered reservoirs, which should be considered source rocks and the type of hydrocarbon production that should be expected throughout the Ardmore Basin.

Study Area

The Woodford Shale is recognized as extending laterally through the subsurface of Oklahoma, and into parts of the Ozark region of Arkansas and Missouri where it is known as the Chattanooga Shale, or Noel Shale (Amsden and Barrick, 1988, Comer and Hinch 1987). This project focuses on the Cumberland syncline tectonic sub region in the Ardmore Basin, southern Oklahoma. The Cumberland syncline is a large feature that occupies parts of Love, Marshall, Bryan, Atoka, Johnston and Carter Counties (Fig. 1). The study area includes Township 2S., Range 1E. in the northwest to Township 7S., Range 12E. in the southeast and encompasses approximately 2,520 square miles.

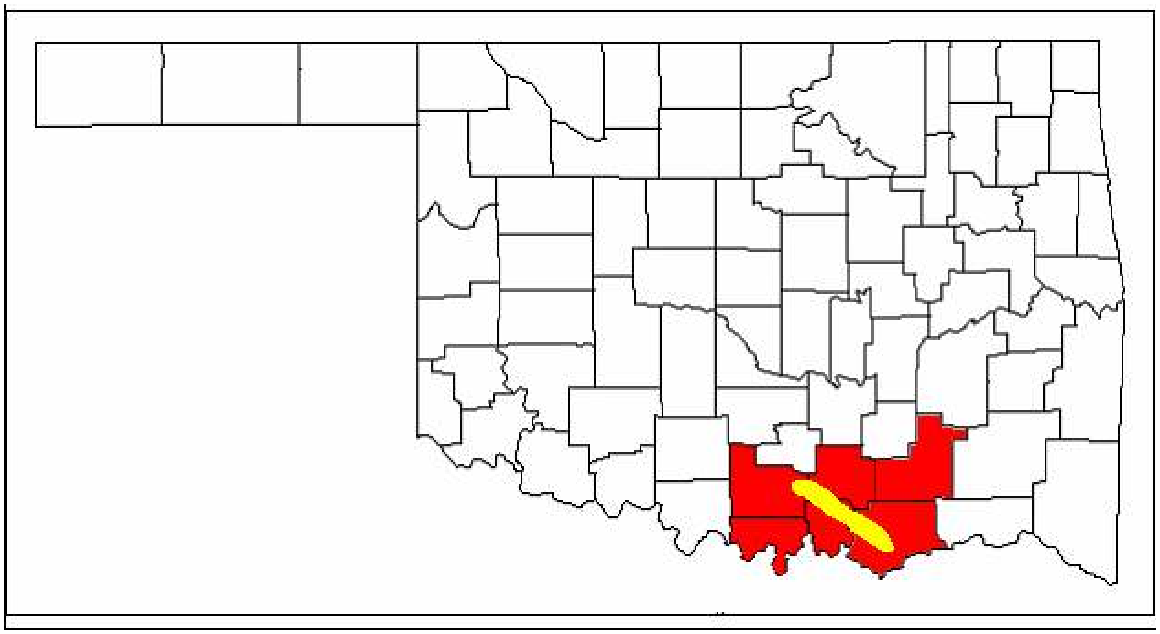

Figure 1. Map showing counties in southern Oklahoma that are partially or wholly included in the study. The Cumberland syncline is the highlighted featured trending northwest to southeast across the shaded area.

Objective and Approach

Due to the delay in the development of the Woodford Shale as a shale gas-play on a large geographic scale, the acquisition of geological data required to understand the reservoir and the stimulation technology necessary to recover gas was hindered due to a lack of public domain data. The primary objective of this study is to differentiate between the source and reservoir portions of the Woodford Shale using log-core correlation and reservoir characterization, production-completion information, and mineralogical analysis from an electron microprobe study. A secondary goal is to determine which factors play critical roles in dictating whether or not the Woodford Shale is producible in a given area. The following approach was used to meet the objectives of this study:

Approach

1. Identify lithostratigraphic and/or electrostratigraphic units within the Woodford Shale. Type logs that are representative examples of these units and correlated to cores were used to understand the lithological differences between units. Photographs/images were taken to document sedimentary, fracture patterns and diagenetic features evident in cores. All data were integrated to identify reservoirs and zones capable of acting as petroleum sources and produce a generalized characterization of the Woodford Shale's internal stratigraphy.
2. Create a structure map that depicts the structural attitude of the Woodford Shale within the Cumberland syncline (Plate 1). The structure map was used to help

evaluate depth of burial and to compare expected vitrinite reflectance data to the types of producing fluids.

3. Analyze the Woodford using the Electron Microprobe (EMP). The EMP was used to survey samples collected from cores to help determine rock mineralogy and petrology. The mineralogical analyses and magnified images of the shale improved the quality of lithologic descriptions and enhanced the understanding of micro-fracture systems within Woodford subunits.

4. Analyze production history for wells producing from the Woodford Shale using data attained from PI/DWIGHTS, and correlate these data points to wireline logs portrayed on stratigraphic and structural cross sections (Plates 2 and 3) created in Petra®. This technique examined the relationship between production volume and Woodford thickness, which is a proxy for thickness of reservoir facies and source material. Structural cross sections helped to determine how the thickness of the Woodford Shale changes with its location within the Cumberland syncline.

5. Determine thermal maturity of the Woodford by geochemical analyses of samples collected from cores. Geochemical samples were sent to Humble Instruments & Services, Inc. for a variety of geochemical analyses including total organic carbon, hydrogen index values and kerogen types. Vitrinite reflectance values were measured on isolated kerogen fragments. These vitrinite reflectance values were compared to data compiled by Dr. Brian Cardott at the Oklahoma Geological Survey (personal communication) and this comparison will assess the validity of the data and hopefully enhance the capability to calculate a possible vitrinite reflectance correction for hydrogen bound within the shale.

Stratigraphy

The stratigraphic nomenclature applied to the Woodford Shale in the Ardmore Basin is shown in Figure 2. The Woodford Shale represents a time of relatively high sea level and widespread transgression that stratigraphically separates the underlying carbonate section (Hunton Group) from the overlying Mississippian carbonates and shales (Kirkland, Denison, et al, 1992). The Woodford is believed to contain the upper Devonian maximum flooding surface (MFS) (Kirkland, Denison, et al, 1992). A MFS represents the highest sea level and maximum landward shoreline shift, and is characterized by deposition of dark organic muds and phosphate rich nodules (Kirkland, Denison, et al, 1992). The Woodford Shale serves as a source rock and seal for the Hunton Group and other formations that sub-crop beneath the pre-Woodford unconformity. The Woodford is estimated to have generated 70% of all oil discovered in central and southern Oklahoma (Kirkland, 1992).

Like other dark shales in the United States, the Woodford Shale is described as highly radioactive shale that is rich in organic matter (Kirkland, Denison, et al, 1992). The source material for the Woodford is dominantly marine algae and phytoplankton in origin based on kerogen typing and conodont identification (Urban 1960, and Cardott 2001). Johnson and Cardott (1992) determined that the kerogen type in the Woodford is a mixture of type II and type III resulting in oil-gas bearing source materials.

In past studies, the Woodford Shale was divided into subunits using faunal evidence and TOC values. Hester (2000) used this approach to delineate areas within the Woodford capable of producing gas and generating hydrocarbons.

<table>
<tr><th>SYSTEM</th><th>STAGE</th><th>ARDMORE BASIN</th><th>SUB UNITS</th></tr>
<tr><td rowspan="7">MISSISSIPPIAN</td><td rowspan="2">Chesterian</td><td rowspan="3">CANEY SHALE</td><td>Sand Branch</td></tr>
<tr><td>Delaware Creek</td></tr>
<tr><td rowspan="3">Meramecian</td><td rowspan="2">Ahloso</td></tr>
<tr><td rowspan="3">SYCAMORE LIMESTONE</td></tr>
<tr><td>Weldon Limestone</td></tr>
<tr><td>Osagean</td><td>pre-Weldon shale</td></tr>
<tr><td>Kinderhookian</td><td rowspan="5">WOODFORD SHALE</td><td>CHERT</td></tr>
<tr><td rowspan="6">DEVONIAN</td><td rowspan="2">Famennian Stage</td><td>BLACK SHALE</td></tr>
<tr><td>INTERBEDDED</td></tr>
<tr><td rowspan="2">Frasnian Stage</td><td>LOWER SHALE</td></tr>
<tr><td>LAG</td></tr>
<tr><td>Pragian</td><td rowspan="5">HUNTON GROUP</td><td>Frisco Formation</td></tr>
<tr><td>Lochkovian</td><td>Haragan- Bois d'Arc</td></tr>
<tr><td rowspan="2">SILURIAN</td><td>Pridolian-Ludolovian</td><td>Henryhouse Formation</td></tr>
<tr><td>Wenlockian Llandoverian</td><td rowspan="2">Chimneyhill Subgroup</td></tr>
<tr><td rowspan="4">ORDOVICIAN</td><td rowspan="2">Ashgillian</td></tr>
<tr><td>SYLVAN SHALE</td><td>Sylvan Shale</td></tr>
<tr><td rowspan="2">Champlain</td><td rowspan="2">VIOLA</td><td>Fernvale</td></tr>
<tr><td>Trenton</td></tr>
</table>

Figure 2. Informal stratigraphic nomenclature of the Ardmore Basin from Ordovician to Mississippian. The dashed line represents a regional disconformity. (Allen, 2000, Boardman and Puckette, 2006, and Barrick et al 1990).

> “First, the Woodford Shale is composed of three distinct depositional units (the upper, middle, and lower informal members) with different physical and geochemical properties. The middle member has higher kerogen content [average total organic carbon (TOC) = 5.5wt. %] than the upper and lower members (average TOC=2.7 and 3.2wt. % respectively)” (Hester, 1989 p. D1)

Since the Woodford Shale is lithologically heterogeneous, it is expected that variations in lithology influence the reported variability in TOC values. The middle “member” that Hester (1989) describes as having a higher TOC value contains a greater percentage of black shales, whereas the lower and upper “members” are usually composed of black shales with interbedded chert and phosphate-rich zones. The presence of chert and/or phosphate nodules decreases ductility and the plastic nature of the shale and facilitates fracturing when structural (tectonic) stresses are applied. These fractures are important in that they form secondary porosity and create permeability, which is necessary for the Woodford to produce oil and gas.

Pre Woodford Strata

The Woodford Shale in the Ardmore Basin rests disconformably on carbonates of the Ordovician- Devonian Hunton group. The thickness of the Hunton Group in the Ardmore Basin averages 600 ft (Allen, 2000). The Hunton was deposited on a shallow carbonate ramp with a dominant open marine setting (Rottmann, 2000).

The Hunton is in erosional, disconformable contact with the overlying Woodford. In most areas, this surface is commonly known as the pre-Woodford unconformity. The unconformity is regional and in the northern part of the study area the Hunton was missing and mapped as being completely eroded. Here, the Woodford Shale overlies the Sylvan Shale or older strata.

In some areas, the Misener Sandstone develops within the lowermost Woodford interval and separates the Hunton Group from the dark Woodford Shale. The deposition of the Misener began as an increase in sea level drowned older river channels and formed estuaries. During this transgression marine tidal currents caused extensive reworking of the Misener sediments (Kuykendall, 2001). The Misener Sandstone is considered both a conduit and a reservoir for hydrocarbons. The Misener Sandstone is widely recognized through subsurface mapping and known for high-volume oil and gas production. The deposition process for the Misener sediments is considered to be fluvial influenced and accumulations are preserved in areas where accommodation space was available in estuaries, valleys or other depocenters.

In the Ardmore Basin, the Sycamore Limestone overlies the Woodford Shale. The lithology of the Sycamore Limestone is described as sandy limestone with an average thickness of 330 feet (Allen, 2000). The Sycamore is Osagean-Meramecan and tends to be thinner than the overlying Meramecean Caney Shale, which has an average thickness of 400 feet throughout the basin (Allen, 2000). The Caney Shale is grey-brown and silt-rich, which reflects a more terrigenious source for material as compared to the source for the Woodford Shale.

The Caney Shale and the Sycamore Limestone reflect regional sea-level changes. The Caney Shale represents an overall landward shift in shoreline, where distal facies supercede more proximal facies. In contrast, deposition of the Sycamore represents an overall shallowing or basinward shift of the shoreline. On the south flank of the Arbuckle Mountains, the youngest Sycamore strata are extremely silt rich and grade into the silty Ahloso Member of the Caney Shale. In the eastern Arbuckle Mountains, the Sycamore Limestone is missing and the Ahloso Member (termed Mayes Member in the subsurface nomenclature) rests on the Osagean Welden Limestone (Boardman and Puckette, 2006).

Deposition

The Woodford was deposited during the Late Devonian and is similar to other Devonian black shales in North America. Devonian black shales formed from muds that were deposited in stratified low-oxygen (anoxic) to euxinic settings in basins in the present western, central, and eastern United States (Kirkland et al, 1992). Devonian rocks include the New Albany, Antrim, Bakken and Ohio Shales (Kirkland et al, 1992).

As discussed previously, the top of the Hunton Group is a regionally extensive unconformity that developed during the late Devonian (Kirkland et al, 1992). This disconformity formed prior to Woodford deposition and represents a major drop in sea level and subsequent regression (Rottmann, 2000). During this regression, the sea withdrew basinward, which exposed the Hunton to meteoric processes and erosion. These processes differentially eroded the Hunton, which is evidenced by the intervals of missing strata and the high variability in the thickness of the Hunton Group (Kirkland et al, 1992).

Erosion of the Hunton landscape, also occurred during the Middle Devonian and a subsequent rise in sea level resulted in the deposition of Frisco Formation carbonate mound facies on the eroded Hunton topography. Sea-level lowering and regression occurred again prior to Woodford deposition, and in many areas it is difficult to distinguish pre-Frisco and pre-Woodford erosion because the Frisco is absent (Axtmann, 1985). The initial Woodford transgression marked a change in depositional style from an oxygenated ramp setting to a deeper-water stratified marine one. Water depth in this latter setting is reported to range from 50-200m. "The Woodford and its equivalents were deposited in a broad relatively shallow epeiric sea" (Sullivan, 1985). As a result of this change, there is a profound difference in lithology and wireline log characteristics between the Hunton and Woodford intervals.

Factors during deposition of the Woodford that ultimately influenced log responses were widespread and recurring water column stratification and the resulting chemically reducing, anoxic environment. Deposition was slow in this anoxic setting, which allowed for the cyclic accumulation of relatively thin strata, high radioactivity, and encouraged accumulation and preservation of organic matter within the sediments (Kirkland,1992). The low concentration of oxygen (anoxia) was generated by stratification of the water column and did not require a deep off shelf setting (Sullivan, 1985). Evidence supporting this premise include high radioactivity as detected by gamma ray tools and the position of the Woodford Shale on the continent (Hester, 1989 and Sullivan, 1985). Higher radioactivity and higher organic content within the formation are directly related to each other, and require slow deposition in order for preservation to occur (Sullivan, 1985). Woodford deposition rates are estimated to average 0.01 mm per year (Kirkland, 1992). Anoxia was therefore necessary to preserve organic material and uranium in the Woodford sediments (Kirkland, 1992). Over (1990) estimated water depth for Woodford deposition of between fifty and four-hundred meters.

The characteristic thickness of the Woodford Shale and the high amounts of type II and III kerogens it contains are the result of deposition in a late Devonian-early Mississippian intracratonic sea that stretched across the eastern United States into Mexico (Kirkland, 1992). This sea as transgressed from the basin created by the Ouachita subduction complex and moved landward across a surface that was exceptionally flat and free of debris (Kirkland, 1992). The sea covered what is presently Oklahoma and as a result, the Woodford (Chatanooga) is traceable in the subsurface and maintains a similar gamma-ray signature across the state.

Structural History

The Cumberland syncline is located in the Ardmore Basin, southern Oklahoma (Figure 3). The Ardmore Basin began forming during the Precambrian to Cambrian as (initial crustal extension) a failed rift arm that was an opening of the Iapetus Ocean (Burke and Dewey, 1973). This failed rift arm formed along the narrow normal fault bounded trough known as the Southern Oklahoma Aulacogen (SOA). According to Cardott and Lambert (1985), sediments were not preserved in the Southern Oklahoma Aulacogen until the middle Cambrian. The Ardmore Basin experienced several episodes of subsidence, which occurred in phases beginning in the Late Cambrian and ending in the Early Mississippian (Cardott and Lambert, 1985). "The first subsidence of the basin has been thought to be in response of thinning of the crust and cooling of a thermal anomaly” (Feinstein, 1981). This thermal anomaly was associated with the extension of the crust due to tensional forces (Cardott and Lambert, 1985).

