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RESERVOIR CHARACTERIZATION OF THE KIZLER NORTH FIELD, LYON CO., KANSAS, USA

MD NAHIDUL HASAN

Southern Illinois University Carbondale, nahidju13@gmail.com

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RESERVOIR CHARACTERIZATION OF THE KIZLER NORTH FIELD, LYON CO.,
KANSAS, USA

by

Md Nahidul Hasan

M.S., Jahangirnagar University, 2017

A Thesis
Submitted in Partial Fulfillment of the Requirements for the
Master of Science Degree

Department of Geology
in the Graduate School
Southern Illinois University Carbondale
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THESIS APPROVAL

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A Thesis Submitted in Partial
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for the Degree of
Master of Science
in the field of Geology

Approved by:

Dr. Sally L. Potter-McIntyre, Chair

Dr. Steven A. Tedesco

Dr. John L. Sexton

Graduate School
Southern Illinois University Carbondale
June 4, 2019

AN ABSTRACT OF THE THESIS OF

Md Nahidul Hasan, for the Master of Science degree in Geology, presented on June 4, 2019, at Southern Illinois University Carbondale.

TITLE: RESERVOIR CHARACTERIZATION OF THE KIZLER NORTH FIELD, LYON CO., KANSAS, USA.

MAJOR PROFESSOR: Dr. Sally L. Potter-McIntyre

The Kizler North Field is near the western flank of the Forest City Basin in Lyon Co., Kansas, USA and produces oil from the Hunton Formation, Viola Formation and Simpson Group reservoirs. The structure strikes NW through the field that is part of a larger wrench fault system. This modern prospect analysis of the Kizler North Field, aids in understanding the reservoir properties of the Hunton Formation, Viola Formation and Simpson Group rocks, the play mechanism of the field, and provides recommendations for additional drilling locations.

A detailed prospect evaluation using 2D seismic data and well log data from the Kizler North Field uses 1) Contour mapping of formations with public data from wells (~n=60), 2) Structural and stratigraphic analysis of 2D seismic data, and 3) Characterization of reservoir properties from well-log data from existing wells. Correlation of 2D seismic data with well data is used to visualize structures, to detect stratigraphic features, and to interpret seismic reflection patterns of the target horizons.

The Viola Formation and Simpson Group production is located at the apex of the anticlinal structure. However, time structure, isopach and isochron maps show that the Hunton Formation is significantly thinned across the axis of the anticline owing to erosion. The thinning of Hunton Formation in the structural top is also observed in the nearby analog Kizler and John Creek fields. Five wrench faults are identified in the study area, which are present only in the pre-

Mississippian Formations. Faults that do not extend far above the target formation are typically the best candidates because the faults have not breached the seal for the hydrocarbons. The trapping mechanism of this field is controlled by wrench faulting where traps are created by four-way closure at the apex of the anticline. Three potential drilling location are based on, 1) four-way closure with wrench fault trapping 2) structural highs in the Viola Formation and/or Simpson Group 3) Hunton Formation thickness 4) absence of fault beyond the reservoir formations.

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CHAPTER 1

INTRODUCTION

1.1 Area of Study

The Kizler North field is located in the Forest City Basin in the midcontinent of North America (Kansas). The field has produced 34388.27bbls oil from 1972 to 2018. The majority of production is from the Hunton Formation and the source rock is the Simpson Group. However, reservoir heterogeneity and migration pathways of this field are poorly understood. New exploration models are needed to discover the remaining petroleum potential in this area and provide characterization of underexplored reservoirs.

Geographically, the Kizler North field is in Township 16 South Range 10 East in the north-western part of Lyon County, Kansas. The field is near the western flank of the Forest City Basin and on the northern flank of the Bourbon Arch in Lyon County, Kansas (O'Connor, 1953). The purpose of this research project is to integrate geological, geophysical, and petrophysical interpretations to better understand the play mechanisms of this field. The major goal is to identify the best prospects of this field.

Figure 1.11: Aerial map of the Kizler North Field with the wells (modified from KGS website, 2018).

Figure 1.12: Base map of the Kizler North Field with the wells (modified from KGS website, 2018).

1.2 Regional Geology

1.2.1 Rock Units

The Forest City basin was originally both a structural and a topographic basin that did not come into existence until after the Mississippian (Figure 1.14). During the Pennsylvanian, the region was subject to deposition of marine and deltaic environments and thicker deposits accumulated in this basin than on the higher lands surrounding it (Lee, 1943). The extent and thickness of these deposits define the extent and depth of the basin (Lee, 1943). The stratigraphy

of the Kizler North Field is described below from older to younger along with their depositional environments (Figure 1.13).

Precambrian: The Precambrian rocks of Kansas consist mainly of granite, gneiss, and schist, but Landes et al. (1927) report wells that also penetrated basic igneous rocks, quartz porphyry, and quartzite. Precambrian rocks of Kansas and adjoining states consist of a complex composed principally of granite or granite gneiss or schist; locally the complex may contain other igneous and metamorphic rocks (Landes, 1927). Most of the samples of Precambrian rocks now available from wells that penetrated the Precambrian of northeastern Kansas are red granite and red quartzite.

Arbuckle Group: The Arbuckle Limestone was originally defined by Taff (1902) as including all the rocks from the top of the Reagan Sandstone (not present in this basin) up to the base of the Simpson Group. The Arbuckle Group rocks are part of the craton-wide Sauk Sequence, which is bounded at its base and top by major interregional unconformities (Sloss, 1949). These interregional unconformities represent major regressions of the sea and erosion and subaerial exposure of vast areas of the craton (Merriam, 1963). Cherty, buff to white, very coarsely crystalline dolomite makes up the Eminence Dolomite. The Gasconade Dolomite consists mainly of cherty, coarsely granular dolomite. In Kansas, the Roubidoux Formation consists mainly of sandy dolomite and fine-grained sandstone (Goebel, 1968). Deposition of the Roubidoux Formation seems to have been preceded by folding and erosion of older rocks. The Jefferson City Dolomite consist mainly of coarsely granular, cherty dolomite (Goebel, 1968).

Figure 1.13: Stratigraphy and play of the Kizler North Field (modified from Charpentier, 1995).

Simpson Group: The Simpson Group is the basal unit of a long-term oceanic inundation on the North American continent called the Tippecanoe transgression (Adler, 1971). Although the Simpson Group was probably deposited over most of the state, subsequent late Mississippian-early Pennsylvanian tectonic movement removed the Simpson Group over much of the Central Kansas uplift, the Nemaha uplift, and northwestern Kansas. The Simpson Group in Kansas is dominantly a sand-shale sequence with minor amounts of carbonate rock. The main reservoir rocks within the Simpson Group are light-gray, quartz-rich sheet sandstones sometimes called the St. Peter or Wilcox Sandstone (Goebel, 1968a). Shales in the Simpson Group are source rocks for the oil in the Forest City basin (Newell et al., 1985).

Viola Formation: Dolomitic limestones characterize the Viola Formation in south-central Kansas, but farther north in the Forest City and eastern Salina basins, it is almost all dolomite (Goebel, 1968a; Cole, 1975). It consists of dolomite and limestone strata containing some cherty beds characterized by black chert grains and spicular fragments of microorganisms (Lee, 1943). In deep parts of the North Kansas basin, the carbonate rocks of the Viola Formation are dominantly dolomite, but toward margins of the basin earthy and granular limestone beds are present (Lee, 1943). During the time period in which the Viola Formation was deposited, North America was located near the equator and an extensive epicontinental sea covered most of the continent (Barnes, 2004).

Maquoketa Formation: The Maquoketa Shale in Kansas is variable in character and thickness. It is roughly separable into an upper and a lower part, but each presents considerable lithologic variety. Throughout most of the area the upper zone is an impure dolomite which consist of loose aggregates of doloclastic siltstone and fine sand. Some spongy doloclastic shale

is also present. The lower part of the formation is much more argillaceous and consists for the most part of dolomitic slightly silty dark clay or clay shale (Newell et al., 1985).

