Discrete Fracture Network Simulation for Sedimentary Enhanced Geothermal Systems: Red River Formation, Williston Basin, North Dakota

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Keywords

Sedimentary enhanced geothermal systems (SEGS), discrete fracture network (DFN), North American stress regime, surface lineaments, subsurface faults, ArcGIS, geostatistical analysis

ABSTRACT

The Red River Formation (Ordovician), which lies between 3.6 and 4.2 km depth in the Williston Basin, is a viable site for installation of sedimentary EGS (SEGS). SEGS is possible there because temperatures in the formation surpass 140° C and the permeability is 0.1-38 mD; fracture stimulation can be utilized to improve performance. A GIS and geostatistical analysis was completed to show that there is a satisfactory correlative relationship between the surface lineaments and the basement faults in the study area. Consequently, the orientations and locations of the surface lineaments and basement faults were combined in a shapefile to represent the area's discrete fracture network. In the future, the results of these two analyses can be utilized to create a reservoir simulation model of an SEGS in the Red River Formation; the purpose of this model would be to ascertain the thermal response of the reservoir to fracture stimulation.

Introduction

The Red River Formation (Ordovician), which lies between 3.6 and 4.2 km depth in the Williston Basin, is a viable site for installation of sedimentary enhanced geothermal systems (SEGS). SEGS is possible there because temperatures in the formation surpass 140° C and the permeability is 0.1-38 mD; fracture stimulation can be utilized to improve performance. A GIS and geostatistical analysis was completed to show that there is a satisfactory correlative relationship between the surface lineaments and the basement faults in the study area.

Research Area

The Williston Basin was selected as a potential candidate for SEGS installation because of its thermal energy and interconnectedness in a discrete fracture network. A 60.0 km × 14.7 km (882 km^2) section of the basin beneath the Nesson Anticline in western North Dakota-- surrounding the junction of Divide, Burke, Williams, and Mountrail counties-- was designated as the specific study area for this project (Figure 1).

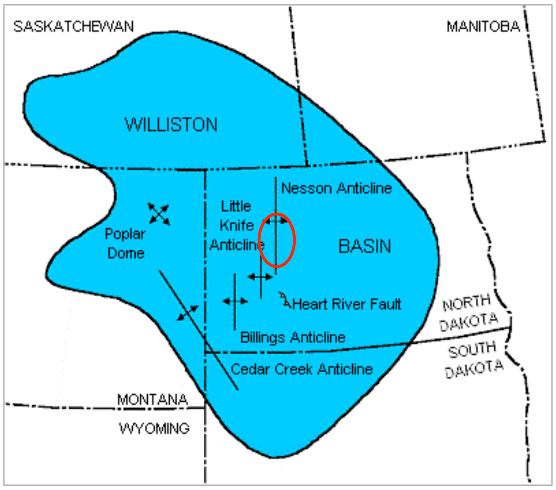


Figure 1. Nesson Anticline Area, Williston Basin (W. Gosnold, Pers. Comm., 2013). Anticlines are represented by black lines with arrows pointing away from the ridge. Research area is shown with a red oval.

In addition to its extensive oil production history, the Williston Basin has a large amount of thermal energy in place and is a productive thermal reservoir. There is an estimated 3.4*10^{19} KJ of thermal energy in the Williston Basin, including both the rock and the pore fluids (Porro and Augustine, 2014). The Williston Basin is classified as ranging from "great to good" reservoir productivity because there are high flow volumes, vertical permeability, strong hydrothermal recharge, and a well-known thermal profile (Porro and Augustine, 2014).

The reservoir productivity is greatly improved by the presence of a discrete fracture network in the subsurface. The existing stress field in the Williston Basin is such that natural stress fractures form from overpressure and interconnect as a result of tight spacing (Freisatz, 1995). This interconnectivity in the subsurface facilitates geothermal heat extraction because there is a medium of travel available for the injected SEGS fluids.

Research Site

The Red River Formation (Ordovician) (Figure 2) has been identified as a potential target for SEGS installation in the Williston Basin as a result of its oil production history, intrinsic rock properties, and temperature. Because Red River Units B and C have been tapped for oil production in the past, there is sufficient data and information available about the formation on the North Dakota Oil and Gas Division website (https://www.dmr.nd.gov/oilgas/) that can be utilized for analysis.

The Red River Formation has porosity and permeability that are conducive for SEGS installation because the lithology consists mostly of limestones and dolostones (Tanguay and Friedman, 2001). The limestones are mainly composed of calcite and contain minor amounts of dolostone, anhydrite, quartz, and halite (Tanguay and Friedman, 2001). The dolostones are mainly composed of dolomite and calcite and contain traces of quartz, anhydrite, and halite (Tanguay and Friedman, 2001). While the porosity and permeability are "very low to low" in the limestones, porosity and permeability are "low to moderate" in the dolostones (porosity of 10-24% and permeability of <1-62.8 mD, respectively) (Tanguay and Friedman, 2001). Because the porosity and permeability are low to moderate, the Red River Formation is a candidate for SEGS.