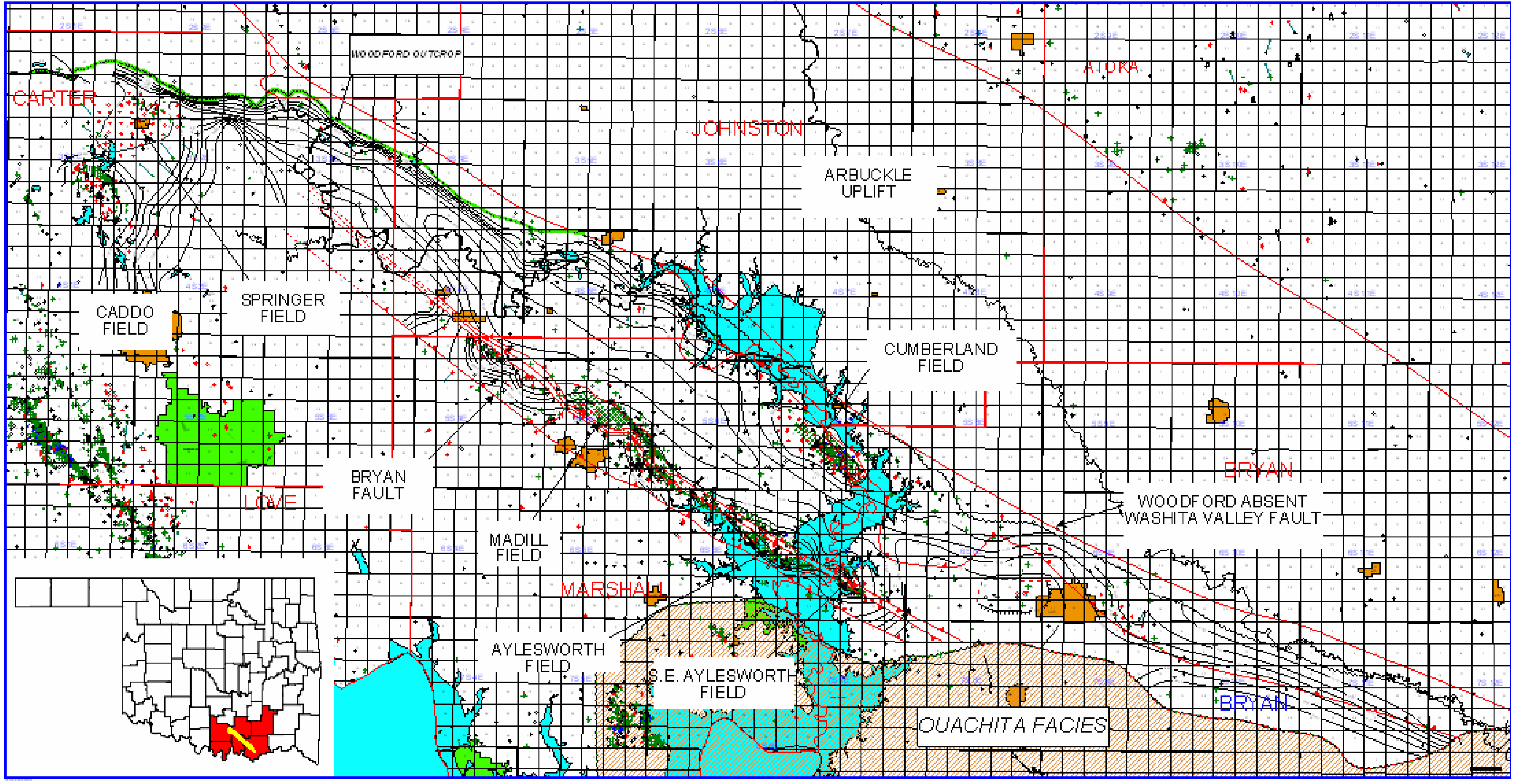

Figure 3. Map of thesis area with major oil-and gas-producing fields identified. Historically oil and gas production from the Woodford Shale has been restricted to these fields.

The second tectonic stage occurred from late Cambrian until Devonian, and was characterized by slow subsidence and sediment accumulation. Deposition was dominantly carbonate, which was continuous over most of the ocean-covered Midcontinent region (Feinstein, 1981).

Woodford sediments were deposited toward the end of the second stage and the beginning of the third. The third stage was later dominated by the Pennsylvanian Orogeny that deformed the strata in the basin that formed over the SOA. Feinstein (1981) noted that after the deposition of the Hunton carbonates, there was near continuous subsidence of the basin, which allowed for the accumulation of a thick column of sediments that became the Upper Mississippian and Pennsylvanian sections within the basin.

Production History

Production of natural gas from shales is not a new endeavor "The first commercial United States natural gas production (1821) came from organic rich Devonian shale in the Appalachian Basin" (Curtis, 2002). These early wells supplied gas that was used to light street lanterns and homes. Gas production from Devonian shales increased with time and by the 1920's gas shale drilling had reached as far as West Virginia, Kentucky and Indiana (Curtis, 2002). The first wells that produced gas from shales in the Midcontinent region began production in the early 20th century (IHS, 2006). However, it was not until the boom of the Barnett Shale and the increase in natural gas prices during the late eighties early nineties that shale gas became a viable drilling objective (Curtis, 2002). Production from the Woodford and Barnett Shale is compared because both are unconventional, thermogenic, high organic-matter rich gas shales located within one hundred miles of each other. To date, drilling practices used in the Barnett Shale have not been fully utilized in the Woodford Shale. The lithologic heterogeneity in the Woodford Shale has resulted in some drilling and production methods to be less than successful and the classification of the Woodford as a higher risk target for gas exploration.

The Woodford differs from the Barnett in that it is not exploited on as large a scale. The first gas producing well from the Woodford Shale in Oklahoma was the Dinwiddie No.1 drilled by the Mannix Oil Company, which was completed in November, 1938. The Dinwiddie was located in the Oklahoma City Field in sec 23, T.12N, R.3W, and produced 372 MMCF (372 million cubic feet) gas. The next well would not be completed in the Woodford Shale until 1941. In 2000, there were around thirty wells producing oil and gas from the Woodford Shale. In 2004, Woodford activity increased and seven wells were completed. In 2005, twenty five were completed. As of November 2006, a total of 190 Woodford completions were recorded for Oklahoma, but not all of these wells were still active. According to production records, the well producing the largest volume of gas is the Neff-Godfrey No. 2 which was drilled by Verdad Oil and Gas Company. This well is located in the Aylesworth field, Bryan County and was completed in 1974. Through November, 2006 it had cumulated over 5.9 BCF (5.9 Billion cubic feet) of gas and had a current monthly production of about 4.9 MMCF of gas (IHS, 2006).

In the Cumberland syncline, production of the Woodford Shale is isolated to a few wells in larger gas fields spread along anticlinal folds at the edge of the syncline (Figure 3). These wells are shallow, with total depths of no more than 5000 feet, and are completed with a cased hole followed by hydraulic fracturing. "Well completion practices employ hydraulic fracturing technology to access the natural fracture system and to create new fractures. Less than 10% of shale gas wells are completed without some form of reservoir stimulation" (Curtis, 2002). In the Ardmore Basin, it has been standard petroleum industry practice to stimulate the Woodford interval using water as the fracturing agent and sand as proppant. To date, most of the stimulations are single stage.

The more expensive practices of drilling horizontal wells, and stimulating using gelled-water, and multiple-stage fracturing that are used widely in the Barnett and Woodford Shales in the Arkoma Basin were not historically implemented in the Ardmore Basin. The cherty, fractured Woodford in Ardmore Basin produced marginally commercial volumes without large stimulation treatments. With increased understanding of the Woodford reservoir facies and increased number of Woodford completions, it is expected that these new technologies will be used successfully in the Ardmore Basin to recover larger volumes of oil and gas from the Woodford.

Vitrinite Reflectance

The most widely used technique to determine thermal maturity of shales is vitrinite reflectance (Ro). In this process, vitrinite reflectance measurements are created by measuring the amount of light reflected through macerals that have been concentrated through pyrolysis. Pyrolisis is a process that seperates carbon chains from other constituents through heating in a vacuum setting. In the maceral type of vitrinite, the amount of light reflected is related to the level of maturation of the rock. The scale by which vitrinite reflectance is measured can be directly related to the type of hydrocarbon that would be expelled from the formation. Lower values of vitrinite reflectance (0%-0.55%) indicate source rocks that were exposed to too low of temperatures and pressures in order to produce any form of hydrocarbon, and are commonly referred to as immature. Formations measuring 0.55%-1.15% Ro are thought of being in the oil window with peak generation occurring at roughly 0.8% to 1% (Hunt,1996). Condensate-rich gas begins generating at a reflectance value of 1.15% and ends around 1.4%. Reflectance values greater than 1.4% indicate source rocks capable of producing only dry gas. Vitrinite reflectance values are generalized into these categories, but there are many cases in which the fluid production from reservoirs does not match the expected fluid based on Ro values. It is worth noting that these measurements only relate to what the analyzed sample should produce and cannot be directly related to a formation on a large scale due to the migration of hydrocarbons through the subsurface (Hunt, 1996).

CHAPTER II

REVIEW OF LITERATURE

Historically, the Woodford Shale was of interest to academia and industry due to its high radioactivity, unusual lithology, and widespread distribution in the subsurface. Most interest in the Woodford arose because it is the most significant petroleum source rock in the Anadarko Basin and other major basins in the Mid-continent region (Hester, 1989). The Woodford Shale was described and named for the type locality and the town of Woodford in Carter County, Oklahoma (Taft, 1903).

Many geochemical studies are published on Devonian age shales in North America. The majority of historic research relates to shales located in the Appalachian Basin and focus on kerogen and bitumen as well as trace elements (e.g. Sullivan, 1985). Similarly work has been done in Oklahoma on the Woodford Shale in the Ardmore, Arkoma, and Anadarko Basins as well as the Arbuckle and Ouachita Mountains (e.g.Cardott and Lambert, 1985 Cardott, 1987 Cardott 2001).

Urban (1960) examined Woodford samples collected from outcrops in the Arbuckle Mountains, described the microfossils, and identified three distinct depositional zones. Urban (1960) called the zones the upper, middle, and lower and stated that each represents a different depositional setting. The upper and lower zones were described as coastal marine environments, whereas the middle zone was considered a more basinward environment. Phosphate nodules were observed throughout the entirety of the Woodford Shale with concentration increasing toward the upper portion of the formation. Phosphate is interpretated as forming in dysoxic water in upwelling conditions (Over, 1992). Tasmanites, a form of algae found predominantly in shallow, nutrient-rich, marine water was recovered from Woodford Shale and used as evidence to support the hypothesis that the Woodford represents deposition in an open marine setting (Urban, 1960). Sullivan (1985) supported the tripartite subdivisions of Woodford by stating that the interpretation of evidence from spores yielded three similar groups.

Leventhal (1981) examined the correlation between the high concentrations of uranium and the amount of organic material within the Woodford. He reported that as the amount of organic matter increased, the amount of radioactive uranium in the sample increased proportionally. This observation is useful in inferring the relative percentage of organic matter from the response of the gamma ray curve.

Bramlett (1981) examined the relationship between fracture patterns and the production of oil and natural gas from the Woodford. Bramlett (1981) measured the orientation of fractures in outcrop and determined that the presence and orientation of the fractures impacted the production capability of the Woodford. In the course of his work, Bramlett (1981) divided the Woodford into five subunits based on observations noticed in outcrops.

Cardott and Lambert (1985) studied the thermal maturity of the Woodford using samples collected from outcrops in the Arbuckle Mountain region of Oklahoma. Samples collected along the Washita Valley fault were found to have vitrinite reflectance values of 0.35-0.77% and were thus thermally immature with respect to producing liquid hydrocarbons. Cardott and Lambert (1985) hypothesized that high heat flow associated with the rifting of the southern Oklahoma aulacogen must have decreased by the time of Woodford deposition and that the faulting regimes present in the Arbuckle Mountains had no effect on the thermal maturity of the Woodford Shale. Cardott and Lamberts' (1985) interpretation concluded that the Woodford never reached a depth of burial and adequately high temperatures to be thermally mature in the Arbuckle Mountains or Ardmore Basin. In contrast, vitrinite reflectance measurements from the Anadarko Basin of Oklahoma, show a systematic increase in mean vitrinite reflectance with depth over much of the basin (Cardott, 1985).

Schmoker (1986) produced a regression equation to predict the vitrinite reflectance of the Woodford Shale and noted large areas in the Anadarko Basin where the Woodford reached thermal maturity and was capable of generating hydrocarbons. Cardott (1987) applied this regression equation to the Woodford at shallow depths (where there is more concern regarding the value of vitrinite reflectance) and reported that there was little difference between Cardott's and Schmoker's products (Cardott, 1987).

Hester et al (1988) subdivided the Woodford on the basis of geochemistry and proposed three subgroups, which were denoted as the Upper, Middle, and Lower. Hester noted that the middle contained the highest amount of total organic carbon (TOC) compared to the other two groups and suggested that the amount of TOC was not a function of thickness of the Woodford, but that it was directly affected by depth of burial. The hypothesis was that with greater the depth of burial, the expected amount of TOC decreases as more carbon is converted into hydrocarbons. Hester et al (1990) proposed that the majority of the hydrocarbons produced in the middle and lower units of the Woodford Shale. This is believed to be the result of their higher TOC content compared to the upper unit and the hypothesis that all three zones were subjected to the same temperatures and pressures during burial.

Over (1990) described the depositional setting of the Woodford as being offshore, quiet and oxygen poor. Conodont biostratigraphy established that the age of the Woodford was Devonian-Mississippian and that the Devonian-Carboniferous boundary could be located within the Woodford. The boundary occurrence was noted to be marked by a “conspicuous phosphate bed”(Over,1990).The phosphate bed was determined to be caused by a change in depositional setting and the influx of oxygenated water from upwelling, consistent amounts of organic matter, and extended periods of no deposition or slow deposition(Over, 1990).

Hester et al (1992) examined the Woodford Shale and called it “a highly radioactive, carbonaceous and siliceous, dark-gray to black shale “ He further noted that based on the distribution of TOC, “The Woodford can be generally described as two similar shales separated by a less dense, more radioactive, and commonly more resistive middle shale member (Hester et al, 1992).”

Cardott (1994) observed that the vitrinite reflectance data (Cardott and Lambert 1985) did not correlate to the fluids being produced from the Woodford. He proposed several hypotheses to explain the discrepancies between fluid types and vitrinite reflectance values. Two primary concerns were identified. First, vitrinite reflectance measurements were originally created in order to rank coals based on the concentration of vitrinite particles found in the matrix of the coal. Second, there is the possibility that vitrinite particles were misidentified as other macerals, altering the result. "Maximum vitrinite reflectance is measured on a coal sample to determine coal rank. In general, large vitrinite particles in coal are abundant, easily identifiable, and usually indigenous. Application of vitrinite reflectance analysis to dispersed vitrinite in shale has numerous sources of error (Cardott, 1994)." The application of this method towards shales and other materials that inherently have lower amounts of vitrinite reflectance than coal produces some errors due to optical studies being conducted on poorer quality vitrinite grains (Cardott, 1994).

CHAPTER III

METHODOLOGY

Log Characterization

Wireline log characterization of the Woodford Shale was accomplished by correlating log signatures to cores. Once a rock-calibrated log signature was established, it was traced through the subsurface by comparing the calibrated signatures to other logs. The wireline logs used were purchased from MJ Systems® and imported into the IHS Petra ® data management system (Petra). Once in Petra, tops were picked for the five wells correlated to cores. These five wells were compared to determine events and characteristics that could be traced from well to well. The following curves were compared: spontaneous potential, gamma ray, shallow resistivity, medium resistivity, deep resistivity, neutron porosity, and density porosity. Wireline log measurements were compared with the lithologies in each core. Once completed, a set of lithologic characteristics and a general understanding of the differences between intervals were noted. Five (5) subunits were determined based on similarities in lithology, chert and phosphate content. These informal subunits or zones are in descending order: Chert, Black Shale, Interbedded, Lower Shale, and Lag.

Subsurface Mapping and Cross sections

Over 11,000 wells are located within the boundaries of the study area. Of those eleven thousand wells, wireline logs were obtained for 4,430 from MJ Systems. Using Petra, the position of the boundaries between units was chosen. The depths of the Woodford/ Caney contact, Black Shale subunit, Interbedded subunit, Lower Shale subunit, and the pre-Woodford unconformity were determined in approximately 1800 wells. The remaining logs in the MJ data set were not used because these wells did not penetrate the Woodford interval or the quality of the log traces was poor. Once the tops of concern were picked, these depths were plotted relative to sea-level reference datum and posted onto the mapping module of Petra.

The sea-level referenced depths of the top and base of the Woodford Shale were used to construct structure maps. These maps were first constructed by hand contouring and then by inputting sea-level referenced values into Petra. After the structure maps were completed, cross sections were constructed using the cross section module in Petra. Cross sections across the syncline were produced to demonstrate the structural placement of the Woodford in the Cumberland syncline. A stratigraphic cross section was constructed using Petra that demonstrated the variations in the thickness of the Woodford.

