DELINEATION OF SUBTLE GEOLOGIC FEATURES BY MULTI-ATTRIBUTE SEISMIC ANALYSIS IN DICKMAN FIELD, KANSAS, A POTENTIAL SITE FOR CO2 SEQUESTRATION

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By

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Introduction

CO_2 sequestration could significantly reduce the amount of CO_2 in the atmosphere. Sequestration is the process of injecting CO_2 into a storage location. In order for sequestration to make a substantial difference in the amount of CO_2 in the atmosphere, a site must be able to successfully store and trap CO_2 for thousands of years. There are several potential storage locations including terrestrial, ocean, and geologic sites as shown in Figure 1 (Hilterman and Bjorklund, 2007). Geologic sequestration sites include unminable coal beds, saline formations, and depleted oil and gas reservoirs. Saline formations and depleted petroleum reservoirs make good sites for possible CO_2 sequestration because of their inherent seal integrity.

The Reservoir Quantification Laboratory (RQL) is currently in the late stages of a study assessing four geological reservoirs for potential CO_2 sequestration (Hilterman and Bjorklund, 2007). They are located in Wyoming, Kansas, Ohio, and Illinois (Figure 2). The aim of this study is to simulate CO_2 injection by creating very accurate and detailed reservoir models with the use of well log data, production data, and seismic data. My study concentrates on the Kansas site which is the Dickman Field in Ness County.

The Dickman Field reservoir of interest is part of the Lower Paleozoic Ozark Plateau aquifer system which extends into nine states and is composed of fresh water and saline portions (Figure 3) (Nissen et al. 2004). The saline portion is known as the Western Interior Plains aquifer system and extends throughout the state of Kansas. The Western Interior Plains system is made of a Mississippian-aged carbonate formation that has been modified by karst processes and is known to be highly fractured. The formation is unconformibly overlain by shale of Pennsylvanian age and was created from channels, which deposited channel sands that are part of the aquifer (Figure 4). This interval of carbonates and sandstones is associated with oil and gas throughout Kansas.

The Dickman Field reservoir is a good candidate for study because of its proven seal integrity and potential storage capacity, which has been predicted to be near 1MtCo2. It is representative of many reservoirs throughout the mid-continent and it's small size allows for a comprehensive and complete study. In order to better understand the processes and factors dictating reservoir characteristics, more detailed geologic models and further attribute analysis needed to be completed. The seal of a reservoir is key in its potential to store fluids. Detailed and accurate depth maps and an extensive study of the currently available attributes can give a lot of insight into the nature of this reservoir's seal.

Many of the subtle geological features present in the Mississippian formation have been delineated through seismic amplitude and attribute data. The hypothothesis of this thesis is that detailed and accurate maps and an extensive study of the currently available attributes can determine if these features are also present in the seal, which is proposed to be within the Marmaton group. The Fort Scott Limestone which is about 150 ft. above the Mississippian is a formation top that was consistently identified in many of the well logs and was chosen to represent the seal of the reservoir. Determining if these features persist into the seal and how they may currently affect the seal is important in understanding how these features could affect flow within and out of the reservoir, locations for drill sites, as well as potential hazards. Background information, typical interpretation with seismic amplitude and well data, and interpretation of the available attributes is presented below with an emphasis on the seal of the reservoir, the Fort Scott Limestone.

Geology

Lithology

The Marmaton Group, which is stratigraphically directly above the Cherokee Group, has been described based on outcrop descriptions from a large belt (10 to 25 miles in width) of outcrops along the Kansas-Missouri boundary as shown in Figure 5(Moore, 1949). The Fort Scott Limestone is the lowest formation in the Marmaton Group. It extends throughout Kansas, Oklahoma, Missouri, Iowa, and Nebraska in the subsurface and in outcrop and classification varies from state to state based on stratigraphic differences and historical nomenclature. For this discussion, the formation definitions and descriptions outlined in Moore(1949), which are generally accepted throughout Kansas, and have been adapted by Zeller(1968), and Merriam(1963), will be followed. Moore(1949) defines the Fort Scott Limestone formation to be composed of 2 limestone members separated by a shale with the total formation thickness ranging from 13-145 feet with an average of about 30 feet throughout Kansas(Merriam,1963).

The upper member is the Higginsville Limestone which is light to dark gray with a medium-grained crystalline texture and a brecciated appearance. Irregular wavy beds and stems of fusulines and large crinoids are found throughout the member and the upper portion is mostly made up of a coral called Chaetetes.

The middle member is the Little Osage Shale which is a grey to black fissile shale with an interbedded layer of coal in the lower section and a very thin limestone in the middle. Both are less than 1 foot in thickness in Kansas. Fossils are scarce throughout the member.

The lower member is more variable depending on location, but can generally be described by an upper portion that is light gray with a coarse crystalline texture and irregular bedding and a lower part that is tan, brownish, or dark gray fossiliferous limestone with thicker, more regular bedding than the upper portion and is commonly found to have conchoidal fracture. The upper portion contains Chaetets and fusulines while mollusks are common in the lower portion.

Depositional Environment

The Marmaton Group, as well as the Cherokee Group stratigraphically above it, are dominantly composed of stratigraphic sequences of marine and nonmarine deposits indicative of numerous advances and retreats of a shallow sea. Throughout both groups, the sequences approximately follow the following order, taken directly from Merriam(1963)

"(1) nonmarine sandstone, commonly uneven at the base, occupying channels cut in subjacent rocks, (2) sandy, silty, and clayey shale, unfossiliferous or containing land plant remains, (3) underclay, (4) coal, (5) black platy shale containing conodonts, and commonly bearing small spheroidal phosphatic concretions, (6) gray to brownish clayey or calcareous shale, or limestone containing a varied assemblage of marine invertebrates."

While sequences often lack certain lithologies from the above description, the order of appearances is generally followed throughout the Marmaton group and Cherokee group, indicating consistent depositional cycles throughout both groups.

The fossiliferous limestone portions of the Fort Scott Limestone are indicative of the latest stage of an advance of a shallow sea and the intervening shale portion would indicate slight retreats of the sea before further advancement allowing deposition of the overlying upper unit of the Fort Scott.

Directly below the Fort Scott Limestone is a black shale which marks the uppermost part of the Cherokee Group. Other formations of the Marmaton Group extend above the Fort Scott Limestone and follow the same cyclic layering of nonmarine and marine sedimentation.

Tectonic History

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The tectonic history of Kansas is relatively simple because Kansas is located on a platformlike extension of a large, stable craton(Merriam, 1963). A thin layer of sedimentary rock covers the basement complex which has had a limited amount of structural deformation and consists of thin units that lay nearly parallel and horizontal.

The Dickman Field is located on the Southwest flank of the Central Kansas Uplift(CKU) as shown in figure 6(Gerhard, 2004). The CKU is a region of uplift that trends northwest and is most likely associated with the plate convergence along the Ouachita Mountains orogenic belt in Arkansas when North America collided with

Gondwanaland from the Southeast. This deformation occurred from the late Mississippian to early Pennsylvanian and is considered the latest major structure deformation to affect the region (Merriam, 1963). Faults and fractures interpreted from oil drilling, drainage patterns, and smaller scale surface structures indicate the presence of NW- and NE-oriented faulting and fracturing in the study area.

Interpretations

Dickman 3D Seismic Attributes Generation

19 attributes have been generated by Geokinetics from the full offset Dickman 3D seismic dataset. Parameters for attribute generation were determined based on acquisition and processing parameters, physical properties of the target area, and resolution limits of the data. Variable parameters, those based on physical properties and resolution limits of the data, were chosen based on test images of curvature. All others were invariable because they were set by acquisition and processing parameters. Table HK.1 lists the parameters used for attribute generation and for all available data sets acquired thus far.

Seismic attribute analysis has been used to link geologic features, such as faults, fractures as well as to determine hydrocarbon deposition, generation, migration, entrapment, etc. Seismic amplitude extraction of dip azimuth and magnitude can directly provide a quantitative measure of the structural characteristics. Coherence, curvature and ant tracking volumes can detect the small scale and subtle change in seismic reflections that are below seismic amplitude resolution. The following gives a list of attributes that have been used for the Dickman field.

The following attribute sections will be accompanied by attribute maps for the Mississippian and Fort Scott Horizon. Each map contains interpretations in green, which were made by evaluating all of the attributes together.

Amplitude

Seismic amplitudes can be calculated in different ways, such as maximum peak and minimum trough, average, RMS(root mean square),etc. They are extracted from a user-defined time window generally on a picked time horizon. An amplitude anomaly can be a direct indicator of hydrocarbons. It's very sensitive to the seismic reflections due to impedance contrast of the adjacent sedimentary layers.

Figure 7 shows amplitude maps for the Mississippian and Fort Scott horizons. Within the Mississippian, some lineations are visible as well as a channel running through the dataset. However, since amplitude is sensitive to many variables and has limited resolution, many features that show up in other attributes are not visible in the amplitude map. The channel interpretations correlate well with the edges of high amplitude packages and a fault in the north correlates well with a low amplitude lineation.

