INCORPORATING SEISMIC ATTRIBUTE VARIATION INTO THE PRE-WELL PLACEMENT WORKFLOW
A CASE STUDY FROM NESS COUNTY, KANSAS, USA

by

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Abstract

3D seismic surveys have become the backbone of many exploration programs because of their high resolution and subsequent success for wildcat test wells. There are occasions when the predicted subsurface geology does not agree with the actual geology encountered in the drilled well. A case in point occurred during the drilling of several wells based upon a 3D seismic survey in Ness County, Kansas, where the predicted Cherokee Sand did not meet the expectations. By better understanding the subsurface geologic features in the subject area, this study will attempt to answer the question "what went wrong?"

Seismic attribute analysis workflow was carried out and the results were correlated to the available geological and borehole data within the survey boundaries. The objective of running this workflow was to describe facies variations within the Cherokee Sandstone. Correlations between seismic attributes and physical properties from well data were used to define these variations. Finally, Distributions of the seismic facies were mapped to predict the distribution of potential reservoir rocks within the prospect area.

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Special thanks to Susan Nissen for her help in setting up the project. Also, many thanks go to Coral Coast Petroleum for providing the data for this study and Schlumberger for donating academic license for their software.

Dedication

I want to dedicate this work for the love of my life Sarah my wife. For her patience, support and encouragement during the last two years. Without her this work would have been impossible for me. So, thank you Sarah …

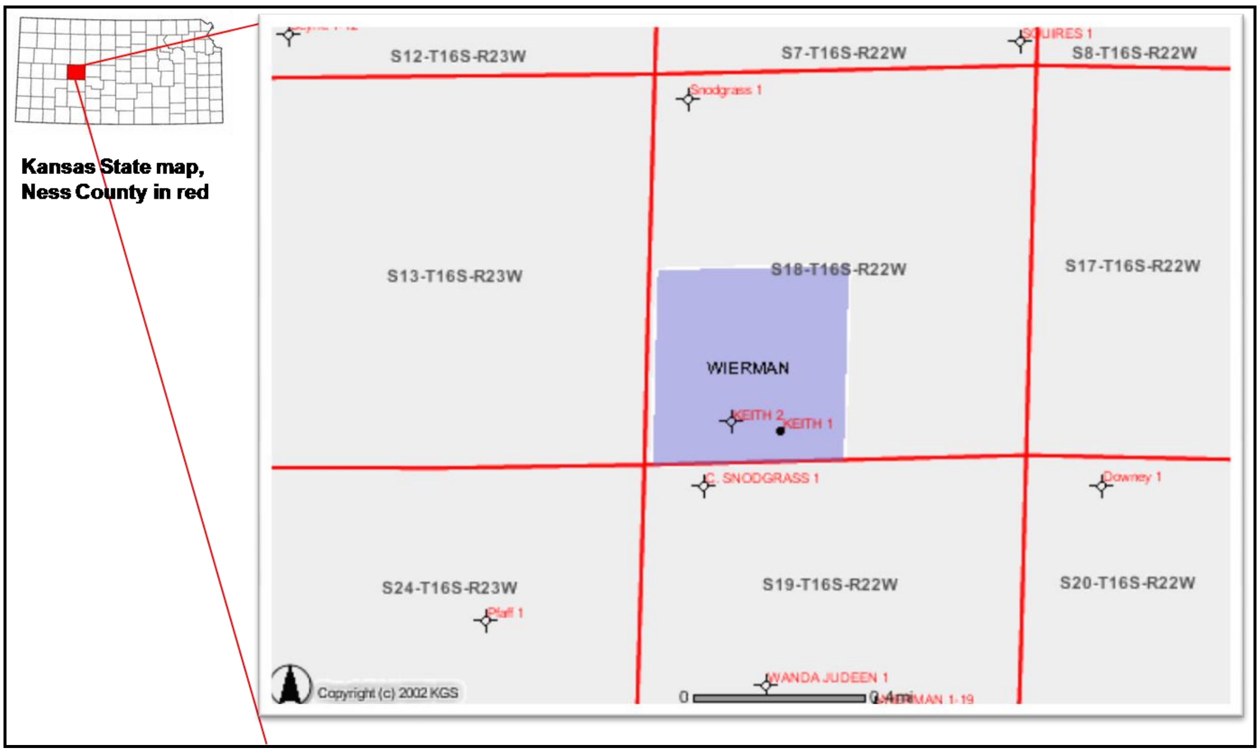
CHAPTER 1 - Introduction

Background

3D seismic surveys have become the backbone of many exploration programs because of their high resolution and subsequent success for wildcat test wells. There are occasions when the predicted subsurface geology does not agree with the actual geology encountered in the drilled well, begging the question "what went wrong?"

In 2003 Coral Coast Petroleum started drilling a wildcat well, Keith #1, with a Cherokee Sandstone target in northeastern Ness County, Kansas. Figure 1-1 shows the location of Keith #1 which is Section 18, Township 16 South, Range 22 West (S18-T16S-R22W). The well produced 162 barrels before it was plugged as dry and abandoned.

Figure 1-1 Map location of the subject well [1]



The prospect was based upon a 3D seismic survey, which predicted the presence of an extensive sandstone reservoir. From discussions with the operator, the potential reservoir was

[1] Modified from (Kansas Geological Survey, 2009)

identified based on two criteria. First, occurrence and tracking of the doublet signal reflection at the base of the Cherokee formation and right at the top of Mississippian formation (Figure 1-2). The second criterion was the isochron (time) thickness at that area (Figure 1-3). However, the predicted sand body was not encountered as expected. The results of a drillstem test encouraged the operator to run production casing and complete the well, however very little oil was produced and the well was subsequently abandoned.

Figure 1-2 Seismic cross section showing the doublet tracking

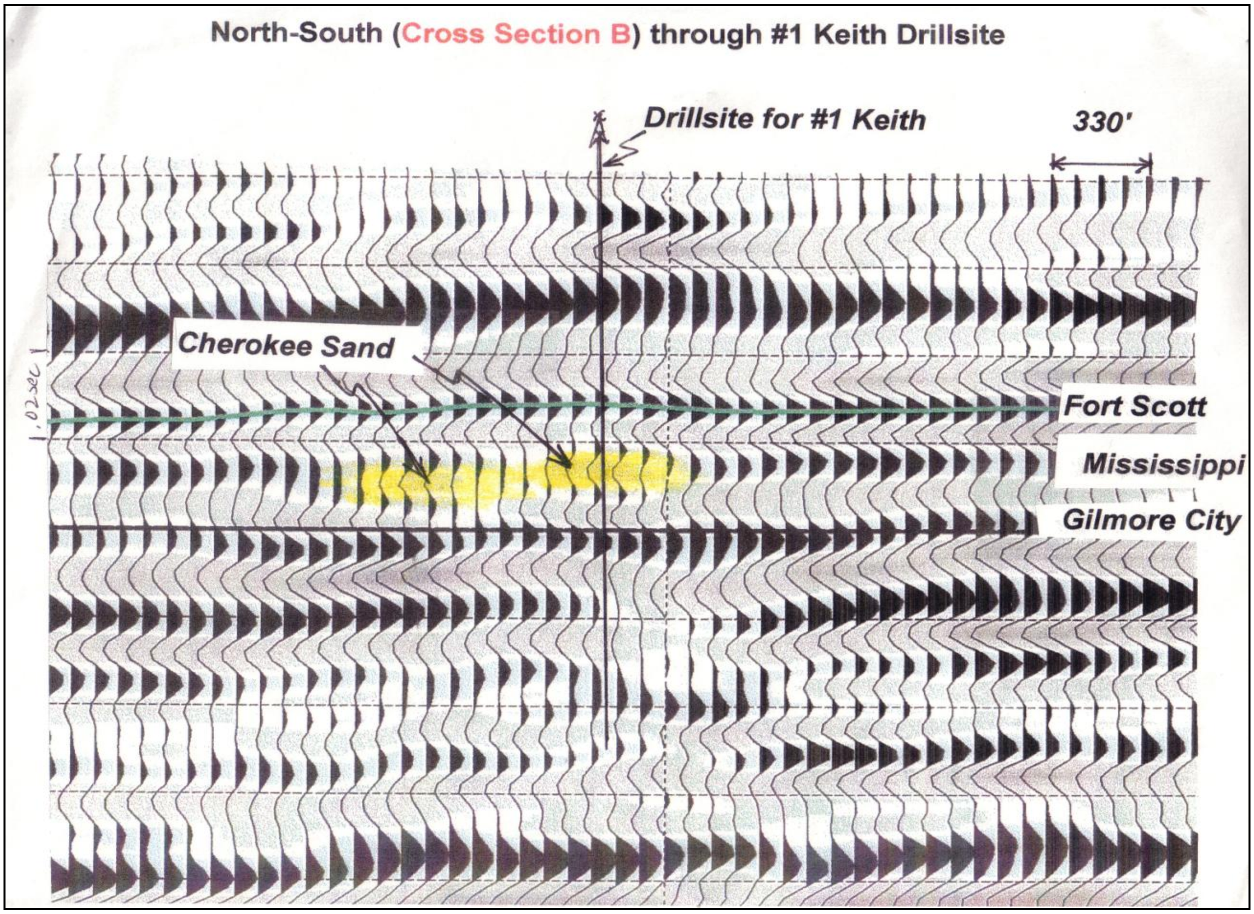
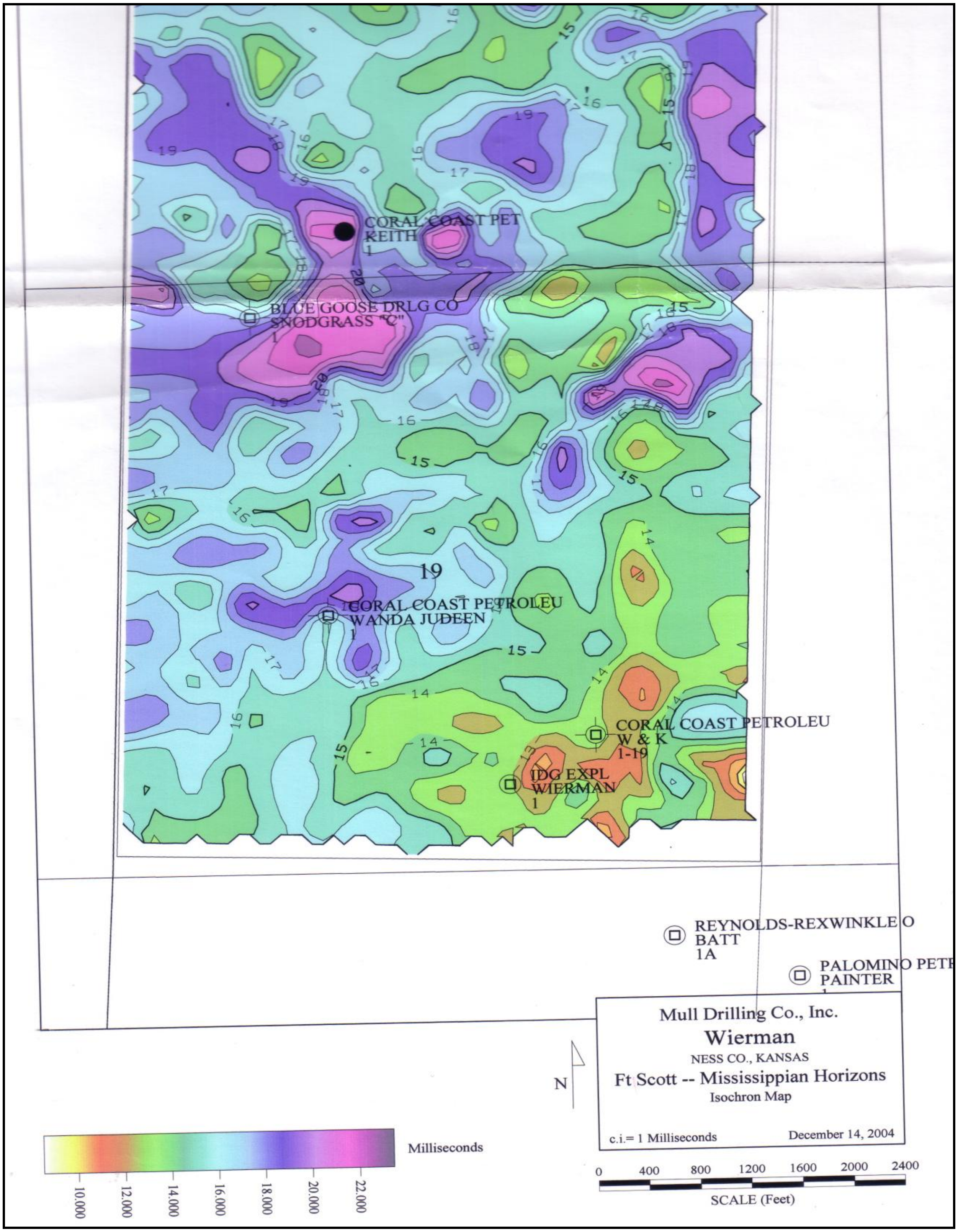


Figure 1-3 Isochron map showing Keith #1 well drill site at the thickest spot in the map



Objective

The main objective of this study is to investigate why using the seismic survey did not give the positive results expected in Keith #1. In addition, this study tries to determine whether additional geophysical interpretation techniques, exclusive of reprocessing the seismic dataset, would have prevented this dry hole with its subsequent large investment of resources. Furthermore, establishing a workflow that avoids the false positive indicators used in this prospect will be of benefit to other operators in this region.

Methodology

As a starting point for this project, data collected from previous work on the Keith Prospect was loaded and reviewed. Collected data include; 3D seismic survey, well logs, maps and any reports or documentations written for the subject wells. For the purpose of this project, Petrel software from an academic license granted by Schlumberger was used to accomplish the workflow of suggested methods for this project (Table 1-1). After loading the available data into Petrel, quality checking and verification of the data was carried out. Synthetic seismograms using the acoustic log collected from the available wells were constructed. The synthetic seismograms were compared against the seismic survey and well top markers which identifies the distribution of each formation within the seismic data. Then, with the help of the synthetics seismograms overlain on top of the seismic sections, the identified formation tops were tracked and interpreted throughout the survey. This generated the basic structure horizons which were used to generate their relative surfaces maps. The next step was to generate the seismic attributes maps for all surfaces. Finally, seismic attributes analysis was carried out as the last step before the results were drawn out.