Production Evaluation

The oil and gas producing capabilities of the Woodford were evaluated by identifying single zone, Woodford producing wells. This was necessary to separate Woodford only completions from those that were commingled or producing from other formations. This was accomplished by examining 1002A completion forms from the Oklahoma Corporation Commission website, and comparing the (1) producing formation records, (2) the depth of perforations and (3) the depth of fracture stimulation or completion. Lastly, the depths of the reported completion intervals were compared to wireline logs to verify the formation record. When this process began, there were 88 candidate wells; this number was reduced to a total of 12 wells that would become the focus of delineating producing zones within the Woodford interval. Many of the original 88 wells were unsuitable as a result of multiple completions, commingling of production, or reported depths that did not reconcile with intervals reported on the 1002A completion forms. Other wells were eliminated because the early vintage well logs did not contain log traces necessary for analysis. After the dataset was established, Woodford producers were populated and the intervals within the Woodford were identified using the subunits established from core-calibrated logs.

Core-Log Correlation

Core-log correlation began with acquisition of cores of the Woodford interval from the Oklahoma Geological Survey Oklahoma Petroleum Information Center (OPIC) Library. These cores were taken from five wells within and adjacent to the Cumberland syncline. The cores that were used included conventional slab cut cores and side wall cores. All cores were described in detail for sedimentological features. These descriptions were supported by photographic records. Selected intervals were sampled for geochemical testing at Humble Instruments and Service, Inc. All core descriptions were compared to the raster log images for the cored well or one located in close proximity. The cored intervals were marked on the wireline logs and the two compared.

Vitrinite Reflectance Study

Forty samples were collected from the five cores. Samples were selected that were considered representative of specific intervals or subunits. Samples were analyzed by Humble Instruments and Services where vitrinite was extracted from each sample and the vitrinite reflectance was measured. Other measurements, including S1, S2, S3, Tmax, HI, and OI were taken. S1 is the measurement of carbon present in the form of free oil, S2 is the amount of carbon present in kerogen, S3 is the amount of carbon dioxide in the sample, Tmax is the maximum temperature that the sample reached, HI is the amount of hydrogen and OI the amount of oxygen respectively. From this information, graphs were produced that showed the type of hydrocarbons the sampled shale should produce. This information was plotted to construct a graph showing the change in vitrinite reflectance as a function of depth and determine if vitrinite suppression is occurring.

Electron Microprobe Analysis

Two selected samples were analyzed using an electron microprobe in order to observe differences in subunit mineralogy, petrology, and fracturing patterns. This phase of the study was designed to determine if there was a relationship between specific log responses for subunits and reservoir characteristics. Specifically, the capability to recognize natural fracture patterns on logs and understand what processes influence the creation or destruction of porosity in densely fractured subunits, could enhance the ability to drill and complete economically productive wells. It is expected that mineralogy through the interval will be somewhat predictable and change according to the relative concentration of phosphate nodules, fossil debris such as spores or radiolarians, and chert. These anomalous zones with PO_4 and silica-rich minerals are expected to relate to subunits that have higher fracture porosity and permeability.

Sample preparation

Samples prepared for microprobe analysis must be capable of being analyzed under a vacuum, uncovered (no slip cover), and able to be attached to either a slide or a round and analyzed using a JEOL superprobe 733 electron microprobe at OSU. For this study, one inch rounds were used exclusively. These samples were prepared in the Oklahoma State University electron microprobe laboratory. Preparation involves several stages, including sample selection, embedding in epoxy, polishing, and finally carbon coating.

Choosing Samples

Samples were selected from cores taken in wells drilled in Custer and Marshall Counties. The cores were acquired through the Oklahoma Geological Society Core Repository in Norman, Oklahoma, and the personal collection of Dr. Jim Puckette. The first sample chosen was from the GHK, Hoffman number 1 well located in sec 1, T.14 N., R. 16W., Custer County Oklahoma. The sample came from a depth of 4,250-4,267 feet (measured depth). The second sample came from the Texaco Incorporated, Drummond No. 1 well located in sec 11, T. 6S., R. 6E., in Marshall County Oklahoma.

CHAPTER IV

FINDINGS

Log Characterization

Based on the comparison of wireline logs, the Woodford Shale was subdivided into five subunits. These are based on the subdivisions established by Bramlett (1981). These subunits are from shallowest to deepest: Chert subunit (Cht), Black Shale subunit (Bksh), Interbedded subunit (Int), Lower Shale subunit (Lowsh), and Lag subunit (Lag). The wireline log characteristics of these subunits can be seen on the type log (Figure 4).

The Chert subunit has a high gamma ray response (> 300 API units), but is composed of alternating layers of lower values (as low as 143 API units). These alternating values are believed to represent interbedded layers of chert and shale. Higher gamma-ray readings indicate shale, and the lower values indicate chert. The neutron porosity reads less than the density porosity (12%), creating neutron-density crossover, and thereby indicating that this subunit contains effective porosity. The true resistivity values (Rt) are high (500-1000 OHM/M), which is typical of the chert subunit. The average thickness for the Chert subunit is between 50 and 80 feet in the thesis area.

The absence of clean chert intervals, which are represented by a decrease in gamma ray measurements, a large decrease in the amount of crossover between the neutron porosity and the density porosity, and a reduction in density porosity to a value of (<3%) mark the boundary between the Chert subunit and the underlying Black Shale subunit. The gamma ray response in the Black Shale is off scale (>300 API units) and remains consistent throughout this subunit. The resistivity curves continue to track each other and read in excess of 2000 ohm-meters (OHM/M). Another distinguishing characteristic of this subunit is that the neutron porosity and the density porosity curves read higher than those for the Chert subunit (average of 0.22 V/V).

V/V is a volume versus volume measurement that becomes unitless so that the neutron porosity and density porosity can be compared on an equivalent scale. The average thickness for the Black Shale subunit is 150 ft. thick.

The Interbedded subunit is characterized by a gamma ray response that varies between 150 and 300 API units, with the lower readings confined to features in the subunit that are thin (log response shows roughly 2 feet) and not equally vertically spaced through the subunit. These lower gamma ray values coincide with crossover of the neutron and the density porosity with density values of 12% and neutron values of 10%. These breaks and crossover differ from that of the Chert subunit in that the alternating higher and lower readings can be correlated across short distances rather than appearing completely random. Resistivities in this subunit also decrease to about 1000 OHM/M across a thin interval. The average thickness for this subunit is about 80 ft.

The Lower Shale subunit is distinguished from the superjacent Interbedded subunit by the absence of the breaks in the gamma ray response and decreased neutron-density crossover. The Lower Shale differs from the Black Shale subunit by the presence of crossover in the neutron porosity and density porosity (5%). The thickness of the Lower Shale is fairly consistent throughout the Cumberland syncline and averages 50 feet.

The Lag subunit is characterized by a high gamma ray response but contains interbedded zones with decreased gamma response in sharp contact with adjacent beds, and a decreased neutron-density crossover compared to overlying units (average of 0.1 V/V). Resistivity decreases in the Lag subunit to 100 OHM/M. The overall distribution and thickness of the Lag subunit is inconsistent. The thickness of the Lag subunit shown in the type log (Figure 4) is approximately 10 ft. Across the study area the thickness ranges from 0 to 30 ft.

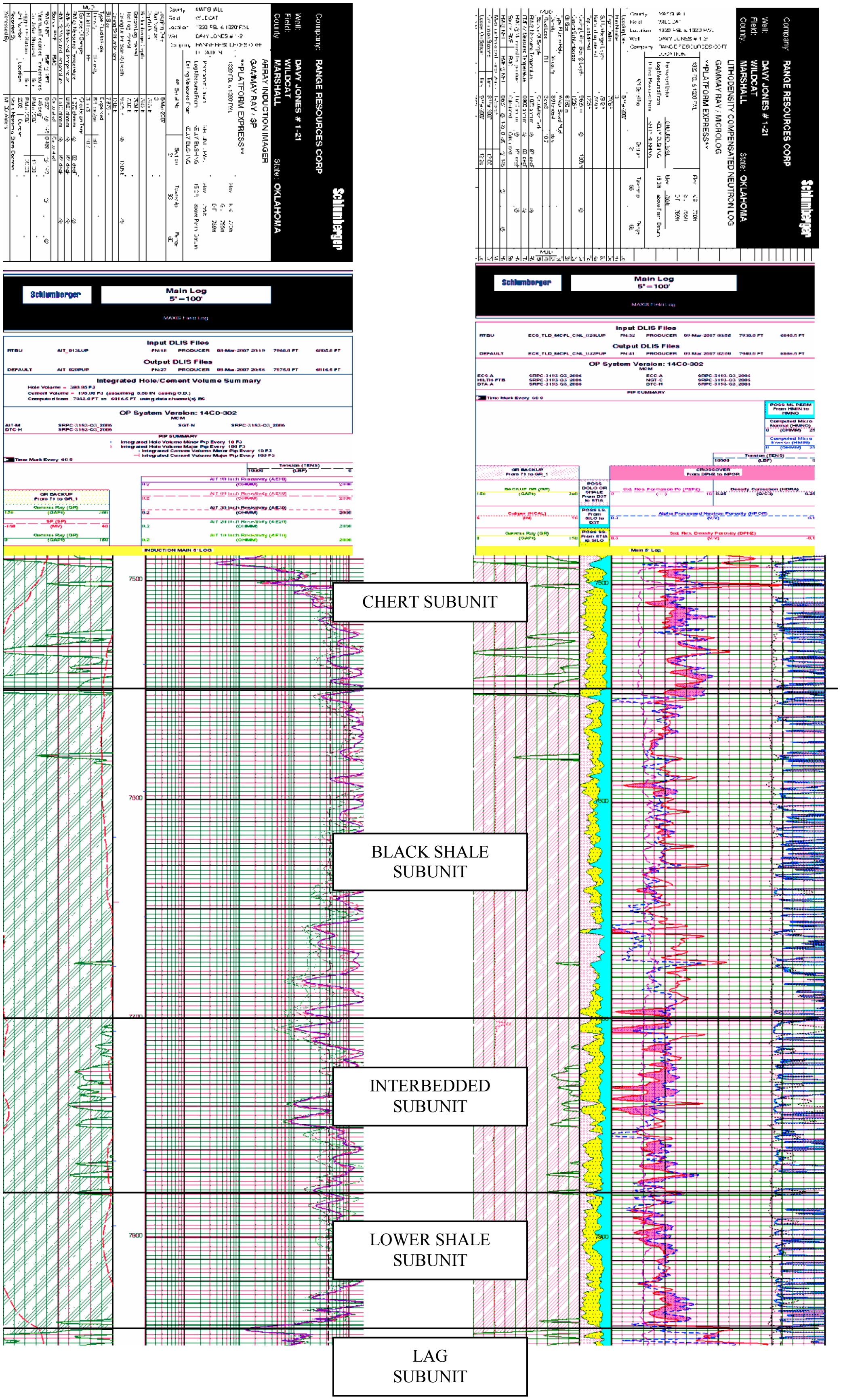

Figure 4. Type log showing subunits within the Woodford Shale. Range Resources, Davy Jones 1-21 well in sec 21, Township 5S, Range 6E, Marshall County, Oklahoma.

Core-Log Correlation

Subunit characteristics determined by log descriptions were correlated to cores to produce lithology linked descriptions and wireline responses. This process was subject to error introduced by the difference between drilling (core) depth and the depth recorded by wireline logs. This is a common source of error in subsurface data that is corrected by locating easily recognizable unit/subunit boundaries in core and log and noting the differences. If samples were taken from a well without a log, the core was correlated to the nearest offset that penetrated the Ordovician. Correlation between subunits identified on logs and cores was achieved with confidence. Once log characteristics of subunits were established it became possible to trace the subunits across the study area.

Chert Subunit

The Chert subunit is the youngest subunit; it is interpreted as interbedded black shale and chert. The thickness of chert beds ranges from 0.25 inches to 3 inches. This unit is fractured (Figure 5) and fractures crossing shale and chert beds were partially cemented with quartz (SiO_2). Intrabed fractures occur within the chert beds, but these were not cemented. Both chert and shale beds were deformed. Minor fractures occur in the clay matrix, but these are mostly cemented. The minor fractures are offset by major ones that also cut laminae of pyrite (FeS_2) (Figure 6). Chert-shale bedding contacts are coated with a black material that is interpreted as carbon residue.

Figure 5. Contact of the cherty subunit (bottom of picture) and the black Shale unit (top of picture). Texaco Incorporated, Drummond 1-N. Depth 3067-2076 feet.

Figure 6. Fracturing of the Chert subunit. Micro-faulting offsets lighter colored pyrite bands. Texaco Incorporated, Drummond 1-K. Depth 3047-3050 feet.

Black Shale Subunit

The Black Shale subunit is distinguished from the Chert subunit in cores by the absence of chert and an increase in the amount of black shale. This subunit is a highly radioactive black shale with little apparent permeability or porosity. Figure 7 shows an example of the Black Shale subunit. On the right side of the picture, a minor fracture pattern can be distinguished by the brighter orange colors. These fractures contain pyrite that is oxidizing. The presence of pyrite was confirmed using electron microprobe analysis.

Figure 7. A section of the Black Shale subunit. Oxidizing pyrite cement in fractures give this sample the orange color. California Oil, Mullen et al #1. Depth 8,982 ft.

Other features in the Black Shale include laminated intervals that show deformation, but no fracturing. The ductile/plastic characteristic of gas-rich zones allowed deformation to occur without the rock fracturing. When samples of this unit were broken along bedding planes, a sulphurous smell was noted. Fracture frequency is less when compared to chert beds, indicating fracturing induced secondary porosity will be more prevalent in cherty beds. Phosphate nodules occur near the top of the Black Shale subunit and are associated with a mass of highly viscous amber-colored hydrocarbons that is believed to be a by-product of oil generation.

Interbedded Subunit

The Interbedded subunit is a dark brown to dark gray shale that contains layers composed of slightly coarser grained material that is silt-rich. The laminated fine grained material reacted with dilute hydrochloric acid (HCL) indicating the presence of calcite cement. No cores of this unit were available and all inferences are the result of bit cutting examination. Cements identified in cuttings indicate the Interbedded subunit is fractured.

Lower Shale Subunit

The lower Shale subunit was differentiated from the Interbedded subunit by the lack of laminations, change in color from a dark gray-brown to a muddy green to gray, and a decrease in the overall grain size of the matrix. Comparison of the Lower Shale subunit to the Black Shale subunit showed that Lower Shale is lighter in color and more brittle. Fractures were present, but could not be analyzed because well cuttings were the only source of rock data.

Lag Subunit

The Lag Subunit was preserved in one sample of well cuttings; little information was obtained concerning this subunit. The Lag Subunit is lighter colored than other subunits and effervesced readily in dilute HCL. Sorting was poor with grain sizes ranging from clay to medium sand. The Lag Subunit is believed to represent an interval composed of reworked material from the underlying units.

Subsurface Mapping and Cross sections

The structure attitude and grain of the Woodford Shale follows the trend of the Cumberland syncline. The Woodford is present throughout most of the study area and absent only in areas denoted on the structure map (Plate 1). Woodford thickness is consistent and averages 300 feet. The thickness varies for subunits and the variability is shown on the structural and stratigraphic cross sections (Plates 2, 3, and 4). All subunits were identified in the subsurface and correlated throughout the syncline. If thermal maturity is attained, there is a probability of producing oil and gas anywhere in the syncline by trapping oil and gas stratigraphically in porous cherty beds in the syncline or along the edges of the syncline on anticlinal folds.

Production History Evaluation

Most Woodford Shale wells were completed in one of two ways. The first and older style was to perforate and complete across the entire Woodford interval. The second is to only open the upper 60 to 100 ft and or the lower 20 to 60 feet. These intervals coincide to the Chert and Lag Subunits, respectively. A cumulative production history by subunit is unknown, but the higher rates of production came from wells completed only in the Chert subunit.

Fracturing stimulation was used during completion of almost every Woodford well. Hydraulic stimulation is necessary because the Woodford is low porosity (2% average across formation) and is considered to have low matrix permeability. Stimulation methods ranged in style and amount, but most used sand, hydrochloric acid (HCL), and or mud cleanout agent (MCA). HCL and MCA were typically used in concentration of 8% to 15% mixed in fresh water to form 2,000 to 5,000 barrel volumes.

The Woodford Shale produces oil and gas throughout the study area, but production is concentrated on structural highs along the northern edge of the Cumberland syncline. The higher rates of production coincide with the Chert subunit. Completion methods varied significantly and a comparison of completion methods to production was attempted. It was determined that the most effective completion methods for vertical wells were a combination of gel and slick water with sand proppant.

Vitrinite Reflectance Study

The geochemical analysis of the Woodford Shale performed by Humble Geochemical revealed that the Woodford Shale was thermally immature and yielded average vitrinite reflectance values that do not increase linearly as a function of depth (Table 1). The geochemical analyses did show that organic matter in the Woodford Shale consists of Type II Kerogen (Figure 8), which corroborates the findings documented in other studies (Bramlett, 1981, Cardott 2001). The average TOC was 7.65%.

A graph of vitrinite reflectance versus present depth (Figure 9) indicates that Woodford data produces a wide range of values, but cluster in the depths where samples were acquired. The overall trend produced by the data suggests that there is little relationship between thermal maturity and depth of current placement.