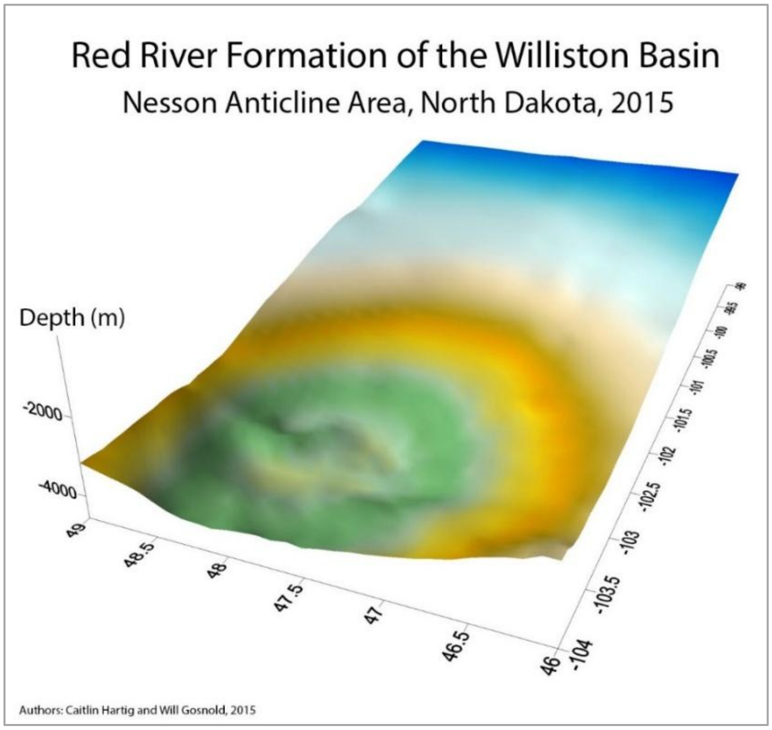


Figure 2. Top of the Red River Formation of the Williston Basin, located in the Nesson Anticline Area (green) of western North Dakota. The shallowest depths are shown in blue and the deepest depths are shown in green.

The temperature of the Red River Formation was determined from analysis of bottom-hole temperature (BHT) data available from the North Dakota Oil and Gas Division Website. These BHT were measured from a downhole instrument that recorded the temperature directly from the bottom of the wellbore (R. LeFever, Pers. Comm., 2015). BHT of the Red River Formation were found to surpass 140° C, which is suitably high for a low-to-moderate temperature geothermal system.

Natural Fracture Data

To understand the natural fracture orientation and location in the Red River Formation, existing data were first examined. Unfortunately, seismic data were unavailable for this study and therefore could not be utilized. Additionally, core images only existed for four wells in the study area (North Dakota Oil and Gas Division). While the cores showed where the natural fractures intersected the wells, they were not oriented, so it was impossible to ascertain the natural fracture orientation from the core images. As a result of this paucity of data, it was necessary to utilize literary analyses of the Williston Basin's stress field orientation, known natural fracture orientations, and surface lineament orientations to deduce the natural fracture orientation of the study area.

Stress Regime and Natural Fracture Orientation

Natural fracture orientation can be inferred from the regional stress field. The stable interior of North America—including the central and eastern United States, most of Canada, and most of the western Atlantic—has been classified into the Midplate stress province (Zoback and Zoback, 1991). The Midplate stress province is characterized by a compressive stress regime of strike-slip and reverse faulting, in which $S_{Hmax} > S_V > S_{Hmin}$ in the United States (primarily strike-slip faulting) and $S_{Hmax} > S_{Hmin} > S_V$ in Canada (primarily reverse faulting) (Zoback and Zoback, 1991; Zoback and Zoback, 1989). The cause of this stress regime has been attributed the absolute plate motion of the North American plate to the Southwest, as well as to the ridge-push motions from the Mid-Atlantic ridge (Bell and Grasby, 2012; Zoback and Zoback, 1989).

Zoback and Zoback (1991) and Bell and Grasby (2012) came to the above conclusions from analyzing well bore breakouts. Well bore breakouts are anisotropic cavities that occur on opposite sides of a borehole wall when the well is distorted as a result of stress (Bell and Grasby, 2012). The breakouts are oriented in the direction of S_{Hmin}, where the elastic compressive stress concentration is the greatest (Zoback et al., 1985).

Zoback and Zoback (1991) analyzed the well bore breakouts with an ultrasonic borehole televiewer. A televiewer is a well-logging tool that contains a magnetically orientated rotating piezoelectric transducer; it emits and receives an ultrasonic (~1 MHz) acoustic pulse that is reflected from the borehole wall at 600 times per revolution (Zoback et al., 1985). The televiewer shows the fractures that intersect the well bores as a function of azimuth and depth, based on the reflectivity of the well bore; the reflected pulse is shown as brightness on a three-axis oscilloscope and yields an "unwrapped" image of the well bore surface (Zoback et al., 1985). Well bore break outs were analyzed in several locations, including the southeastern corner of Saskatchewan (Zoback and Zoback, 1989), which is ~100 km away from the current study area in western North Dakota.

Bell and Grasby (2012) analyzed the well bore breakouts with a 4-arm dipmeter imagery log for Mesozoic and Paleozoic shales, limestones, and dolostones. A dipmeter is an instrument that documents the cavities on opposite sides of the well bore in order to ensure that the lateral elongation of the borehole was caused by stress caving (Bell and Grasby, 2012). A dipmeter works by recording the extensions of opposing pairs of pads, in addition to the compass orientation of one of the pads (Bell and Grasby, 2012). One well analyzed was in northern Alberta and showed twenty-three ~254.8-m thick breakout intervals in the well bore that were centered at a depth of 3496.35 m (Bell and Grasby, 2012). Only ten measurements were available in western Canada (Bell and Grasby, 2012).