Table 1-1 Suggested methods

Step	Method description
Step 1	Create new project in Petrel, load and quality check available data
Step 2	Synthetic seismograms - generation and interpretation
Step 3	Horizon tracking and surface generation
Step 4	Seismic attributes generation
Step 5	Seismic attributes analysis

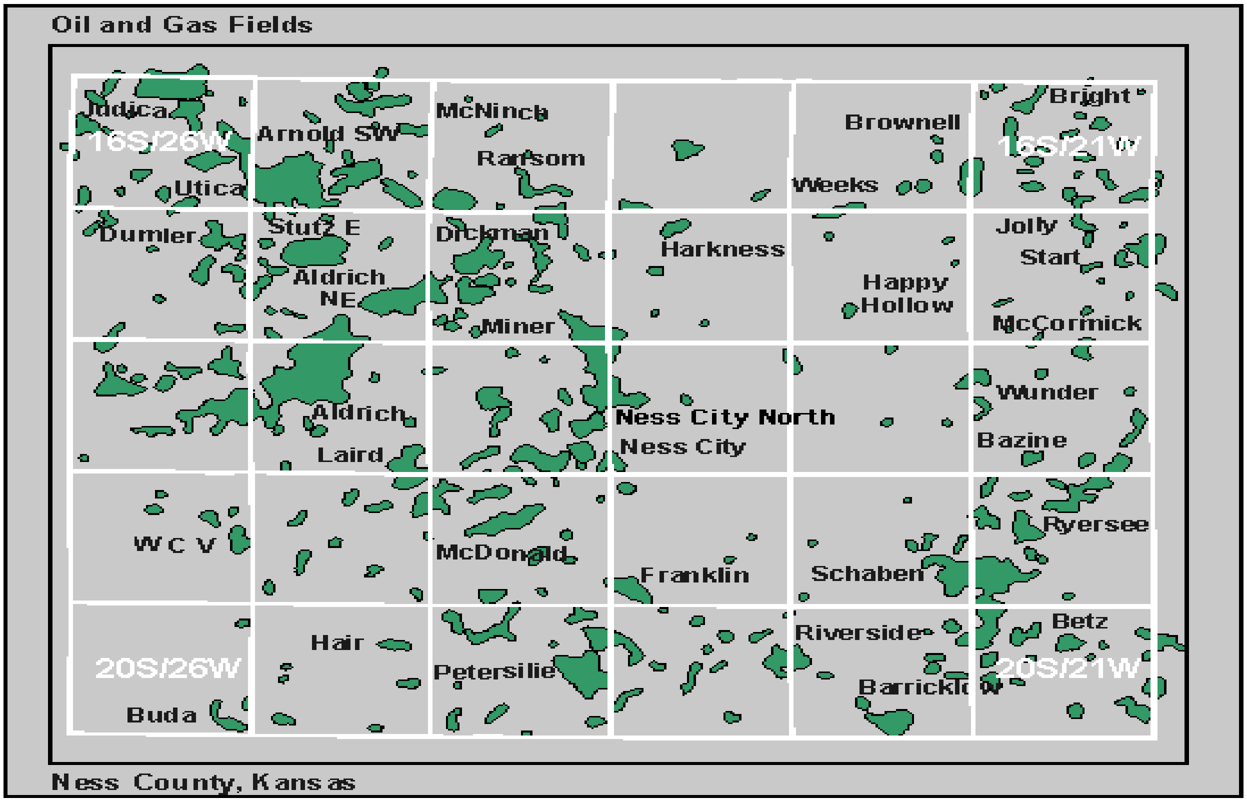
CHAPTER 2 - Literature Review

Brief History

Ness County is located in the western half of the State of Kansas. The eastern part of the county lies on the western flank of the central Kansas uplift. Strucker No. 1 was the first exploratory well in Ness County, which is located at SE NW of S1-T17S-R26W, in 1922. The well was abandoned at total depth of 3,500 ft. In 1929, Aldrich No. 1 was drilled in NE SW of S7-T18S-R25W. The well was drilled on the Beeler anticline and oil was found on the top of the "Mississippi Lime" which was encountered at 4,422 ft. Initial production of Aldrich No. 1 was 100 bpd (Carpenter, 1945).

In 2006, the number of producing wells in Ness County reached 891 wells with total production of 1,774,405 bbls of oil and 110,843 mcf of gas for that year. The majority of these wells are producing from Mississippian zones (Kansas Geological Survey, 2009). The pinching out of the "Mississippi Lime" towards the northeast of the Ness County and the related fold towards the west half of the county are the two principle geologic conditions for the presence of oil accumulation in the county (Carpenter, 1945). In this area production occurs primarily within Pennsylvanian-aged sandstone (Cherokee). Figure 2-1 shows the distribution of oil fields in Ness County.

Figure 2-1 Distribution of Oil fields in Ness County [2]



Geological Review

Upper Mississippian

The Upper Mississippian Series in Kansas consists predominantly of beds of limestone and dolomite, with interspersed beds of sandstone and shale, and minor amounts of chert.

Rocks of the Meramecian Stage lie disconformably on Osagian rocks, but in northeastern and southwestern Kansas the disconformity is unclear. It consists of Warsaw Limestone, Salem Limestone, St. Louis Limestone and Ste. Genevieve Limestone. The upper formations consist mostly of granular, sandy, oolitic and fossiliferous limestone, but lower formations contain interbedded dolomite or are mainly dolomite and silty, dolomitic limestone containing variable quantities of chert. Meramecian rocks, except for the Ste. Genevieve Limestone, probably extended originally throughout Kansas but were eroded from much of the State before Pennsylvanian deposits were formed (Zeller, 1968).

[2] Modified from (Kansas Geological Survey, 2009)

The Warsaw Limestone is 30 to 40 feet thick in the Forest City and Salina basins and 250 feet thick in the central part of the Hugoton embayment. The Salem Limestone conformably overlies the Warsaw Limestone. Its thickness is about 50 feet in the deepest part of the Salina basin, where it underlies Pennsylvanian rocks, and in the Forest City basin, where it underlies the St. Louis Limestone. In the Hugoton embayment, it is about 200 feet thick. Although restricted to basin areas, the St. Louis Limestone is more widely distributed. It is not recognized in the Salina basin. Maximum thickness in the Forest City basin is about 50 feet and in the Hugoton embayment about 200 feet. The Ste. Genevieve Limestone, which lies disconformably beneath Chesteran rocks but seemingly conformable on the St. Louis Limestone, is widespread in the Hugoton embayment, but is not recognized in the Salina basin. Its thickness is more than 200 feet in the Hugoton embayment (Zeller, 1968).

Important unconformities separate the rocks of the Chesteran Stage from Pennsylvanian rocks above and Meramecian beds below. Chesteran rocks are unknown in south-central and northern Kansas. In the subsurface of southwestern Kansas, Chesteran rocks are confined to deeper parts of the Hugoton embayment in Morton, Stevens, Seward, Meade, Grant, Haskell, and parts of adjacent counties. Thickness ranges from 0 feet to more than 300 feet near the Oklahoma state line. In Kansas Chesteran rocks are thin or absent on several structural highs (Zeller, 1968).

Cherokee Group

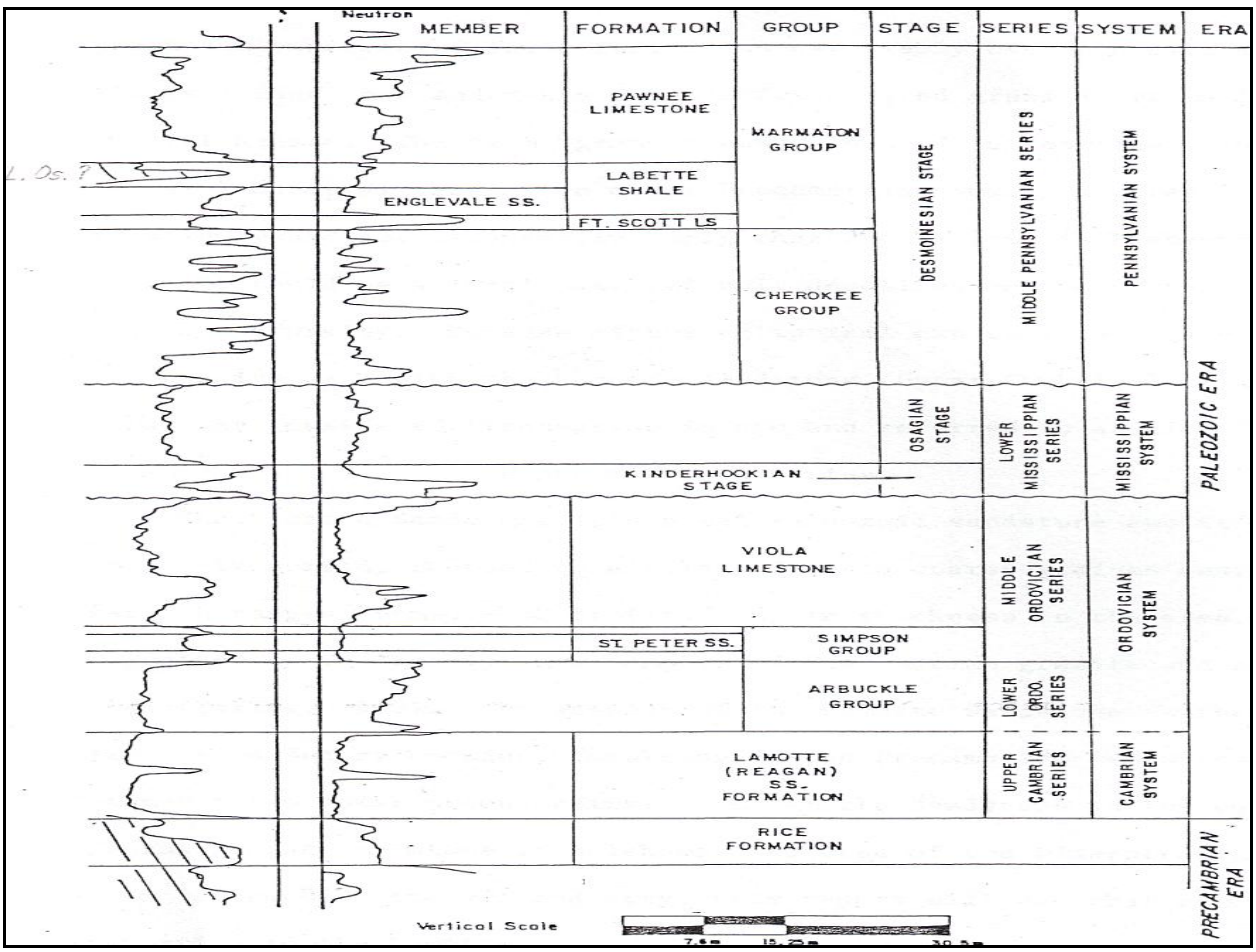
Stratigraphy

The Desmoinesian Stage of the Middle Pennsylvanian Series represents the initial period of deposition in the area following the Mississippian unconformity. The Cherokee Group is the lowest division of the Desmoinesian Series and is composed mostly of shale and sandstone, with minor amounts of limestone. Thickness of the Cherokee Group in the area ranges from 5 to 200 ft (Stoneburner, 1982).

The Marmaton Group conformably overlies the Cherokee Group. The group is divided into four limestone formations with each one separated by a formation of shale. The lower two limestone units are the Fort Scott and Pawnee limestone and the shale separating them is the Labette shale formation. These formations represent changes from clastic to carbonate deposition in the area (Stoneburner, 1982).

The Fort Scott Limestone is primarily cream to tan to light-gray macrocrystalline limestone characterized by local occurrences of fusulinids, crinoids stems, and rare developments of oolitic limestone. The thickness of the formation generally ranges from 8 to 12 ft. The Labette Shale Formation ranges from 15 to 50 ft in thickness and consists of gray, reddish-brown and maroon shale with consistent dark-gray carbonaceous shale present in the upper part. The lower section is typically micaceous and silty, with local development of sandstones. The Pawnee Limestone conformably overlies the Labette Shale. The lithology of the formation is predominantly chert, with some limestone and dolomite. The thickness of the Pawnee Limestone is ranging from 30 to 70 ft (Stoneburner, 1982). Figure 2-2 illustrates the stratigraphy in Ness County based upon well log signatures.

Figure 2-2 The relationship between the stratigraphy and a generalized type log in the area [3]



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[3] Modified from (Stoneburner, 1982)

Depositional Environment

In western Kansas, the Cherokee Group overlies rocks ranging in age from Precambrian to Atokan. The Cherokee was deposited in environments that are transitional from continental to marginal marine as the Hugoton Sea transgressed the Mississippian unconformity onto the Central Kansas uplift (Cuzella, 1991).

Figure 2-3 shows the stratigraphic relations of Cherokee rocks to older and younger units. The area of study is roughly in the region between wells 9 and 10 in the cross section. In the southwest the Cherokee strata appear to be thicker than towards the Central Kansas Uplift. Near the uplift the Cherokee group is mainly composed of clastic material derived from the eroding Central Kansas uplift. Away from the uplift in the southwest it consists mainly of limestone and black shale (Merriam, 1963).