When vitrinite reflectance values for the subunits were compared to the present burial depth (Figure 10), possible increases in vitrinite reflectance as a function of depth in the Black Shale, become evident. This may not be unique to the Black Shale, but it was the only subunit that had cored intervals from different depths. The subunits that demonstrate lower vitrinite reflectance values (Chert subunit and Lag subunit) were compared to logs to establish a relationship between log porosity, apparent fractures and vitrinite reflectance values. Subunits with higher vitrinite reflectance values, which are the Black Shale and the Lower Shale, have higher radioactivity, less porosity and less inferred heterogeneity as indicated by gamma ray response.

The vitrinite reflectance data indicate a trend increase in vitrinite reflectance values with depth. Rock identified as reservoir has lower vitrinite reflectance values, whereas the rock with higher vitrinite reflectance values is typed as source rock. In addition, these data indicate that the Woodford Shale in this area is classified as thermally immature to having low oil-generative capabilities. These samples indicate the Woodford is not in the thermal gas producing window.

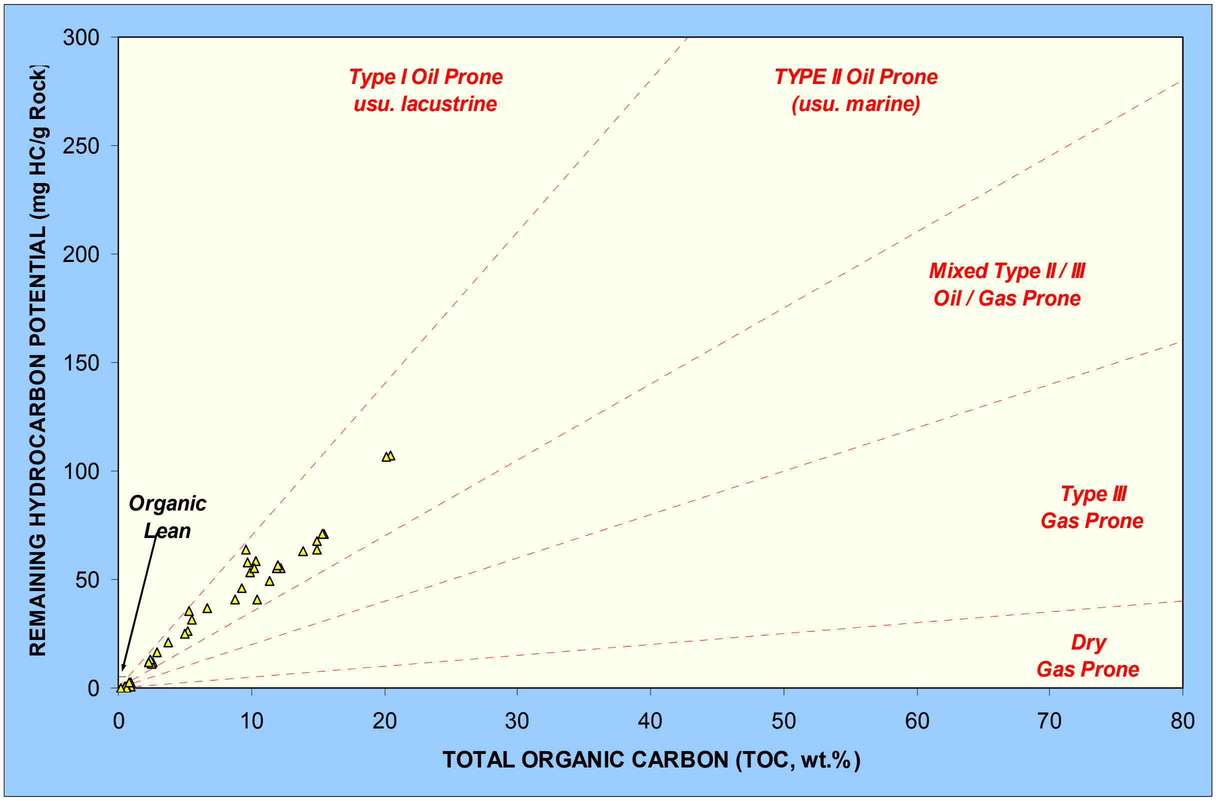

Figure 8. Plot of the type of kerogen versus the amount of remaining hydrocarbon (mg HC/g of rock). Chart courtesy of Humble Instruments.

Well	SUBSEA DEPTH	Median Depth	Client	Leco TOC	S1	S2	S3	Tmax	Calc. RO	SUBUNIT
7-18 Spencer Albin	-6324	7221	Sample 18	0.970	2	0.74	1.02	428	0.544	Interbedded
7-18 Spencer Albin	-7544	8441	Sample 19	0.520	0.6	0.66	0.51	435	0.67	Lower
7-18 Spencer Albin	-7612	8509	Sample 22	0.620	0.27	0.26	0.78	427	0.526	Lower
7-18 Spencer Albin	-7754	8651	Sample 21	0.560	0.41	0.49	0.26	427	0.526	Lower
7-18 Spencer Albin	-7756	8653	Sample 20	0.590	0.43	0.58	0.5	433	0.634	Lower
7-18 Spencer Albin	-8372	9269	Sample 23	0.210	0.04	0.05	0.31	416	0.328	Lag
California Oil Co Mullen et al #1	-8034	8978	Sample 26	20.470	3.82	107.01	0.52	441	0.778	BLACK
California Oil Co Mullen et al #1	-8037	8981	Sample 27	2.520	1.42	11.29	0.09	444	0.832	BLACK
California Oil Co Mullen et al #1	-8038	8982	Sample 28	20.120	4.43	106.83	0.58	444	0.832	BLACK
California Oil Co Mullen et al #1	-8042	8986	Sample 16	5.250	10.1	26.39	0.24	440	0.76	BLACK
California Oil Co Mullen et al #1	-8068	9012	Sample 36	10.260	4.48	55.03	0.32	437	0.706	BLACK
California Oil Co Mullen et al #1	-8070	9014	Sample 12	9.880	4.19	53.26	0.34	438	0.724	BLACK
California Oil Co Mullen et al #1	-8073.5	9017.5	Sample 24	11.420	2.81	49.41	0.54	440	0.76	BLACK
California Oil Co Mullen et al #1	-8075	9019	Sample 25	11.870	3.96	55.21	0.4	439	0.742	BLACK
California Oil Co Mullen et al #1	-8076	9020	Sample 1	8.810	3.3	40.72	0.39	440	0.76	BLACK
DRUMMOND 1-K	-2329	3045	Sample 9	6.730	3.42	37	0.42	432	0.616	CHERT
DRUMMOND 1-K	-2330	3046	Sample 10	13.920	3.98	63.28	0.83	428	0.544	CHERT
DRUMMOND 1-K	-2331	3047	Sample 11	15.440	9.2	71.2	0.93	427	0.526	CHERT
DRUMMOND 1-K	-2332	3048	Sample 7	10.440	4.19	40.96	0.88	422	0.436	CHERT
DRUMMOND 1-K	-2334	3050	Sample 8	9.290	6.69	46.07	0.94	426	0.508	CHERT
Drummond 1-N	-2309	3050	Sample 14	5.560	3.28	31.37	0.35	429	0.562	CHERT
Drummond 1-N	-2311	3052	Sample 2	14.920	7.08	67.77	1.26	423	0.454	CHERT
Drummond 1-N	-2315	3056	Sample 5	3.760	2.63	20.96	0.35	426	0.508	CHERT
Drummond 1-N	-2316	3057	Sample 6	14.940	8.07	64.07	1.17	419	0.382	CHERT

Table 1. Spreadsheet showing the wells and intervals sampled and analyzed. Results of geochemical analyses provided by Humble Geochemical.

Drummond 1-N	-2317	3058	Sample 3	12.170	8.79	55.4	1.21	420	0.4	CHERT
Drummond 1-N	-2319	3060	Sample 17	5.000	2.54	24.91	0.33	430	0.58	CHERT
Drummond 1-N	-2321	3062	Sample 38	15.350	9.46	70.86	1.11	423	0.454	CHERT
Drummond 1-N	-2323	3064	Sample 37	12.000	12.14	56.34	0.57	430	0.58	CHERT
Drummond 1-N	-2326	3067	Sample 4	10.330	7.65	58.72	0.65	432	0.616	CHERT
Drummond 1-N	-2328	3069	Sample 13	2.890	1.25	16.66	0.26	435	0.67	CHERT
Drummond 1-N	-2331	3072	Sample 35	9.750	3.35	57.75	0.53	433	0.634	CHERT
Texas oil # 1 CHAPMAN 3	-3148	4023	Sample 29	9.600	6.33	63.6	0.55	438	0.724	BLACK
Texas oil # 1 CHAPMAN 3	-3150	4025	Sample 32	2.300	1.9	12.13	0.26	433	0.634	BLACK
Texas oil # 1 CHAPMAN 3	-3169	4044	Sample 31	0.980	0.86	2.31	0.19	432	0.616	BLACK
Texas oil # 1 CHAPMAN 3	-3198	4073	Sample 30	2.360	2.83	13.2	0.21	438	0.724	BLACK
Texas oil # 1 CHAPMAN 3	-3202	4077	Sample 33	5.310	5.33	35.32	0.36	437	0.706	BLACK

Table 1. Spreadsheet showing the wells and intervals sampled and analyzed. Results of geochemical analyses provided by Humble Geochemical.

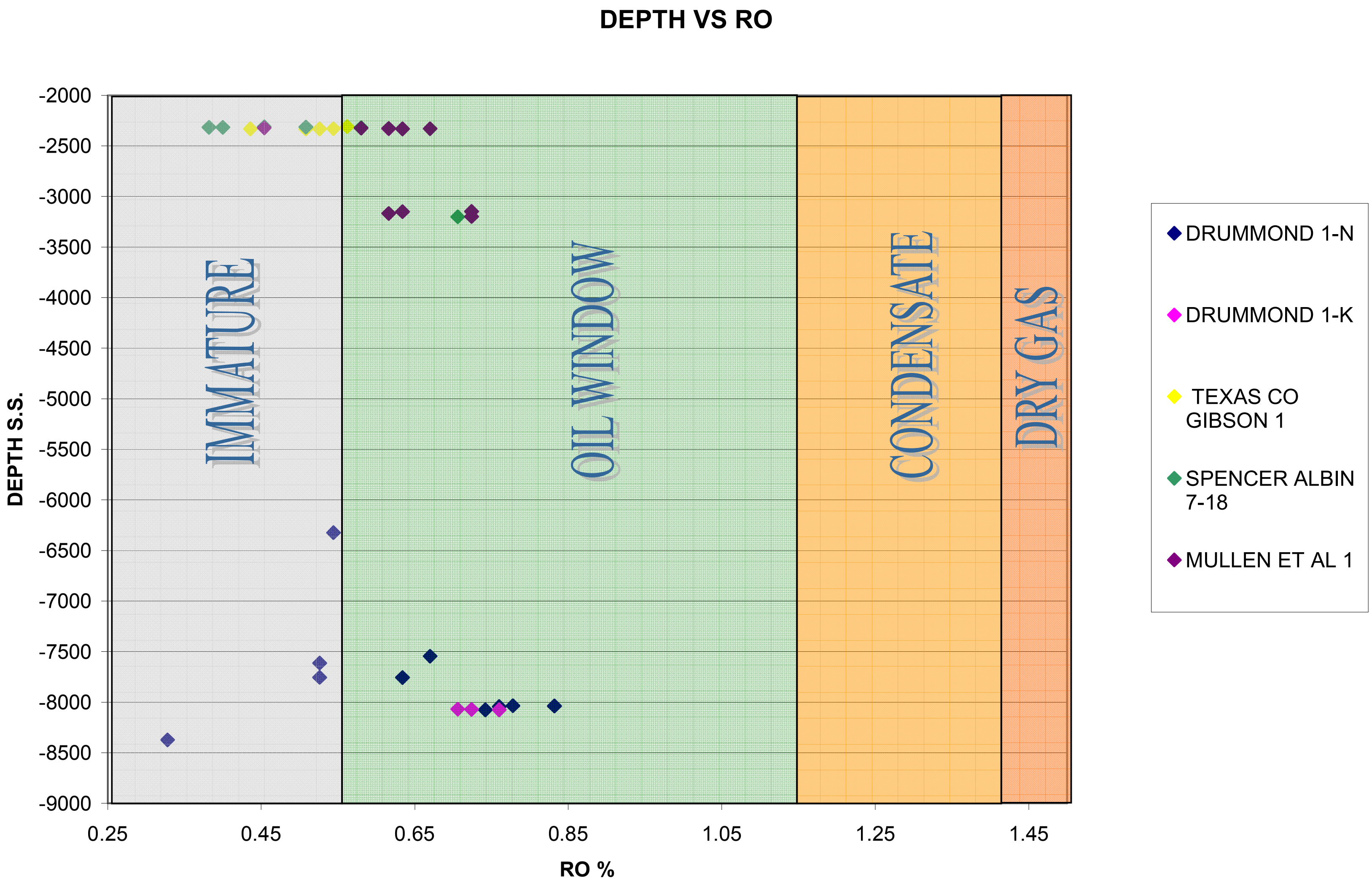

Figure 9. Plot of vitrinite reflectance (Ro) versus present depth subsea. No clear trends are evident relating thermal maturity to present depth.

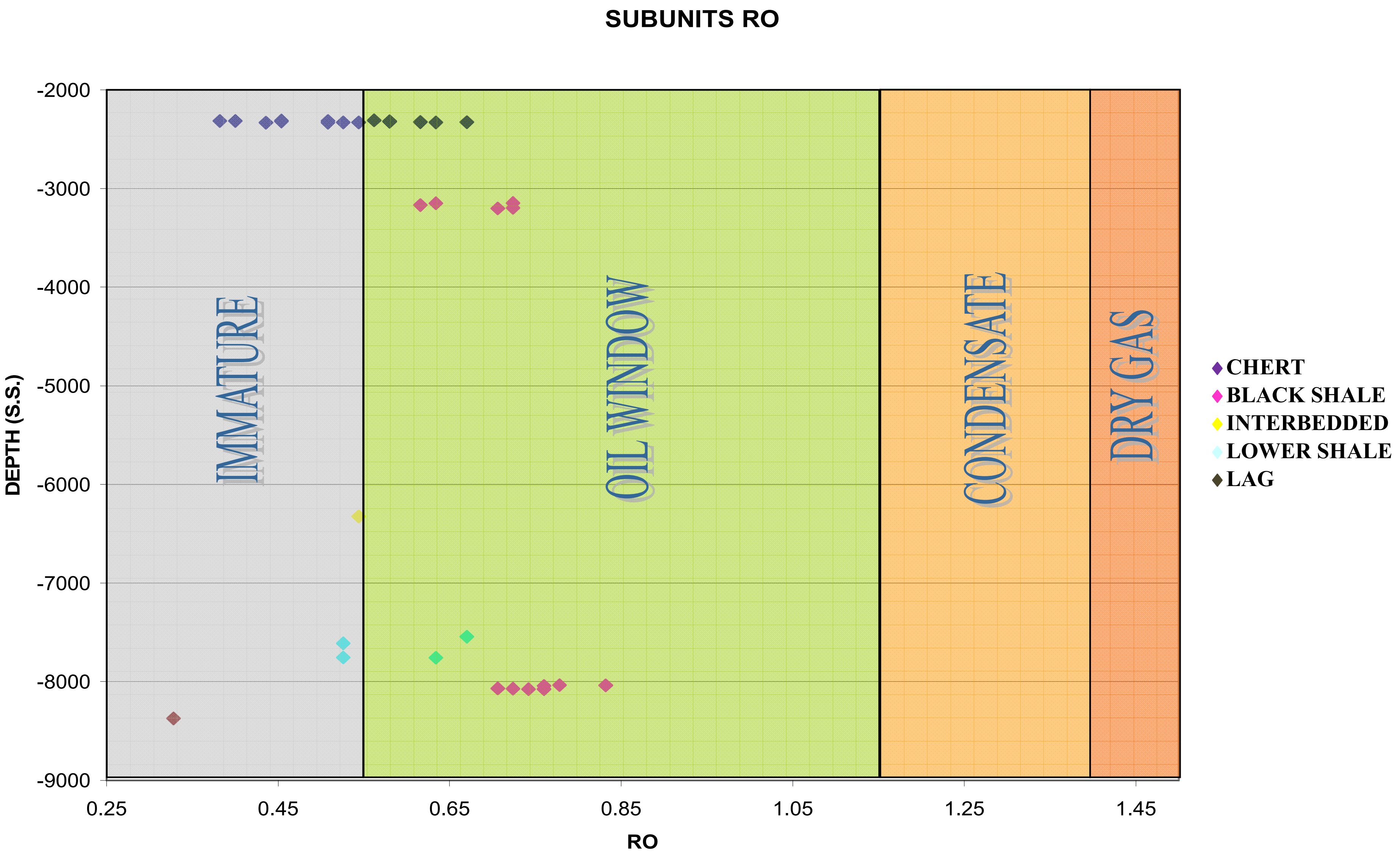

Figure 10. Plot of vitrinite reflectance (Ro) versus depth for specific subunits of the Woodford shale. Samples of the Black shale shows an increase in Ro with depth. This relationship was not established in other subunits which lacked adequate samples to make the comparison.