Hunton Formation: Silurian and Devonian rocks in Kansas are a package of limestones and dolomites between the overlying Chattanooga Shale and underlying Maquoketa Shale. The dolomitic reservoir rock of the Hunton Formation varies from light-gray and dense to tan and sucrosic crystalline. The variations result from both original fabric and diagenetic recrystallization. Porosity is significantly increased by the presence of mm- to cm diameter vugs. The missing Lower Devonian strata in the Kansas represent a significant period of erosion or non-deposition in the rock record that is expressed by only a subtle unconformity (Lee, 1943, 1956; Merriam, 1963).

Chattanooga-Kinderhook Group: The Chattanooga-Kinderhook Group consists of limestone, dolomite, and shale. The Chattanooga Shale is a gray, greenish-gray, and red shale with minor limestones (Lee, 1956; Goebel, 1968b), but in southeast Kansas it is a black pyritiferous shale. Sandstones at or near the base of the Chattanooga Shale are not a major source of hydrocarbons in the midcontinent (Adler, 1971), but they can produce locally significant amounts of hydrocarbons. The Misener, occurring at the base of the Chattanooga Shale consists disseminated, rounded sand grains (Goebel, 1968b).

Mississippian Group: Mississippian rocks in Kansas can be divided into two general sequences. The Mississippian rock units are mainly limestone with some dolomite and some of the units contain chert beds (Merriam, 2010). The younger group of rocks is Chesterian and consists of marine and non-marine shales and sandstones with minor limestones. Unconformable below the Chesterian rocks is a group of shallow-marine limestones, cherts, and cherty limestones that are Kinderhookian, Osagian, and Meramecian (Goebel, 1968c). The

Kinderhookian, Osagian, and Meramecian limestones that underlie the Chesterian rocks in southwestern Kansas are present all over the state except where they have been removed by late Mississippian-early Pennsylvanian erosion over the Central Kansas uplift and parts of the Nemaha uplift (Goebel, 1968c). The thickness of the Mississippian rocks is largely dependent on structural movement that occurred during late Mississippian-early Pennsylvanian time (Goebel, 1968c, d)

Cherokee Group: The Cherokee Group is a succession of shale with lenticular sandstones, thin coals, and minor limestones (Zeller, 1968). The deposits are predominantly fluvial-deltaic, with minor terrestrial and open-marine rocks. The Cherokee Group was deposited on an extensive pre-Pennsylvanian erosion surface on the flanks and over the crests of the Central Kansas uplift where it locally pinches out (Goebel, 1968d). Lenticular sandstones occupy the lower Cherokee Group including those that fill valleys incised into the underlying strata, apparently cut by rivers directed off the Central Kansas uplift (Walters, 1953).

1.2.2 Basin Formation

The Phanerozoic tectonic pattern that controls sedimentation and diagenesis in Kansas is a direct reflection of its Precambrian history (Gerhard, 2004). Many cratonic structures are simply rejuvenation of pre-Panerozoic weakness planes (Carlson, 1999). The crystalline basement of the midcontinent of North America was fractured to form orthogonal crustal blocks by northeast- and northwest-oriented faults in latest Archean or Early Proterozoic time by north-south compressional strain (Sims, 1990; Baars et al. 1995). The entire North American craton was fractured by compressional strain collision and resultant wrench faulting during Proterozoic, prior to 1.2-Ga (Baars et al., 1995). The compressional stress field began to relax by 1.2 Ga, and extension and volcanic activity along the mid-continental rift system (MRS) slowly worked

southward from the Canadian Shield, ending in Kansas in latest Proterozoic time (Baars et al., 1995). Cooling and deformation of the rift by 1.2Ga permitted brittle fractures to develop (Schmus et al., 2003). The direction of the fractured blocks caused by compression and rifting is important in deciphering the events and the directional property of both structures and fracture/faults (Berendsen and Blair, 1986; Merriam, 2010). Precambrian wrench-fault-originated rhombic blocks are precursors to Phanerozoic structures (Marshak and Paulson, 1996).

Figure 1.14: Principal structural features of Kansas (modified after Leatherock, 1945).

During the Late Mississippian, the surface of the whole region was uplifted with gentle folding. The principal fold was the Nemaha anticline which extends across Kansas from southeastern Nebraska to central Oklahoma is a major pre-Desmoinesian post-Mississippian element (Lee, 1943). The exposed rocks were then subjected to erosion for such a long period that the surface was worn down nearly to sea level. The rocks were again deformed before the advance of the Pennsylvanian sea over the area (Lee, 1943). The beveled crest of the Nemaha anticline was re-elevated and formed the Forest City Basin in the adjacent depressed area.

The Nemaha ridge is a part of the Nemaha tectonic zone, a failed Precambrian rift within the Midcontinent Rift System. (Merriam, 1963; Johnson and Cardott, 1992; McBee, 1995). The Forest City basin and the Cherokee basin are generally coeval, but these basins were not developed in their final form until the rejuvenation of the Nemaha anticline in and the warping of the post-Mississippian peneplanation occurred (Lee, 1943).

1.2.3 Petroleum Systems

In the Kizler North Field, shales of the Ordovician Simpson Group are probably the most important source. In the deeper parts of the Forest City basin these Ordovician source rocks may have been mature by the Late Pennsylvanian or Permian (Charpentier, 1995). The dark, marine shales of the Pennsylvanian (especially Desmoinesian) cyclothems are also likely an important source (Charpentier, 1995).

The oil-bearing reservoirs are: The Middle Pennsylvanian Bartlesville shoestring sand in the Middle Pennsylvanian Cherokee Group, the Late Devonian Hunton Limestone, and the Ordovician Viola Limestone and Simpson Group (O'Connor, 1953; Merriam, 2010).

The reservoirs are related to a structural closure associated with the wrench fault system and reservoir dolomitization (Newell 1987). These wrench fault systems of this field are difficult to locate but very prolific (Tedesco, 2017).

The proposed play mechanism for the Kizler North Field is (Charpentier, 1995):-

Play: Pre-Woodford Paleozoic Play

Reservoirs: the Simpson Group (net pay 10ft), Hunton Formation (net pay 5ft) and Viola Formation (net pay 9ft).

Source rocks: Simpson Group TOC > 1.1wt%. Potential source rocks in the shales of the Simpson Group contains Type I and II kerogen.

1.3 History of the Kizler North Field

a. Production and existing wells

The boundary of Kizler North Field is Township 16S- Range 10E: ALL Section 3 East section 2 and 4, ALL Section 9. According to Kansas Geological Survey oil and gas well database, there were 14 wells drilled typically of 3000ft+ depth. The wells used for this study are described in this section. All the wells information below comes from “Written Geologic Report” of Running Foxes Petroleum Inc. and Kansas Geological Survey- Oil and Gas Well Database.

Figure 1.15: Kizler North Field boundary along with the wells (modified from KGS website, 2018).

Figure 1.16: Production charts of the Kizler North Field (created from data of KGS website, 2018).

Triemer 9-14 Well: Triemer 9-14 well is located in T16S R10E, Sec. 9, SE NW SE SW in Lyon County operated by Running Foxes Petroleum Inc. This well was spudded in January 7, 2014 and drilled to 3263ft. The producing zones of this well is Hunton Formation and Simpson Group (KGS database, 2018).

The Hunton Formation between the depths of 3050 to 3054ft shows excellent oil. This unit consists tan-cream dolomite, large rhombohedra crystals, fair porosity, excellent live saturation, and strong odor, dull fluorescence, excellent cut, oil floating in cup. The Viola Formation shows excellent odor but was judged not worthy of further testing due to asphaltic nature. The Upper St. Peter Sandstone of the Simpson Group showed fair visible porosity, strong pungent odor, dull fluorescence, excellent cut over all samples, oil floating in cut, some dead oil lining porosity (KGS database, 2018).

Figure 1.17: Production charts of Triemer #9-14 well of Kizler North Field (created from data of KGS website, 2018).