Figure 2-3 A southwest-northeast stratigraphic cross section from Kearny to Ellis Counties [4]

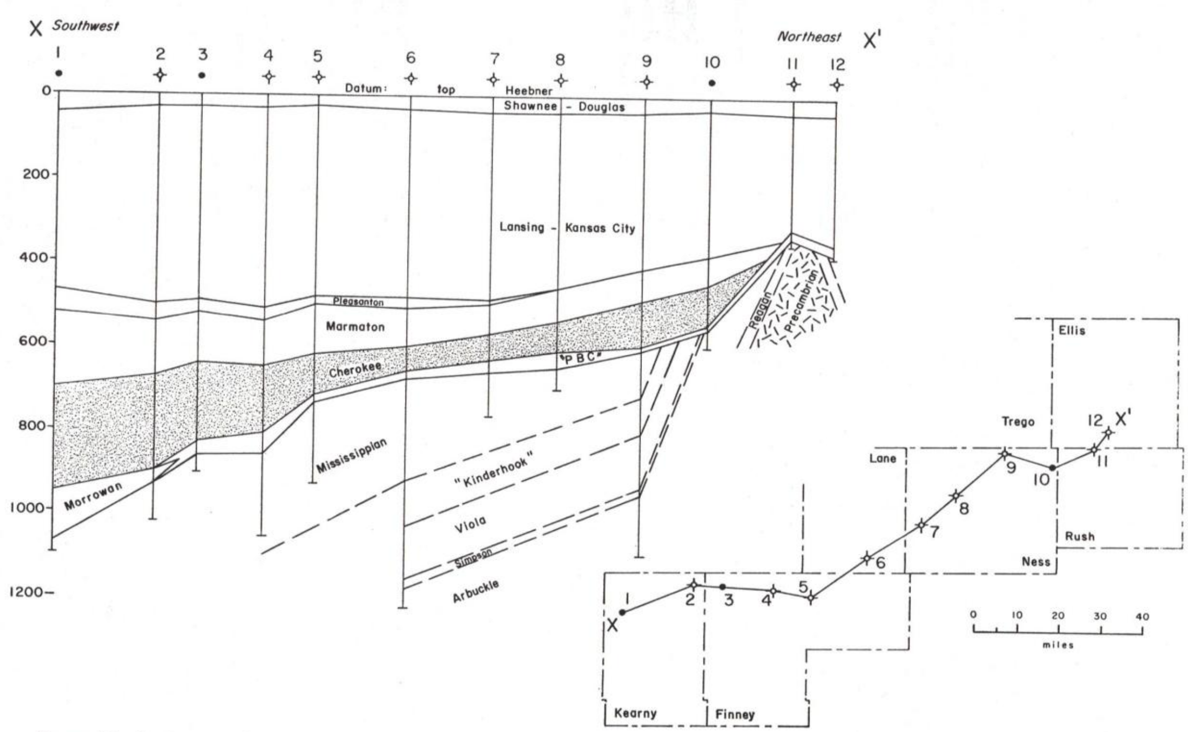


Figure 70.—Southwest-northeast cross section from Kearny County to Ellis County showing stratigraphic relation of Cherokee rocks to younger and older units southwest of Central Kansas Uplift (from Goebel and Merriam, 1957).

[4] Modified from (Merriam, 1963)

Sandstones are deposited along the Mississippian unconformity, which is defined by a tilted sequence of alternating resistive rocks and shale, and underlying the clastic sequences where the attitude of the unconformity controls the trend and distribution of the sandstones. The result is a series of escarpments and valleys, where later streams have cut into less resistant strata (Stoneburner, 1982).

Analysis of Gamma ray logs collected around the study area showed characteristics of channel sandstones. The sandstones displayed an increase upward in radioactivity which indicates that the lower portion of the sand has cleaner and coarser sand at the base, and fines upward in grain size. Based on Walter's Law, this fining up sequence corresponds to the lateral sequence across a channel, from shales and siltstones of the flood plain facies, to fine-grained sandstones in the point-bar facies, to coarser grained sandstones and conglomerates in the channel facies (Stoneburner, 1982).

3D Seismic

In 1917, Reginald Fessenden was issued the first (U.S.) patent entitled "Methods and apparatus for locating ore bodies". His method was based on the application of seismic waves similar to acoustic waves in water to detect icebergs. This was among many inventions which Fessenden worked on after the sinking of Titanic by an iceberg in 1912. Since then and until recent history and development of the common-midpoint, vibroseis, digital processing and 3-Dimensional techniques, the amount of geological information extracted from seismic data has greatly improved (Figure 2-4 and Figure 2-5). Exploration Seismology Technology uses artificially generated elastic waves to define locations of mineral deposits, and has become the backbone of many exploration programs because of its high resolution and subsequent success. Locating mineral deposits such as hydrocarbons, ores, water and geothermal reservoirs is not the only use of this technology today; it also obtains geological information that aid in better understanding of different engineering projects. When the information extracted from seismic data is integrated with other available geophysical and geological data, this can supply new knowledge about the structure and distribution of rock types. However, and as known in this field, the technology by itself cannot guarantee successful results even if integrated with other information. This can be related to the wide range of possible interpretations that could be extracted from the data, where each possibility is dependent on the approach used to interpret the data. Ultimately, the best interpretation is the one based on a consistent approach which integrates the latest and most developed workflows (Sheriff and Geldart, 1982; 1983).

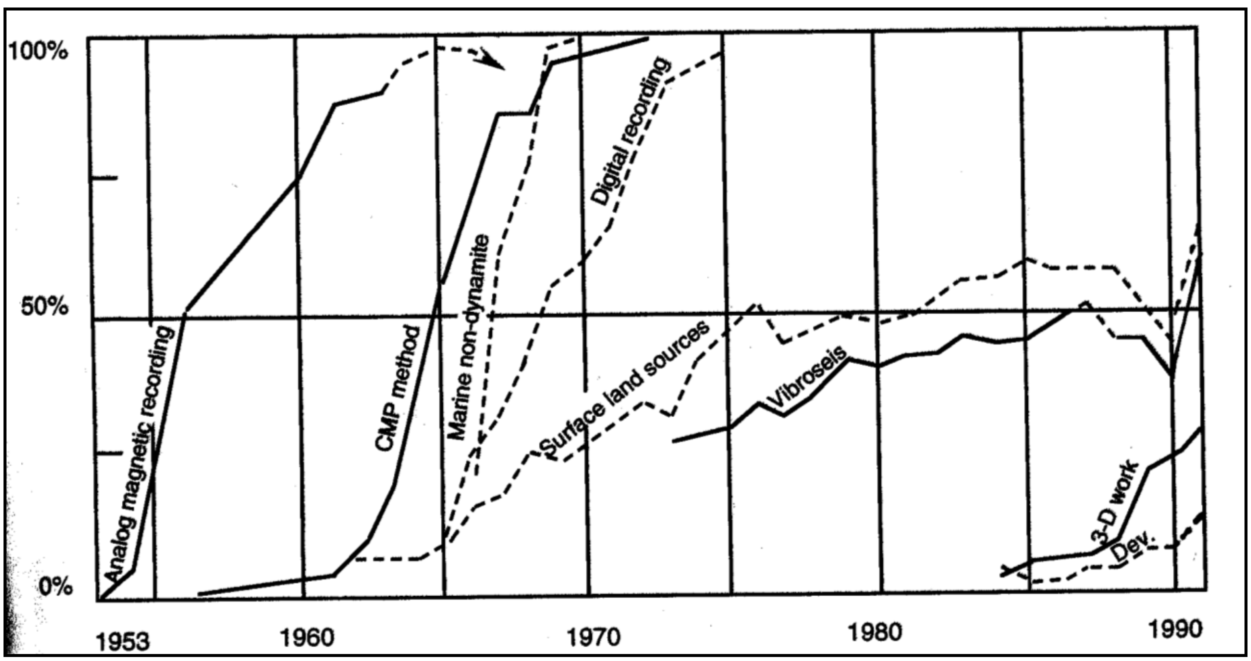
In the last several years, the relationship between specific attributes of the seismic data and reservoir development were recognized. Many of these seismic attributes are now used by geoscientists to map geological features. Some attributes can be indicators of changes in lithology. Examples of such attributes include seismic amplitude, envelope, root mean square (RMS) amplitude, spectral magnitude, acoustic impedance and elastic impedance. Layer thicknesses can also be indicated by seismic attributes, such as peak-to-trough thickness, peak frequency and bandwidth. Other seismic attributes such as coherence, amplitude gradients, dip-azimuth and curvature can be used to indicate seismic textures and morphology (Chopra and Marfurt, 2008).

Attributes can derive additional information from seismic data that can be used as a baseline for quantitative and/or qualitative interpretations. Quantitative interpretation means that seeking numerical estimations of properties throughout the seismic dataset. On the other hand, qualitative interpretation means that defining geobodies reflecting similar physical properties. In both cases, there are two important steps for a successful workflow that could facilitate making exploration or development decisions. First is the careful selection of which seismic attributes will best serve the objective. Second is testing the results against available existing knowledge and models. Therefore, integration of geological models and well data to information extracted from seismic attributes can establish more acceptable and reliable interpretation workflows. (Hart, 2002).

Figure 2-4 Chronology of seismic instrumentation and methods [5]

1914	Mintrop's mechanical seismograph
1917	Fessenden patent on seismic method
1921	Seismic reflection work by Geological Engineering Co.
1923	Refraction exploration by Seismos in Mexico and Texas
1925	Fan-shooting method
	Electrical refraction seismograph
	Radio used for communications and/or time-break
1926	Reflection correlation method
1927	First well velocity survey
1929	Reflection dip shooting
1931	Reversed refraction profiling
	Use of uphole phone
	Truck-mounted drill
1932	Automatic gain control
	Interchangeable filters
1933	Use of multiple geophones per group
1936	Rieber sonograph; first reproducible recording
1939	Use of closed loops to check misties
1942	Record sections
	Mixing
1944	Large-scale marine surveying
	Use of large patterns
1947	Marine shooting with Shoran
1950	Common-midpoint method
1951	Medium-range radionavigation
1952	Analog magnetic recording
1953	Vibroseis recording
	Weight-dropping
1954	Continuous velocity logging
1955	Moveable magnetic heads
1956	Central data processing
1961–2	Analog deconvolution and velocity filtering
1963	Digital data recording
1965	Air-gun seismic source
1967	Depth controllers on marine streamer
1968	Binary gain
1969	Velocity analysis
	Transit satellite positioning
1971	Instaneous floating-point amplifier
1972	Surface-consistent statics
	Bright spot as hydrocarbon indicator
1974	Digitization in the field
1975	Seismic stratigraphy
1976	Three-dimensional surveying
	Image-ray migration (depth migration)
1984	Amplitude variation with offset
	Determining porosity from amplitude
	DMO (dip-moveout) processing
1985	Interpretation workstations
1986	Towing multiple streamers
1988	*S*-wave exploration
	Autopicking of 3-D volumes
1989	Dip and azimuth displays
1990	Acoustic positioning of streamers
	GPS satellite positioning

Figure 2-5 Percentage of seismic activity involving various technologies [6]



[5] Modified from (Sheriff and Geldart, 1982; 1983)

[6] Modified from (Sheriff and Geldart, 1982; 1983)

CHAPTER 3 - Methodology

Data Loading

The first step of any study is to collect all available data and quality check the collected data before and after loading the project. As mentioned above, Schlumberger Petrel software was used throughout this study. The collected data includes data from the field and data related to previous work done by the company. Field data of course include; the 3D seismic survey, well logs from Keith #1, and all other well data available within the limits of the survey boundaries. On the other hand, data from previous work include; maps and reports generated by for the purpose of the subject well.

Finally, a new project in Petrel was created and all related data was loaded and quality checked to verify the validity of the data.

Field Data

In 2002, Coral Coast Petroleum conducted the Wierman Field 3D seismic survey. The survey was acquired with 2.0 millisecond sampling rate for 136 inlines running west to east and 61 crosslines running south to north. Its width is around 0.9 miles from the west edge of S18-T16-R22W, and approximately 2.1 miles long from slightly above the north edge of S18-T16-R22W. The survey was received as a standard .SEGY file. Other information about the seismic survey include; the Seismic Reference Datum (SRD) of 2700 ft and a replacement velocity of 9000 ft/s. The projection system used to load the survey was *NAD27 Kansas State Planes, Southern Zone, US Foot*. The loading parameters for the loaded seismic survey is summarized in the following snapshot of the ASCII header that was extracted after loading to Petrel

Figure 3-1 ASCII header of Wierman 3D Seismic survey loaded to Petrel project

```
C 1 CLIENT  CORAL COAST PETROLEUM
C 2 AREA WIERMAN 3D  NESS CO.  KANSAS
C 3 PROCESSING CONTRACTOR: STERLING SEISMIC SERVICES, Ltd.
C 4 PROCESSING DATE: 12/02
C 5 OUTPUT FORMAT : SEGY IBM 32 FLOATING POINT
C 6 SAMPLE INTERVAL    2.0 MS  SAMPLES/TRACE  1001
C 7 FORMAT THIS REEL  SEGY     MEASUREMENT SYSTEM   FEET
C 8 SAMPLE CODE: FLOATING PT (IBM 32 FLOAT)
C 9 MIGRATED FXY ENHANCED 3D VOLUME - 20-128 HZ FILTER
C10 82.5 FT by 82.5  FT BINS
C11
C12  NON STANDARD HEADER LOCATIONS/ HEADER NAME,#bytes,FORMAT,1st BYTE
C13  INTEGER VALUES:  iline_no,4I,,9/     xline_no,4I,,13/   tr_fold,2I,,31/
C14  FLOATING POINT VALUES: cdp_x,4R,IBM,73/   cdp_y,4R,IBM,77/
C15  INTEGER VALUES:        cdp_x,4I,,81   /   cdp_y,4I,,85/
C16
C17
C18
C19   DATUM 2700 FEET - 9000 F/S REPL VELOCITY
C20
C21                  WIERMAN 3D
C22 ***** MIGRATED FXY ENHANCED 3D VOLUME****
C23 INLINE 1-136 XLINE 1-61/ 2 ms SR / 2.0 SEC /SEGY IBM 32 FLT /CDPS 1-8296
C24 1001 SAMPLES / TRACE
C25   SURVEY REPRESENTATION
C26   CDP 8236                 CDP 8296
C27  (136,1) INL/XL      (136,61) INL/XL
C28    X ................... X
C29    .                     .
C30    .                     .
C31    .                     .
C32    .                     .
C33    X ................... X
C34  (1,1) INL/XL        (1,61) INL/XL
C35   CDP 1                 CDP 61
C36 INLINES RUN WEST TO EAST  - XLINES RUN SOUTH TO NORTH
C37
C38
C39
C40 END EBCDIC
```

Other field data collected include data available for wells falling within the limits of the survey boundaries. There are 4 wells that had digital well log data. The 4 wells are Keith #1, Keith #2, Wanda Judeen and W&K #1. Well data includes; location, elevation, status, logging data, formation tops markers and the total depth of the well (TD). There are other wells within the area but no information known for them except for locations, status, raster logs and formation tops. Table 3-1 lists all wells within the subject area. Table 3-2 and Table 3-3 list available data for the above wells.