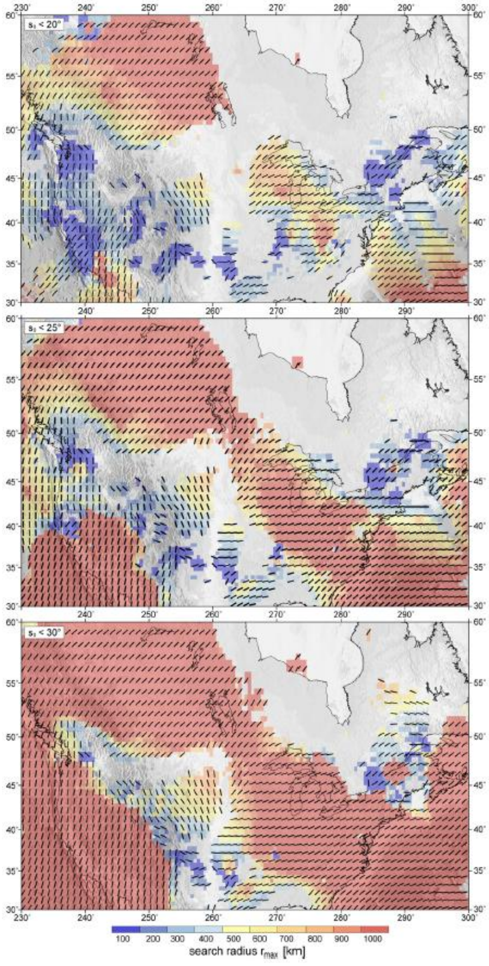


Figure 3. World Stress Map current regional stress field of North America. The mean direction of maximum horizontal stress is shown with grey lines; the maximum search radius-- for which the standard deviation of the maximum horizontal stress orientation ≤25°-- is shown in color) (Heidbach et al., 2010).

Heidbach et al. (2010) expanded on the work of Zoback and Zoback (1991) to create the world stress map. The world stress map shows that the current regional stress field remains the same—oriented northeast/southwest—closer to the study area in western North Dakota (Figure 3) (Heidbach et al., 2010).

The results of the above well bore breakout analyses showed a maximum horizontal stress (compression) (S_{Hmax}) oriented in the east/northeast direction and a minimum horizontal stress (compression) (S_{Hmin}) oriented in the north/northwest direction (Zoback and Zoback, 1991; Bell and Grasby, 2012; Heidbach et al., 2010). Because S_{Hmax} is oriented northeast/southwest, the natural fracture orientation can be inferred to also be oriented northeast/southwest.

In other studies, there is an opposing viewpoint that local stresses, rather than tectonic movements, are responsible for the stress regime in the Williston Basin. These studies propose that the Nesson Anticline was formed along reactivated basement block boundaries in response to varying tectonic stresses and crustal flexure that occurred intermittently throughout the Phanerozoic (LeFever et al., 1987; Freisatz, 1995; Laird and Folsom, 1956). In essence, these studies suggest that the stress regime of the Williston Basin is extensional, rather than compressional.

LeFever et al. (1987) examined structural relief plots and split the area of the Nesson Anticline into nine distinct areas, each having its own independent structural history. Episodes of alternating uplift and subsidence occurred in each of these blocks in different intervals over the Phanerozoic (LeFever et al., 1987). Most of these areas experienced the largest amount of uplift in the Devonian or in the Early Mississippian, while a few of these areas did not experience the largest amount of uplift until the Pennsylvanian

(LeFever et al., 1987). These results agree with the ideas of Laird and Folsom (1956), who believe that the Nesson Anticline formed sometime in the late Ordovician and became more active at the end of the Paleozoic.

Other studies have been completed in the Canadian Williston Basin in Saskatchewan and Manitoba to determine the natural fracture orientation in the subsurface of the Williston Basin. In the Torquay-Rocanville trend near the Weyburn oil field in southeast Saskatchewan, the flow of oil has been determined to be in a preferential northeast-southwest orientation (Chen et al., 2009). As a result, it is suggested that natural fractures in the area have a dominant northeast-southwest orientation (Chen et al., 2009). Furthermore, a carbonate aquifer in southern Manitoba (middle Ordovician to Devonian) shows two dominant fracture orientations observed in bedrock exposures: northwest-southeast (110°-130°) and northeast-southwest (020°-040°) (Chen et al., 2011). The northwest trending group (perpendicular to S_{Hmax} and parallel to S_{Hmin}) has a higher fracture density (440 fractures), but consists of mostly healed or closed fractures (Chen et al., 2011). Despite its lower fracture density (330 fractures), the northeast trending group (parallel to S_{Hmax}) is the preferential fluid-flow pathway (Chen et al., 2011; Wegelin, 1987).

Fluid in the subsurface should theoretically flow preferentially in the direction of maximum stress. Because Chen et al. (2011) and Wegelin (1987) observed the subsurface fluid to flow in a preferential northeast direction, it can be assumed that the direction of maximum stress in the subsurface (S_{Hmax}) is oriented to the Northeast (a horizontal stress). As a result of this information, it can be deduced that the maximum horizontal stress (S_{Hmax}) is greater than the vertical overburden stress (S_V). These findings suggest that the stress of the region is $S_{Hmax} > S_{Hmin} > S_V$-- a compressive regime-- which is consistent with the results of Bell and Grasby (2012) and Zoback and Zoback (1991). If the stress regime were extensional, on the other hand, then $S_V > S_{Hmax} > S_{Hmin}$ (Zoback, 1989). Thus the stress field of the United States craton is a compressive regime that is caused by the northeastern movements of the North American plate and the spreading of the Mid-Atlantic ridge.