Electron Microprobe Analysis (EMP)

Two samples were collected from cores for electron microprobe (EMP) analysis. The first sample analyzed was from the GHK Hoffman No. 1 in sec 1, T. 14N., R. 16W., Custer County. The sample contained visible, pyrite-cemented fractures (Figure 11) and EMP analyses confirmed the mineralogy (Figure 12). The contact between the cement and adjacent shale was examined. Textural relationships show that the pyrite formed after compaction and oil generation because the pyrite filled pre-existing voids and didn't create fractures or show deformation at crystal boundaries (Figure 13). Pyrite formed in primary porosity as framboidal structures resulting in a fairly uniform distribution (Figure 14). Iron concentrations were mapped in the sample to determine the distribution of Fe in the matrix and pyrite (Figure 15). These results showed that the iron was only detected in pyrite.

The second sample was collected from the Texaco Incorporated, Drummond 1-N in sec.11, T. 6S., R 6E., Marshall County. During preparation, problems were encountered due to degassing. The sample appeared to be homogeneous to the naked eye, but once magnified it was evident that small framboidal shaped inconsistencies were composed of pyrite (Figure 16). The EDS spectra of the Marshall County pyrite samples were compared to spectra from Custer County and found to be very similar.

In both wells, the pyrite is disseminated (Figure 17), formed following compaction of the host shale, and partially occludes porosity. Chert and phosphate nodules were not detected in either sample. It was determined through the core-log correlation that both samples were from the Black Shale subunit.

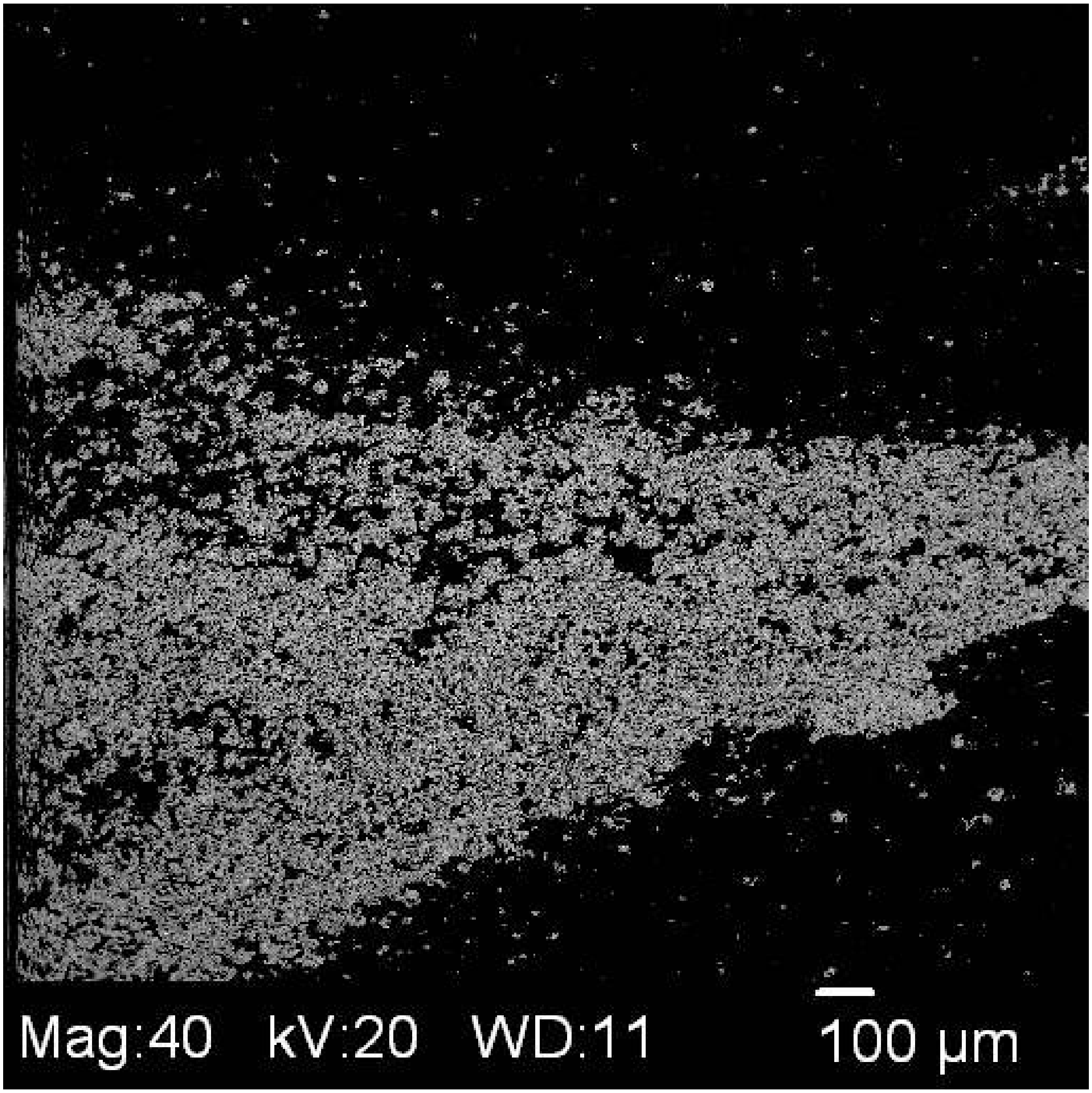

Figure 11. Photomicrographs of FeS_2 cementing a fracture (light colored material). GHK Hoffman no.1, Custer County, Oklahoma. Depth is 4250-4260 ft.

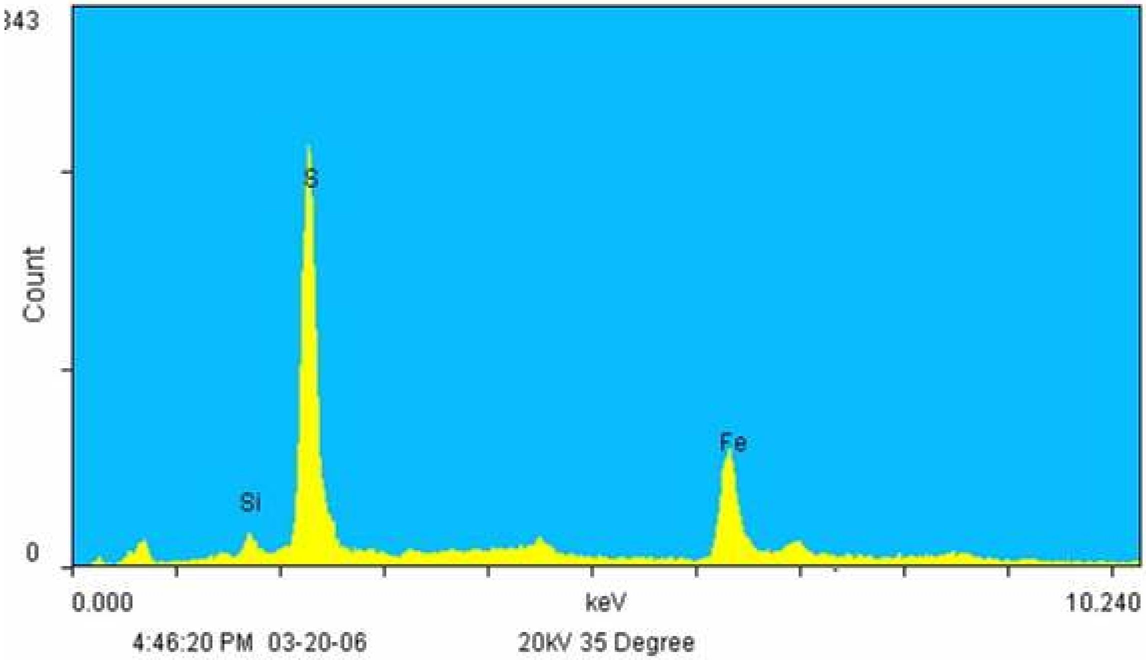

Figure 12. EDS spectra of pyrite cement showing prominent peaks of sulfur and iron. GHK Hoffman no. 1, Custer County, Oklahoma. Depth 4250-4260 ft.

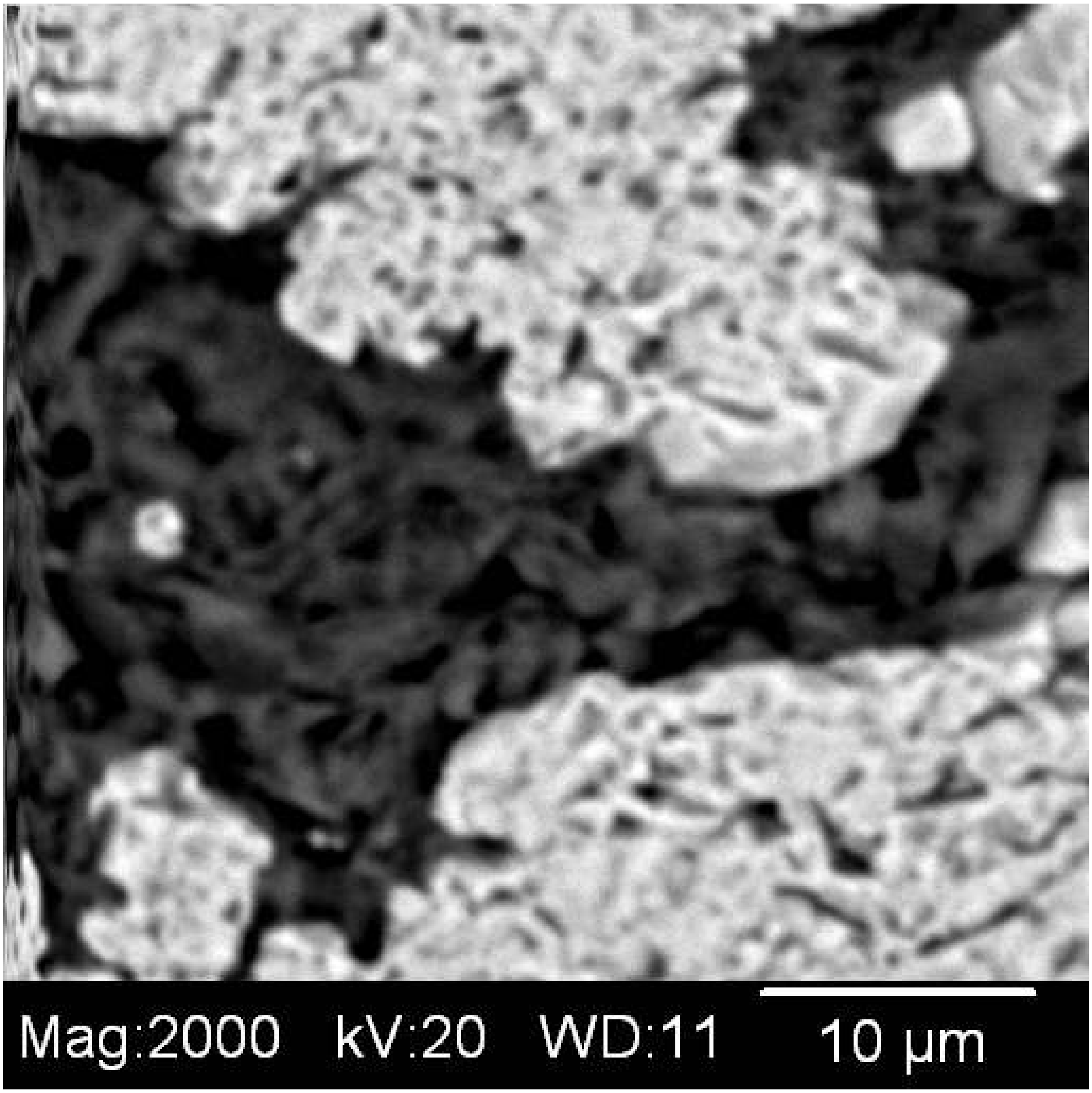

Figure 13. Photomicrograph of the contact between the pyrite (lighter color) and the host shale. Pyrite formed after compaction because it filled existing voids and does not deform adjacent clay crystals. GHK Hoffman no. 1. Depth is 4250-4260 ft.

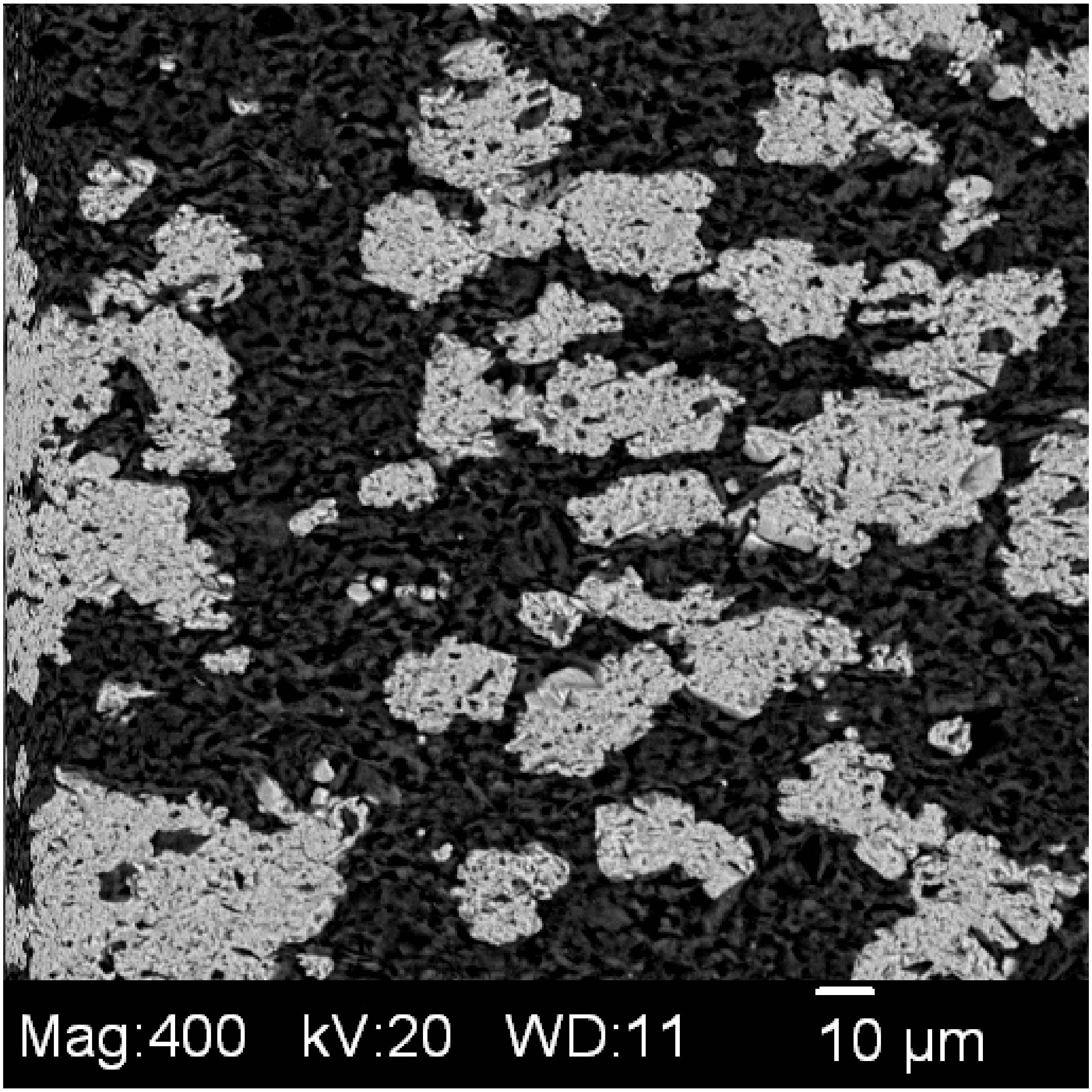

Figure 14. Disseminated pyrite infilling primary porosity in the Woodford Shale. As a result, pyrite is rather uniformly distributed in areas of the rock. GHK Hoffman no.1. Depth 4250-4260 ft.