Table 3-1 Data available in each well

Well Name	Elevation	Status	TD	Well Logs	Tops
Keith #1	2455 KB	Oil, plugged & abandoned	4520	Digital	Yes
Keith #2	2456 KB	Plugged & abandoned	4510	Digital	Yes
Wanda Judeen	2445 KB	Dry, plugged & abandoned	4530	Digital	Yes
W&K #1	2430 KB	Dry, plugged & abandoned	4530	Digital	Yes
Squires 1	2439 KB	Dry, plugged & abandoned	4597	TIFF	Yes
Snodgrass 1	2442 KB	Dry, plugged & abandoned	4466	TIFF	Yes
C. Snodgrass	2456 KB	Dry, plugged & abandoned	4510	TIFF	Yes
Wierman 1	2432 GL	Dry, plugged & abandoned	4450	TIFF	N/A
Wierman 2	2411 TOPO	Approved to Drill	4400	N/A	N/A

Table 3-2 Digital well logs available

Well Name	Sonic	Gamma	Density	Porosity	Resistivity	SP
Keith #1	Yes	Yes	Yes	Yes	Yes	Yes
Keith #2	Yes	Yes	N/A	Yes	Yes	Yes
Wanda Judeen	Yes	Yes	Yes	Yes	Yes	Yes
W&K #1	Yes	Yes	Yes	Yes	Yes	Yes

Table 3-3 The formation tops markers for each well. The unit is feet MD

Well Name	Stone Corral	Heebner Shale	Pawnee Lime	Fort Scott	Cherokee	Mississippian
Keith #1	1783	3847	4244	4344	4356	4495
Keith #2	N/A	3842	4259	4335	4362	4487
Wanda Judeen	1801	3848	4238	4345	4361	4529
W&K #1	1779	3825	4222	4326	4350	4452
Squires 1	1785	3822	N/A	N/A	4302	N/A
Snodgrass 1	N/A	3814	N/A	4229	4305	4417
C. Snodgrass	1783	3841	4257	N/A	4370	4462

Previous Works Data

Data from previous work include any information reported by Coral Coast Petroleum. These data were collected in forms of interpretations, maps or reports. Previous works data are significant for understanding how the company professionals interpreted field data and eventually made their decisions towards drilling. So far, previous works released for this study from the company include; two seismic cross sections (Figure 3-2 and Figure 3-3) and two isochron maps (Figure 3-4 and Figure 3-5). Careful analysis of these maps and cross sections show that the drillsite was chosen based on two criteria. First criterion was the isochron thickness at that area. Thickening of the Cherokee section often occurred along the paleolows in the Mississippian, where sand typically is deposited. The second criterion was the occurrence and tracking of the doublet signal reflection at the base of the Cherokee formation and right at the top of Mississippian formation. Apparently, the company professionals were tracking these doublets under the assumption that they might reflect a change in the lithology. Moreover, the doublets locations in the cross section tied with the thickness maps under thicker areas which might gave more incentive to decide the positioning of the well.