The Fort Scott horizon also shows the north fault as well as a possible extension of the fault in the east, a few other lineations as well as a small dark package that may correlate to channel in the Mississippian horizon.

Time Gradients

Time gradient attributes are straight forward calculations based on an amplitude data set. The gradient is simply the change in time over a certain distance of a reflection. These calculations are done by fitting a plane through a reflection and calculating the dip and azimuth of the plane from the point of interest. This is illustrated in Figure 9. The dip refers to the magnitude and the azimuth refers to the direction. The gradient can be calculated in many different directions including along the inline direction, crossline direction, and the direction of maximum dip or magnitude (Rijks and Jauffred, 1991).

These attributes are viewed better on horizons than on time slices. They give insight to the geometry of a surface, and can help delineate any features that have changed the shape of the formation interfaces represented by the reflections. The following datasets have been calculated from the Dickman 3D amplitude dataset by Geokenetics: dip in the crossline direction (crossline dip), magnitude in the crossline direction (crossline gradient), dip in the inline direction (inline dip), gradient in the inline direction (inline gradient), direction of maximum dip (dip azimuth), magnitude of maximum dip (dip magnitude), direction of maximum gradient (grad azimuth), and magnitude of maximum gradient (grad magnitude).

A dip map measures magnitude of local dip (ms/m or ms/ft), e.g. the inclination of a horizon. Dip azimuth measures angle in degrees from local reference directions and dip magnitude (the magnitude of maximum dip). Rijks and Jaufred (1991) showed that horizon-based dip magnitude and dip-azimuth are useful in delineating subtle faults whose displacements measure only a fraction of a seismic wavelet. They can help to determine fault locations, subtle trace to trace vertical shift, minor faults or flextures, stratigraphic features such as channels, small-scale reservoir disturbance, etc.

A gradient magnitude operator detects the amplitude edges at which pixels change their gray-level suddenly. For an image volume f(**x**), the magnitude of the gradient vector is:

$$|\nabla f| = \sqrt{\left(\frac{\partial f}{\partial x}\right)^2 + \left(\frac{\partial f}{\partial y}\right)^2 + \left(\frac{\partial f}{\partial z}\right)^2} \qquad (1)$$

assuming a local maximum at an amplitude edge. The amplitude along the enhanced discontinuity surface varies irregularly depending on the amplitude contrast of the adjacent sedimentary layers. This can be used to detect amplitude change due to fault or fractures.

Figure 10 shows the dip azimuth map for the horizons. Areas of similar azimuth direction show up in the same color. This map is difficult to interpret on it's on but is easier in conjunction with the magnitude map which is shown in Figure 11.

On the Mississippian maps, when the dip magnitude changes within the channel, the dip azimuth also changes slightly. The edges of the channel do not correlate with highest dip or a certain dip direction, rather, it correlates in areas where the dip changes from a high dip to a low dip. The northern fault falls in a break between large areas of constant dip. To the northwest of the fault, the dip is consistently around 50 degrees with high magnitude and to the southeast, the dip is consistently around -50 degrees and of much lower magnitude. The Fort Scott horizon maps show similar characteristics for the fault. No other features appear to have significance in these maps.

Figures 11 and 12 show similar maps, however now they show the azimuth and magnitude of the gradient. These maps are even more difficult to interpret as the maximum gradient is dependent on both magnitude and direction. However, these maps show similar behavior for the fault. The channel appears to have varying azimuths on the channel depending on location on the channel and the gradient tends to be highest along the edges.

Coherence

The use of coherence on 3D seismic data was developed in the early 1990's by Bahorich and Farmer for quantifying waveform similarity between neighboring traces (Chopra and Marfurt, 2005). This was done by computing a localized, normalized cross-correlation of adjacent traces. For example, if a set of seismic traces are cut by a fault, the undisturbed traces on either side of the fault have very high continuity, while the trace(s) affected by the fault will produce a low correlation coefficient at that point (Bahorich and Farmer, 1995). This would lead to a discontinuity in the coherence, producing a lineation of low coherence along the fault.

Another method to calculate coherency is semblance- or variance-based. Semblance is the energy ratio of the average of the traces along a specific dip to the trace.. Variance is simply 1 minus the semblance. Figure 16 diagrammatically shows how this is done. Figure 16(a) shows the original traces within a specific window and dip, 16(b) shows the average of these traces, and 16(c) shows how the traces are all replaced with a scaled version of the average that best fits the original trace (Chopra and Marfurt, 2007). The semblance is the ratio of figure 16(c) to figure 16(a). Similar to crosscorrelation-based coherency, where there are low similarities between a trace and the average trace, a high discontinuity will be produced (Chopra and Marfurt, 2007).

This attribute will delineate geological features, such as faults, channels, fractures, and other stratigraphic boundaries by highlighting subtle differences between neighboring traces. In traditional 3D interpretation, such features can become difficult to view at certain alignments relative to bedding and viewing orientation. Since coherence will suppress laterally coherent features such as bedding, these features will be exemplified regardless of their orientations. Bahorich and Farmer demonstrated that while some of these features can appear more in focus in attributes such as dip and azimuth, coherence tends to give a more accurate portrayal, being independent of how well a horizon has been interpreted.

The coherent energy gradient can also be effective in delineating lateral changes in rock thickness, which are expressed in seismic data as changes in thin bed tuning (Marfurt, 2004).

Figure 15 shows maps showing total energy, which are equivalent to figure 16(c). This map shows average energy over a window of 10 ms. Different lithologies, thicknesses, reservoir characteristics etc will produce different levels of energy. The darker the color, the higher the energy. This map looks very similar to the amplitude map but with poorer resolution. Small features, such as the acquisition footprint in the amplitude map, is no longer resolvable. Figure 16 is analogous to the ratio of 14(c) to 14(a) which is the energy ratio or semblance. Areas where the magnitude of the average energy is greater than the original trace energy show up as light and dark extremes. This means that areas of discontinuity or low magnitude energy ratio show up in greys. So, features that correlate with discontinuities such as channel edges, faults and fractures lie in changes from light to dark. The fault can be seen in both horizons as a light lineation and the channel package is highly differentiable in the Mississippian horizon.

Curvature

Curvature is defined as the deviation of a surface from a straight line. In other words, it is the rate of change of direction of a curve at a certain point, which is the second derivative of the curve. It can also be described as the inverse of the radius of a circle that fits the curve at that point, such that a straight line will produce zero curvature, a synform produces a negative curvature, and an antiform produces a positive curvature. This can be extended into 3 dimensions by using a surface instead of a line and an ellipsoid instead of a circle. Since the surface at a point can have different curvatures at different azimuths, an ellipsoid is used instead of a sphere (Roberts, 2001).

Figure 17 illustrates the naming conventions for the different possible curvatures for the 3-dimensional case (Roberts, 2001). The curvatures along the surface's dip and strike are known as the dip curvature and strike curvature. These curvatures will always be orthogonal to each other, as will the maximum and minimum curvatures. The maximum curvature is defined as the surface of an orthogonal plane that intersects the surface at the azimuth with the maximum curvature, or where a circle of the smallest radius would fit the curve. The minimum curvature is not necessarily the plane with the smallest curvature on the surface, it is simply the plane orthogonal to the maximum curvature. The maximum curvature can be calculated for both positive and negative curvatures, giving two independent volumes. A large number of combinations of these curvatures can create varying curvatures, but this study focuses on maximum curvatures (Roberts, 2001).

Since curvature describes the shape of a reflection, it is essentially linked to the structure of the subsurface. Curvature should be able to illuminate any geological feature that dictates the shape of a reflection such as channels, faults, fractures, karst modifications, meteor craters, and volcanoes. These features could have affected the rocks when the interface represented by the reflection was at the surface of the earth or after burial.

Four curvature datasets have been created from the Dickman 3D amplitude dataset. These include maximum curvature, minimum curvature, most positive curvature and most negative curvature.

Figure 18 shows the positive curvature maps where high magnitudes of curvature are shown in black. Figure 19 shows the negative curvature maps where high magnitudes of curvature are shown in white. Interpreted features do not correlate with high magnitudes in either map, but instead seem to correlate with certain edges. Therefore, it is useful to look at curvatures together on one map. Figure 20 shows maps showing positive curvature in red, negative curvature in blue and energy ratio in grey scale. Now it is obvious that features correlate well between areas of high magnitude curvature. The green interpretations can now be more accurately placed showing where the fractures, faults, and channel features lie.

Conclusion

The Dickman Field is a good site to study in regards to its capacity to potentially store CO2 because of its small size, availability of data, and the applicability to many midcontinent reservoirs. Data sets have been compiled and typical interpretation has been completed. Further analysis and interpretation of the seismic data has been conducted to lineate certain features within the seal of the reservoir.