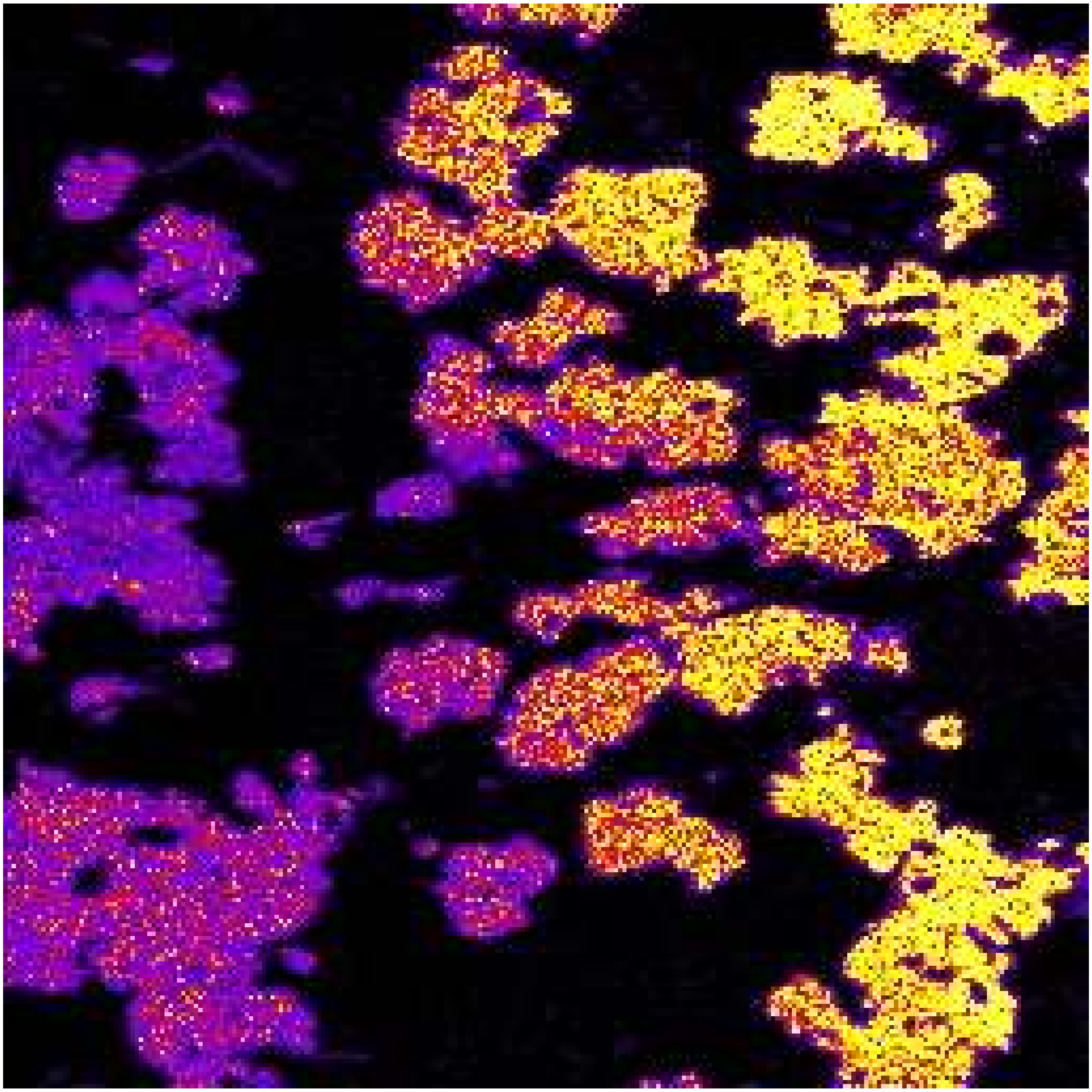

Figure 15. WDS element map showing concentration of iron. Purple represents low concentration, yellow higher concentration. Iron is restricted to pyrite and is not detected in adjacent clays. GHK Hoffman no. 1. Depth 4250-4260 ft.

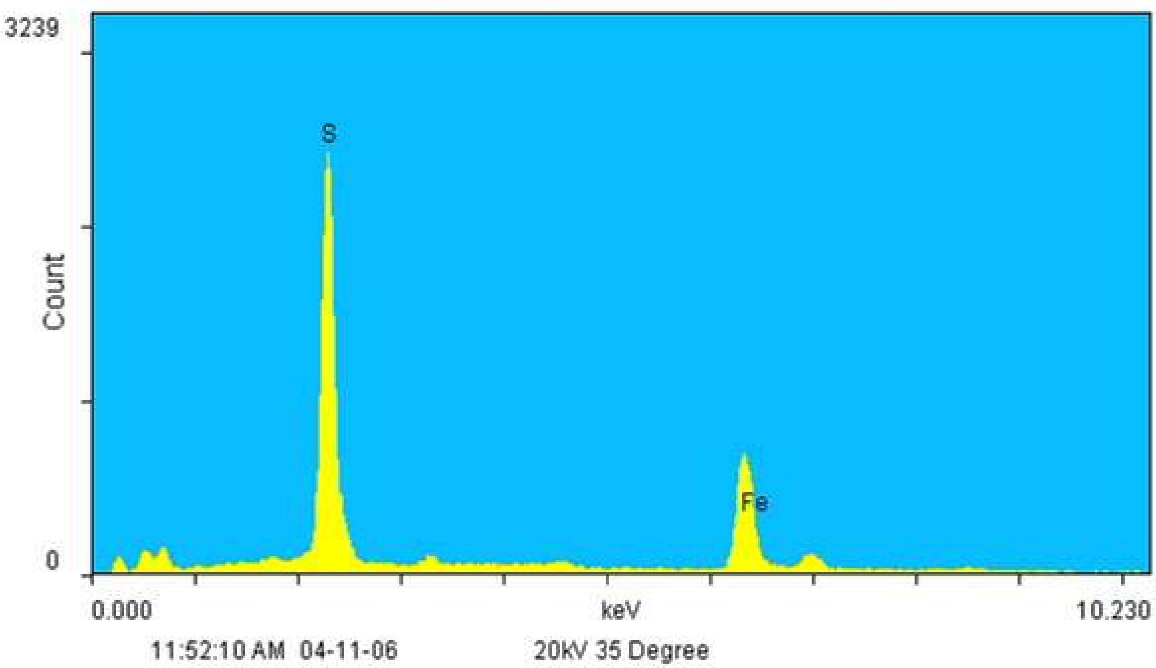

Figure 16. EDS spectra of pyrite in the Woodford Shale. Prominent sulfur and iron peaks are evident. Drummond 1-N, sec. 11, T. 6S., R.6E., Marshall Co., Oklahoma. Depth 3056-3057 ft.

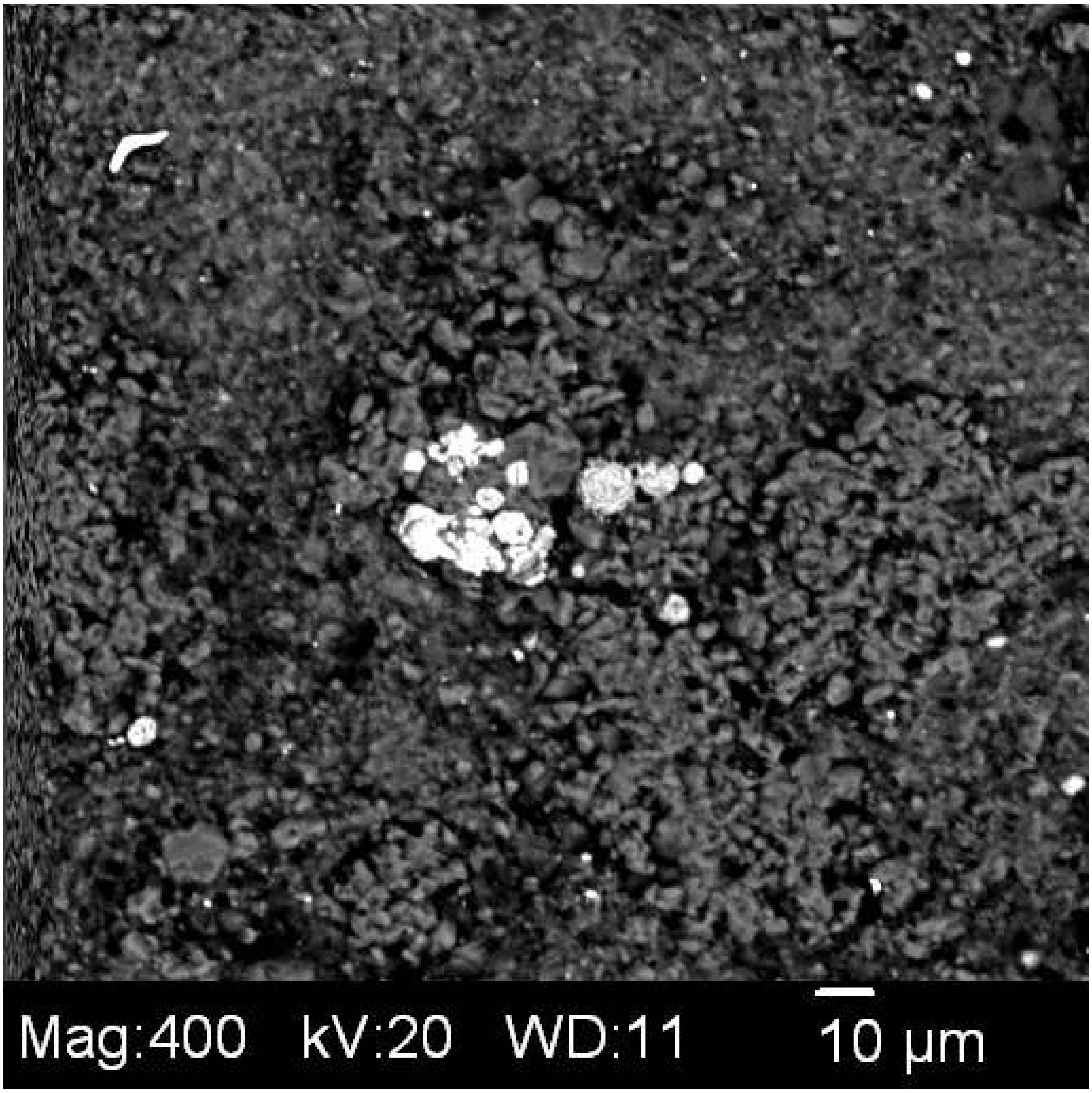

Figure 17. Cluster of pyrite (lighter color) in shale matrix. Pyrite occurs in porosity, which it partially occludes. Drummond 1-N. Depth 3056-3057 ft.

CHAPTER V

CONCLUSIONS

Based on the examination and interpretation of lithologic, petrophysical, geochemical and mapping data from the Ardmore Basin, the following conclusions are proposed. (1)The Woodford Shale can be subdivided into five units with distinct lithologic characteristics and wireline log responses. (2) These subunits are classified as either reservoir or source rocks depending on the respective chert content and fracture frequency. (3) A linear relationship does not exist between present depth of burial and vitrinite reflectance, but within subunit samples, those samples from greater depths were more thermally mature than shallow ones. (4) Vitrinite reflectance values confirm those reported by Cardott (1985) suggesting that the Woodford Shale in the Cumberland syncline is oil-prone at all sampled depths. Scatter in the present depth versus vitrinite reflectance plots is attributed to tectonicism and uplift, which creates a discrepancy between present depth and maximum burial, and (5) FeS_2 is post compaction and fills voids in the rock fabric.

It was determined that units containing greater amounts of chert are likely better reservoir rocks because they have higher permeability. Shale-rich units though porous contain fewer fractures and more pyrite as an accessory mineral that partially occludes primary porosity. These intervals were not completed in older vintage Woodford wells because of the lower porosity measurements recorded on wireline logs. Within the

Woodford interval, there were two shale sections that fall into this classification, the Black Shale subunit and the Lower Shale subunit.

Reservoir rocks all demonstrated several key characteristics. They contain chert and occasionally phosphate nodules, and have a corresponding higher density of fractures. The presence of chert and or phosphate decreases clay content and ductility and increase the propensity of the shale to fracture during deformation. Cherty reservoir facies within the Woodford Shale contain permeability and porosity based on log analysis, and production history confirms that these intervals were completed for oil and gas production. The highest initial production volumes were recorded for the Chert subunit. Occasional production was also recorded for the Lag subunit.

The Interbedded subunit is considered a transition unit between reservoir and source rock. The Interbedded unit is permeable in some wells and is commingled with cherty zones. The contribution of the Interbedded subunit to production is believed to be minor.

The geochemistry study showed that the selected samples had average TOC values of 7.65%. The kerogen samples were characterized as Type II, which indicates a marine source. Vitrinite reflectance measurements yielded an average value of 0.6%, which is far below the condensate gas window of 1%. Using the vitrinite measurement alone there is no reason to suspect suppression due to the lack of an obvious relationship between vitrinite reflectance and depth. The vitrinite data does not show distinct linear relationships between vitrinite reflectance, depth, and oil generation capability. There were poorly defined trends showing an increase in vitrinite reflectance values with depth. Reservoir subunits demonstrated lower vitrinite reflectance values and lower oil generation capability than the source rock subunits. However, these results may be an artifact of sampling density. Additional sampling from a wider range of depths is needed to verify this finding.

The results of the vitrinite study confirm the results of Cardott (1985). If the vitrinite reflectance values are correct, wells producing gas from the Woodford Shale in the Ardmore Basin tapped associated gas from nearby oil accumulations.

Future Work

In order to develop a better understanding of the Woodford Shale as both a reservoir and source in the Ardmore Basin, future studies would benefit from whole core analysis across the entire Woodford interval. Furthermore, future work should focus on Hydrogen Index mapping to determine if hydrogen suppression is altering vitrinite reflectance measurements and, as a result, the understanding of the distribution of the oil and gas-bearing Woodford Shale in the Ardmore Basin.

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Appendix I

Lithologic and Geochemical data of Core

A. Anschutz, Spencer Albin No. 7-18, sec.18, T.5S., R. 3W., Carter County, Oklahoma, Interval: 8221-9269 feet. Source: well cuttings.

B. Texaco, Drummond No. 1-K, sec.11, T.6S., R.6E., Marshall County, Oklahoma, Interval: 3045-3050 feet. Source: slab core.

C. Texaco, Drummond No. 1-N, sec.11, T.6S., R.6E., Marshall County, Oklahoma, Interval: 3050-3075 feet. Source: slab core.

D. California Oil Co., Mullen et al No. 1, sec.29, T.5S.,, R.2W., Carter County, Oklahoma, Interval: 8978-9023 feet. Source: slab core.

E. Texas Oil Co., Chapman No. 3, sec.45, T.4S., R.4E., Marshall County, Oklahoma. Interval:4020-4090 feet. Source: slab core.

A.

DEPTH	SAMPLE #	DESCRIPTION	TOC	HI	OI	TMAX	Ro	IMAGE
8221	Sample 18	Brown to rust red, very clay-rich fragments of a hard shale; reaction with acid.	0.97	76	105	428	0.54	
8356		Dark gray shale, brittle, falls apart very easily.						
8385		Dark gray very fine sand to silt, brittle, falls apart very easily.						
8441	Sample 19	Med gray to white, med sand to silt; reaction to acid shale fragment.	0.52	127	98	435	0.67	
8443		Brown to grayish white shale, mainly clay, some reaction to acid.						
8487		Med. to dark. gray med. silt shale, no calcite.						
8491		Light brown to dark gray high amounts of clay, some shale clay to silt, no reaction to acid.						
8496		Light gray to white brittle shale to siltstone; strong reaction to acid.						
8502		Light gray siltstone, brittle; reaction to acid very little (no shale).						
8509	Sample 22	Med sand to shale nodules, gray to white in color. Reaction to acid	0.62	42	126	427	0.53	
8651	Sample 21	Mainly gray (light) shale, cherty strong; reaction to acid.	0.56	88	46	427	0.53	

8653	Sample 20	Gray fissile shake with white calcite, silty.	0.59	98	85	433	0.63	
8678		Black very fissile shale; reaction with acid, some paraffin.						
9269	Sample 23	White to green shale (green shale looks fissile); strong reaction to acid.	0.21	24	148	416	0.33	

B.

DEPTH	SAMPLE #	DESCRIPTION	TOC	HI	OI	TMAX	Ro	IMAGE
3045 -47	Sample 9 - (Nodule)	Phosphate nodules present 1 inch tarry substance amber color wavy lamination. Black Shale random fracturing Filled in by secondary diagenesis. When fractured along lamination smell of light sulfur. Fissile, no reaction with acid. Major fractures cut laminations. Smaller fractures are cemented.	6.73	550	6	432	0.62	100-590 100-591
	Sample 10- Black shale with in laminations		13.92	455	6	428	0.54	
	Sample 11- Black shale with tar substance on side		15.44	461	6	427	0.53	
3047 -50	Sample 7 -laminae	Laminations more continuous, separation .25 inches, wavy twice thickness as normal fractures are perpendicular to lamination not filled. Shiny surface on broken sides, dead oil in fractures. Less micro-fractures, not as random at base, random fracturing no lamination fractures filled harder shale fine grain dead carbons old surfaces have tar substances.	10.44	392	8	422	0.44	
	Sample 8 - Hard non laminated Heavy odor		9.29	496	10	426	0.51	100-585 100-586

C.