Figure 3-2 Coral Coast's seismic cross section #1 showing the target sand

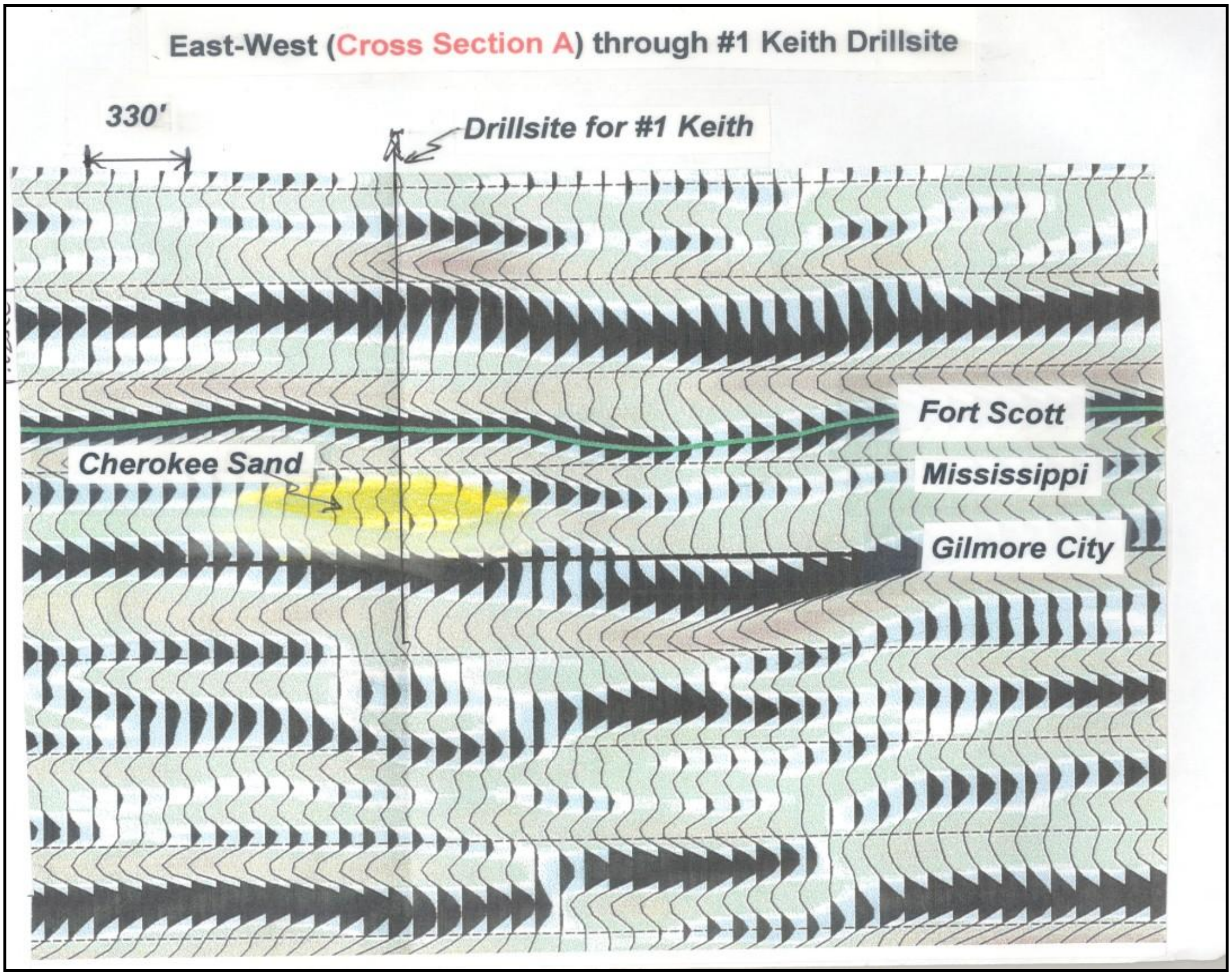


Figure 3-3 Coral Coast's seismic cross section #2 showing the target sand

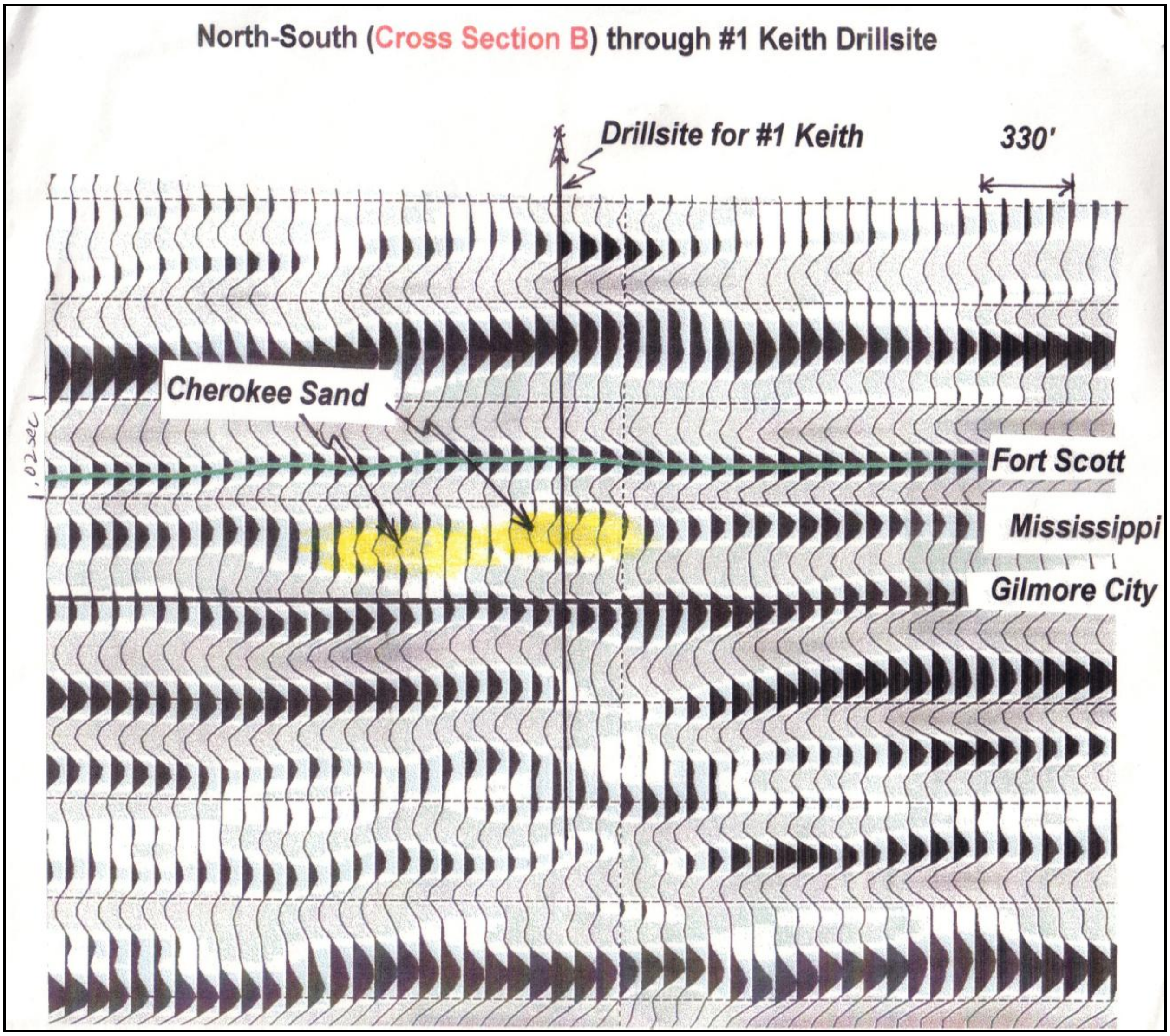


Figure 3-4 Coral Coast's isochron map #1

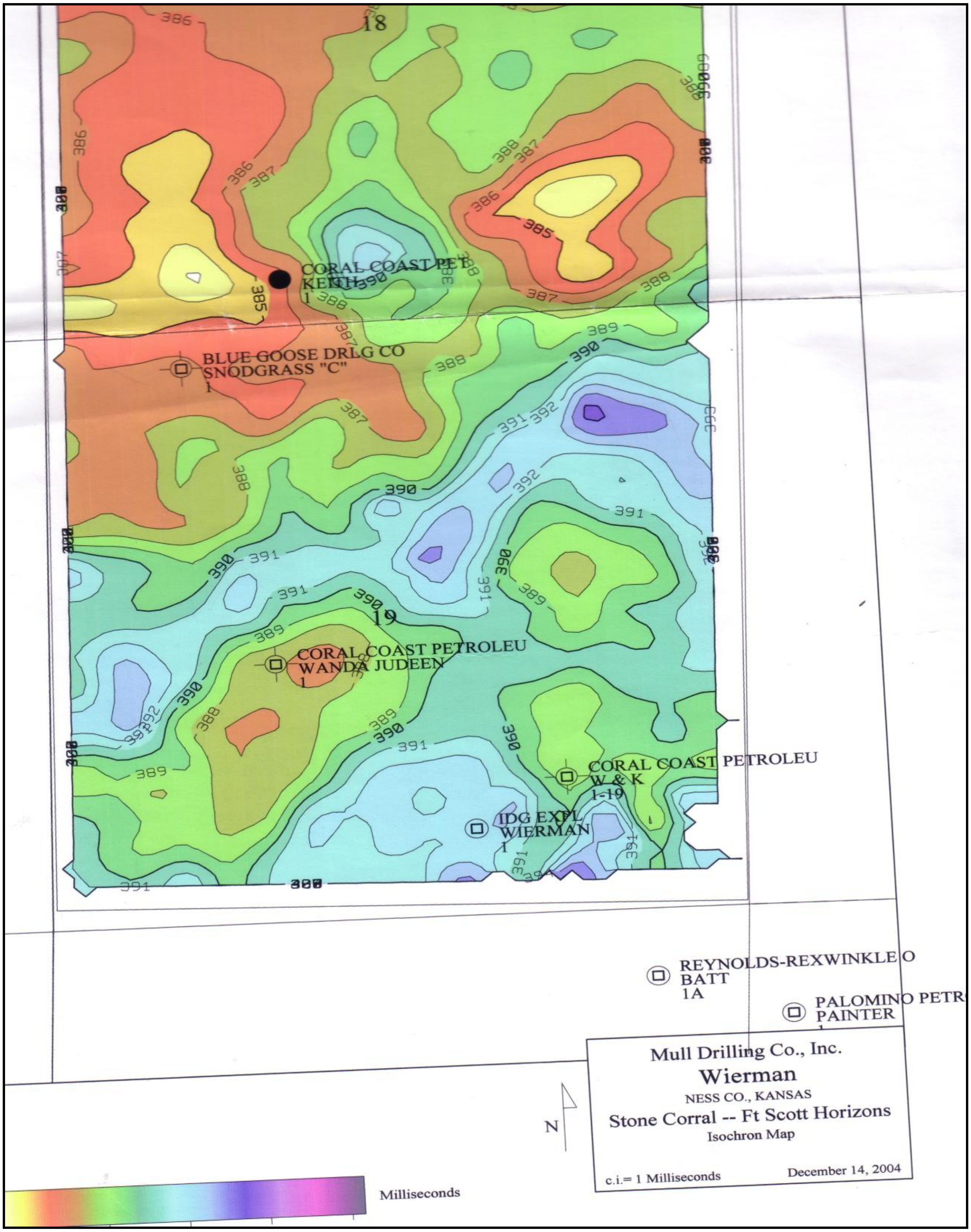
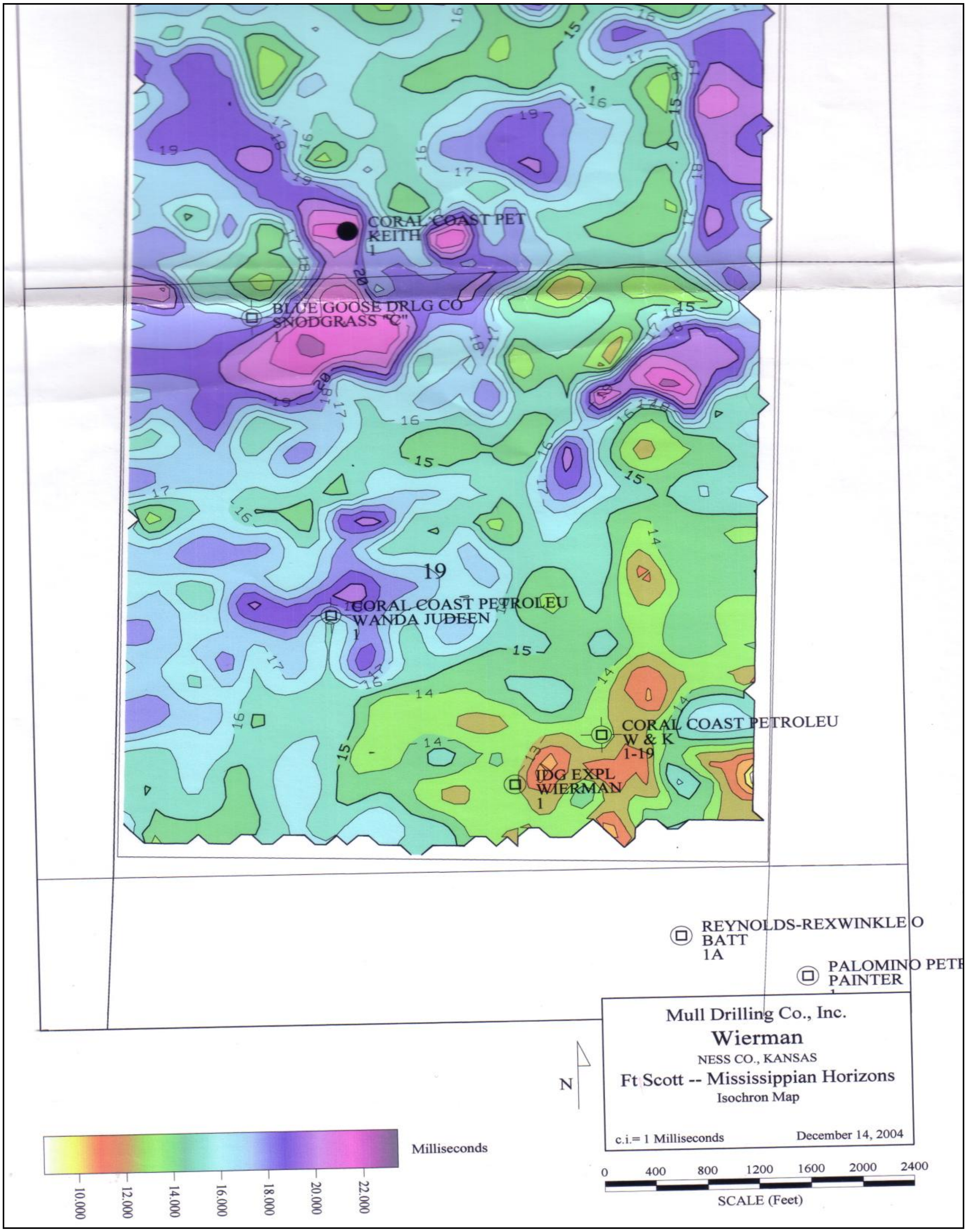


Figure 3-5 Coral Coast's isochron map #2



Schlumberger Petrel

Petrel is a PC-based software application which covers a wide range of workflows from seismic interpretation to reservoir simulation. The basic principle of Petrel integrated solution is that geophysicists, geologists and reservoir engineers can move just across domains within one software application, rather than moving between different software applications. One of the key benefits of integrated solutions such as Petrel is the elimination of import and export problems. Moreover this type of solutions promotes and encourages collaboration between different domains[7]. The wide range of functionality in Petrel covers:

Table 3-4 Functionalities available in Petrel [8]

3D visualization	Facies Modeling
Well correlation	Petrophysical Modeling
Classification and Estimation (Neural Net)	Data Analysis
Creation of synthetic seismograms	Uncertainty Analysis
Seismic attributes	Fracture Modeling
Geobody Interpretation	Volume Calculation
2D & 3D seismic interpretation and modeling	3D well design
Seismic volume rendering and extraction	Streamline simulation
3D mapping	ECLIPSE Simulation
3D grid modeling for geology and reservoir simulation	Simulation post-processing
Velocity Modeling (Domain Conversion)	Remote Simulation Run submission
Well log upscaling	Plotting

To learn more about Petrel: SLB Petrel[9]

Synthetic Seismograms

The first step in every seismic interpretation project is to start with the challenge of tieing seismic reflections to formation markers from well logs via synthetic seismograms. The main

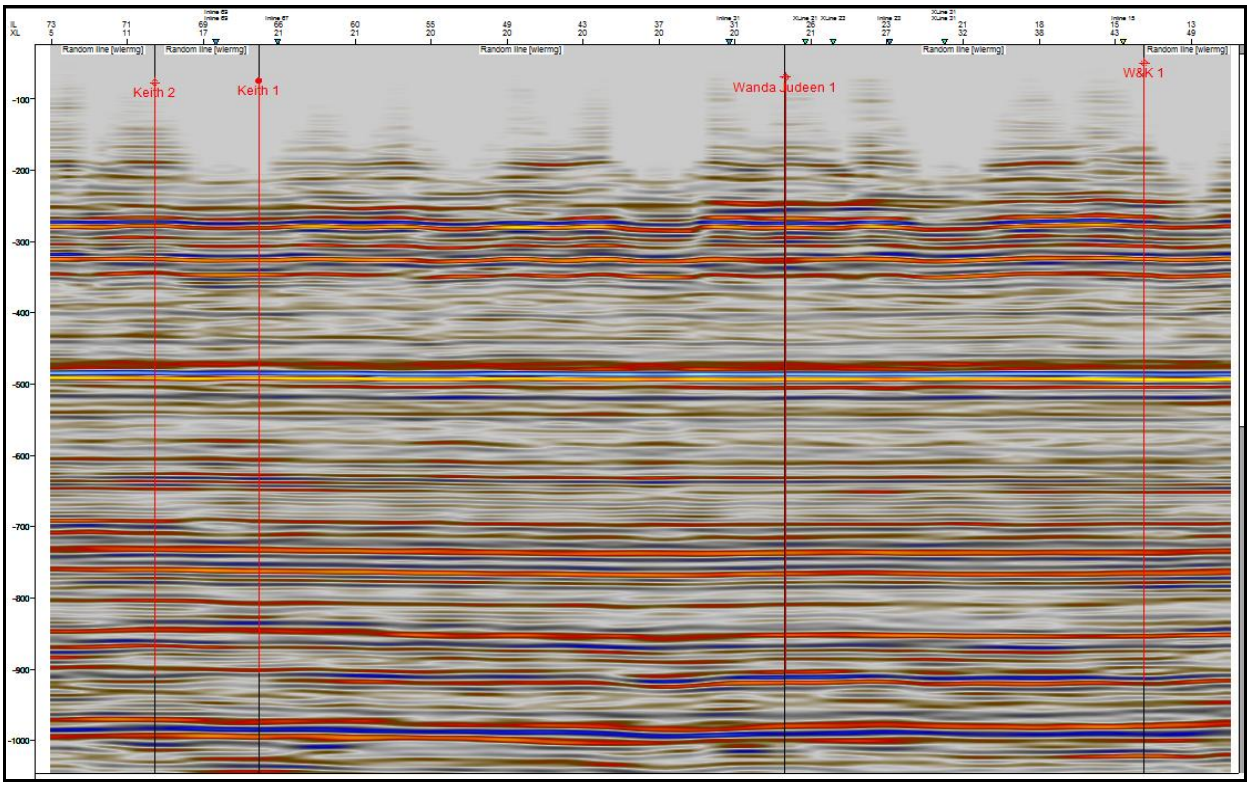
[7] Information gathered from Petrel help files

[8] Modified from Petrel help files

[9] http://www.slb.com/content/services/software/geo/petrel/index.asp?

input for synthetics is the time-depth (T-D) relationship or chart. T-D charts can be generated from either a check-shots survey or an acoustic (sonic) log. In this case study, there were no check-shots available in the area within the limits of Wierman seismic survey boundaries. So, T-D charts were generated from the sonic logs available with the wells. Figure 3-6 shows a cross section view of the wells displayed on the seismic after tieing.

Figure 3-6 Wells tied to the seismic in a cross section view



A seismic-to-synthetics tie was achieved after generating synthetic seismograms by convolving an extracted seismic wavelet with the normal incidence reflectivity at each of the wells. Only two of the wells resulted in acceptable synthetics. Those wells are; Keith #1 and Wanda Judeen. Figure 3-7 and Figure 3-8 show the generated wavelets profiles for each well respectively. The profiles show zero phase shift and normal polarity for both wavelets. The wavelets envelop spectrums show a dominant frequency of about 48 Hz. Since the average velocity in this area is around 8000 ft/s, the dominant wavelength can be calculated to enable an estimation of the temporal resolution limit of the seismic data. After that, radial well seismic had been extracted around each well which are important in order to match the synthetic to the seismic data. Finally, a complete synthetics package for each well was generated as a result of the Synthetic Process.

The synthetics normally do not exactly match character-wise to the seismic. This is when the synthetic interpretation step is required. In order to match the generated synthetic seismograms to the seismic trace, minor stretching and squeezing is required until an acceptable level of match is reached. Adjustments of the synthetics need to be done with the help of the formation tops and the change in acoustic impedance value. If the acoustic impedance value at a specific formation is going from low to high that means the formation top should match a peak. And, if the acoustic impedance value is going from high to low then the formation top should match to a trough. Table 3-5 lists the formation tops were picked and their respective change in acoustic impedance and reflections. The last step in synthetics interpretation is to check the quality of the match. The normalized correlation coefficient (-1<= values <=1) between the synthetic trace and the real seismic value can be used as a match-quality indicator. The higher the value of the correlation coefficient the better quality of the match and the opposite is true. Based on that, the correlation coefficient value after the interpretation showed 0.3. This value can be considered as a good enough match for tieing seismic events to the corresponding geological tops. The reason for the low correlation coefficient value could be related to T-D relationships. The fact that T-D relationships for the wells were generated from the available sonic log and not from a check-shots survey may contributed to this result. Figures 3-9 and 3-10 show the final synthetics seismograms interpreted for each of the wells and Table 3-6 shows the time depth for the well tops in each well.

Table 3-5 The interpretation of each of the formation tops

Formation top	Change in acoustic impedance	Reflection
Stone Corral	Low to high	Peak
Pawnee Limestone	High to low	Trough
Cherokee Group	High to low	Trough
Mississippian System	Low to high	Peak

Table 3-6 The picked time depths for formation tops. The unit is milliseconds

Well Name	Stone Corral	Pawnee Lime	Cherokee	Mississippian
Keith #1	490.45	864.52	876.69	903.60
Wanda Judeen	492.07	869.85	880.86	905.47