Kerr 9-12: Kerr 9-12 is located in T16S R10E, Sec. 9, N2 NE NW SW in Lyon County operated by Running Foxes Petroleum Inc. This well was spudded in January 14, 2014 and drilled to 3327ft. The Hunton Formation at 3002-3008ft in this well shows fair oil. This unit consists tan-cream dolomite, large rhombohedral crystals, fair-poor porosity, spotty live saturation, fair odor and dull fluorescence. Overall poor shows in Simpson Group were judged not worthy of further testing. Currently, treated brine and water is injected in the Arbuckle Formation at an approximate rate of 3000 barrels/day. No production data is available for this well (KGS database, 2018).

Triemer 14-2 Well: Triemer 14-2 is located in T16S R10E, Sec. 14, SW SW NW NE in Lyon County is operated by Running Foxes Petroleum Inc. This well was spudded in December 16, 2013 and drilled to 3368ft. The producing zones of this well is the Simpson Group. No shows of oil or gas in the Hunton and Viola Formations. The Simpson Group (3313-27ft) consists 90% dolomite, tan-brown-cream color, hard, sugary texture, medium sand grains, vuggy porosity, and

good oil odor. This prospect has been enclosed by drilling on a 40acre spacing, which has proven that the Simpson target is small in area, or extremely narrow (KGS database, 2018)

b. Analog fields: Description and Isopach maps of Kizler and John Creek Field

Kizler Field: The boundary of Kizler Field is- Township 16S- Range 10E Section 16 and 21 (Figure 1.15). This field was discovered in January 1, 1969. The reported producing zone is Simpson Group (3292ft). According to Kansas Geological Survey oil and gas well database, there were 13 wells drilled typically of 3200+ft depth (KGS database, 2018).

Figure 1.18: Production charts of the Kizler Field (created from data of KGS website, 2018).

John Creek Field: The boundary of John Creek field is- Township 15S- Range 9E: Section 22-27, 34, 35 and Township 16S- Range 9E Sec 2, 3 (Figure 1.15). John Creek Field was discovered in December 8, 1953. The reported producing zone is the Viola Formation. According to Kansas Geological Survey oil and gas well database, there were 119 wells drilled typically of 3000+ft depth (KGS Database, 2018).

Figure 1.19: Production charts of the John Creek Field (created from data of KGS website, 2018).

CHAPTER 2

METHODOLOGY

This section explains the detailed methods of local geology, seismic interpretation, and petrophysical interpretation used to specifically answer the proposed research questions. The main research question is: what are the best prospects for this field? I have used three methods to answer this question: 1. An interpretation of the local geology using ArcGIS 10.6 software, 2. Seismic interpretation using Petrel Software, and 3. Petrophysical Interpretation using Interactive Petrophysics software (Figure 2.11). This chapter is split into three sections with detailed workflows for each of the software packages.

Figure 2.11: Flowchart showing the methods and techniques that will be used for this research.

1. Local Geology: To characterize the local geology, maps and isopach maps of major rock units were produced by ArcGIS 10.6 software.

- a) Well tops information was collected from Kansas Geological Survey Database of the study area and an Excel file was created with formation thickness. Approximately well tops from 60 wells were collected for the following formations: Simpson Group, Maquoketa Formation, Viola Formation, Hunton Formation, Chattanooga-Kinderhook Group, Mississippian Group and Cherokee Group.

- b) The excel files were loaded in the correct geographic coordinate system (NAD 1927 14N).
- c) The Geographic Coordinate System were changed to Projected Coordinate System (UTM) using the “Project” tool in ArcGIS 10.6.
- d) The “Spatial Analysis => Topo to Raster interpolation” tool was used to create raster data surface.
- e) The “Contour” tool was used to create isopach maps, i.e., contour map of formation thicknesses.
- f) Public Land Survey System (PLSS) grids were overlaid on the isopach maps using the shape files from United States Geological Survey website and the required map elements (scale, legend, north arrow, well spots) were added.

2. Seismic Interpretation: To characterize the structural configuration, time structure maps and isochron maps were produced using Petrel software.

- a) Data loading: All of the available seismic lines (Figure 2.12) were imported into Petrel in the SEG-Y format. The seismic lines were loaded in time domain, with the proper coordinate system (NAD 1927 14N). For importing, the “EBSIDIC and Binary headers” format was used for the line detection method. The data loading parameters were overridden using the information (line number, line number format, common depth point number) from the trace headers. A new seismic survey folder was created in Petrel to store the lines. The available three wells were then loaded in a well folder along with their associated formation tops and well log data.

Figure 2.12: Available 2D seismic lines of the study area.

- b) Data Conditioning: The “Remove Bias” attribute was applied to all the seismic lines. This attribute was used to remove the DC bias from the seismic traces. DC bias occurs when the average of the trace values departs from zero and typically caused by processing

artifacts (Farfour and Yoon, 2015). Both 2D and 3D windows were used in combination with the interpretation window for seismic interpretation.

- c) **Synthetic Seismogram Generation and Matching:** Synthetic seismogram is a seismic trace created from well logs, and it is used to compare the original seismic data collected near the well location (Onajite, 2014). Two synthetic seismograms (Figure 2.13) were generated using the depth shifted well log data for Kerr #9-12 and Triemer #14-2 wells using “Seismic to well tie” module in Petrel. Triemer #9-14 well was excluded because there were no intersecting seismic lines with this well. While generating synthetic seismogram, it is not recommended to use Ricker wavelet because it makes certain assumptions about power spectrum and phase (minimum/zero) of the wavelet (Hosken, 1988). In this study, a statistical extracted wavelet from the intersecting seismic lines was used to generate the synthetic seismograms.

Velocity (sonic) and density logs were used to compute an impedance log for the wells. Reflection coefficients (RC) at the step changes were calculated. Multiplication of reflection coefficient with extracted wavelets from seismic data gives the synthetic seismogram for a well.

$$\text{Velocity} \times \text{Density} = \text{Acoustic Impedance}$$

Then, RC was computed for the reflecting interfaces which is the difference in acoustic impedance between stratigraphic layers divided by their sum. Then RC was convolved with the source wavelet to produce synthetic seismogram. (Onajite, 2014)

$$\text{RC} * \text{Wavelet} = \text{Synthetic Seismogram}$$

After a synthetic seismogram is generated, it was matched to the seismic data. The synthetic seismogram is bulk shifted to get the best matching between the synthetic seismogram and the seismic trace.

Figure 2.13: Synthetic seismogram created using sonic and density log of Kerr #9-12 well.

Wavelet extracted from Seismic line K2, 12ms bulk shifted.

- d) Stratigraphic tops were correlated to seismic horizon for the major identifiable formations using synthetic seismogram generated from sonic and density logs.
- e) Seismic Horizon Picking- Seismic horizons were picked following peak-to-peak or trough-to-trough using “Manual Picking” tool.
- f) Faults were mapped in the five 2D seismic lines using “Fault Mapping” tool in Petrel.

- g) Time structure maps were generated (a structure map where values are in two-way seismic travel time, not having been converted to depth) of the major formations to see the structural pattern using “Surface” tool in Petrel. The time structure maps were created using 1ms (milliseconds) contour interval.
- h) Isochron maps (a contour map that displays the variation in time between two seismic events or reflections) were created using “Calculation =>Make thickness map” tool from “Surface Settings”.
- i) Time structure and isochron maps show two-way travel time (TWTT) to the picked horizon. The thickness is approximated using 1ms= 6ft in the isochron maps. In this research, time structure and isochron maps were not converted into depth because check shot or Vertical Sounding Profile (VSP) data is unavailable for the study area.
- j) Public Land Survey System (PLSS) grids were overlaid on the isopach maps and required map elements (scale, legend, north arrow, well spots) were added.

3. Trap Characterization: The main reservoirs in the field are the Hunton Formation, Viola Formation and Simpson Group. Using seismic data, I interpret whether the traps are structural, stratigraphic, or both by identifying the structural and stratigraphic pattern of the major formations using the isopach and isochron maps.

4. Petrophysical Interpretation: Using petrophysical data, attributes of the producing formations were determined (shale volume, water saturation, hydrocarbon saturation, effective porosity, total porosity, water resistivity and lithology) using Interactive Petrophysics software.