The seismic attributes available in the Dickman Field data set have been used to more accurately interpret both the Mississippian and Fort Scott horizons. The Mississippian horizon contains a known channel as well as a fault and many fractures. The extent of faulting and fracturing in the seal of the reservoir, the Fort Scott horizon, was previously unknown. The interpretations shown above indicate that while there is some fracturing and faulting in the Fort Scott, it is not nearly as extensive as it is in the Mississippian. Further work including more data acquisition and processing and interpretation of other available attributes could lead to even further delineation of these features. Modeling that includes the interpreted features could lead to a better understanding of the significance of the features on the reservoir's ability to act as a CO_2 storage container and flow within the reservoir.

Figures

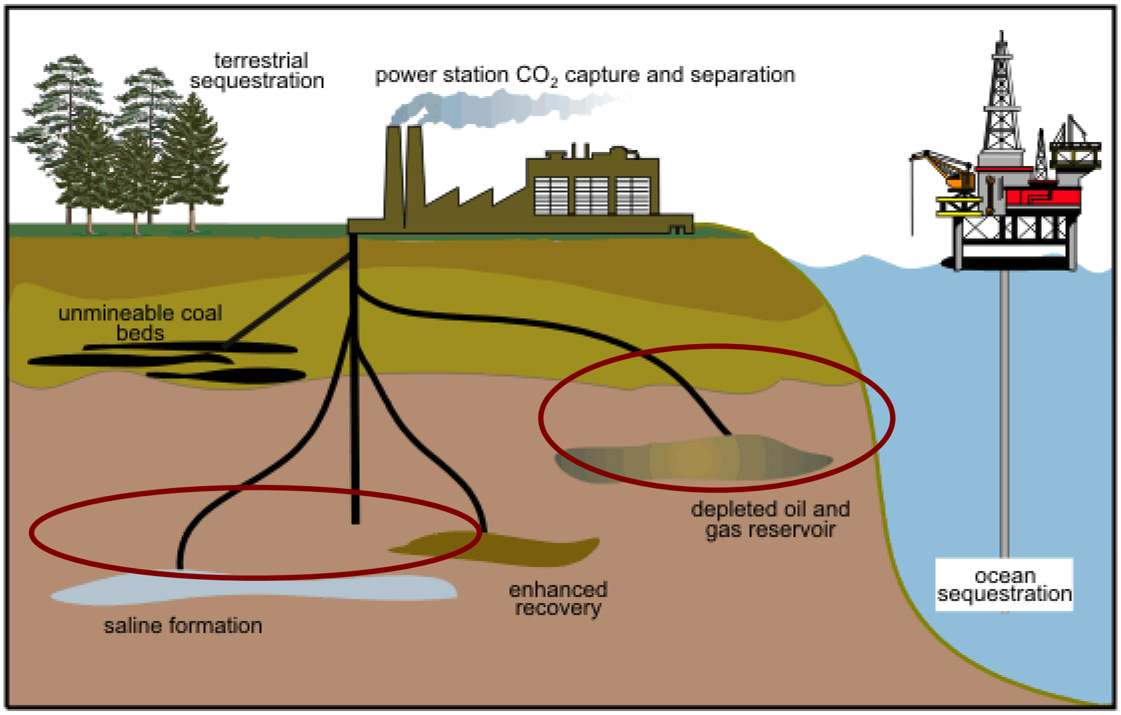

Figure 1: Diagram showing the possible types of CO2 sequestration. Saline formation and depleted oil and gas reservoir are circled in red and are the focus of the RQL CO2 sequestration study. Both types make good potential sites because of their known seal integrity. http://www.eia.doe.gov/kids/classactivities/images/carbon%20sequestration.gif

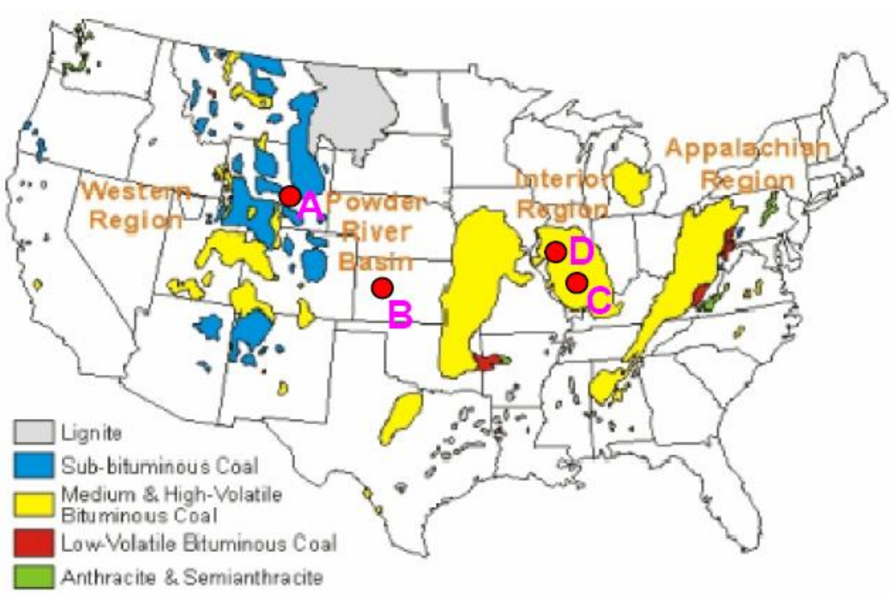

Figure 2: Map showing the RQL sites which are (A) Wyoming, (B) Kansas, (C) Ohio, and (D) Illinois (Hilterman and Bjorklund, 2007).

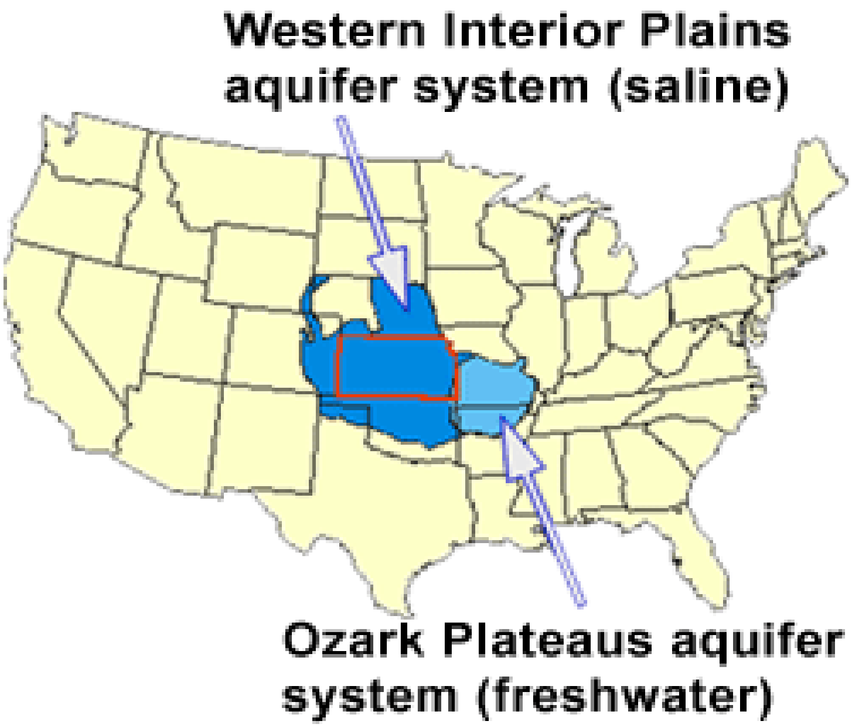

Figure 3: Map showing the Lower Paleozoic Ozark Plateau aquifer system that extends into 8 states and has a saline portion called the Western Interior Plains aquifer system(Nissen, Marfurt, Carr, 2004).