Figure 3-7 Wavelet profile window for Keith #1

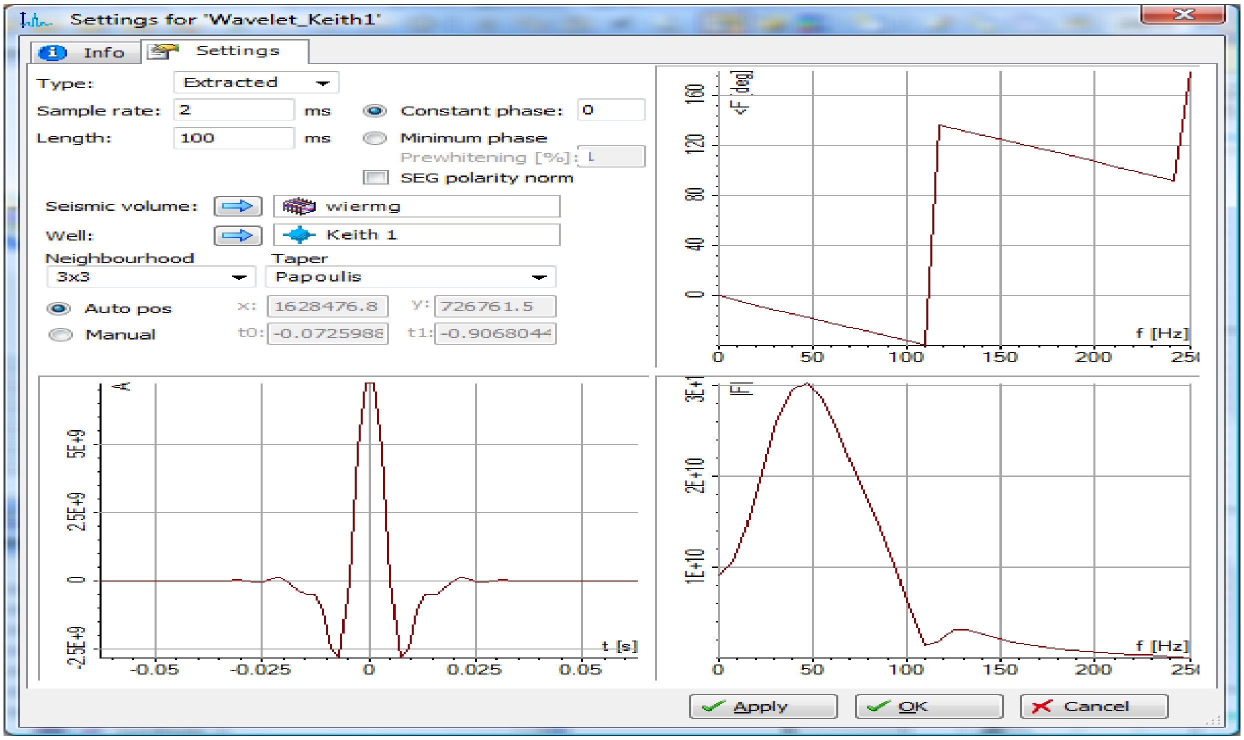


Figure 3-8 Wavelet profile window for Wanda Judeen

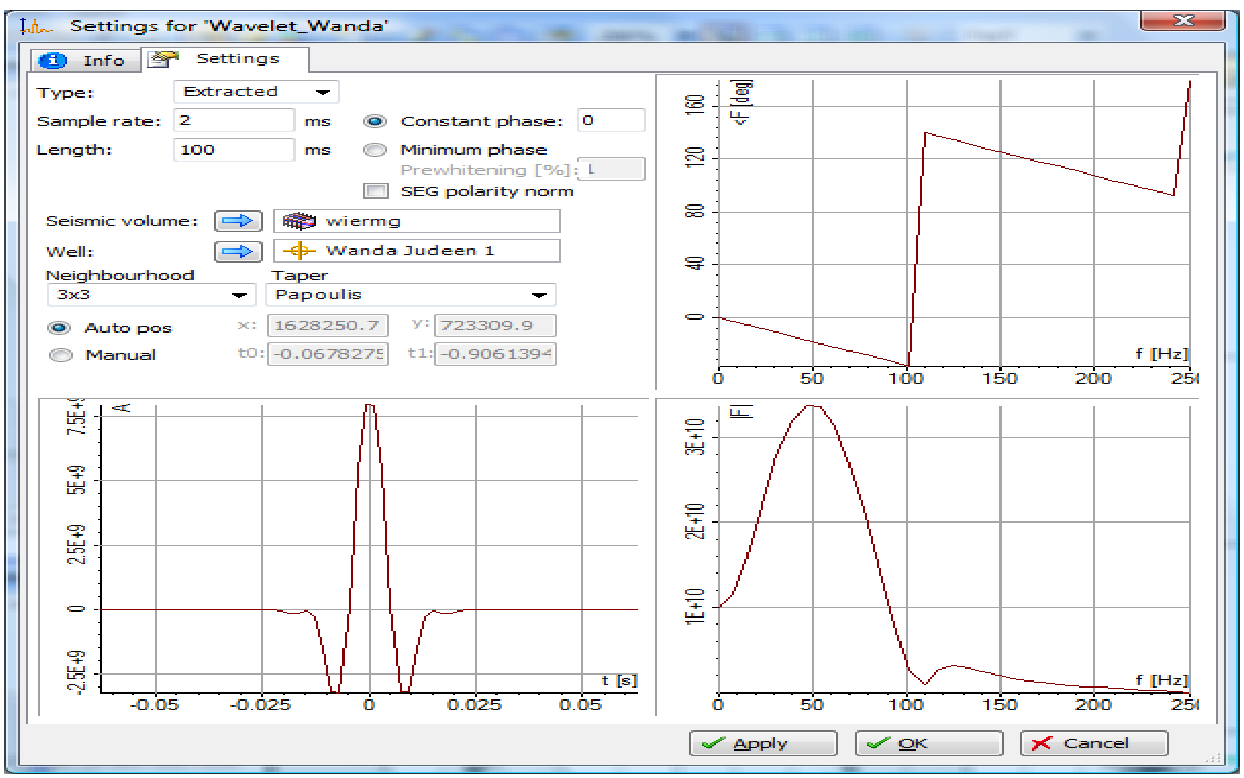


Figure 3-9 Synthetics interpretation window for Keith #1

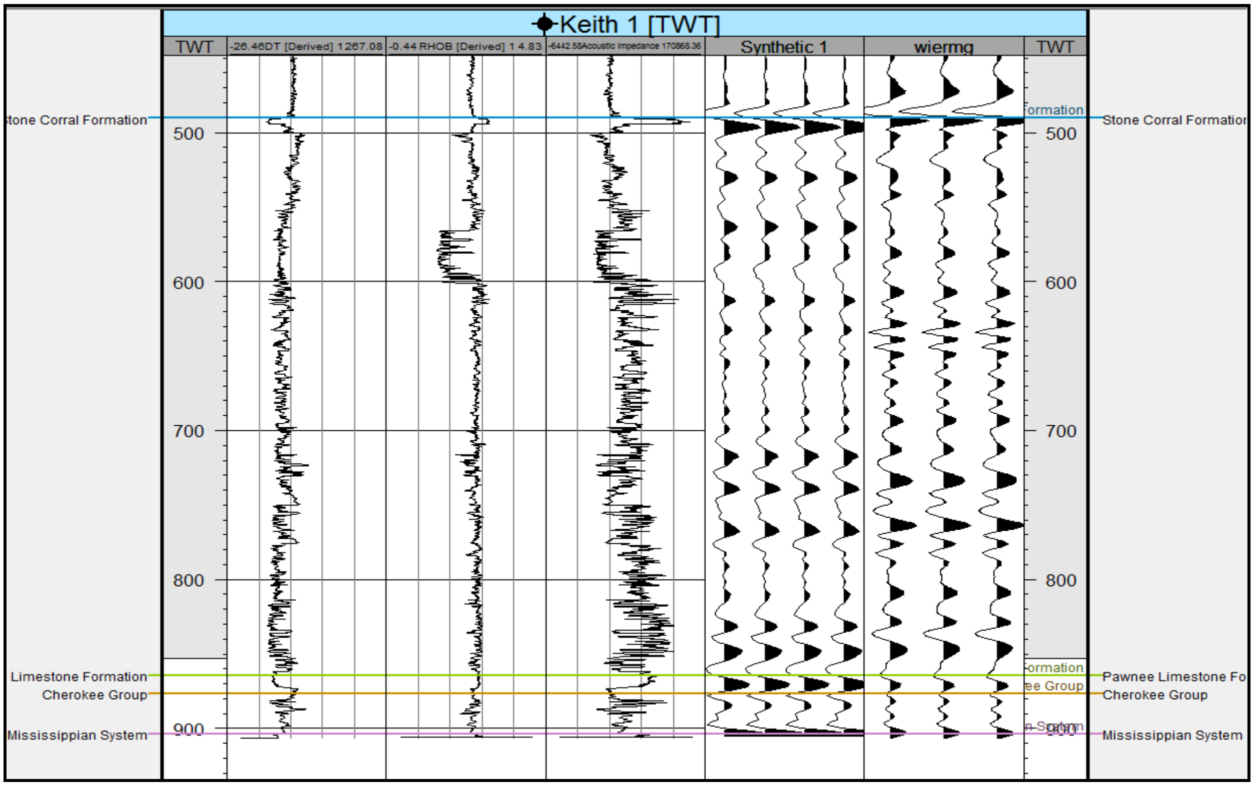
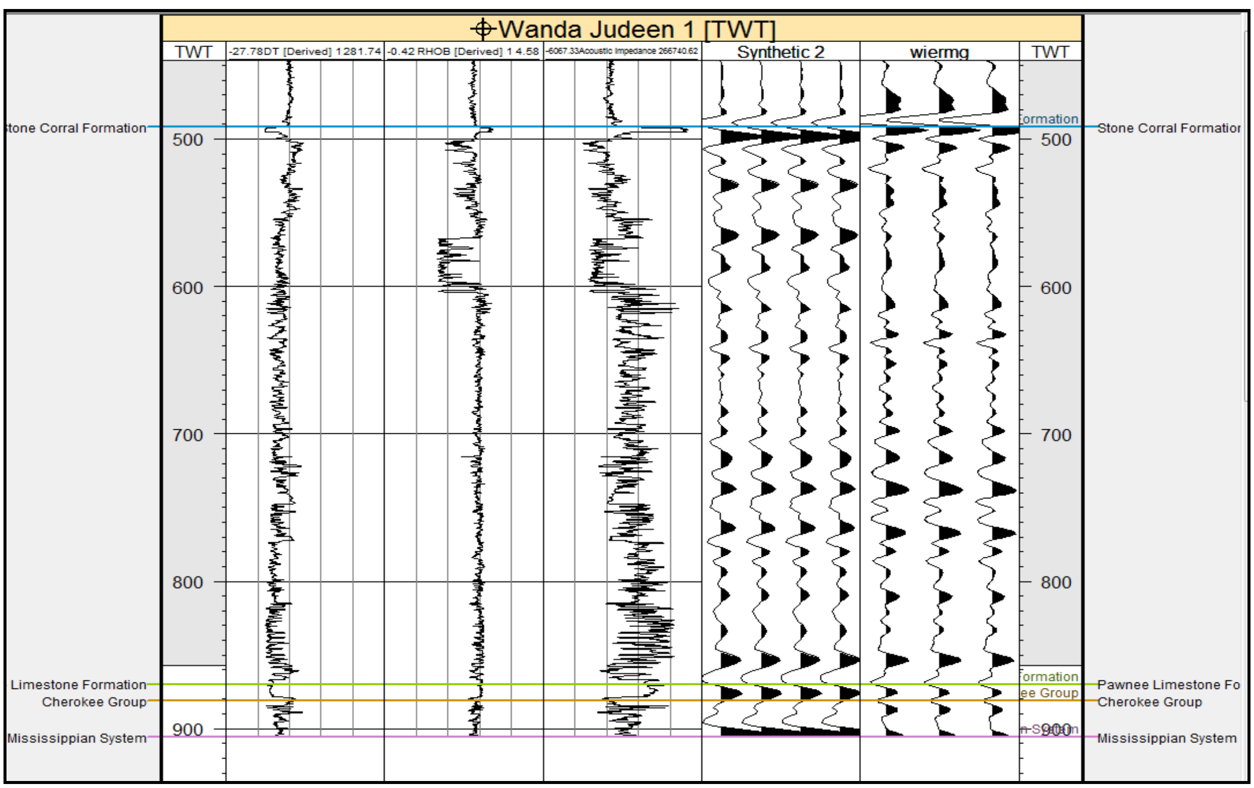


Figure 3-10 Synthetics interpretation window for Wanda Judeen

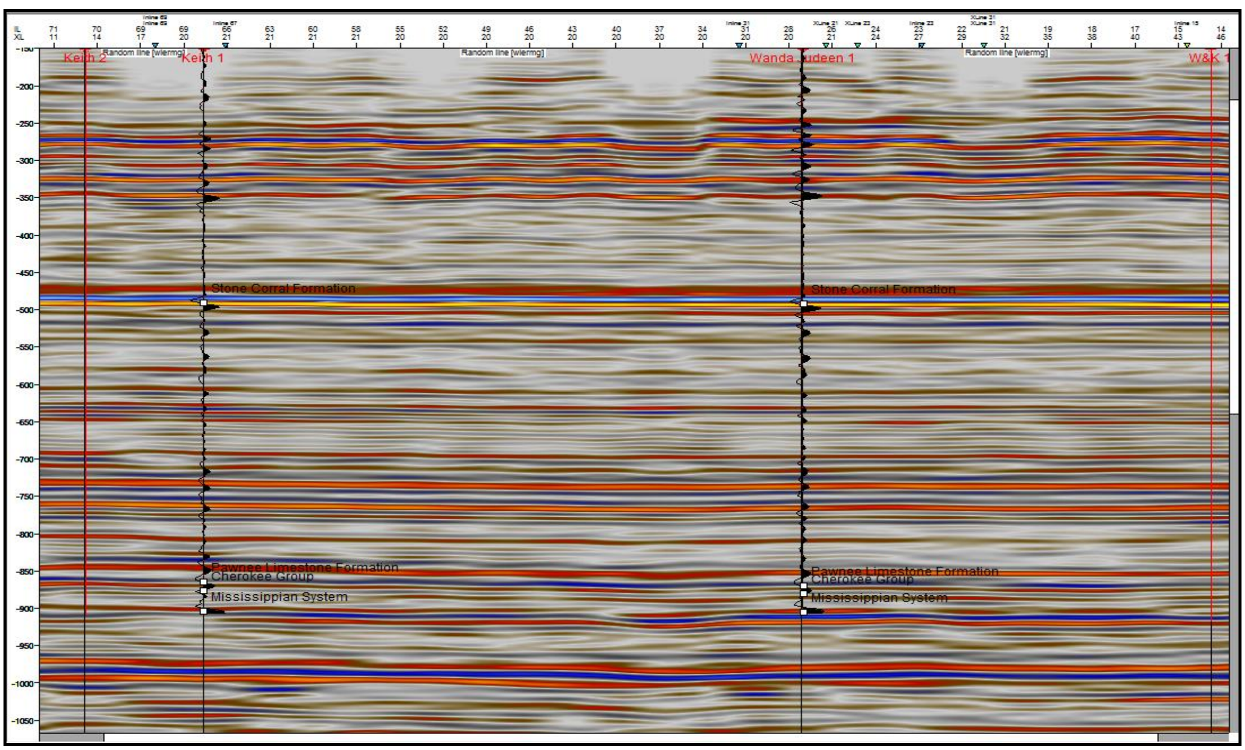


Horizon Tracking and Surface Generation

After the synthetic interpretations were reached, the formation surfaces were tracked and identified throughout the entire seismic volume. To start with, a composite line of the seismic volume running through all wells was extracted. Then, the wells and their synthetics traces were displayed on top of it. In addition, the well formation tops were displayed. The Seismic Interpretation process in Petrel was used to complete this task. The composite line was displayed in an interpretation window in the time domain (Figure 3-11). The benefit of using a composite line section at the start of the horizon tracking is to guide the later inline and xline tracking in areas where well controls are absent. After the composite line tracking completed, regular inlines and xlines were tracked with an increment of 5.

Initially, each of the horizons was tracked using the 2D Seeded Auto-tracking function. Next, 3D Auto-tracking function was used to track all the points within the seismic volume. Finally, Manual Tracking function was used in some areas where auto-tracking could not track the events anymore. The outcomes of this process would be the generation of the respective horizon of each formation marker that was tracked.

Figure 3-11 Interpretation window shows the composite seismic line cross section



The next step was to generate the surfaces for each of the tracked horizons respectively. Make/Edit Surface process in Petrel was used in this step. In general, the process takes a horizon as an input, the algorithm used to generate the surface and the specific boundaries for the surface. The algorithm used for all the surfaces was the Kriging (Petrel 2008) and the boundaries were automatically set from the input horizons. Figure 3-12 shows the maps for the Stone Corral surface on the left and the Pawnee Limestone surface on the right. Figure 3-13 shows the maps for the Cherokee Group surface on the left and the Mississippian surface on the right. All the surfaces maps show the locations of the wells. Through the rest of this study the focus will be on the Cherokee and the Mississippian surfaces.