- a) Data of the three wells were loaded into new database in Interactive Petrophysics (IP) software.

b) Data Conditioning: Because of wellbore instability, tool anomalies, and random error, subsurface data must be corrected for any extraneous and/or erroneous values (Smith, 2011). In order to provide a robust petrophysical analysis, this study incorporates two data-conditioning techniques used to organize, examine, and in some cases, rectify raw well-log data.

- I. Log mnemonic Standardization: Individual well logs are designated by company mnemonics rather than names. This task was accomplished by examining each well header to determine the correct logs to be incorporated from each well and renaming them for standardization.
- II. Log editing: The caliper log shows flushed zone above the Mississippian Group but no significant wellbore instability below that. For that reason, it was not necessary to perform log editing and well log normalization to remove extraneous data commonly generated for the reason of flushed zones in the wellbore.
- III. Depth Shifting: Wellbore instabilities and/or wash-out can create depth discrepancies in the well logs (Hearst and Nelson, 1985). During data acquisition, wireline tools may become stuck against the wellbore wall, causing the logging cable to stretch. Cable stretch results in inaccurate positional data (Zangwill, 1982). It is important to acknowledge this issue to achieve meaningful petrophysical calculations at depth. In order to rectify the errors due to cable tension, all well logs in this study were depth shifted to a pre-determined standard: the gamma ray log (Figure 2.14). The gamma ray log was chosen as the depth standard because it is often used to locate perforation

intervals during well completion and stimulation operations (Hillier, 2015).

Using the interactive depth shift module in IP, individual curves were overlain on the gamma ray curve (Figure 2.24). Using knowledge of the stratigraphy, each curve was scaled to represent diagnostic deflections across all well logs for each well. If discrepancies were present, individual logs were squeezed and stretched between chosen deflections points on the gamma ray curve and the corresponding shift curve.

Table 2.10: Nomenclature of well logs used in this study.

Logging Tool	Operational Mnemonics				
	Baker Hughes	Halliburton	Schlumberger	Weatherford	This Study
Bulk Density	ZDEN	RHOB	RHOZ	RHOB	RHOB
Caliper	CALX	CALI	HCAL	CALI	CALD
Compressional Sonic	DT24	BCS	SLT	CPSL	DT
Deep Lateral Resistivity	RD	LLD	RLA5	RLLD	ILD
Density Correction	ZCOR	DRHO	HDRA	DRHO	DRHO
Neutron Porosity	CNC	NPHI	TNPH	NPHI	NPLS
Photoelectric Effect	PE	PE	HPEFZ	PEF	PE
Shallow Resistivity	RS	LLS	RLA1	RLLS	SFL
Total Gamma Ray	GR	GR	HGR	GR	GR

IV. Formation Top Identification: Formation tops attained from the mud-logging of the well were loaded. Formation tops were determined by comparing gamma ray fluctuations with known lithologies (Figure -2.14). This step was performed on each well.

- c) Data Visualization: Well log data for each well were arranged in a standard pattern to observe the crossovers and interpret the characteristics of the wellbore, porosity and lithology (Figure 2.15). A four-track blank plot was launched, and depth was loaded in the first track. Caliper and gamma-ray logs were loaded in the second track. Variable shading was used to see the gamma response throughout the well to help interpret the lithologies. The caliper log was used to interpret wellbore stability. The serrated deflections in the caliper log indicates wellbore instabilities and/or wash-out. The neutron and density logs (proxies for porosity) were loaded on the third track. The yellow shading represents density/neutron crossover which indicates presence of gas. Track four is the resistivity track where lime color represents deep/shallow resistivity crossover which indicates presence of hydrocarbon.

Figure 2.14: Depth-shifting module in Interactive Petrophysics™. The gamma ray log is presented in all tracks (green curve). Additionally, depth, deep resistivity, neutron porosity, bulk density and shallow resistivity logs are presented in tracks one through five (Well Triemer #9-14).

Figure 2.15: Depth-shifted data loaded in the tracks of Triemer #9-14 well. Depth in the first track, gamma and caliper log in the second track, neutron and density log in the third track (yellow represents density/neutron crossover which indicates presence of gas), and resistivity logs in the fourth one (lime represents shallow/deep resistivity crossover which indicates presence of hydrocarbon).

d) Petrophysical Parameters Calculation: Well logs of the three wells were used to evaluate and analyze the petrophysical properties of shale volume (Vsh), water saturation (Sw), hydrocarbon saturation (Sh), effective porosity (PHIE), total porosity (PHIT) and water resistivity (Rw). The methodology for evaluation of these properties is detailed below. The Hunton Formation, Viola Formation and Simpson Group were targeted for these parameters because these three formations are the only reported producing reservoirs in the nearby fields.

I. The purpose of shale volume (Vsh) calculation is to determine the lithology of the rock. It is an important step in the formation evaluation because the existence of shale in the formation reduces the effective porosity and permeability of the reservoir (Ruhovets and Fertl, 1982). The presence of clay minerals can also cause log-derived water saturation and porosities to be erroneous because of the presence of hydroxyls within the clay crystal lattice and/or interstitial water between phyllosilicate layers which can cause porosity logs to overestimate the total porosity (Asquith and Krygowski, 2004). Vsh for this study were calculated using the “Shale volume calculation” module in IP software. The gamma-ray logs were selected as the input curve. Equations from the IP clay module:

$$V_{sh} = \frac{GR - GR_{clean}}{GR_{clay} - GR_{clean}}$$

Where, GR = Gamma Ray Log

GR_{clay} = Gamma Ray Log in shale zone

GR_{clean} = Gamma Ray Log in clean sand zone

II. Water Saturation and Porosity: In this step, compositional and fluid constituents are calculated for each of the well (i.e., porosity, water saturation, and hydrocarbon saturation). Using the Water Saturation module in IP, Archie's equation was selected for calculating the water saturation in this study. Neutron, density, sonic, deep resistivity, shallow resistivity, Vsh, and temperature gradient were the selected input curves. Chosen inputs for Archie's cementation exponent (m) =2, saturation exponent (n) =2, and tortuosity component (a) =1 because these values are typically used for carbonate rocks (Archie, 1952). The initial porosity model was the neutron density model. The principal output curves were total porosity (PHIT), effective porosity (PHIE) and water saturation (Sw). Dolomite has been used as the main lithology shading because the Hunton Formation, Viola Formation and Simpson Group are primarily dolomitic.

Archie Equation:

$$S_w = \left(\frac{a \cdot R_w}{R_t \cdot PHIE^m} \right)^{\frac{1}{n}}$$

Where, Sw= Water Saturation

m= cementation exponent

n=saturation exponent

a= tortuosity component

Rw= Water resistivity

PHIE= Effective Porosity

III. Pickett plots (Figure 3.35A) were used to determine water resistivity (R_w) and update Archie's water saturation parameters using porosity/resistivity crossplot (Pickett, 1973). The Pickett crossplot in IP incorporates porosity, deep resistivity and Archie's parameters on a log plot. After the initial run, the water bearing line ($S_w=1$) was plotted along the southwest edge of the data points (Asquith and Krygowski, 2004). Once the water bearing line is established, the slope of the line determines the value of the cementation factor (m). Using a tortuosity (a) value of one, the water-bearing line was extrapolated to intersect the y-axis of the Pickett plot. This intersection gives the value of water resistivity (R_w).

IV. RHOMA-Umaa mineral composition plots (Figure 3.35B) were configured for each of the formations where RHOMA is apparent density of mineral matrix and Umaa is bulk photoelectric absorption of the mineral matrix.

RHOMA/Umaa plot helps to interpret the lithology of the target zones.

Equation Used: $U_{maa} = (RHOB * PE - PHIT * U_{fluid}) / (1 - PHIT)$

e) Cutoff and Summations: The final step in formation evaluation is to identify the zones of interest based on volume of shale (V_{sh}), effective porosity ($PHIE$) and water saturation (S_w) parameters (Figure 2.16). This is accomplished by assigning cutoff values to these play controlling parameters (Brooks and Montolvo, 2012) and calculating curve statistics across each zone of interest. The two types of zone identification procedures are discussed below: "Pay Flag" and "Reservoir Flag."