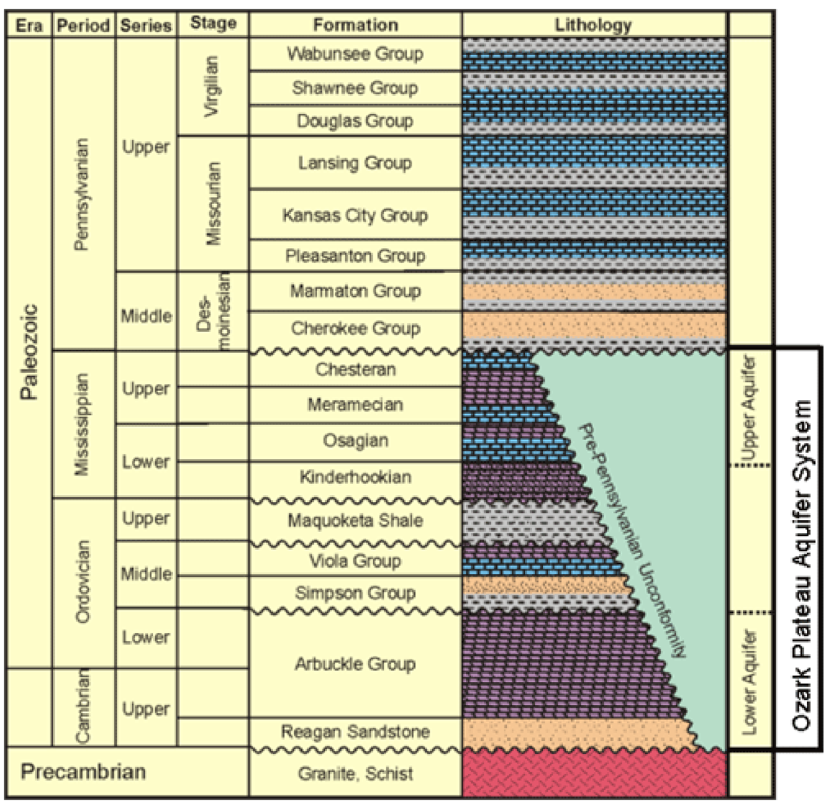

Figure 4: Stratigraphic section showing the Lower Paleozoic Ozark Plateau aquifer system which is made up of a Mississippian carbonate that is unconformibly overlain by a Pennsylvanian shale (Nissen, Marfurt, Carr, 2004).

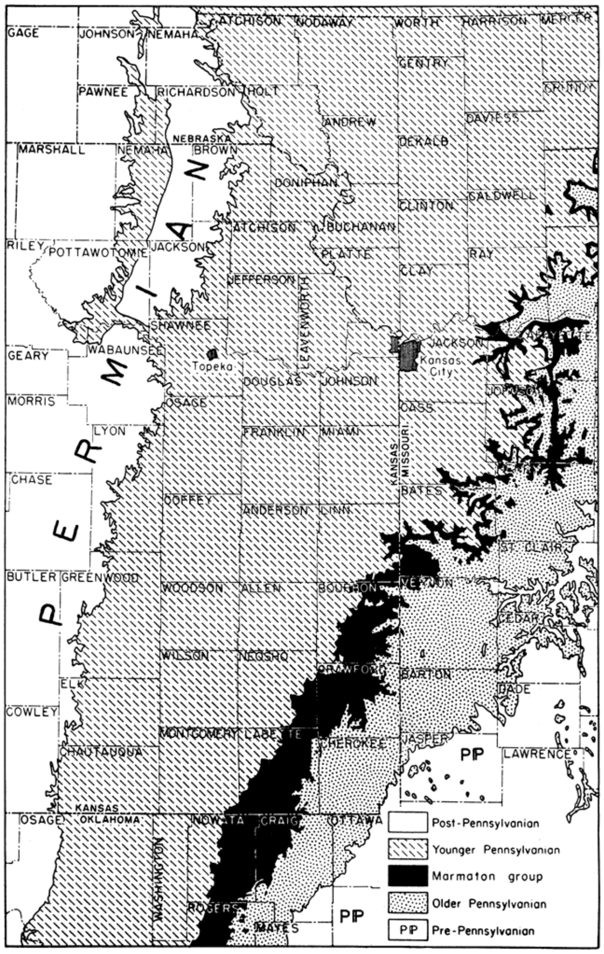

Figure 5: Distribution of Marmaton outcrops in Kansas and parts of adjoining states. The Marmaton group comprises the upper part of the Desmoinesian Series of Pennsylvanian rocks in the northern midcontinent region.(Moore, 1949)

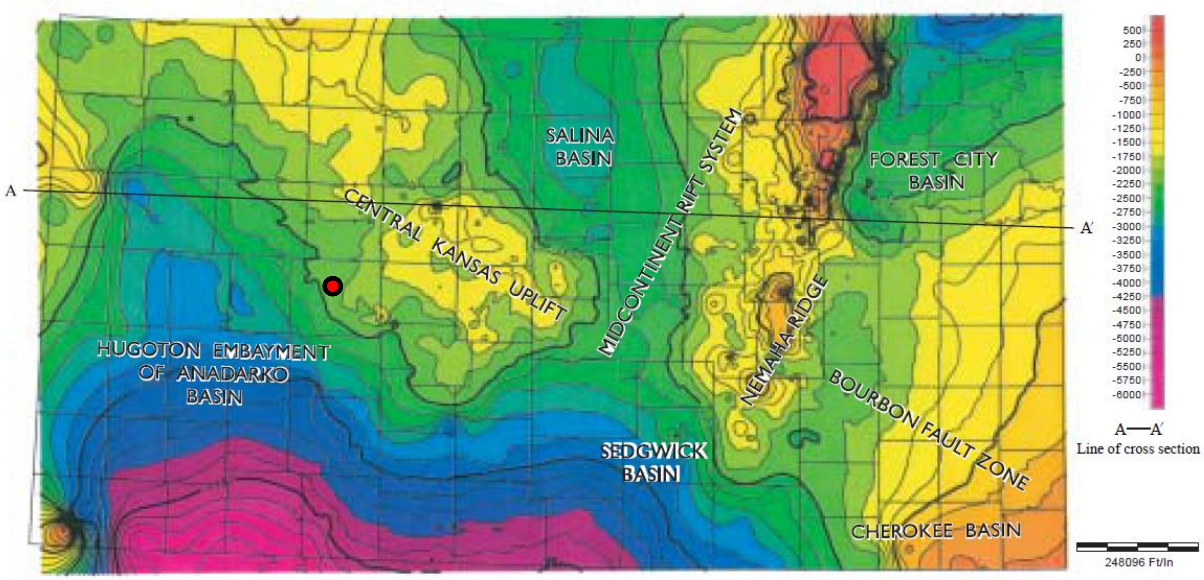

FIGURE 4. Map showing topographic (structural) relief on the present Precambrian/Phanerozoic surface. Major geologic structures of Kansas are labeled (T. Carr, personal communication, 2003). A-A' is line of section for fig. 5.

Figure 6: map showing topographic relief and the location of Dickman F ield with respect

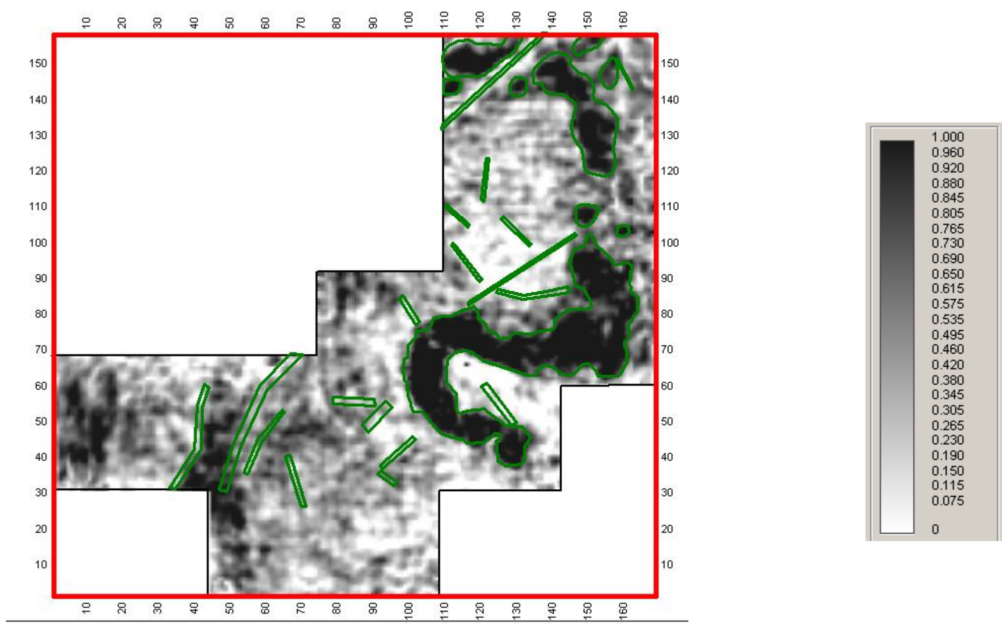

Figure 7: Seismic amplitude map extracted from the Mississippian horizon.