To contrast the interpretation in this study with the previous interpretation work, two isochron maps were generated then compared to the ones received from the company. It is unlikely that two different interpretations would be identical, but they should agree with each other to an acceptable degree. Before making these comparisons, one point needs to be clarified. As mentioned in the geological review section, the Fort Scott limestone is the lowest member of the Marmaton Group which lies above the Cherokee group. The thickness of the Fort Scott ranges between 8 to 12 feet. So, it is not unusual that the two tops are interchangeably used in some cases. With this small difference in mind, the first isochron map was for the time thickness between the Stone Corral and the Fort Scott surfaces. This map was compared with the time thickness map between the Stone Corral and the Cherokee surfaces generated for this study. The second was for the time thickness between the Fort Scott and the Mississippian surfaces. This was compared with the time thickness map between the Cherokee and Mississippian surfaces generated for this study. Figure 3-14 shows a reasonable match between the first two maps, and Figure 3-15 shows a reasonable agreement between the other two maps.

Figure 3-12 Stone Corral and Pawnee Limestone Surfaces

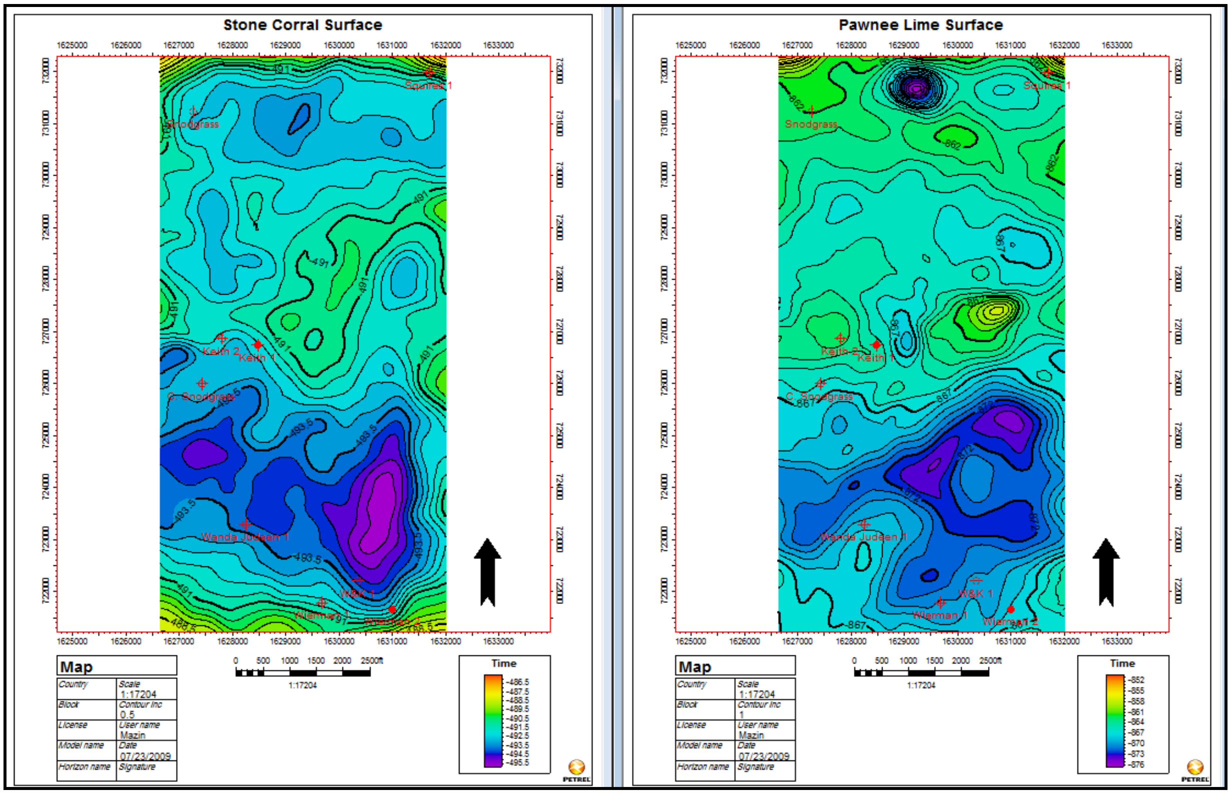


Figure 3-13 Cherokee and Mississippian Surfaces

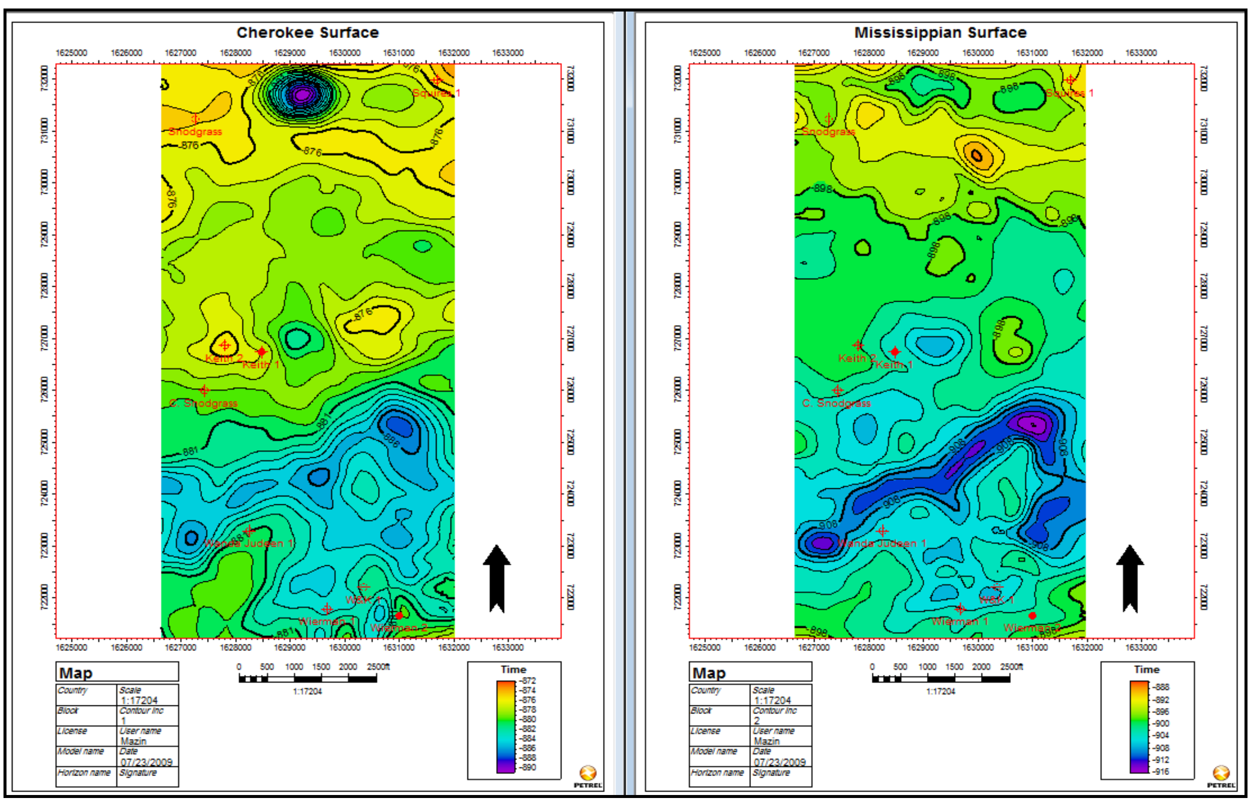


Figure 3-14 Comparison between the first set of isochron maps

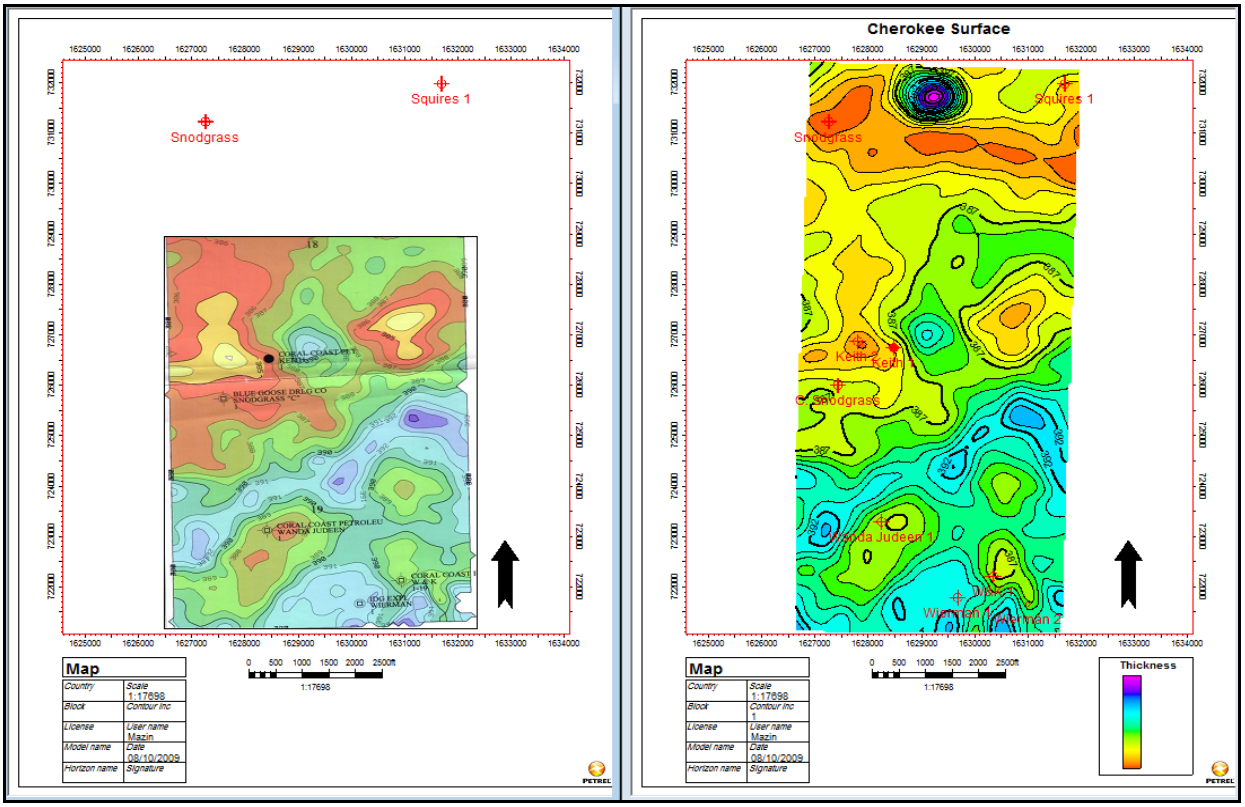
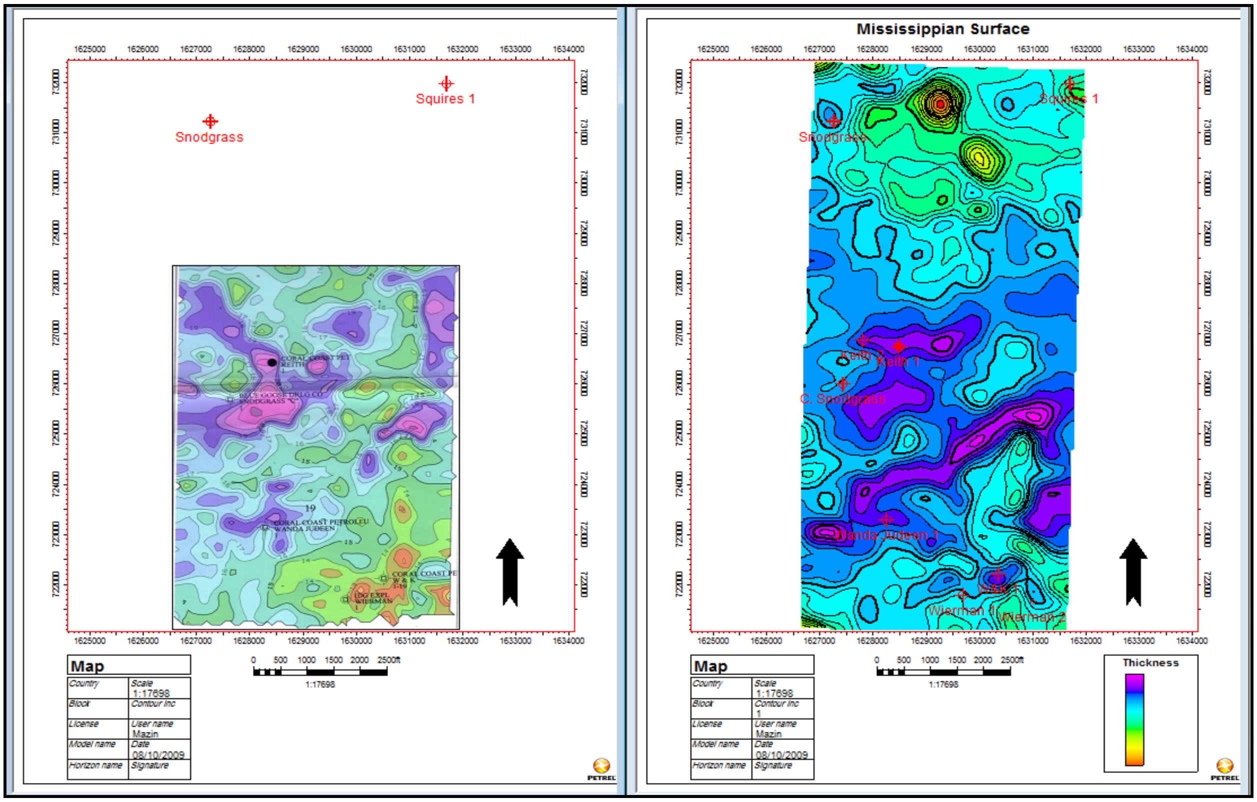


Figure 3-15 Comparison between the second set of isochron maps



Seismic Attributes

The objective of running the seismic attributes workflow was to come up with qualitative results that can be correlated with the geological and borehole data, and ultimately determine why the original interpretation was incorrect. This was driven by the fact that the drilling of the Keith #1 was based on the potential identification on an extensive sand body at that location. The geological information needed from running this workflow includes; lithological changes, porosity indications, hydrocarbon indications and fluid content and movement. The seismic attributes can be extracted along a certain surface, a window interval around the surface or can be extracted for the whole seismic volume. Window attributes are helpful in this case because our target lies in the lower interval of the Cherokee Group. The range of the window, 15 milliseconds around the Mississippian surface, was determined using well logs. Gamma, sonic, porosity and resistivity logs from Keith #1 indicated that the lower Cherokee sand lies within the 10 milliseconds interval above the top of the Mississippian surface. Therefore, the 15 milliseconds around the Mississippian surface represent 5 milliseconds below the surface and 10 milliseconds above it.