I. Reservoir Flags: Reservoir flags were calculated by assigning static cutoff values to effective porosity, and shale volume curves. Reservoir flags were

assigned to intervals with the following criteria: effective porosity values above 9% and shale volumes below 65%. The 50-percentile (P50) cutoff sensitivity values of PHIE and Vsh were used, obtained using the Cutoff Sensitivity module in IP. The mean cutoff (P50) is selected which incorporates both the optimistic (P90) and the pessimistic (P10) one.

- II. Pay Flags: Pay flags were calculated the same way as reservoir flags. The main difference between the two flags is the static cutoff value assigned to water saturation to eliminate water-filled reservoirs and highlight hydrocarbon reservoirs. Water saturation values were set to 50% as cut off. All other parameters were kept constant between both flags. Within the cutoff and summation module, the above petrophysical flags were used to calculate hydrocarbon pore thickness (PhiSoH), also known as hydrocarbon pore volume for each of the target formation. PhiSoH is used for original oil in place (OOIP) calculation and as a scale to define “reservoir potential.”

Hydrocarbon Pore Thickness: $\text{PhiSoH} = \text{PHIT} * (1 - S_w) * H$

Where, PHIT= Total Porosity

S_w = water saturation

H= Reservoir thickness

Figure 2.16: Effective porosity cutoff derived using cutoff sensitivity module.

- f) The final plot (Figure 3.36, 3.37, 3.38) consists of eight tracks for each of the wells in this study. Track one contains the depth and caliper-log data. The diameter of the wellbore was represented by mirror display of caliper log data. Corrected formation tops were loaded in the second track. Caliper and gamma-ray logs were loaded in the correlation track. Variable shading was used to see the gamma response throughout the well to interpret lithology. Deep and shallow resistivity curves were loaded in the resistivity track. Lime color shading represents deep/shallow resistivity crossover. The shaded area represents higher resistivity which is generally caused by the presence of hydrocarbon or low porosity. The fifth track is the porosity track. Sonic, density, and neutron logs were loaded in this track. Yellow shading represents the density/neutron crossover. Within the hydrocarbon zone, the separation of these curves varies depending on the type of fluid encountered; therefore, the yellow shading highlights areas of hydrocarbon or high porosity. Track six is the lithology track. The volume of dry clay (VDCL), total porosity (PHIT), shale volume (Vsh) curves were loaded in this track. The white color shading on the right side of the total porosity curves represents total porosity. The left side of the VDCL curve is shaded as dry clay, and the remaining lithology is identified as dolomite.

Track seven represents the saturation parameters. The water saturation curve and reservoir flag were loaded in this track. Water saturation below 50% is green as this is designated the reservoir and pay cutoff. The reservoir flags were shown on the right side of the track. The parameters were: $PHIE > 9\%$ and $Vsh < 65\%$. Track eight represents the fluid parameters. Total porosity (PHIT), effective porosity (PHIE), bound-water volume (BVW) curves were loaded. The BVW is shaded as light cyan color. The area between the BVW and PHIE curve indicates hydrocarbon which is shaded as lime color. The pay flags were shown on the left side of the track. The parameters were: $PHIE > 9\%$, $Sw < 50\%$ and $Vsh < 65\%$.

- g) Multi-well cross-section was drawn to observe the change in formation thickness across all the three wells. Rocks younger than Pennsylvanian Lenapah Formation is excluded from the correlation because all of the targets are older.

Deliverables:

- One isopach map of each major formations throughout the field as well as for the nearby Kizler and John Creek Field.
- 2D seismic interpretation of the major structures, the target reservoir, and the major traps. Time structure maps of the major formation and isochron maps.
- Shale volume, water saturation, hydrocarbon saturation, effective porosity, total porosity, water resistivity values for the producing units.
- Recommendations for additional drilling locations.

CHAPTER 3

RESULTS

3.1 LOCAL GEOLOGY

3.1.1 Isopach Maps of the Study Area

The isopach maps of the major formations created from the collected well tops are given below.

Figure 3.10 is an isopach map of Viola Formation created using 25 wells tops from Kizler North and nearby fields. The thickness of this formation ranges from 18ft to 269ft. The formation is thickest in the western central part of the study area and thins gradually to the east.

Interestingly, the other formations do not follow this sedimentation pattern. The overlying Maquoketa Formation is thickest over the two same thick spots as the Viola Formation; however, it thins dramatically to the south-western part of the study area. The thickness of this Maquoketa Formation ranges from 6ft to 101ft. Generally, most of the area shows Maquoketa Formation thickness greater than 77ft (Figure 3.12).

Figure 3.12 is an isopach map of Hunton Formation created using 59 wells tops from Kizler North and nearby fields. The thickness of this formation ranges from 10ft to 141ft. Generally, most of the area shows formation thickness less than 50ft. Considerable thickness increasing is observed in the north-western corner of the field. Interestingly, the Hunton Formation in the study area thins at the apex of the anticline. The other formations do not follow this pattern.

The thickness of Chattanooga-Kinderhook Group ranges from 34ft to 189ft. Generally, formation thickness is around 131ft. Two closed contours are observed in the eastern and northern part of the area. The closed contours are not observed in the isopach maps of other

formations. The thickness of Mississippian Group ranges from 215ft to 379ft. Generally, formation thickness increases from west to east. Figure 3.13 is an isopach map of Cherokee Group created using 30 wells tops from Kizler North and nearby fields. The thickness of this formation ranges from 249ft to 461ft. Generally, formation thickness is highest in the centroid of the map and thin gradually to the east and west. The closed contour in the centroid shows high formation thickness in the anticlinal apex whereas reverse in the western one.

Figure 3.10: Isopach Map of Viola Formation of the study area. Green dots are well with data.

Figure 3.11: Isopach Map of Maquoketa Formation of the study area. Green dots are well with data.

Isopach Map of Hunton Formation of the study area

Figure 3.12: Isopach Map of Hunton Formation of the study area. Green dots are well with data.

Figure 3.13: Isopach Map of Cherokee Group of the study area. Green dots are well with data.

Figure 3.14: Cross-section along the northeast-southwest direction of Kizler North Field.

Figure 3.15: Cross-section along the northwest-southeast direction of Kizler North Field.

3.1.2 Isopach Maps of the Kizler Field

Figure 3.16 is an isopach map of Viola Formation created using all wells tops from the Kizler Field. The thickness of this formation ranges from 81ft to 90ft. The formation is thickest in the central part of the field. The Viola Formation is thickest in the axis of the anticline. The overlying Maquoketa Formation is thickest over the same spot. The thickness of this formation ranges from 63ft to 74ft. Generally, formation thickness increases from north to south.

Figure 3.18 is an isopach map of the Hunton Formation created using all wells tops from the Kizler Field. The thickness of this formation ranges from 17ft to 30ft. The formation thickness is lowest over the spot where the Viola Formation and Maquoketa Formation is highest. The Hunton Formation is thickest at the flank of the anticline. The thickness of Chattanooga-Kinderhook Group ranges from 141ft to 145ft. Generally, formation thickness does not vary that much. The thickness of Mississippian Group ranges from 312ft to 371ft. The group is thickest in the northern part and gradually thins in the southern part of the field.

Figure 3.16: Isopach Map of Viola Formation of the Kizler Field. Green dots are well with data.

Figure 3.17: Isopach Map of Maquoketa Formation of the Kizler. Green dots are well with data.

Figure 3.18: Isopach Map of the Hunton Formation of the Kizler Field. Green dots are well with data.

3.1.3 Isopach Maps of the John Creek Field

Figure 3.19 is an isopach map of Maquoketa Formation created using 28 wells tops from the John Creek Field. The thickness of this formation ranges from 65ft to 90ft. The formation thickness is highest in the central part of the John Creek field. Four closed contours representing anticlinal structure are observed. The formation is thickest in the structural top. The Maquoketa Formation thickness decreases in the northern part of the field. Figure 3.20 is an isopach map of Hunton Formation created using 27 wells tops from John Creek Field. The thickness of this formation ranges from 63ft to 145ft. Generally, formation thickness is below 94ft for most of the area. The Hunton Formation is thinnest in the axis of the anticline which is also observed in the isopach maps of the Kizler Field.