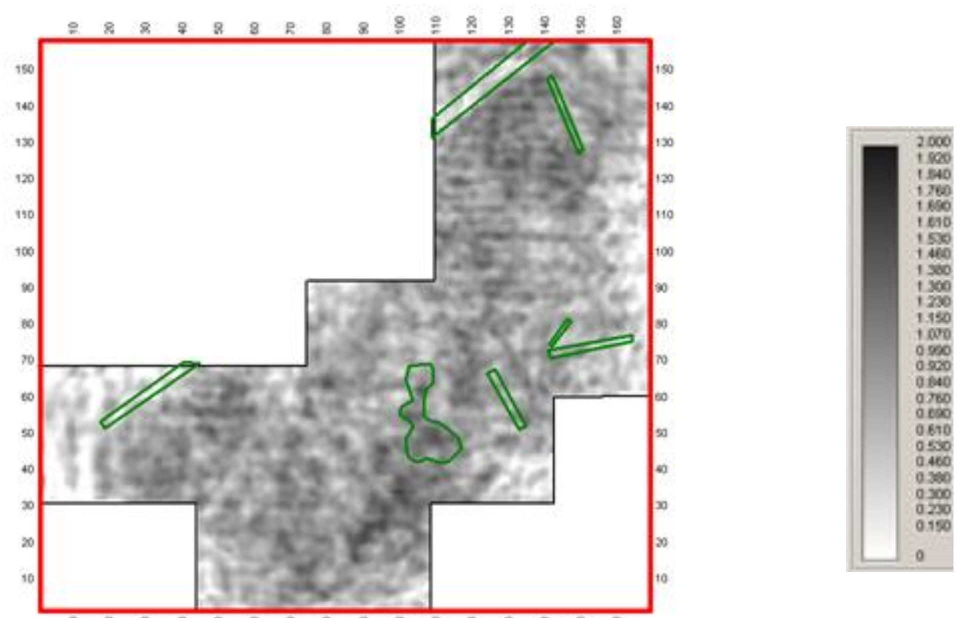

Figure 8: Seismic amplitude map extracted from the For Scott horizon.

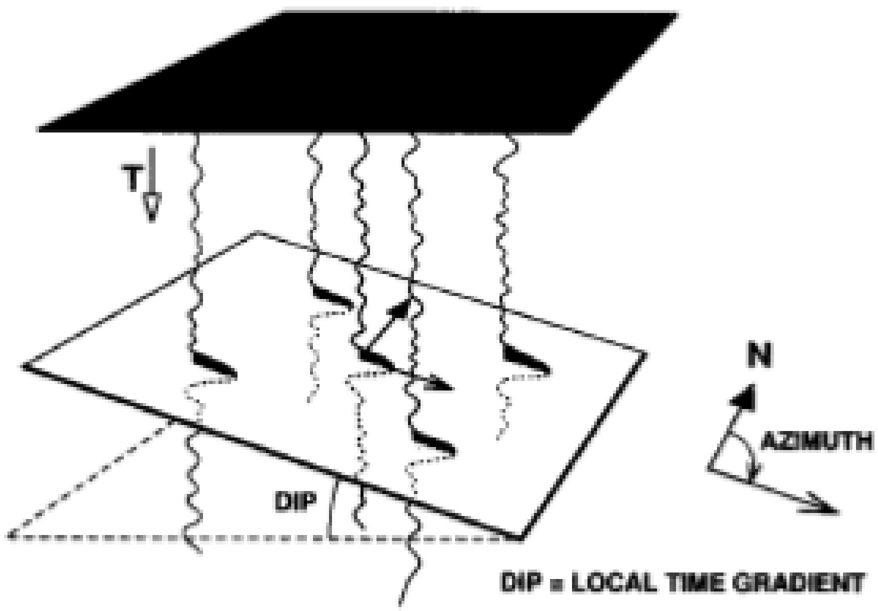

Figure 9: Diagram showing the principle of dip and azimuth calculation (Rijks and Jauffred, 1991).