In summary, the consistent findings of Chen et al. (2011), Wegelin (1987), Bell and Grasby (2012), Zoback and Zoback (1991), and Heidbach et al. (2010) show that the natural fractures in the subsurface of the Williston Basin are oriented northeast and northwest and that the northeast trending group is the conduit for fluid flow. This information is applicable to the natural fracture orientation in the Nesson Anticline area of the basin in North Dakota.

Surface Lineament Orientation

In addition to the two directions of natural fractures obtained from the Canadian studies, there are also two distinct surface lineament (joint) zones in the area that are also trending northeast and northwest. Northeast and northwest trending lineaments have been observed across Winnipeg (Chen et al., 2011) as well as in the Nesson Anticline area and Mountrail County, North Dakota (Anderson, 2011; Gerhard et al., 1987).

It has been argued that surface lineament orientation can reflect the orientation of the basement faults in the subsurface, and therefore by extension can reflect the specific orientations and locations of the natural fractures in the formation (Bell and Grasby, 2012; Anderson, 2011; Penner, 2006; Freisatz, 1995; Freisatz, 1991; Gerhard et al., 1987). The assumptions are that: 1) the basement faults cut through the subsurface formation in question; 2) the trends of the natural fractures in the subsurface are parallel to the trends of the basement faults; and 3) the surface lineaments are formed either a) by the motion of the basement faults, or b) by the same source that formed the basement faults. It has also been proposed that the surface lineaments are connected to the basement faults as fault traces (Anderson, 2011; Chen et al., 2011; Freisatz, 1995).

In spite of the similarities in trend between the basement faults and the surface lineaments, advances and retreats of Pleistocene glacial till show “ridge and swale” topography that is also nearly coincident with the inferred direction of preferred fracture orientations (Chen et al., 2011; Gerhard et al., 1990). Furthermore, Cenozoic detrital sedimentary rocks can mask the geologic expression of the basin (Gerhard et al., 1990). Because of this, lineaments may not be able to adequately predict the orientations of the subsurface features (Chen et al., 2011; Gerhard et al., 1990; Gerhard et al., 1987).

Research Question

A paucity of natural fracture orientation data in the subsurface impedes immediate understanding of the natural fracture orientation of the study area in western North Dakota. While there are many known surface lineaments in the area and some known basement faults, it is disputed that the surface lineaments are, in actuality, caused by the basement faults. Thus it is uncertain whether or not it can be said with confidence that the surface lineaments reflect the orientations and locations of the natural fractures in the subsurface.

As a result of this uncertainty, it was necessary to conduct a GIS and geostatistical analysis comparing the trends of the surface lineaments to the trends of the basement faults in order to determine whether or not they are sufficiently correlated. If a strong spatial correlation were found to exist between the trends of the surface lineaments and the trends of the basement faults, the approximation of the specific natural fracture orientations and locations in the Red River Formation would be greatly facilitated.

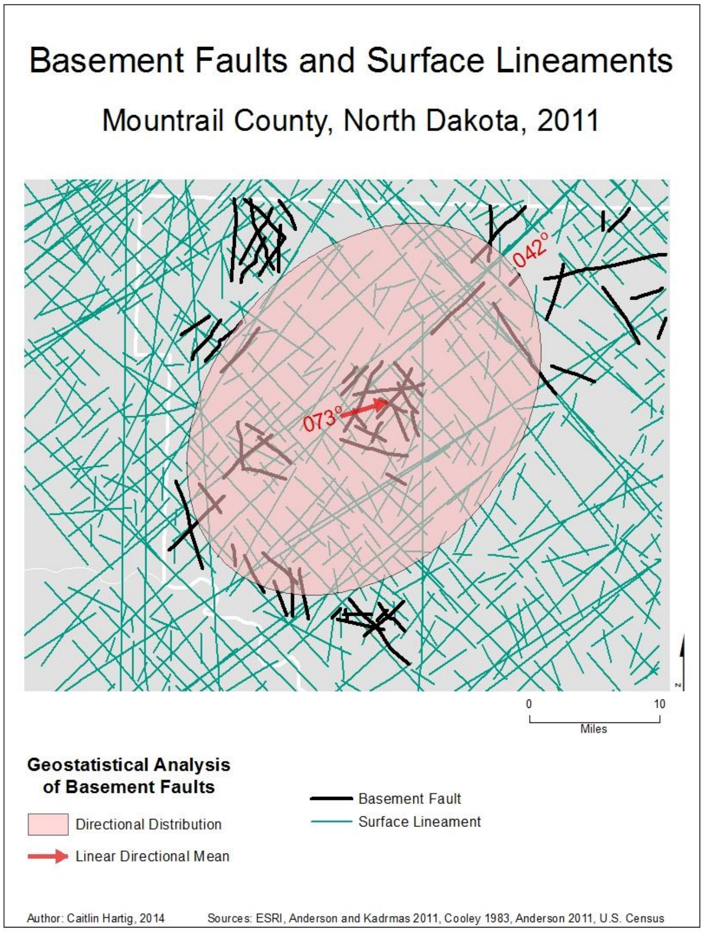


Figure 4. Basement Faults and Surface Lineaments of Mountrail County, North Dakota, 2011. The linear directional mean shows that the average azimuthal direction of all basement faults is 073° (ENE). The directional distribution shows that the average azimuthal direction of the basement faults within one standard deviation of the linear directional mean is 042° (NE).