The thickness of the Chattanooga-Kinderhook Group ranges from 92ft to 181ft. Generally, the group thickness is highest in the closed contours. The thickness of the Mississippian Group ranges from 214ft to 306ft. The formation thickness is typically lowest in the centroid of the field and thickens in the north-eastern part.

Figure 3.19: Isopach Map of Maquoketa Formation of the John Creek Field. Green dots are well with data.

Figure 3.20: Isopach Map of Hunton Formation of the John Creek Field. Green dots are well with data.

3.2 SEISMIC RESULTS

The focus of this section is the structural interpretation of the Kizler North Field using available 2D seismic data. The picked reflectors were Heebner Formation top, Lansing Formation top, Kansas City Formation top, Cherokee Group top, Mississippian Group top, Kinderhook Group top, Hunton Formation top, Viola Formation top, Simpson Group top and Precambrian top.

Five major en echelon wrench faults are present in the study area. The faults strike northwest, antithetical to the Nemaha anticline. The seismic lines show the major faults and some of these faults display a change in dip direction during the Kinderhook (Figure 3.21, 3.22) and another change in dip direction during the Mississippian (Figure 3.24, 3.25). Most of the faults are sub-vertical and the late stage dip directions are to the S or SW at angles of $\sim 60^\circ$. The sense of slip is sinistral in the southern part of the field and slightly dextral in the north. All the faults identified in the seismic section are sub-vertical. Two of the faults (second and third from the south) exhibit flower structures with two branches each. The centers of these flower structures are downthrown. The identified five wrench faults are present in all pre-Mississippian Formations to Precambrian basement. Among the five wrench faults, two are present at a very small scale in the Mississippian Group, and one is prominent (Figure 3.26). The Heebner Formation, Lansing Formation, Kansas City Formation and Cherokee Group lack wrench faulting. Only two fault sticks among twenty-five go beyond Mississippian and identified in one seismic section only. As, not identified in other sections, possibly they are very small-scale fractures caused by the basement reactivation. The structural trend of the interpreted faults from the seismic sections is northwest.

Figure 3.27 is a time structure map of the Hunton Formation. Two closed contours are observed in the central part of the map. Similar to the isopach maps of the Kizler and John Creek fields, the isochron map of the Hunton Formation shows highest formation thickness in the flanks of the anticline and lowest in the axis. The Hunton Formation shows two closed contours in the time structure map. In the time structure map of the top of the Viola Formation, two closed contour features strike northwest in the central part of the map over the same two spots as the Hunton Formation (Figure 3.28). However, the formation thickness is highest at the axis of the anticline, unlike the Hunton Formation. The time structure maps of the Simpson Group and Precambrian basement follow the same structural pattern as Viola Formation (Figure 3.29 & 3.3).

Figure 3.21: Detailed horizon and fault interpretation of W-E line K1.

Figure 3.22: Detailed horizon and fault interpretation of W-E line K2.

Figure 3.23: Detailed horizon and fault interpretation of SW-NE line K3.

Figure 3.25: Detailed horizon and fault interpretation of N-S line K5.

Figure 3.26: Kizler North 2D Mississippian Group time structure map, Contour interval=1ms or approximately 6 ft.

Figure 3.27: Kizler North 2D Hunton Formation time structure map, Contour interval=1ms or approximately 6 ft.

Figure 3.28: Kizler North 2D Viola Formation time structure map, Contour interval=1ms or approximately 6 ft.

Figure 3.29: Kizler North 2D Simpson Group time structure map, Contour interval=1ms or approximately 6 ft.

Figure 3.30: Kizler North 2D Precambrian time structure map, Contour interval=1ms or approximately 6 ft.

Figure 3.31: Kizler North 2D Hunton-Viola isochron map, Contour interval=1ms or approximately 6 ft.

Figure 3.32: Kizler North 2D Hunton-Simpson isochron map, Contour interval=1ms or approximately 6 ft.

Figure 3.33: Kizler North 2D Viola-Simpson isochron map, Contour interval=1ms or approximately 6 ft.

3.3 FORMATION EVALUATION

The focus of this section is the petrophysical characterization of three wells in the Kizler North Field to determine shale volume, water saturation, hydrocarbon saturation, effective porosity, total porosity, water resistivity and lithology. These properties are then used to identify the target reservoir and pay zones in the study area. Below are the results of the petrophysical interpretation.

Overall, the Hunton Formation shows five feet of net pay at Triemer #9-14 but has a high water saturation in Kerr #9-12. The Viola Formation shows approximately nine feet of pay zones in Triemer #9-14 and Kerr #9-12 wells. A correlation of the pay zones from each well across the field is shown in Figure 3.39.

Well Triemer #9-14: The Hunton Formation has two pay zones with 5ft of net pay (Figure 3.36). The Hunton Formation is primarily dolomite with 35% (avg.) Vshale, an effective porosity of 11.7% (avg.) and a water saturation of 51.9% (avg.). The Viola Formation has three pay zones within it with 9ft of net pay. The Viola Formation is primarily dolomite with 9% (avg.) Vshale, an effective porosity of 10.9% (avg.) and a water saturation of 49.9% (avg.). The Simpson Group has three pay zones within it with 7ft of net pay. The Simpson Group is primarily dolomite with 22% (avg.) Vshale, has an effective porosity of 10.7% (avg.) and a water saturation of 34.6% (avg.). Currently, the well is producing from the Hunton Formation. The Viola Formation is not in production due to asphaltic nature of petroleum fluids (KGS Database, 2019).

Well Kerr #9-12: The reservoir zones of Hunton Formation have high water saturation (64.1% avg.) hence no pay zone. The Hunton Formation is primarily dolomite with 35% (avg.) Vshale, an effective porosity of 12.2% (avg.). The Viola Formation does not have any pay zone

because of high water saturation too (Figure 3.37). The Viola Formation is primarily dolomite with 9% (avg.) Vshale, an effective porosity of 10.5% (avg.) and a water saturation of 60.1% (avg.). The Simpson Shale has one pay zones with 3ft of net pay. The Simpson Group consists of dolomite with 5% (avg.) Vshale, has an effective porosity of 11.5% (avg.) and a water saturation of 67.5% (avg.). The St. Peters Sandstone of the Simpson Group has not been analyzed because of the absence of well log data. The Kerr #9-12 well is not producing and is used as injection well (KGS database, 2019).

Well Triemer #14-2: The Triemer #2 well is not located in the boundary of Kizler North field (Figure 1.11). This well is a wild cat drill hole. The isopach map (Figure 3.2, 3.4) created from the well tops of the study area and surrounding area shows four-way structural closure at this location. The Hunton Formation does not have any pay zones because the reservoir zones have high water saturation (88.4% avg.). The Hunton Formation is primarily dolomite with 31% (avg.) Vshale, an effective porosity of 10.2% (avg.). The Viola Formation has negligible pay zone (0.5ft) with a water saturation of 59.6% (avg.) and an effective porosity of 10.9% (avg.). The Simpson Group has not been analyzed because of the absence of well log data.

Figure 3.34: Stratigraphic column along with the well logs of Triemer #9-14 well.

An example of Pickett plots (Figure 3.49A) to determine water resistivity (R_w) and update Archie's water saturation parameters using porosity/resistivity crossplot (Pickett, 1973). And an example of RHOMA/Umaa plots (Figure 3.49B) to interpret the lithology of the target zones.

A

B

Figure 3.35: A) Logarithmic deep resistivity- total porosity crossplot (Pickett plot) used to graphically solve Archie's water saturation equation. B) RHOMA-Umaa mineral composition plot where RHOMA is apparent density of mineral matrix and Umaa is bulk photoelectric absorption of the mineral matrix. Where, $U_{maa} = (RHOB \cdot PE - PHIT \cdot U_{fluid}) / (1 - PHIT)$.

Figure 3.36: Final Petrophysical plot of Triemer #9-14 well.

Figure 3.37: Final Petrophysical plot of Kerr #9-12 well.

Figure 3.38: Final Petrophysical plot Triemer #14-2.