DEPTH	SAMPLE #	DESCRIPTION	TOC	HI	OI	TMAX	Ro	IMAGE
3050-52	Sample 14	Very few discontinuous laminations, ½ inch separation. Mainly black shale with limited major fracturing and a lot of minor fracturing that is filled. Major fractures cut through lamination.	5.56	564	6	429	0.56	100-594
3052-55	Sample 2	No reaction of acid with laminae. Fractures are 30 degrees off perpendicular to laminae. Fractures have been mainly filled by secondary cements. Shale is black. Secondary larger grain than shale. Carbon odor on new breaks no nodules present. Highly laminated!	14.92	454	8	423	0.45	100-572 100-573 Picture of lamina 100-574 Picture of fracture fill in 100-575 fracture patterns
3056-57	Sample 5 – solid black shale no laminate	E.M.P. INTERVAL More continuous lamina (separation .5in) Same lamina thickness. Fractures in non-laminated portion are not filled as much. Carbon in fractures. Fractures mainly perpendicular to lamina. Largest fractures are in this pattern. Laminated coarser grain than non laminated. Contacts between laminated and non laminated highly fissile.	3.76	557	9	426	0.51	100-582 Picture of Core
	Sample 6 – contact between laminated and black shale		14.94	429	8	419	0.38	100-583 Picture of Non laminated bounded by either side by laminated

3057-60	Sample 3	Coaly luster, laminations are larger and fewer. No reaction with HCL. Laminations are discontinuous, .75 inches apart and are wavy. Lamination's thickness is 1/16 inches. Fracture pattern is random. No nodules present.	12.17	455	10	420	0.4	
3060-62	Sample 17 - Cherty portion	Laminated portion (at top) wavy parallel, lower portions heavily cherty. Shows both micro and macro fractures, scarce in the laminated portions.	5	498	7	430	0.58	100-597 100-598 100-600
3062-64	Sample 38	Black, faintly fissile shale, minor fracture pattern, shiny surface. No laminations or nodules present. Appears cherty.	15.35	462	7	423	0.45	100-602
3064-67	Sample 37	Black thicker shale (4in) separated by lamination thickness (3in). Minor fracture pattern, but cemented. Shiny fresh surfaces.	12	470	5	430	0.58	100-601
3067-69	Sample 4- From cherty portion with no lamina	Thick lamina fewer in number than before, .25 inch separation. Few nodules, .25in in size. Black. Layers of lamina separated by layer of no lamina. Fewer fractures with no laminae. Coaly luster.	10.33	568	6	432	0.62	100-580 Picture of Core 100-581 Picture of small nodule
3069-72	Sample 13	Coaly luster on fractured sides with strong oil smell when broken. No continuous lamination. Minor fracture pattern. Conchoidal pattern, tar present.	2.89	576	9	435	0.67	100-593
3072-75	Sample 35	Black, hard, cherty, conchoidal, shiny surfaces were broken, highly fissile.	5.31	665	7	437	0.71	

D.

DEPTH	SAMPLE #	DESCRIPTION	TOC	HI	OI	TMAX	Ro	IMAGE
8978-81	Sample 26 - Phosphate Nodule	Phosphate nodules present. Some calcite in sheets along fracture planes, hard shale, some chert, few laminations. Shale mainly breaks parallel. Few minor and major fractures.	20.47	523	3	441	0.78	
	Sample - 27 Black shale		2.52	448	4	444	0.83	
8981-84	Sample 28 - Phosphate nodules.	Phosphate nodules (1.3in) Black hard shale, few to no laminations	20.12	531	3	444	0.83	100-599
8984-87	Sample 16 - System chart sample	Laminations scarce. Separated laminations by large area. Thick portions of black. NodulesSample sound very large (3-4 in wide) occurring next15 to thinly laminated portionsBlack Shale some pyrite no minor or major fracture	5.25	503	5	440	0.76	100-595 100-596
9010-13	Sample 36	Black hard shale (6in) broken by few laminae.	10.26	536	3	437	0.71	
9013-16	Sample 12 - Black Shale	Thinly laminated, all parallel, no fractures. Black extremely fine grain Cross cutting bedding feature with major Fracture pattern with lamina 1/8 inch separation No reaction with HCL.	9.88	539	3	438	0.72	100-592
9016-19	Sample 24 - Striation	Black, hard, few thick laminations, near nodule. Prominently cherty shale, visible silica grains.	11.42	433	5	440	0.76	
	Sample 25 - Hard cherty part.		11.87	465	3	439	0.74	100-598

9019-23	Sample 1	Black, finely laminated (<1mm) . Fractures are perpendicular to laminations. Fractures filled in? Breaks along lamination have luster similar to coal. No reaction with HCL.	8.81	462	4	440	0.76	100-571 Picture of core

E.

DEPTH	SAMPLE #	DESCRIPTION	TOC	HI	OI	TMAX	Ro	IMAGE
4020-21		Shale, light grayish green, cherty angular.						
4022-23		Black to med green, fissile shale, no laminations very hard, No reaction to HCL.						
4023-24	Sample 29	Black hard shale, no laminae or reaction to acid.	9.6	662	6	438	0.72	
4024-25	Sample 32	Black to dark green ,very cherty, hard shale.	2.3	527	11	433	0.63	
4026-27		Black fissile hard shale, shiny where broken.						
4028-29		light green, very hard shale.						
4039-40		Black shale with white spots. (phosphate nodule)						
4041-42		Black to med green, very hard shale.						
4042-43		Black to med green very hard shale. Shiny on fractured surface.						
4044-45	Sample 31	Grayish green, appears cherty, very hard and fissile shale.	0.98	236	19	432	0.62	
4045-46		Black hard shale with thicker laminae.						
4066		Black shale, shiny surfaces, white specs.						
4067		Black Shale cement in minor fracture. Shiny where broken.						

4068		Black, hard shale, bowed laminae shiny surfaces.						
4073	Sample 30	Medium gray shale, hard, fissile. No laminations or reaction to HCL.	2.36	559	9	438	0.72	
4075		Gray hard shale with vf sandy layer.						
4077	Sample 33	Black hard shale with very small nodules, some lamination.	5.31	665	7	437	0.71	
4079		Light gray hard shale with some vf sand.						
4082		Black hard shale with shiny surfaces.						
4090	Sample 34	Light gray, hard shale.	0.82	293	22	440	0.76	

Appendix II

Pictures of Core

Image 100-571. Black shale subunit. Diameter 4.5 inch. California Oil, Mullen et al #1. Depth 9019-9023 ft.

Image 100-572. Chert layering and color indicative of the Cherty subunit. Core diameter 4 inch. Texaco, Drummond 1-N, Depth 3052-55 ft.

Image 100-573. Characteristic chert layering and concave voids resulting from extracted phosphate nodule. Chert subunit. Drummond 1-N, Depth 3052 feet.

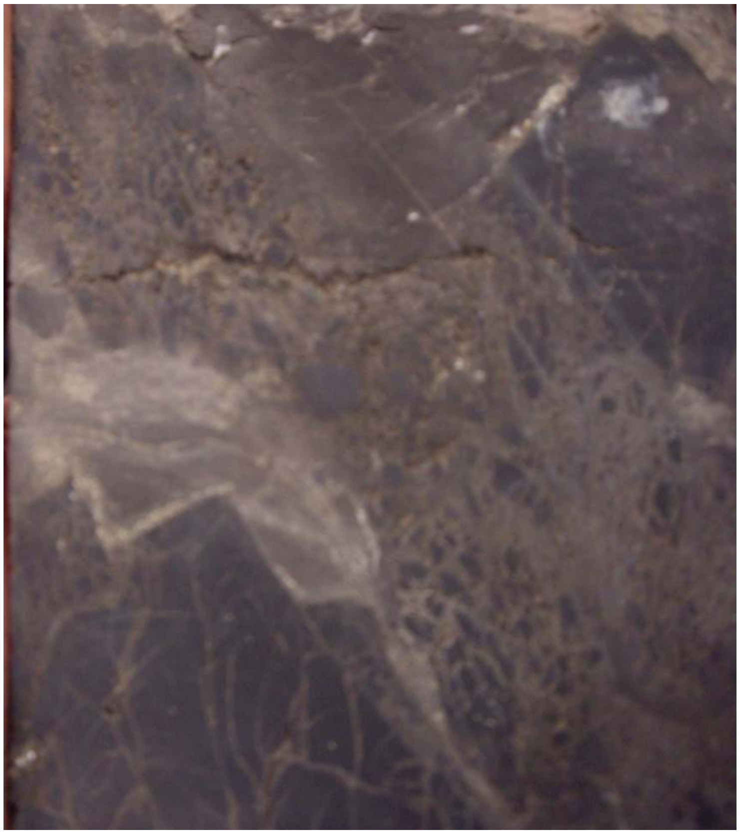

Image 100-574. Chert subunit showing the contact of chert and shale. Fracture pattern in shale matrix is evident due to pyrite cement. Width 4 inch. Drummond 1-N.Depth 3052-55 feet.

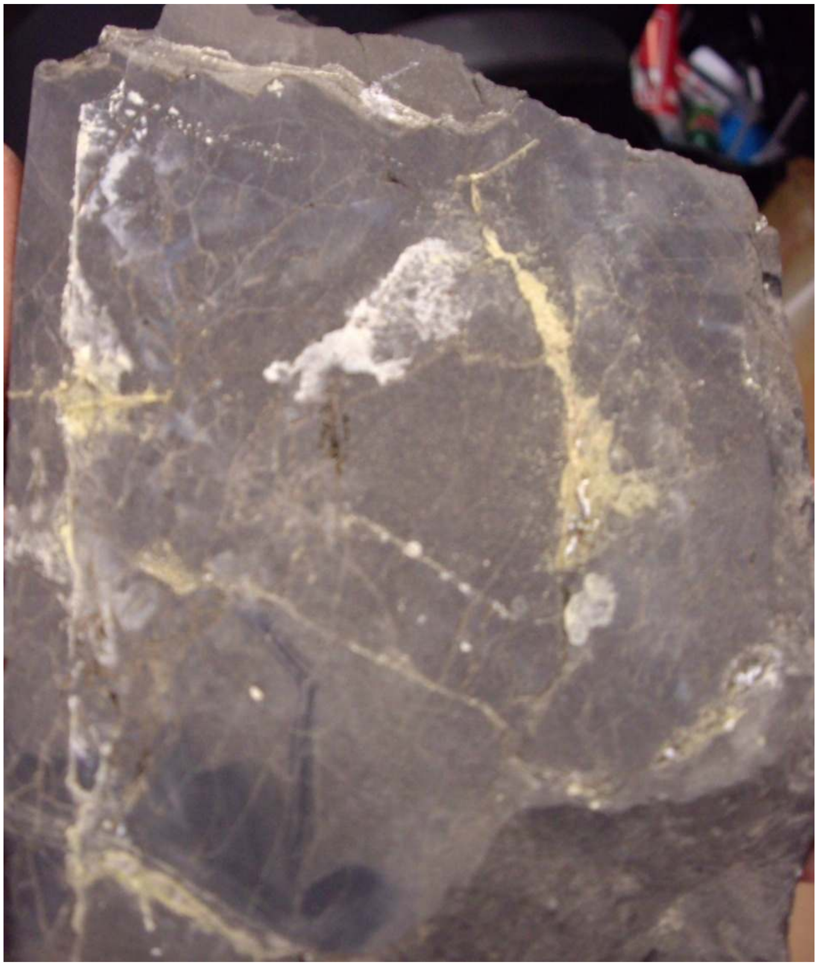

Image 100-575. Pyrite mineralization along the margins of fractured chert. Chert subunit. Drummond 1-N. Depth 3052 feet.

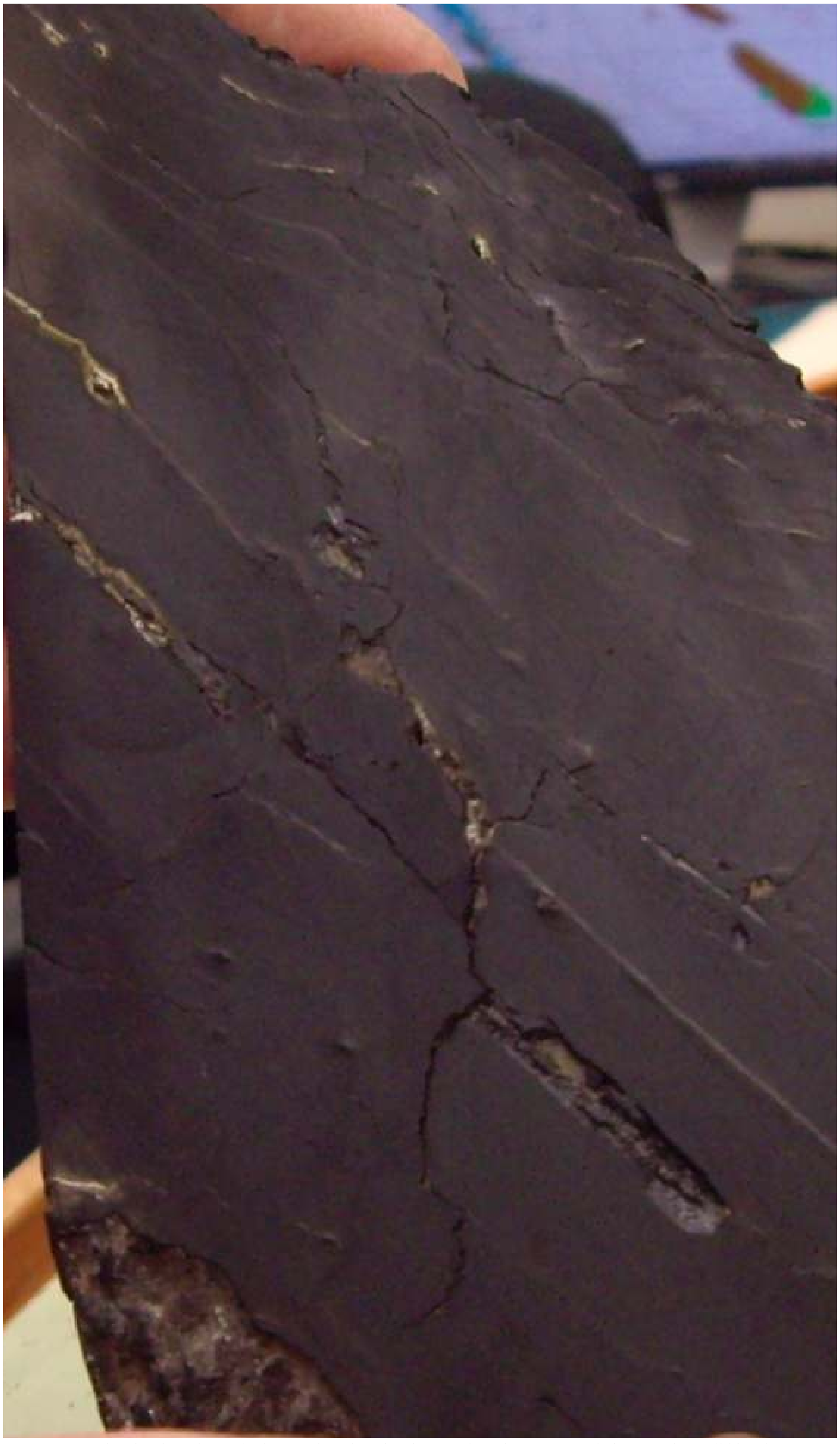

Image 100-579. Shale beds of the Black shale unit shown with pyrite filled fractures. Texas Oil Co., Chapman #3. Depth 4023-24 feet.

Image 100-580. Contact of the Cherty subunit (bottom of picture) and the Black Shale unit (top of picture). Drummond 1-N. Depth 3067-76 feet.

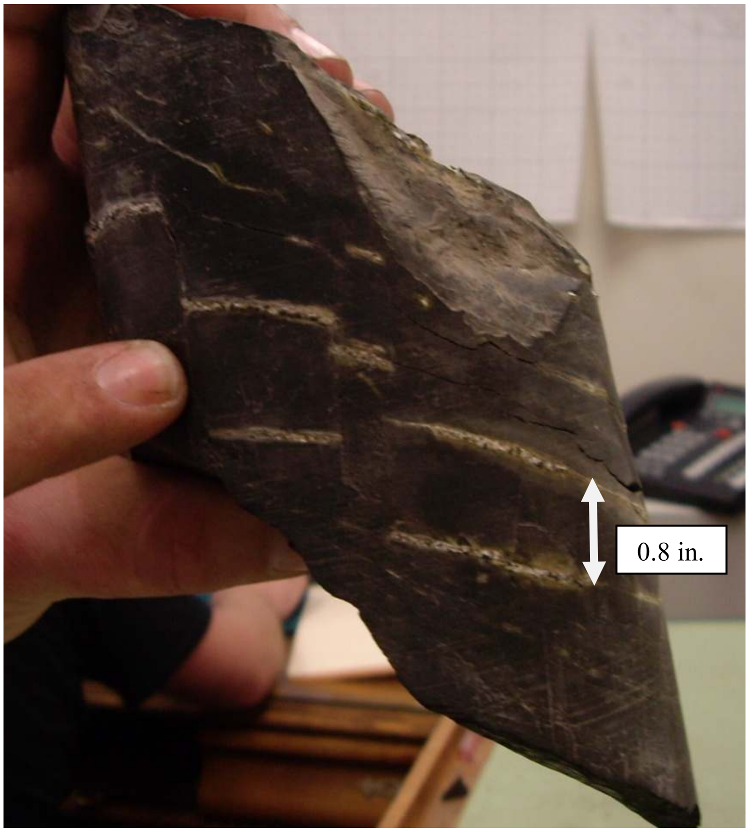

Image 100-586 Fractures cutting pyrite bands in the cherty subunit. Texaco, Drummond 1-K. Depth of 3047-3050 feet.

Image 100-591. Fractures and oil staining in Black Shale subunit. Height 7 inch.
Texaco, Drummond 1-K. Depth 3045-3047 feet.