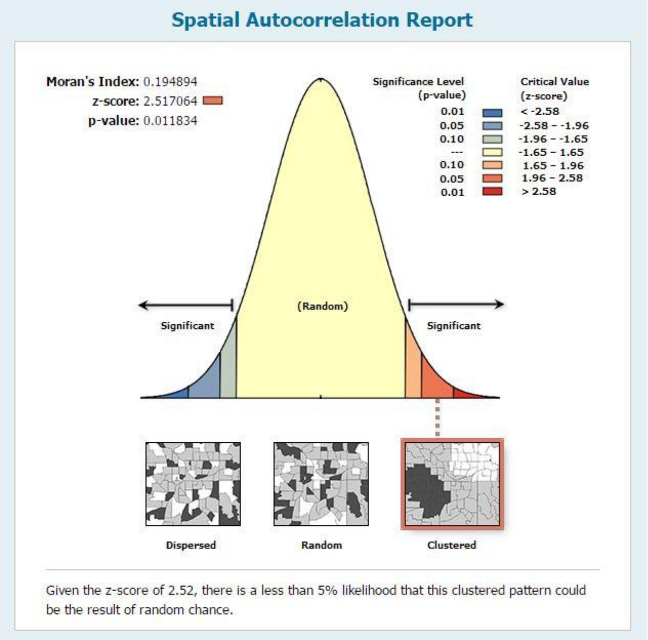
GIS and Geostatistical Analysis

To begin the GIS and geostatistical analysis, two distinct shapefiles were needed: one containing the spatial distribution of the surface lineaments, and the other one containing the spatial distribution of the subsurface basement faults. The first shapefile was spatially referenced and digitized by Anderson and Kadrmas (2011); it contained the spatial distributions of all historic surface lineaments in the Williston 250k from Cooley (1983) and other sources. Lineaments in this file were derived from four distinct sources: 1) previous studies, 2) digital shaded relief data, 3) aerial imagery, and 4) LANDSAT data/imagery (Anderson, 2008). The second shapefile was a diagram of basement faults in Mountrail County, North Dakota (Anderson, 2011) that was georeferenced to a shapefile of Mountrail County (United States Census, 2014) and digitized into a separate layer. The basement faults have been identified from seismic data (Anderson, 2011).

Once the two distinct shapefiles were acquired, the linear directional mean tool and the directional distribution tool were run on both layers in ArcGIS (Figure 4). The surface lineaments trend in two distinct directions (northwest and northeast); therefore, the results of the linear directional mean and the directional distribution were not included on the map because they did not reflect both directional trends.

Subsequently, Moran's I analyses (Figures 5-6) were run on the lineaments and the faults. From the clustered results, it is unlikely that either the lineaments or the faults were formed by random chance.

Next, the trends for each distinct surface lineament and each distinct basement fault were obtained for

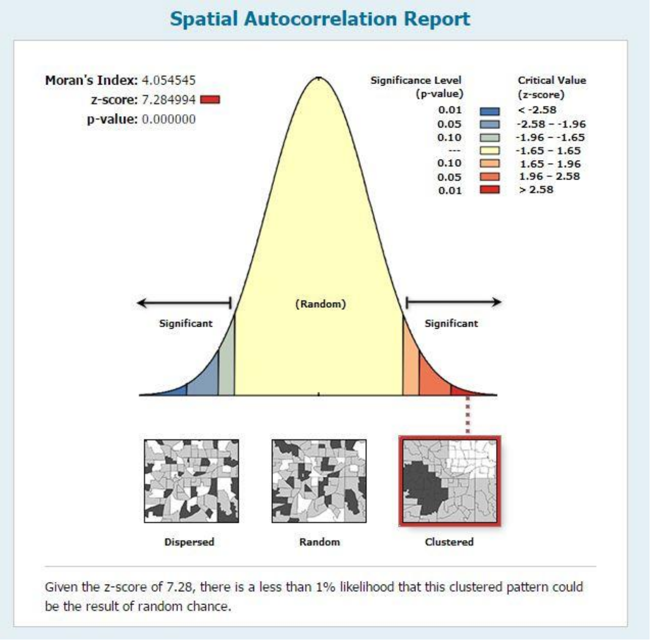

Spatial Autocorrelation Report

Moran's Index: 0.194894
z-score: 2.517064 🟧
p-value: 0.011834

Significance Level (p-value)		Critical Value (z-score)
0.01	🟦	< -2.58
0.05	🟦	-2.58 - -1.96
0.10	🟩	-1.96 - -1.65
---	🟨	-1.65 - 1.65
0.10	🟧	1.65 - 1.96
0.05	🟧	1.96 - 2.58
0.01	🟥	> 2.58

Given the z-score of 2.52, there is a less than 5% likelihood that this clustered pattern could be the result of random chance.

Figure 5. Moran's I Analysis of the basement faults along a standard deviation curve.


Spatial Autocorrelation Report

Moran's Index: 4.054545
z-score: 7.284994 🟥
p-value: 0.000000

Significance Level (p-value)		Critical Value (z-score)
0.01	🟦	< -2.58
0.05	🟦	-2.58 - -1.96
0.10	🟩	-1.96 - -1.65
---	🟨	-1.65 - 1.65
0.10	🟧	1.65 - 1.96
0.05	🟧	1.96 - 2.58
0.01	🟥	> 2.58

Given the z-score of 7.28, there is a less than 1% likelihood that this clustered pattern could be the result of random chance.