The tables below contain the parameters computed from the well logs data of all three wells of the Kizler North Field. The Pay Cutoffs were: Vsh > 65%, PHIE < 9%, Sw > 50%

Table 3.11: Summary of Computed Petrophysical Parameters from Well Triemer #9-14.

Formation	Net Pay	Net Reservoir	Rw	Avg. PHIE(Res.)	Avg. Sw (Res.)
Hunton	5.0'	13.50'	0.1874	11.7%	51.9%
Viola	9.0'	26.0'	0.2605	10.9%	49.9%
Simpson	7.0'	7.5	0.1753	10.7%	34.6%

Table 3.12: Summary of Computed Petrophysical Parameters from Well Kerr #9-12.

Formation	Net Pay	Net Reservoir	Rw	Avg. PHIE(Res.)	Avg. Sw (Res.)
Hunton	0'	22.25'	0.1874	12.2%	64.1%
Viola	0'	25.75'	0.2605	10.5%	60.1%
Simpson	3'	16.25'	0.1753	11.5%	67.5%

Table 3.13: Summary of Computed Petrophysical Parameters from Well Triemer #14-2.

Formation	Net Pay	Net Reservoir	Rw	Avg. PHIE(Res.)	Avg. Sw (Res.)
Hunton	0'	17.75'	0.1874	10.2%	88.4%
Viola	0.5'	9.25'	0.2605	10.9%	59.6%
Simpson	No well log data to this depth				

Table 3.14: Petrophysical Parameters from the pay zones of the studied wells.

Well: TRIEMER 9-14									
Zone	Top (ft)	Bottom(ft)	Gross(ft)	Net	N/G	Phi	Sw	Vsh	Production
Hunton	2933.00	2977.00	44.00	5.00	0.114	0.118	0.423	0.035	8146bbl
Viola	3044.50	3136.00	91.50	9.00	0.098	0.123	0.362	0.009	Asphaltic
Simpson	3136.00	3162.50	26.50	7.00	0.264	0.107	0.335	0.022	Do Drill Stem test
Well: KERR #9-12									
Zone	Top (ft)	Bottom(ft)	Gross(ft)	Net	N/G	Phi	Sw	Vsh	Production
Hunton	2997.00	3033.00	36.00	0.00	0.00	----	----	----	No
Viola	3103.00	3194.00	91.00	0.00	0.00	----	----	----	Production
Simpson	3194.00	3221.00	27.00	3.00	0.111	0.113	0.398	0.005	
Well: TRIEMER #14-2									
Zone	Top (ft)	Bottom(ft)	Gross(ft)	Net	N/G	Phi	Sw	Vsh	Production
Hunton	3108.00	3161.90	53.90	0.00	0.00	----	----	----	No
Viola	3227.90	3320.90	93.00	0.50	0.005	0.150	0.477	0.007	Production
Simpson	No well log data to this depth

Figure 3.39: Multi-well correlation between Triemer #9-14, Triemer #14-2 and Kerr #9-12 wells.

CHAPTER 4

DISCUSSION

Effects of Tectonics: A major change in the tectonic development of the Kansas region took place near the end of Mississippian during the Ouachita orogeny, which defines the structural framework of the Forest City Basin (Merriam, 1963; Berendson and Blair, 1986). The cross-cutting relations observed in our data show reactivation of the pre-existing basement faults during the Mississippian to Pennsylvanian (Figure 3.26-3.30; Figure 4.12). As the rigid basement complex has been overlain by only a thin layer of sedimentary rocks, stresses transmitted through the basement in response to Phanerozoic orogenies would tend to deform the overlying rocks in a brittle manner (Berendsen and Blair, 1986).

The pre-Desmoinesian to post-Mississippian-structural elements in Kansas show two sets of trends. The first one is northeast (N20E) aligned with the Nemaha Anticline, and the other is northwest (N45W) aligned with the coeval Central Kansas Uplift (Merriam, 1963; Berendson and Blair, 1986). The identified wrench faults in the Kizler North Field strike northwest. This northwest trend aligns with the ancestral Central Kansas Uplift that was probably established in the Proterozoic during the accretionary history of the Midcontinent (Berendson and Blair, 1986). (The ancestral Central Kansas Uplift is a term used for the early Paleozoic development of the Central Kansas Uplift; Merriam, 1963). Although the strike of the faults is a result of reactivation of the Central Kansas uplift during the Ancestral Rocky Mountain orogeny, the sinistral strain was caused by trans-tensional stress associated with the reactivation of the Midcontinent Rift System along the Nemaha Anticline. This stress created sinistral flower structures in the Kizler North Field (Figure 3.27-3.33).

The seismic data show that late stage wrench faulting occurred twice. The first wrenching occurred during the Kinderhook evidenced by the sub-vertical faults except for at the top where the dip changes to $\sim 60^\circ$ towards southwest (Figure 3.21, 3.22). The second wrenching event occurred after the Mississippian and is evidenced by the time structure map that shows the extension of three fault traces into the Mississippian rocks (Figure 3.26), and by the seismic lines that also show a shift in dip direction on the faults in the Mississippian rocks at $\sim 60^\circ$ to the southwest (Figure 3.24, 3.25). This reactivation corresponds to documented reactivation of the Central Kansas Uplift during the Ancestral Rocky Mountain orogeny (Berendson and Blair, 1986); however, the wrenching implies that reactivation of the MRS structural elements as well (such as the Nemaha Ridge) in order to create the sinistral offset. The latest stage event breached the Mississippian rocks and allowed for hydrocarbon migration out of the reservoirs. This explains the dry holes in the regions where the faults extend into the Mississippian rocks (Kerr #9-12, Trust #3).

Figure 4.11: Map showing faults in Kansas (Merriam, 1963).

Figure 4.12: Event chart of the Petroleum systems of the Kizler North Field. The development of Nemaha Tectonic zone and Central Kansas uplift structural features are coeval (pre-Desmoinesian post-Mississippian).

The wrench fault system at the Kizler North Field is important for petroleum accumulation to act as a trapping mechanism across the structural anticline in the center of the basin. The study area contains two four-way dipping closures terminated by adjacent wrench faults (Figure 3.28). This matches with the findings of Wilcox et al. (1973), who reported that the structural traps can be formed in the wrench zone by faulting or a combination of faulting and folding (the case presented in this work). The anticline was uplifted during the Mississippian, and the Hunton Formation eroded from the axis of the anticline. Thus, the Hunton Formation

reservoir forms stratigraphic trap on the flanks of the anticline (Figure 4.12). The Viola Formation and Simpson Group are thickest at the apex of the anticline (approximately 66ft). The thinning of Hunton Formation in the structural top is also observed in the nearby analog Kizler (Figure 3.18) and John Creek (Figure 3.23) field. The isopach maps of both of these fields show that the Hunton Formation at the apices of the anticlines is half of the thickness at the flanks.

Effects of Lithology: The lithology of the Hunton Formation, Viola Formation and Simpson Group in the Kizler North and analog fields (Kizler field and John Creek field) is dominantly dolomite. All these three reservoir formations have excellent porosity (approximately 10-12% effective porosity). The high effective porosity probably results from dolomitization of the reservoir rocks. The low-temperature hydrothermal fluid migrated through the open wrench fault/fracture system caused the dolomitization (Tedesco, 2017). The low-temperature hydrothermal fluids were expelled by tectonic compression during the Ouachita-Marathon Orogeny (Ordovician through Pennsylvanian) from Anadarko and Arkoma basins (Gerhard, 2004). The diagenesis and dolomitization by low-temperature hydrothermal fluid controls the dolomite crystal size (0.0125mm to 3.5mm) and crystal fabric which ultimately controls the effective porosity and permeability of the Paleozoic reservoir rocks in Kansas (Jensik, 2013; Tedesco, 2017). The vuggy porosity in the reservoir rocks of the Kizler North Field typically has a pore diameter greater than 1/16mm and is not fabric selective (Choquette and Pray, 1970).