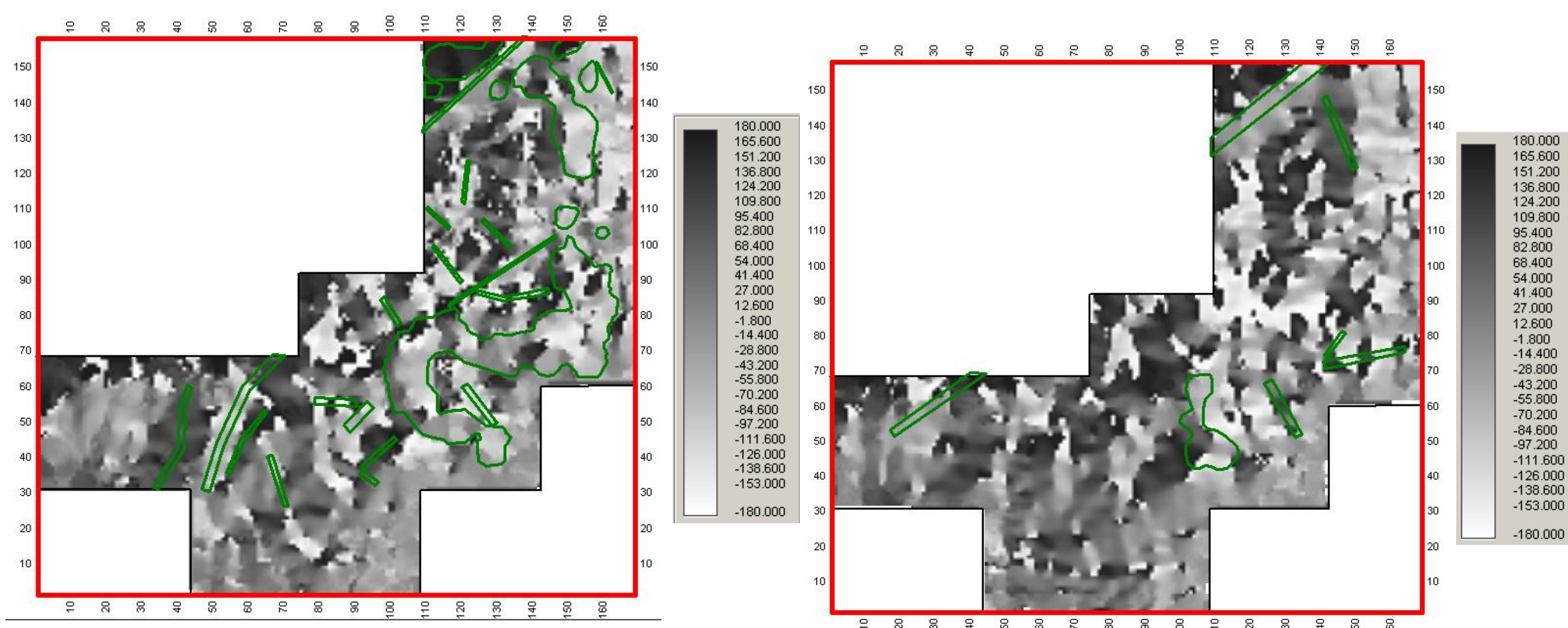

Figure 10: Dip Azimuth maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

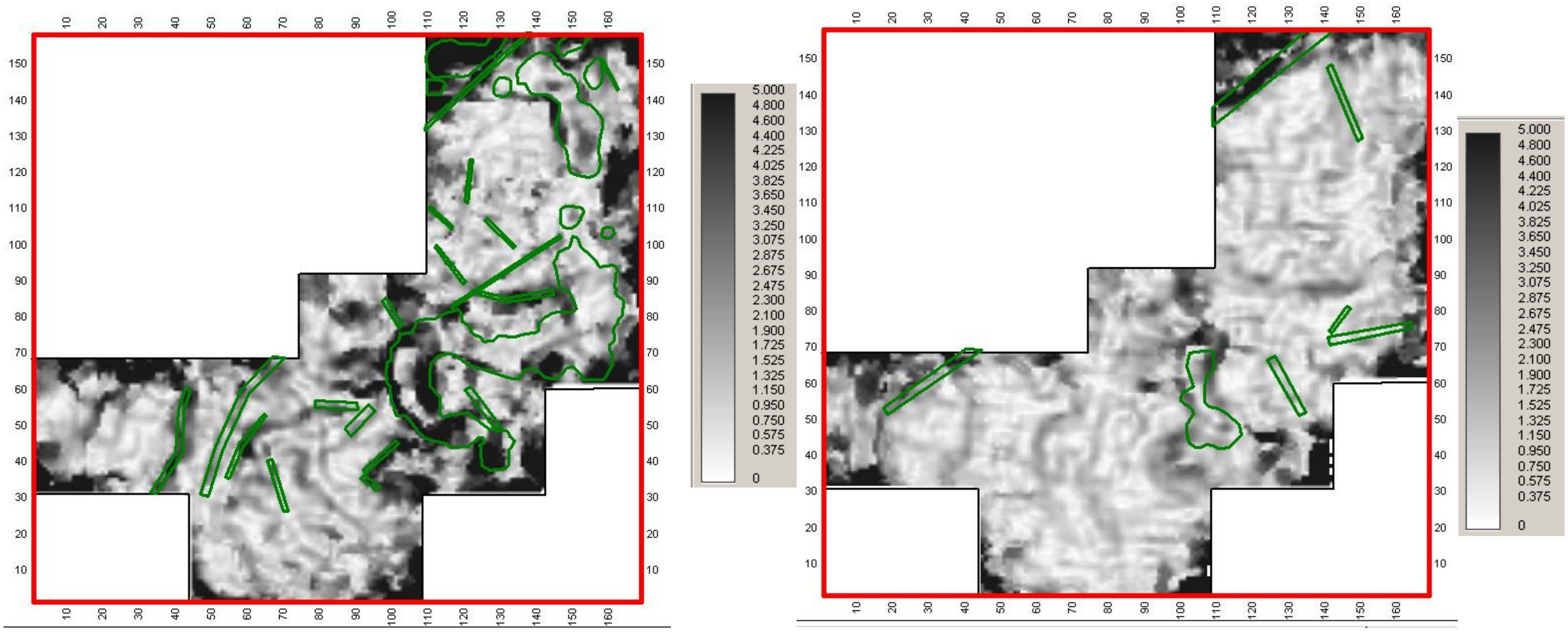

Figure 11: Dip magnitude maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

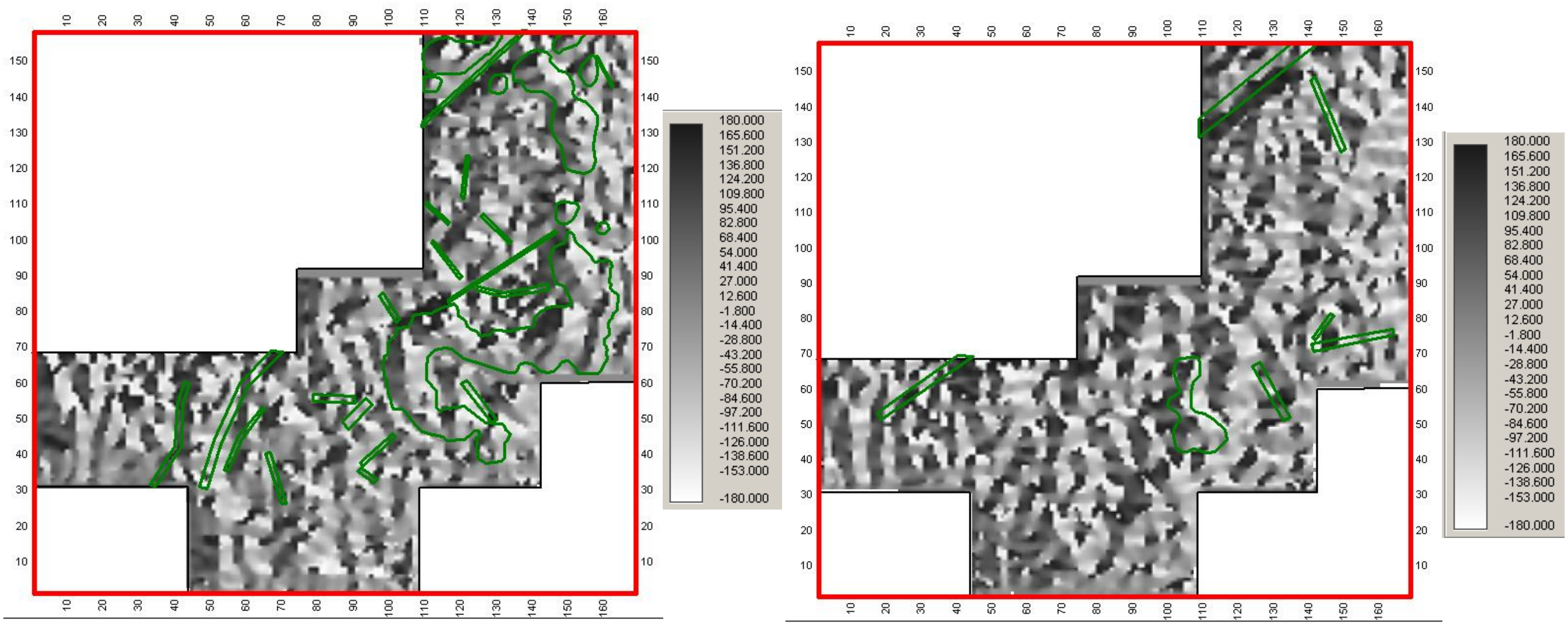

Figure 12: Gradient azimuth maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

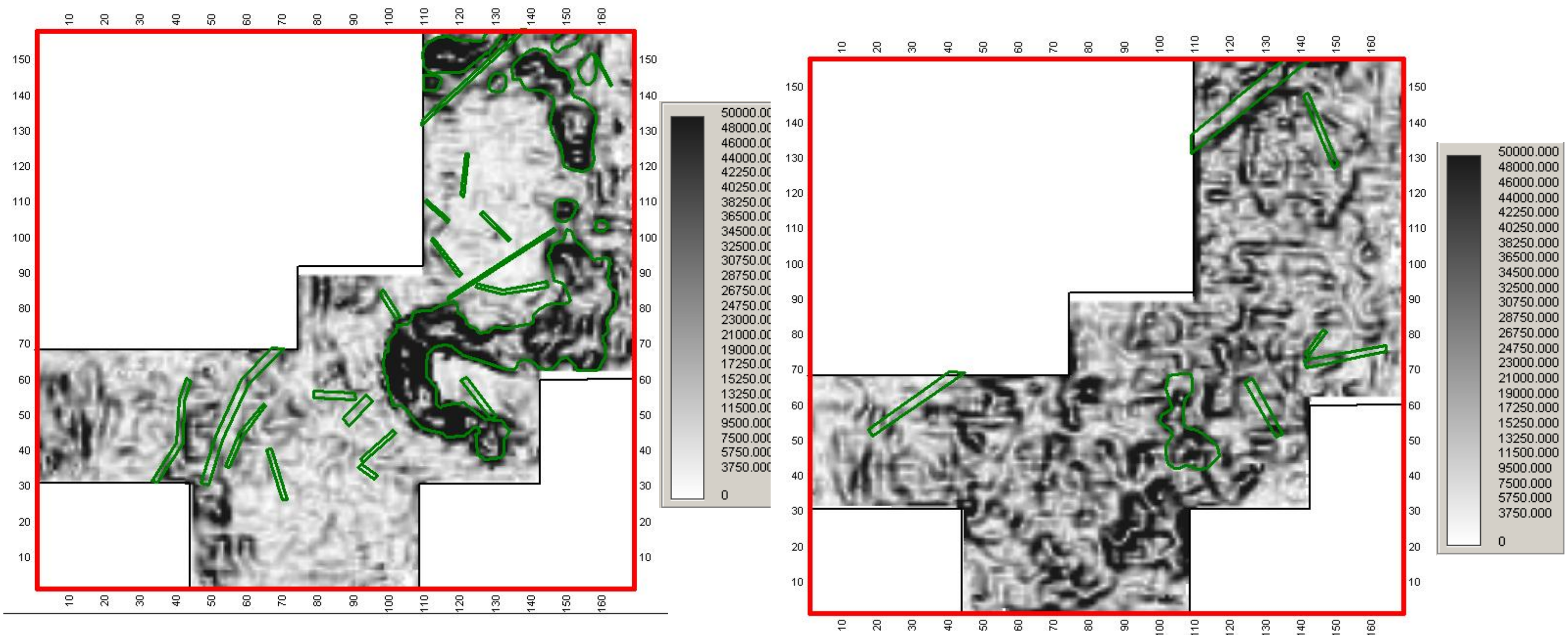

Figure 13: Gradient magnitude maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

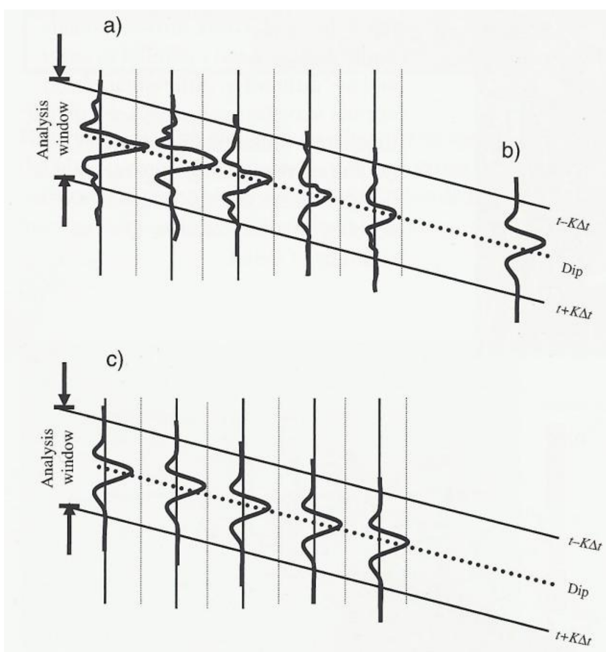

Figure 14: A diagram showing how semblance-based coherence is calculated. (a) Shows the input traces and the analysis window in which the energy will be calculated, (b) shows the calculated average trace, and (c) shows the traces replaces with the average trace. The semblance is the ratio of the energy