Figure 6. Moran's I Analysis of the surface lineaments along a standard deviation curve.

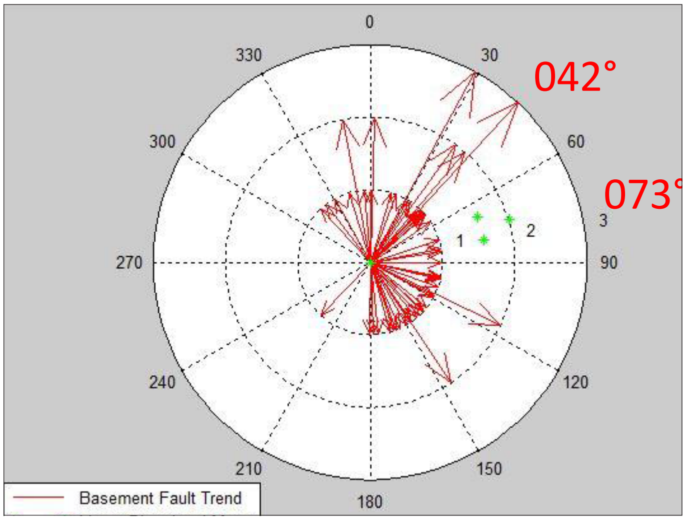


Figure 7. Compass plot of the basement fault trends. An average ENE trend is indicated. The fault density is greatest at 042°, which is coincident with the directional distribution calculated in Figure 4. The linear directional mean calculated in Figure 4 (green stars) is pictured at 073°.

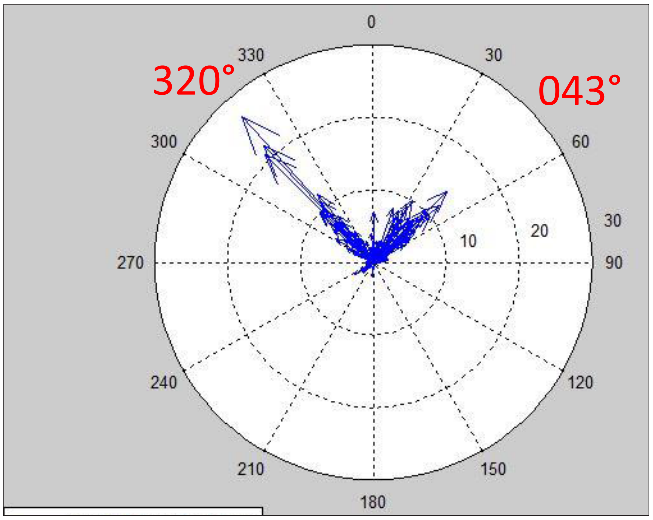


Figure 8. Compass plot of the surface lineament trends. Two distinctive trends are indicated: 320° (NW) and 043° (NE). Lineament density is greater in the northwest direction.

the geostatistical analysis with the linear directional mean tool. Compass plots were created in MATLAB to analyze the relationships between the basement fault trends and the surface lineament trends (Figures 7-9). Finally, the results were compared to determine whether the spatial correlation was strong enough to argue common causality.

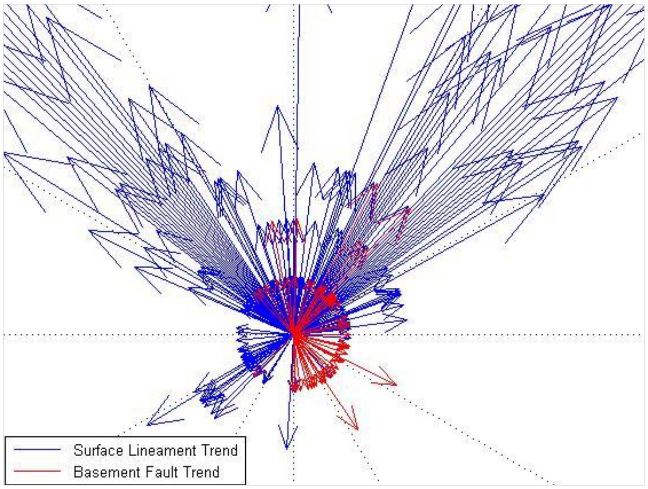


Figure 9. Compass plot of the basement fault trends and the surface lineament trends. The large magnitude of the lineaments and the small magnitude of the faults makes comparison difficult.

Discussion

The average azimuthal direction of all subsurface faults, 073° (Figure 4), is in the same orientation as the regional stress field, S_{Hmax} (ENE). The clustering shown in the Moran's I analysis for the faults (Figure 5) is thus explained because the current regional stress field likely caused the faults to form.

The compass plot of the surface lineaments in Figure 8 shows two distinct trend directions: 320° (NW) and 043° (NE). The lineaments thus formed in the directions parallel to both S_{Hmin} and S_{Hmax} of the regional stress field, respectively. Furthermore, the azimuthal direction of lineaments trending northeast (043°) (Figure 8) is almost exactly coincident with the azimuthal direction of most subsurface faults (042°) (Figures 4 and 7). Therefore, the clustering shown in the Moran's I analysis for the lineaments (Figure 6) is thus explained because the current regional stress field likely caused the faults to form, and then the faults likely caused the lineaments to form. It is also possible that the current regional stress field directly caused the lineaments to form.