Despite having similar favorable reservoir qualities (high porosity and low Vshale) in the dolomite reservoir rocks in all three wells and four-way anticlinal closure, Treimer #9-14 is the only producing well among the three studied wells. Kerr #9-12 and Treimer #14-2 both have high water saturation (Table 3.14). The Hunton Formation have 64.1% and 88.4% water saturation in

Kerr #9-12 and Treimer #14-2 respectively. The Viola Formation and Simpson Group also show approximately 60% and 68% water saturation respectively.

Summary: As favorable reservoir qualities are present throughout the Kizler North Field, tectonics are the controlling features for hydrocarbon recovery. We propose that high water saturation in reservoir intervals can be caused by upward migration of petroleum through the faults. The repeated reactivation of the basement faults after the Mississippian resulted in migration of petroleum out of these reservoirs. Therefore, in the Kizler North Field, it is important to look for the faults that do not extend beyond the reservoir intervals. The dry wells, Kerr #9-12 and Trust-3, are located on a structure that exhibits late stage wrenching and propagation of the fault into the Mississippian Group. However, the trapping fault close to Treimer #9-14 does not extend into the Mississippian Group, and this reservoir is charged. The Trust #4 well has similar faulting pattern as Treimer #9-14 (very small-scale fault in the Mississippian Group) and produces from the Hunton Formation (20000bbl cum.). It is likely that the Simpson Group could produce from Treimer #9-14 well, as there is enough closure observed in the time structure map (Figure 3.29).

Of course, an alternate explanation for high water saturation is that the reservoir was never charged at all. However, because these reservoirs are producing elsewhere in the field, it is not likely that these reservoirs were never charged. Therefore, the most likely explanation for the dry holes is that the Mississippian reactivation and wrenching created migration pathways responsible for upward migration and the resulting high water saturation observed in these wells.

The exploration model for the Kizler North and analog fields is to look for subtle basement-rooted wrench fault systems that transect the reservoir dolomites with anticlinal

closure. Faults that do not extend far above the target formation are typically the best candidates because the faults have not breached the seal for the hydrocarbons.

Figure 4.13: Proposed well location.

CHAPTER 5

CONCLUSION

The Hunton Formation, Viola Formation and Simpson Group rocks are the potential reservoir units of the Kizler North Field. The reservoir formations have high effective porosity and low shale volume; however, in places, the reservoirs have high water saturation. We conclude that the observed high water saturation in dry holes is a result of migration out of the reservoir via late stage propagation of wrench faults into the Mississippian rocks. We document two late stage wrenching events during the Kinderhook and the Mississippian.

The trapping mechanism of this field is controlled by wrench faulting that create four-way closures terminated by adjacent wrench faults (Hasan, 2018). The Viola Formation and Simpson Group are thickest at the apex of the anticline. The Hunton Formation is eroded from the axis of the anticline, leaving this formation on the flanks forming stratigraphic trap. The exploration model for the Kizler North field is to look for subtle basement-rooted wrench fault systems that transect the reservoir dolomites with anticlinal closure. The developed trapping mechanism of Kizler North Field can be of help for exploration or development of analog fields. The field does not require fracking for production because of the high porosity of the reservoir rocks caused by reservoir dolomitization.

Three locations have been identified for drilling based on the developed exploration model. The criteria for selecting these locations were, 1) four-way closure with wrench fault trapping 2) structural high of Viola Formation and/or Simpson Group 3) thick Hunton Formation forming stratigraphic traps 4) absence of fault beyond the reservoir formations.

The proposed three drilling locations are shown in Figure 4.13, and the coordinates are given below.

- Proposed 1: X=2624682.07, Y=738929.29
- Proposed 2: X=2625504, Y=738098.69
- Proposed 3: X=2624059.91, Y=735406.02

X and Y are in NAD 1927 FIPS 1502 projected coordinate system.

Proposed wells 1& 2 are where the Hunton Formation, Viola Formation and Simpson Group located on a structural four-way closure with wrench fault trapping. Proposed well 3 shows the Viola Formation and Simpson Group over a structural high, and thick Hunton Formation. This well is proposed to recover the abandoned reserves of Trust-4. The previous operator employed fracking methods which resulted in significant water encroachment and premature abandonment of the field (education.aapg.org/pitchapalooza/pitch-running-foxes-kizler.pdf). The low transmissibility observed in the Hunton and Viola Formation can be opened with acid treatment (Well completion report, 2014). The thickness of Hunton Formation ranges from 60-78ft. Viola Formation has a thickness from 30-48ft, and Simpson Group is 36-66ft at these proposed locations.

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APPENDICES

APPENDIX A

ISOPACH MAPS

Figure 1: Isopach Map of Chattanooga-Kinderhook Group of the study area. Green dots are well with data.

Figure 2: Isopach Map of Mississippian Group of the study area. Green dots are well with data.

Figure 3: Isopach Map of Chattanooga-Kinderhook Group of the Kizler Field. Green dots are well with data.

Figure 4: Isopach Map of Mississippian Group of the Kizler Field. Green dots are well with data.

Figure 6: Isopach Map of Mississippian Group of the John Creek Field. Green dots are well with data.

APPENDIX B

SEISMIC INTERPRETATION

Figure 1: Synthetic seismogram created using sonic and density log of Triemer #9-14 well.

Figure 2: Kizler North 2D Heebner time structure map, Contour interval=1ms or approximately 6ft.

Figure 3: Kizler North 2D Lansing time structure map, Contour interval=1ms or approximately 6ft.

Figure 4: Kizler North 2D Kansas City time structure map, Contour interval=1ms or approximately 6 ft.

Figure 5: Kizler North 2D Cherokee Group time structure map, Contour interval=1ms or approximately 6 ft.

Figure 6: Kizler North 2D Kinderhook time structure map, Contour interval=1ms or approximately 6 ft.

Figure 7: Kizler North 2D Cherokee-Mississippian isochron map, Contour interval=1ms or approximately 6 ft.

Figure 8: Kizler North 2D Mississippian-Viola isochron map, Contour interval=1ms or approximately 6 ft.

Figure 9: Kizler North 2D Viola-Precambrian isochron map, Contour interval=1ms or approximately 6 ft.

Figure 10: Kizler North 2D Simpson-Precambrian isochron map, Contour interval=1ms or approximately 6 ft.

APPENDIX C

FORMATION EVALUATION

Triemer #9-14 Well:

A

B

Figure 1(A) is the Pickett plot of Viola Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.2605.

Figure 1(B) is the RHOMA-Umaa mineral composition plot of the Viola Formation which shows dominance of dolomite and some quartz.

A

B

Figure 2(A) is the Pickett plot of Simpson Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.1753.

Figure 2(B) is the RHOMA-Umaa mineral composition plot of the Simpson Formation which shows dominance of dolomite and some quartz.

Kerr #9-12 Well:

A

B

Figure 3(A) is the Pickett plot of Hunton Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.1874.

Figure 3(B) is the RHOMA-Umaa mineral composition plot of the Hunton Formation which shows dominance of dolomite.

A

B

Figure 4(A) is the Pickett plot of Viola Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.2605.

Figure 4(B) is the RHOMA-Umaa mineral composition plot of the Viola Formation which shows dominance of dolomite.

A

B

Figure 5(A) is the Pickett plot of Simpson Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.1753.

Figure 5(B) is the RHOMA-Umaa mineral composition plot of the Simpson Formation which shows dominance of dolomite and some quartz.

Triemer #14-2:

A

B

Figure 6(A) is the Pickett plot of Hunton Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.1874.

Figure 6(B) is the RHOMA-Umaa mineral composition plot of the Hunton Formation which shows dominance of dolomite and calcite.

A

B

Figure 7(A) is the Pickett plot of Viola Formation. By assigning the value of $a=1$, $n=2$ and establishment of water line, the formation water resistivity (R_w) is determined to be 0.2605. Figure 13(B) is the RHOMA-Umaa mineral composition plot of the Viola Formation which shows dominance of dolomite.

VITA

Graduate School
Southern Illinois University

Md Nahidul Hasan

nahidju13@gmail.com

Jahangirnagar University
Master of Science, Geological Sciences, August 2017

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Major Professor: Dr. Sally L. Potter-McIntyre