Image 100-592. Non-fractured shale of the Black shale subunit.
California Oil Co. Mullen et al #1 from a depth of 9014 ft.

Image 100-596. Black shale subunit cemented with pyrite. California Oil, Mullen et al #1 from a depth of 8986 ft.

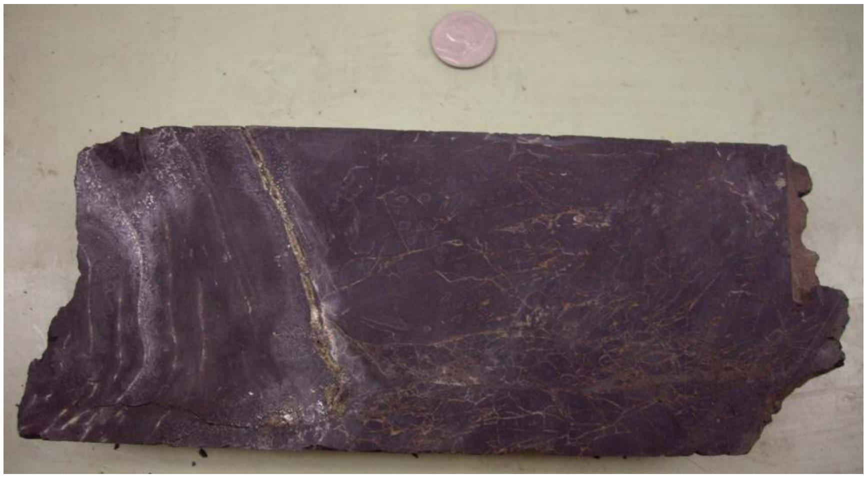

Image 100-599. Pyrite cemented fractures within the Back shale subunit. California Oil, Mullen et al #1 from a depth 8982 ft

Image 100-600. Phosphate nodule in the cherty subunit. Drummond 1-N. Depth of 3060 feet.

VITA

Joe Marcus Wicker

Candidate for the Degree of

Master of Science

Thesis: LITHOLOGIC AND GEOCHEMICAL ASSESMENT OF THE HYDROCARBON PRODUCING CAPABILITY OF THE WOODFORD SHALE IN SOUTHERN OKLAHOMA

Major Field: Geology

Biographical:

Personal Data:

Born in Lawton, Oklahoma to Valerie Ann Wicker, and raised there till the age of 12. Moved to Bad Kreuznach, Germany and attended Bad Kreuznach American High school. Moved to McAlester, Oklahoma at the age of 15. After completion of high school moved to Stillwater, Oklahoma to attend Oklahoma State University.

Education:

Graduated in 2002 from McAlester High School B.S. in Geology
Oklahoma State University 2005
M.S. in Geology Oklahoma State University, December 2008

Experience:

Intern at Lamamco drilling from 2003 to 2005
Geo-tech at Ironsights Operating from 2005 to 2007
Associate Geologist at XTO Energy from 2007 to present

Professional Memberships:

Member of American Association of Petroleum Geologists since 2003.
Member of Oklahoma State University Geological Society since 2003.
Member of Tulsa Geological Society since 2003.
Member of Geological Society of America since 2003.
Member of Fort Worth Geological Society since 2007.

Name: Joe Wicker Date of Degree: May, 2008

Institution: Oklahoma State University Location: Stillwater, Oklahoma

Title of Study: LITHOLOGIC AND GEOCHEMICAL ASSESMENT OF HYDROCARBON PRODUCING CAPABILITY OF THE WOODFORD SHALE IN SOUTHERN OKLAHOMA

Pages in Study: 92 Candidate for the Degree of Master of Science

Major Field: Geology

Scope and Method of Study: The late Devonian and early Mississippian Woodford shale was studied throughout the Cumberland syncline in Love, Johnston, Marshall, Bryan, Atoka, and Carter Counties, Oklahoma. The purpose of this study was to determine if the Woodford could be subdivided based on variations in core characteristics, wireline response, production history, vitrinite reflectance, and electron microprobe response to produce generalized subunits that can be traced through the subsurface. Furthermore the subunits were classified into either reservoir or source rock intervals within of the Woodford Shale.

Findings and Conclusions: Based on the examination and interpretation of rock, petrophysical, and mapping data from the Ardmore Basin, the following conclusions are proposed. (1)The Woodford Shale is differentiated into five units with distinct lithologic characteristics and wire line log responses. (2) These subunits could be classified as either reservoir or source rock. It was determined that units containing greater amounts of shale are source rocks because they have lower permeability determined by the absence of primary or secondary fracture patterns. Within the Woodford there were two shale intervals that fall into this classification, the Black Shale subunit and the Lower Shale subunit. Reservoir rocks all demonstrated several key characteristics. They contain chert and occasionally phosphate nodules that correspond with more highly fractured intervals. The presence of chert and or phosphate decreases ductility and increase the brittleness of the shale causing it to fracture during deformation. The three subunits that were characterized as reservoirs were the Chert subunit, the Interbedded subunit, and the Lag subunit. Geochemical analysis determined that kerogens were type II, which denotes a marine source. Vitrinite reflectance measurements yielded an average value of 0.6%, which is far below the condensate gas window value of 1%.

ADVISER’S APPROVAL: Jim Puckette

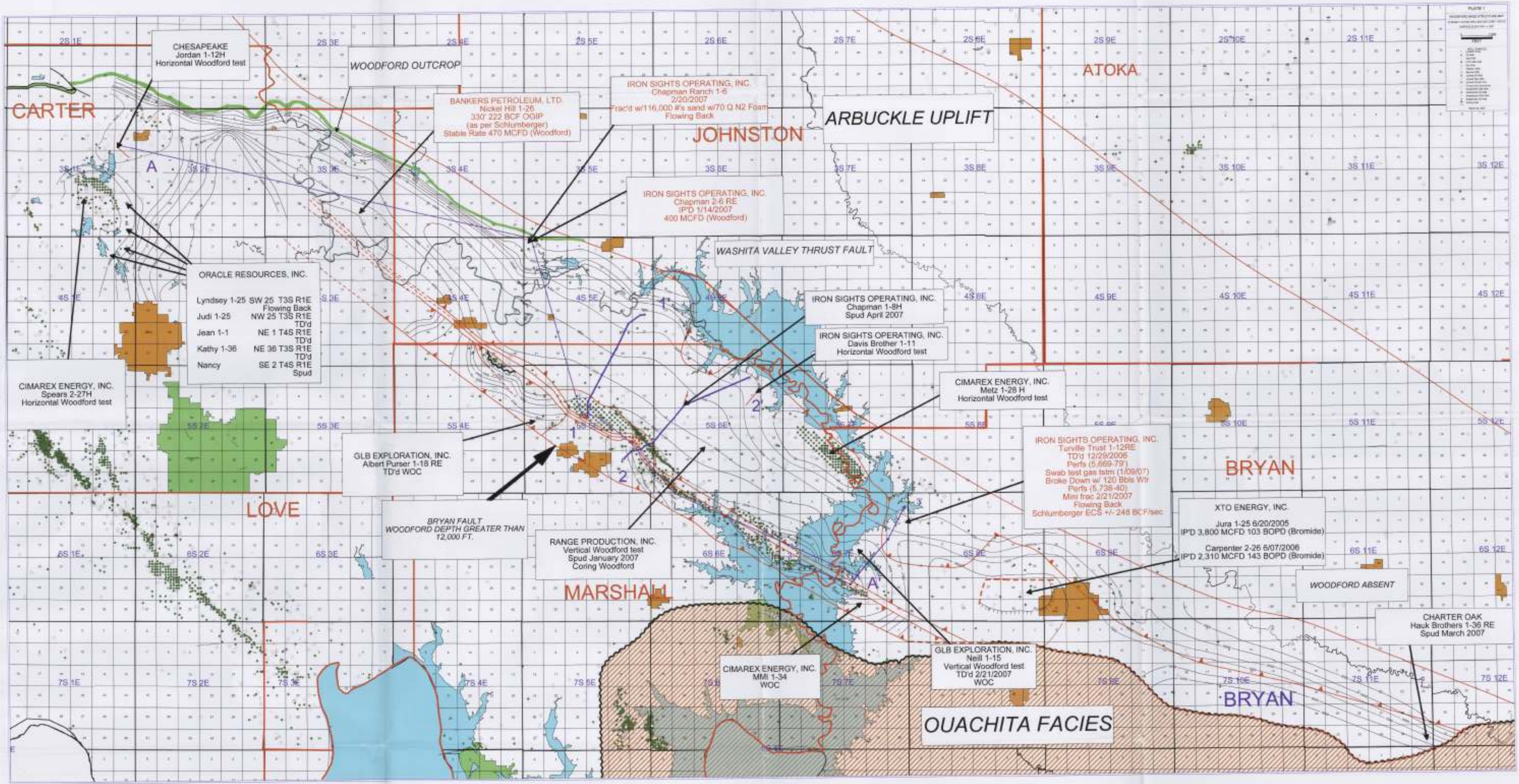
CARTER
JOHNSTON
ATOKA
LOVE
MARSHALL
BRYAN
BRYAN
ARBUCKLE UPLIFT
OUACHITA FACIES
WOODFORD OUTCROP
WASHITA VALLEY THRUST FAULT
WOODFORD ABSENT
A
A'
1
1'
2
2'
CHESAPEAKE
Jordan 1-12H
Horizontal Woodford test
BANKERS PETROLEUM, LTD.
Nickel Hill 1-26
330' 222 BCF OGIP
(as per Schlumberger)
Stable Rate 470 MCFD (Woodford)
IRON SIGHTS OPERATING, INC.
Chapman Ranch 1-6
2/20/2007
Frac'd w/116,000 #'s sand w/70 Q N2 Foam
Flowing Back
IRON SIGHTS OPERATING, INC.
Chapman 2-6 RE
IPD 1/14/2007
400 MCFD (Woodford)
ORACLE RESOURCES, INC.
Lyndsey 1-25 SW 25 T3S R1E Flowing Back
Judi 1-25 NW 25 T3S R1E TD'd
Jean 1-1 NE 1 T4S R1E TD'd
Kathy 1-36 NE 36 T3S R1E TD'd
Nancy SE 2 T4S R1E Spud
CIMAREX ENERGY, INC.
Speers 2-27H
Horizontal Woodford test
IRON SIGHTS OPERATING, INC.
Chapman 1-8H
Spud April 2007
IRON SIGHTS OPERATING, INC.
Davis Brother 1-11
Horizontal Woodford test
CIMAREX ENERGY, INC.
Metz 1-28 H
Horizontal Woodford test
GLB EXPLORATION, INC.
Albert Purser 1-18 RE
TD'd WOC
BRYAN FAULT
WOODFORD DEPTH GREATER THAN
12,000 FT.
RANGE PRODUCTION, INC.
Vertical Woodford test
Spud January 2007
Coring Woodford
IRON SIGHTS OPERATING, INC.
Turville Trust 1-12RE
TD'd 12/29/2006
Perfs (5,669-79')
Swab test gas tstm (1/09/07)
Broke Down w/ 120 Bbls Wtr
Perfs (5,738-40)
Mini frac 2/21/2007
Flowing Back
Schlumberger ECS +/- 248 BCF/sec
XTO ENERGY, INC.
Jura 1-25 6/20/2005
IP'D 3,800 MCFD 103 BOPD (Bromide)
Carpenter 2-26 6/07/2006
IP'D 2,310 MCFD 143 BOPD (Bromide)
CIMAREX ENERGY, INC.
MMI 1-34
WOC
GLB EXPLORATION, INC.
Neill 1-15
Vertical Woodford test
TD'd 2/21/2007
WOC
CHARTER OAK
Hauk Brothers 1-36 RE
Spud March 2007
2S 1E
2S 3E
2S 4E
2S 5E
2S 6E
2S 7E
2S 8E
2S 9E
2S 10E
2S 11E
3S 1E
3S 2E
3S 3E
3S 4E
3S 5E
3S 6E
3S 7E
3S 8E
3S 9E
3S 10E
3S 11E
3S 12E
4S 1E
4S 3E
4S 4E
4S 5E
4S 6E
4S 8E
4S 9E
4S 10E
4S 11E
4S 12E
5S 2E
5S 3E
5S 4E
5S 5E
5S 6E
5S 8E
5S 10E
5S 11E
5S 12E
6S 1E
6S 2E
6S 3E
6S 6E
6S 7E
6S 8E
6S 9E
6S 11E
6S 12E
7S 1E
7S 2E
7S 3E
7S 4E
7S 5E
7S 6E
7S 7E
7S 9E
7S 10E
7S 11E
7S 12E
PLATE 1

PLATE 2

Stratigraphic cross section

WOODFORD SHALE

18,000 Net Acres (300' shale)

ARDMORE BASIN, OKLAHOMA

'Woodford Only' Production

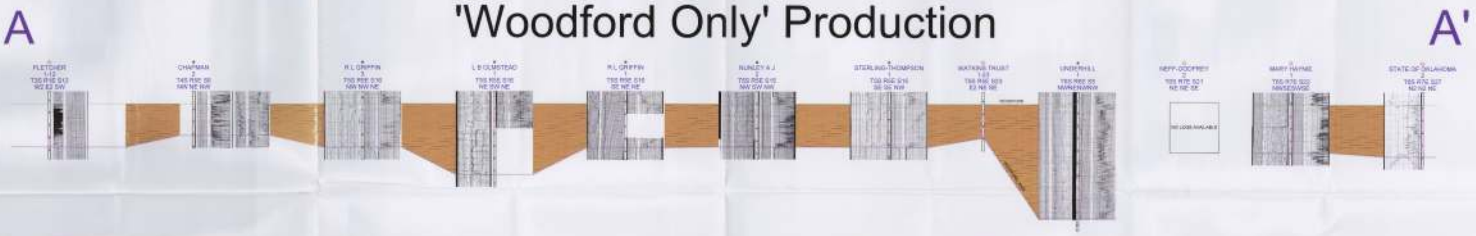

PLATE 5

Structural cross section

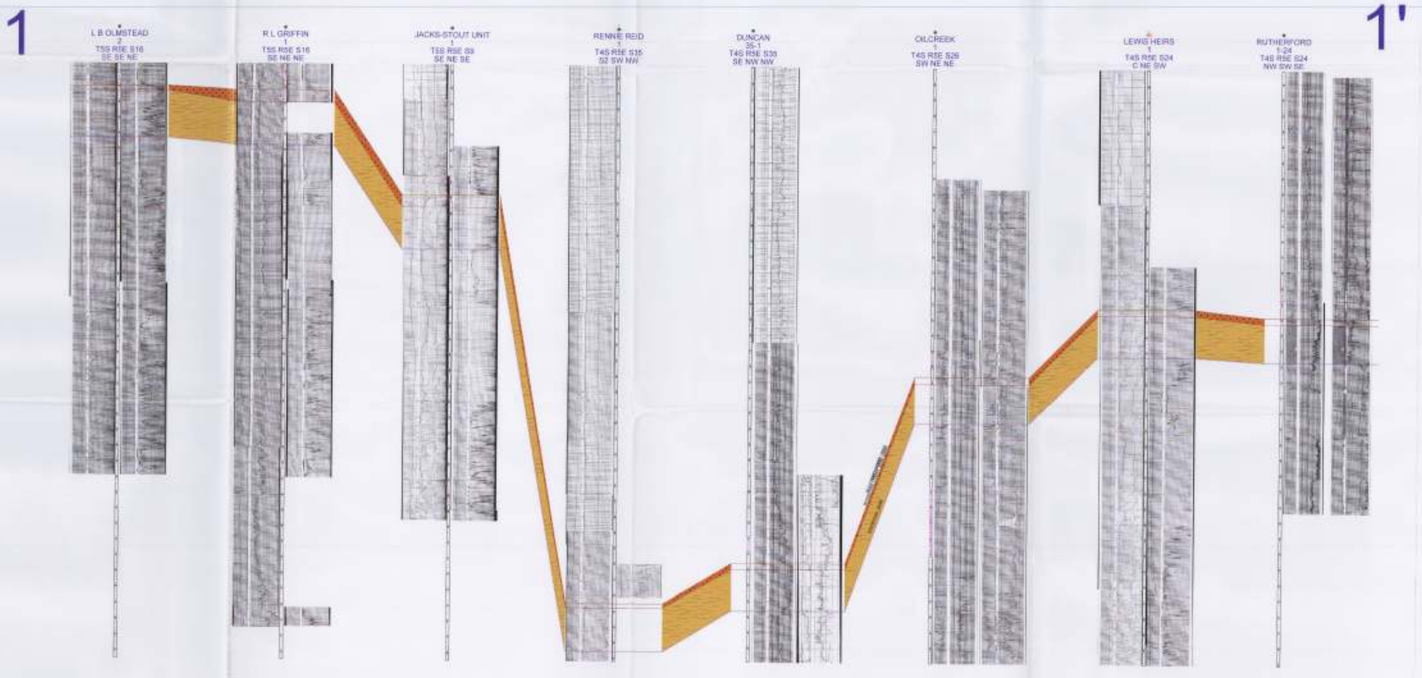

PLATE 4

Structural cross section