Conclusion

A dearth of available seismic data in western North Dakota and a lack of oriented cores hindered the immediate understanding of the natural fracture network present in the Red River Formation. Studies in the Williston Basin of the regional stress field, natural fracture orientation, and surface lineament trends thus provided guidance in deducing the orientation and location of the natural fractures in the subsurface of the Red River Formation. The GIS and geostatistical analysis of the surface lineaments and the basement faults in Mountrail County, North Dakota, showed that there is sufficient spatial correlation between the surface lineaments and the basement faults. It can thus be argued that the current regional stress field caused the faults to form, and that the fault movements subsequently caused both the natural fractures and the surface lineaments to form. Alternately, the current regional stress field could have directly caused the faults, natural fractures, and surface lineaments to form. Because the current regional stress field is consistent over the study area (Figure 3), it can be assumed that the same relationships apply to the lineaments and faults in the adjacent Burke, Divide, and Williams counties.

As a result of this correlation between the surface lineaments, basement faults, and natural fractures, it can be assumed that the surface lineaments mimic the underlying orientations and locations of both the basement faults and the natural fractures in the subsurface. According to Anderson (2011), there are four different types of relationships between surface lineaments and basement faults: coincident, adjacent, bridging, and extending. Furthermore, the basement faults are assumed to be subvertical (+/- 6° from vertical) (W. Gosnold, R. LeFever, F. Anderson, and S. Nordeng, Pers. Comm., 2014). The geometry of these relationships is summarized in Figure 10.

In all four relationships shown in Figure 10, the lineament trends are coincident with the fault trends. Therefore, due to lack of more exact information regarding the specific natural fracture orientation and location in the subsurface, it can be assumed that the surface lineaments and natural fractures are coincident in terms of orientation and location. Consequently, the natural fractures in the study area are assumed to trend in the same directions as the surface lineaments: 320° (NW) and 043° (NE), on average.

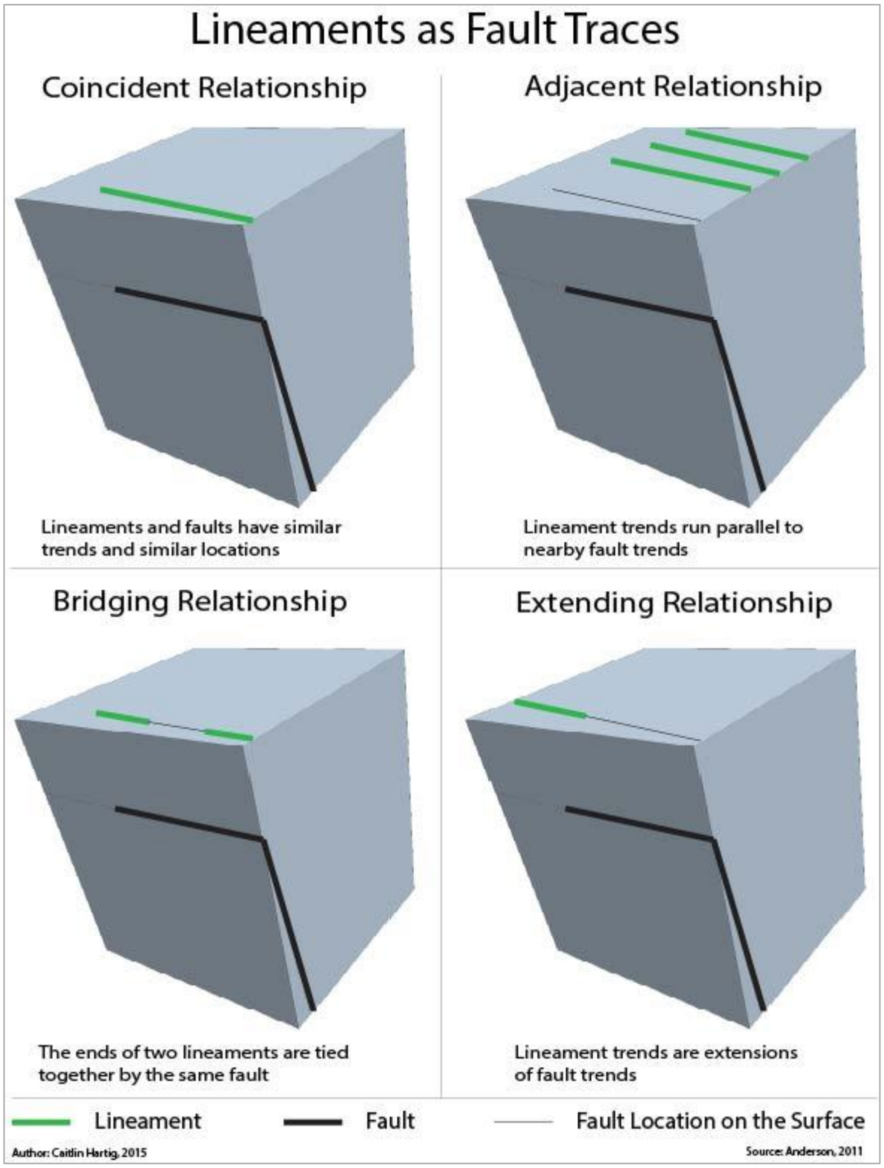
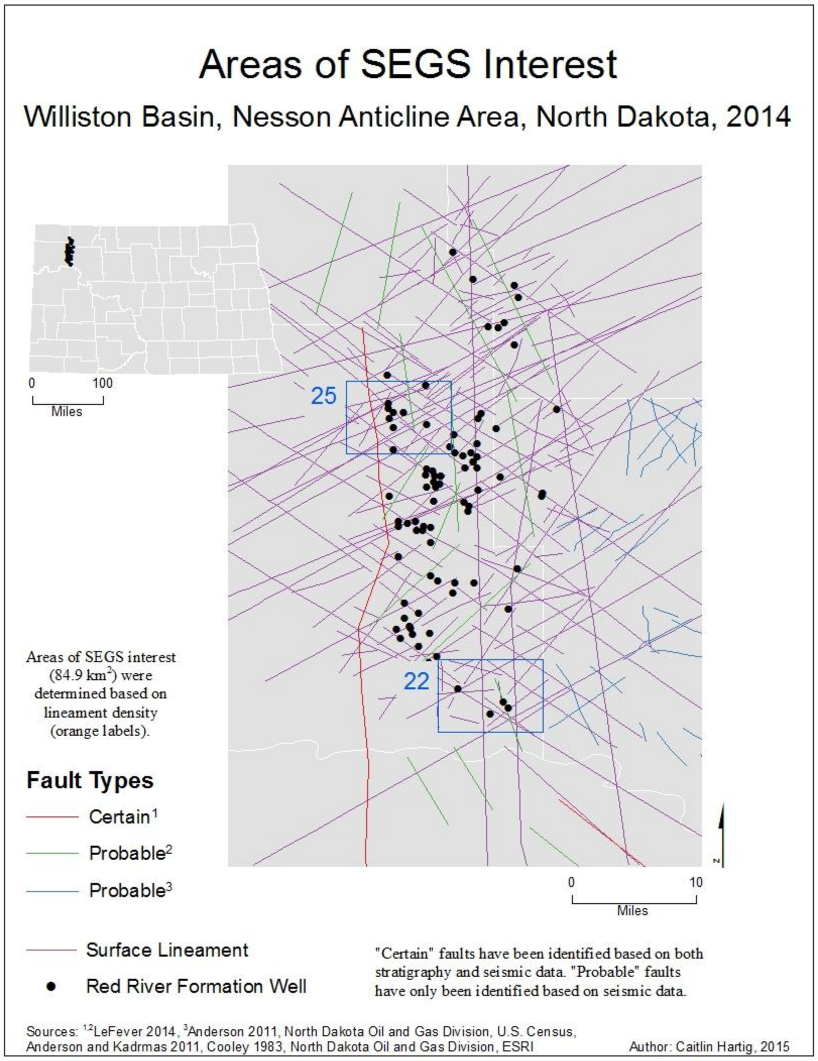