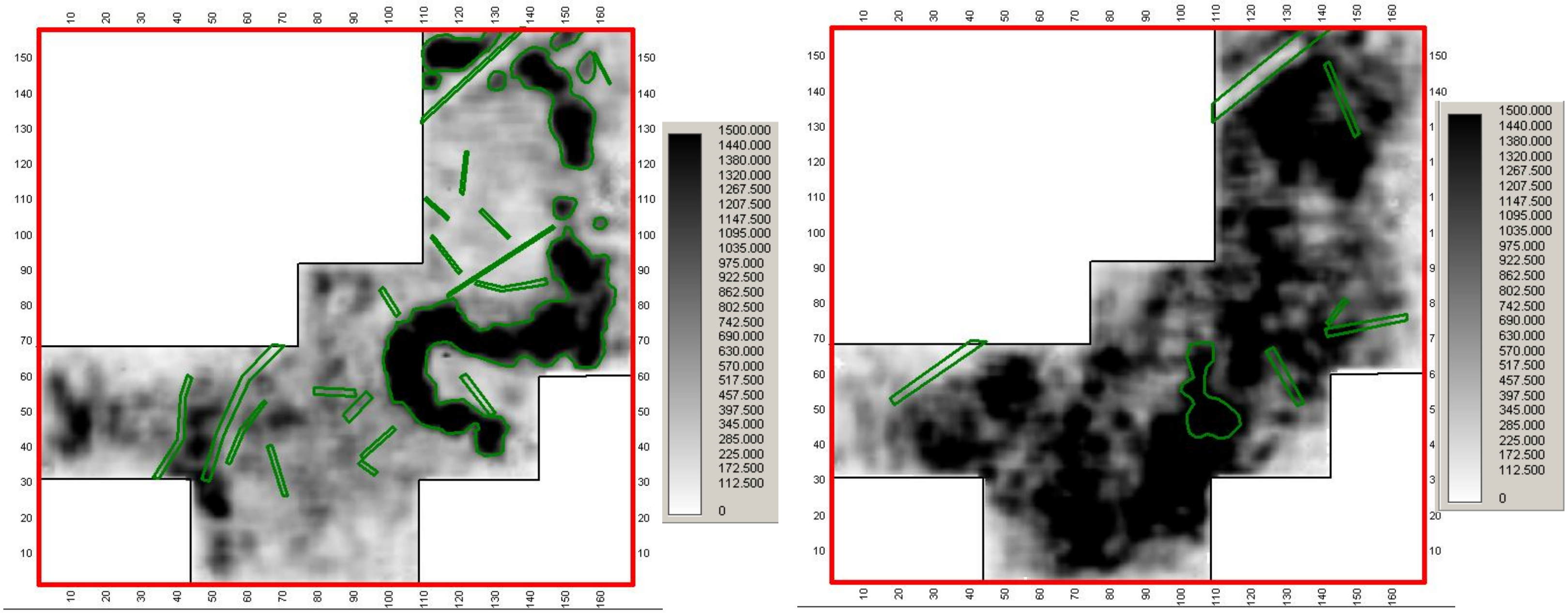

Figure 15 Total energy maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

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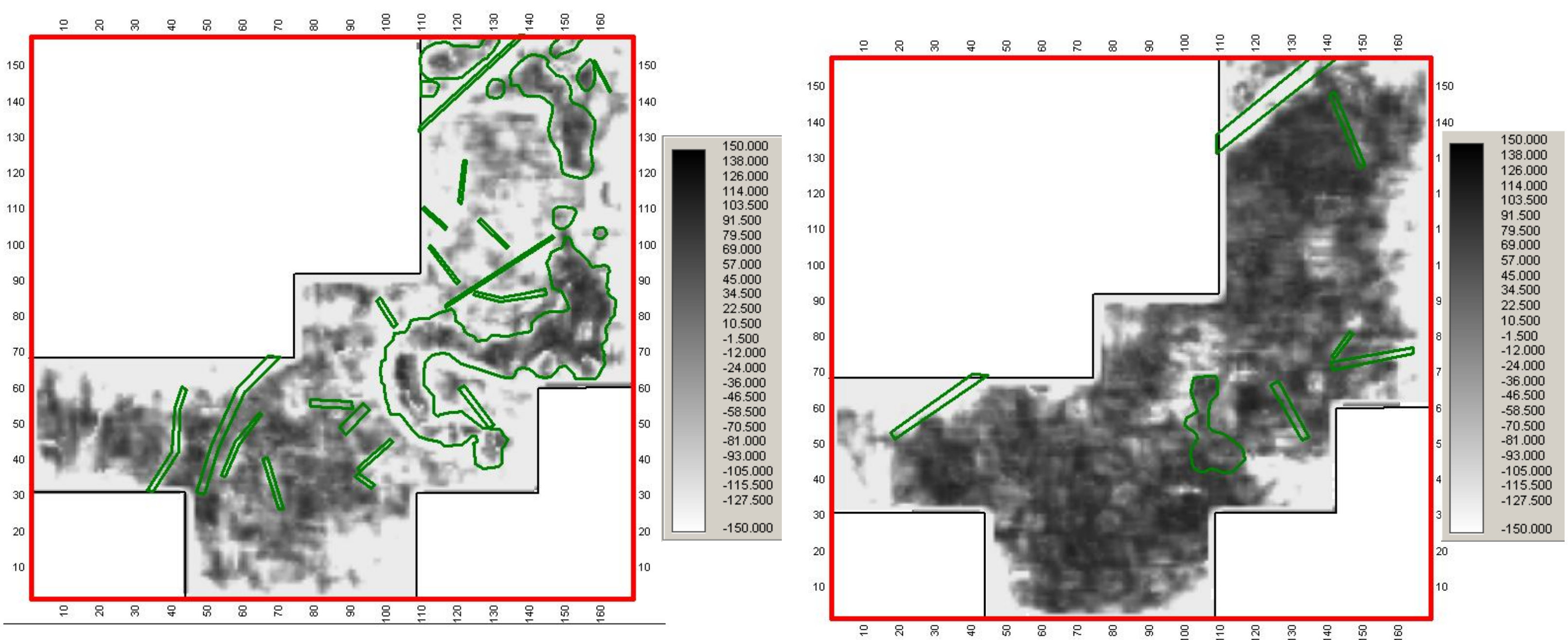

Figure 16: Energy ratio maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

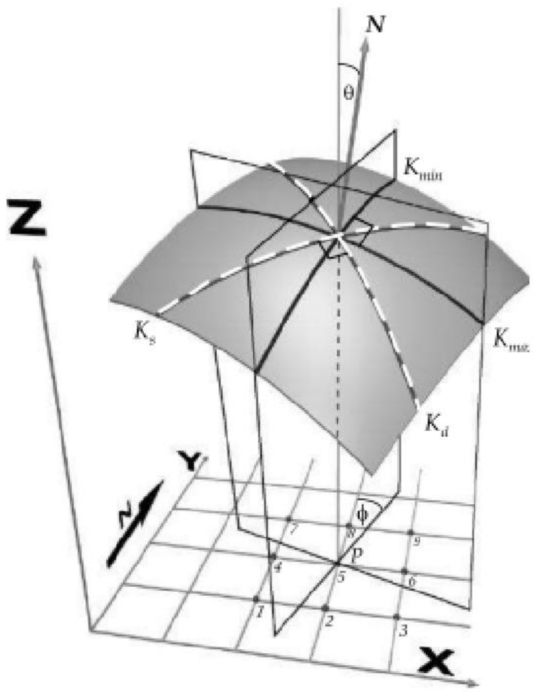

Figure 17: Diagram showing curvature naming conventions in 3D. X and y represent the map axes and z represents depth. N is the vector normal to the point P which makes an angle ɵ with the vertical. K_{max} is the maximum curvature, K_{min} is the minimum curvature, K_s is the strike curvature, and K_d is the dip curvature (Roberts, 2001).