Figure 10. Lineaments as fault traces. Shown are coincident, adjacent, bridging, and extending relationships, respectively.

In agreement with the ideas of Chen et al. (2011) and Wegelin (1987), the natural fracture density is significantly greater in the northwest direction (S_{Hmin}) than in the northeast direction (Figure 8). On the other hand, the natural fractures trending to the Northeast (S_{Hmax}) are fewer in number but will be the conduits for flow. Because of this, it was suggested that the northeast trending fractures are more likely to remain open with the addition of fracture stimulation (Chen et al., 2011). Therefore, the hydroshearing dilation axis would be parallel to S_{Hmax} in the northeast direction (Bell and Grasby, 2012). Furthermore, production wells for the SEGS should be placed northeast of the injection wells in order to maximize fluid flow.

An additional map, Figure 11, was made to show all known basement faults and all known surface lineaments in the study area. Faults labeled "certain" have been identified based on both stratigraphic and seismic data, while faults labeled "probable" have only been identified from seismic data. All known surface lineaments are shown in the study area and-- due to lack of better knowledge-- can be used as a proxy for the natural fractures in the subsurface. Consequently, the shapefile displayed in Figure 11 can be utilized to represent the discrete fracture network (DFN) of the study area in a reservoir simulation model.

Furthermore, it has been shown that higher overall production rates correlate to areas of greater lineament density (Anderson, 2011). The greatest lineament density occurs in the northeastern corner of Williams County, which has 25 lineaments per 84.9 km^2 (0.94 lineaments/km^2) (Figure 11). Because the lineament density is greatest in the northeastern corner of Williams County, this part of the study area would be an ideal spot to test in a reservoir simulation model for placement of the SEGS.



Areas of SEGS interest (84.9 km^2) were determined based on lineament density (orange labels).

"Certain" faults have been identified based on both stratigraphy and seismic data. "Probable" faults have only been identified based on seismic data.

Sources: ^{12}LeFever 2014, ^{3}Anderson 2011, North Dakota Oil and Gas Division, U.S. Census, Anderson and Kadrmas 2011, Cooley 1983, North Dakota Oil and Gas Division, ESRI

Author: Caitlin Hartig, 2015

Figure 11. Basement faults and surface lineaments in the study area. Because the surface lineaments and basement faults are spatially correlated, it can be assumed that the surface lineaments mimic the trends of the natural fracture network in the subsurface. Therefore, the shapefile shown in this map can be utilized in a reservoir simulation model to represent the discrete fracture network of the study area. Areas of SEGS interest are shown based on lineament density. Blue rectangles that are 9.016 km by 9.417 km (84.9 km^2) highlight a section of northeastern Williams County with 25 lineaments and a section of southeastern Williams County with 22 lineaments.

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