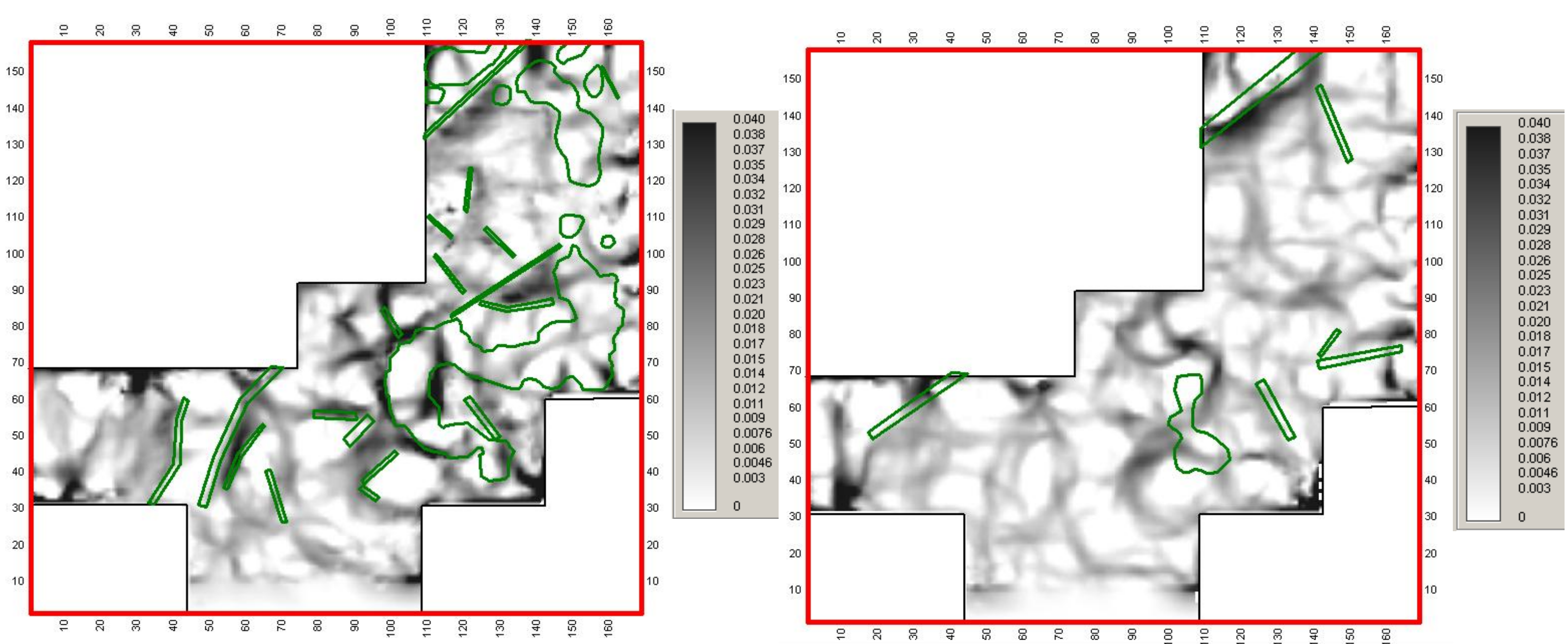

Figure 18: Positive curvature maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

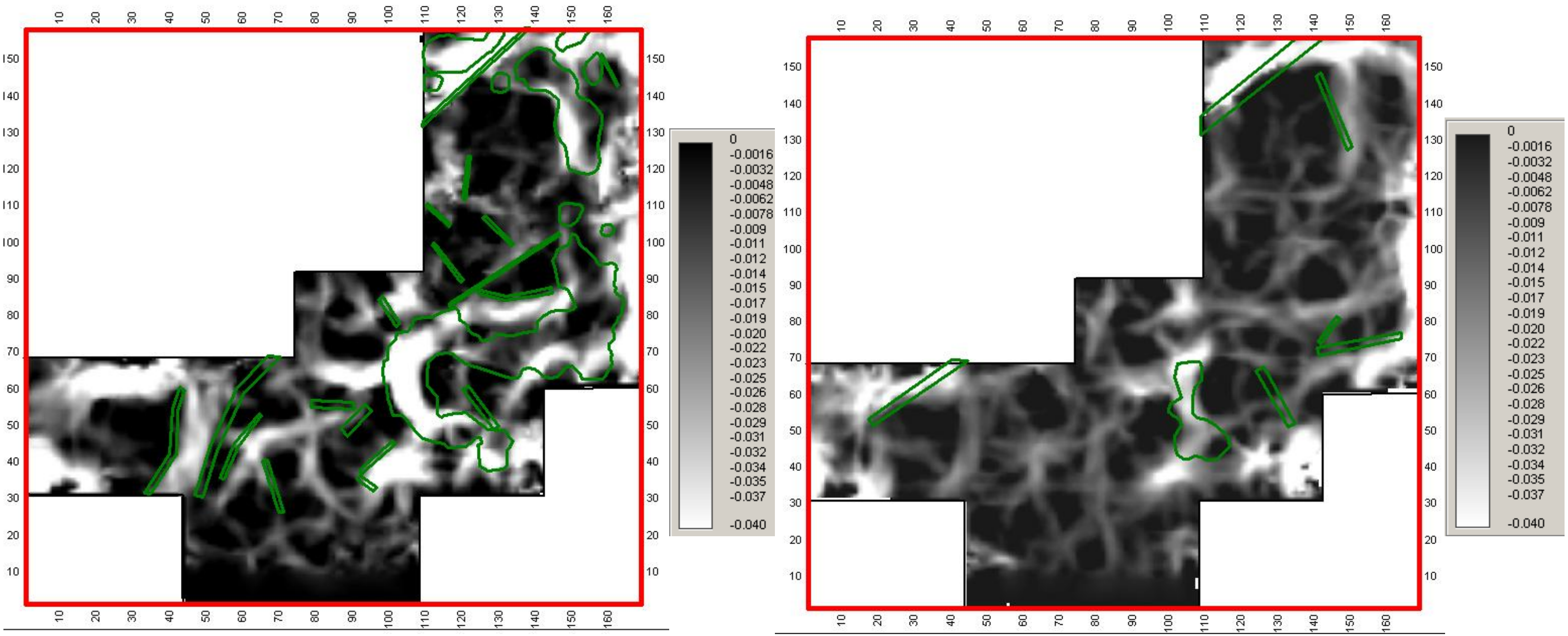

Figure 19: Negative curvature maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

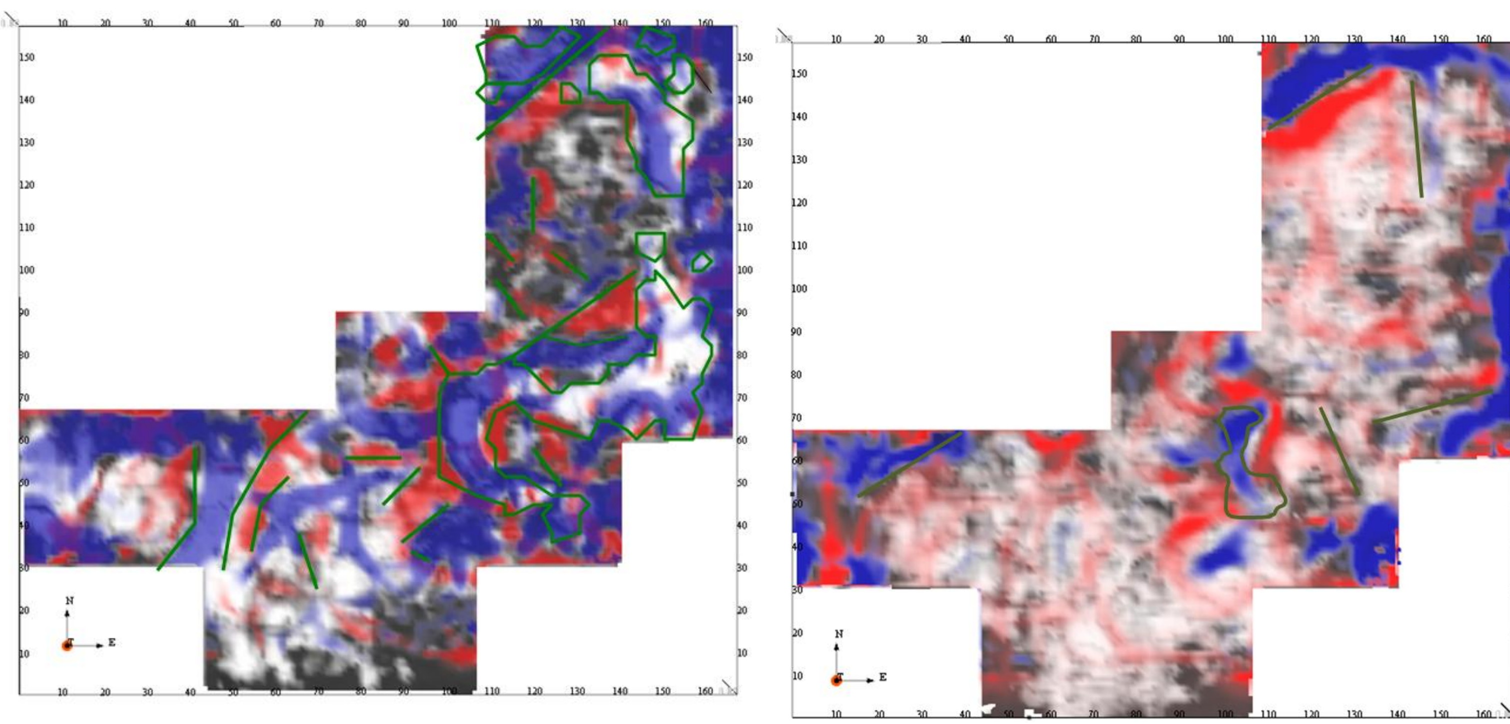

Figure 20: Energy ratio maps extracted from the Mississippian horizon(left) and Fort Scott horizon(right).

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