Table 3-7 lists the seismic attributes used in this workflow with a description and the reflected interpretation for each one.

Table 3-7 Attributes descriptions

Attribute	Description	Information gained
RMS Amplitude	The square root of the sum of the squared amplitudes, divided by the number of live samples	May relate directly to hydrocarbon indications in the data and other geologic features which are isolated from background features by amplitude response
Relative acoustic impedance (AI)	A running sum of regularly sampled amplitude values calculated by integrating the seismic trace, passing the result through a high-pass Butterworth filter, with a hard-coded cut-off at (10*sample rate) Hz	may indicate porosity or fluid content in a reservoir

Average energy	The squared RMS Amplitude	Can be used to map direct hydrocarbon indicators and/or major lithological changes in a window
Attenuation	The differential loss of high frequencies relative to low frequencies as measured above and below the point of interest	Identifies fracture zones and fluid movement

Figure 3-16 shows the relative acoustic impedance and the average energy attributes maps extracted on the interval of 15 milliseconds. Figure 3-17 shows the attenuation and the RMS amplitude attributes maps extracted on the same interval. The attribute maps shown by those two figures will be analyzed in the discussion chapter to investigate the lower Cherokee sands in an effort to find the answers for this study.

Figure 3-16 Relative AI and Average Energy maps 15 ms around Mississippian surface

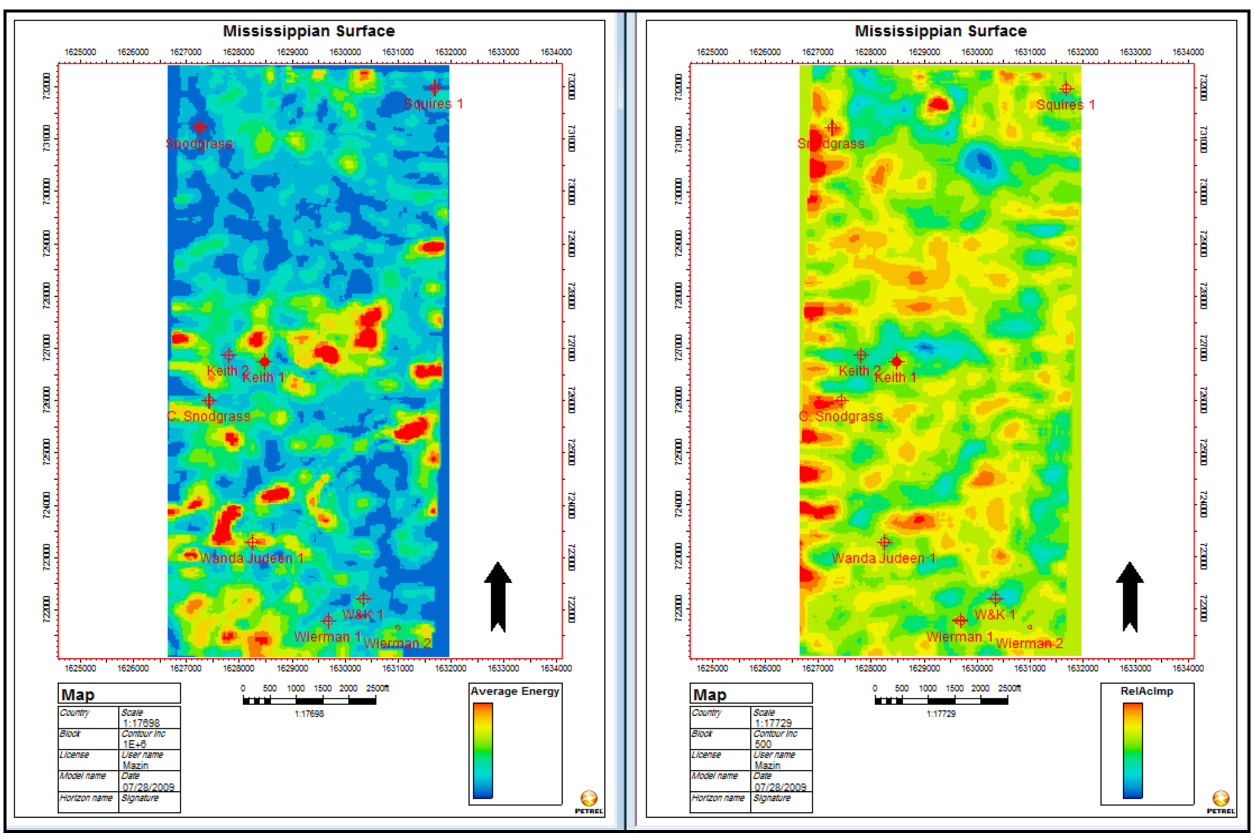
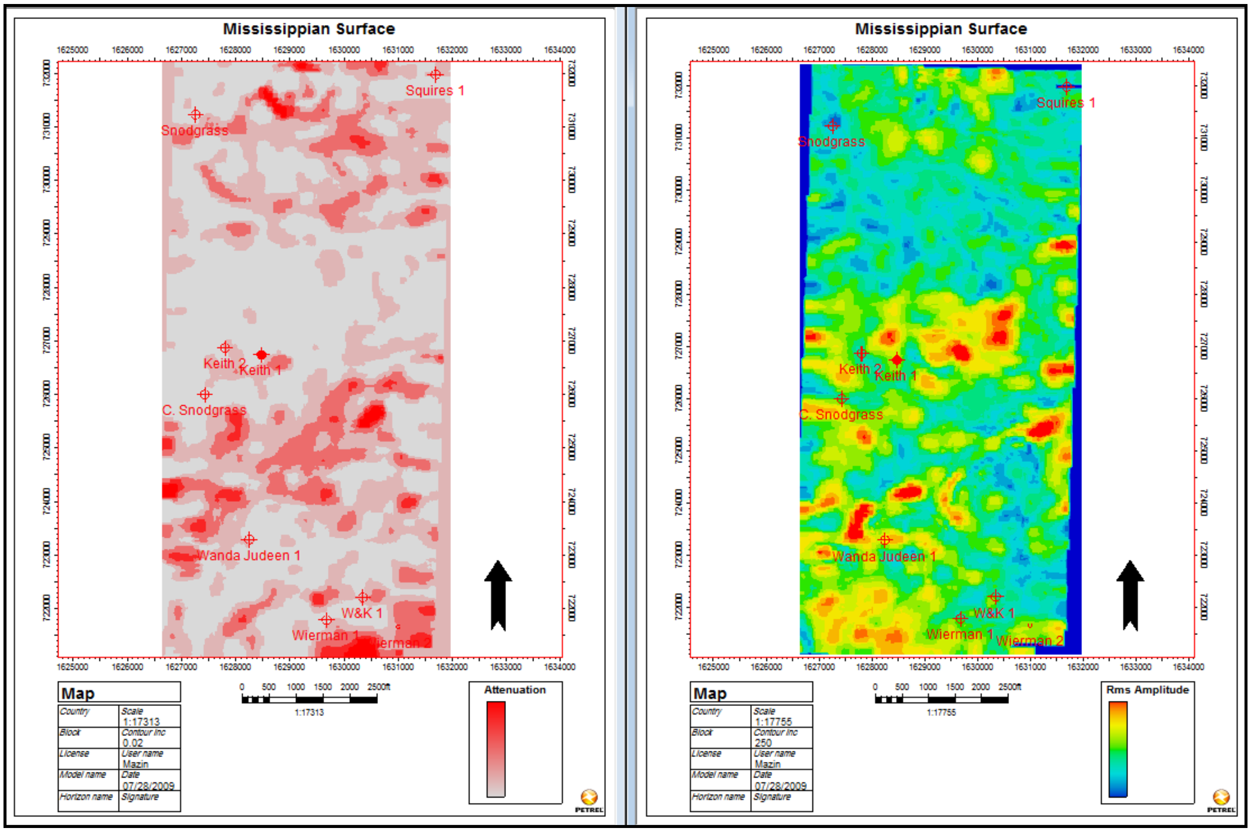


Figure 3-17 Attenuation and RMS Amplitude maps 15 ms around Mississippian surface



CHAPTER 4 - Discussions

All maps shown in this section were generated using the following parameters. Attributes were extracted within an interval of 15 milliseconds around the Mississippian surface, 5 milliseconds below and 10 milliseconds above. This window was chosen to capture the information of the seismic attributes within the lower Cherokee sand target zone. Higher attribute values are represented by hotter colors and lower attribute value by cooler colors. As a starting point, the analysis will be focused on the location of Keith #1 and the surrounding wells, namely Keith #2 and C. Snodgrass. Similar analysis will be drawn on larger attribute maps covering the complete region to include the rest of the wells within the seismic coverage.

Figure 4-1 Zoomed amplitude and energy maps around Keith #1 area

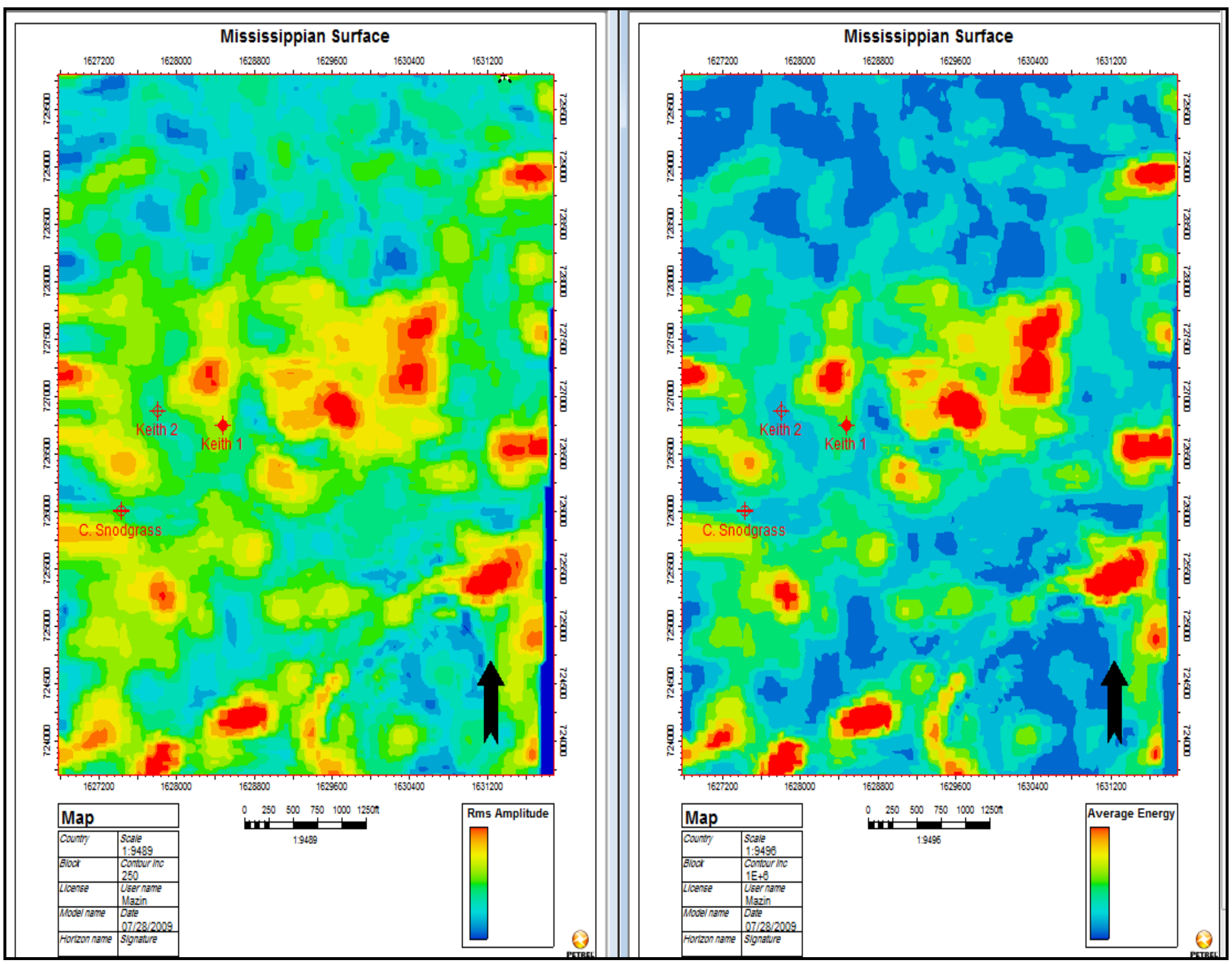


Figure 4-1 shows RMS amplitude map on the left and the average energy map on the right. Looking at the RMS amplitude map, higher amplitude spots are indicative of hydrocarbon or geologic features. On the other side, the average energy map, which is the square of the RMS amplitude, shows a similar but more concentrated pattern. The higher value areas in the energy map are indicative of greater lithological contrast between the formations within the calculated window. Therefore, higher energy areas can be translated as areas where the Mississippian surface, known as dolomite facies, is contrasting with the overlying Cherokee reservoir facies. And, lower energy areas represent areas where the Mississippian surface and the overlying Cherokee zone are reflecting a closer match in lithology, i.e. tight or no reservoir areas. Also, higher amplitude and energy areas can be translated as areas with possible higher hydrocarbon indications and vise-versa. General observation of the maps shows that all the wells are positioned on lower amplitude and energy areas.

Figure 4-2 Zoomed relative AI and energy maps around Keith #1 area

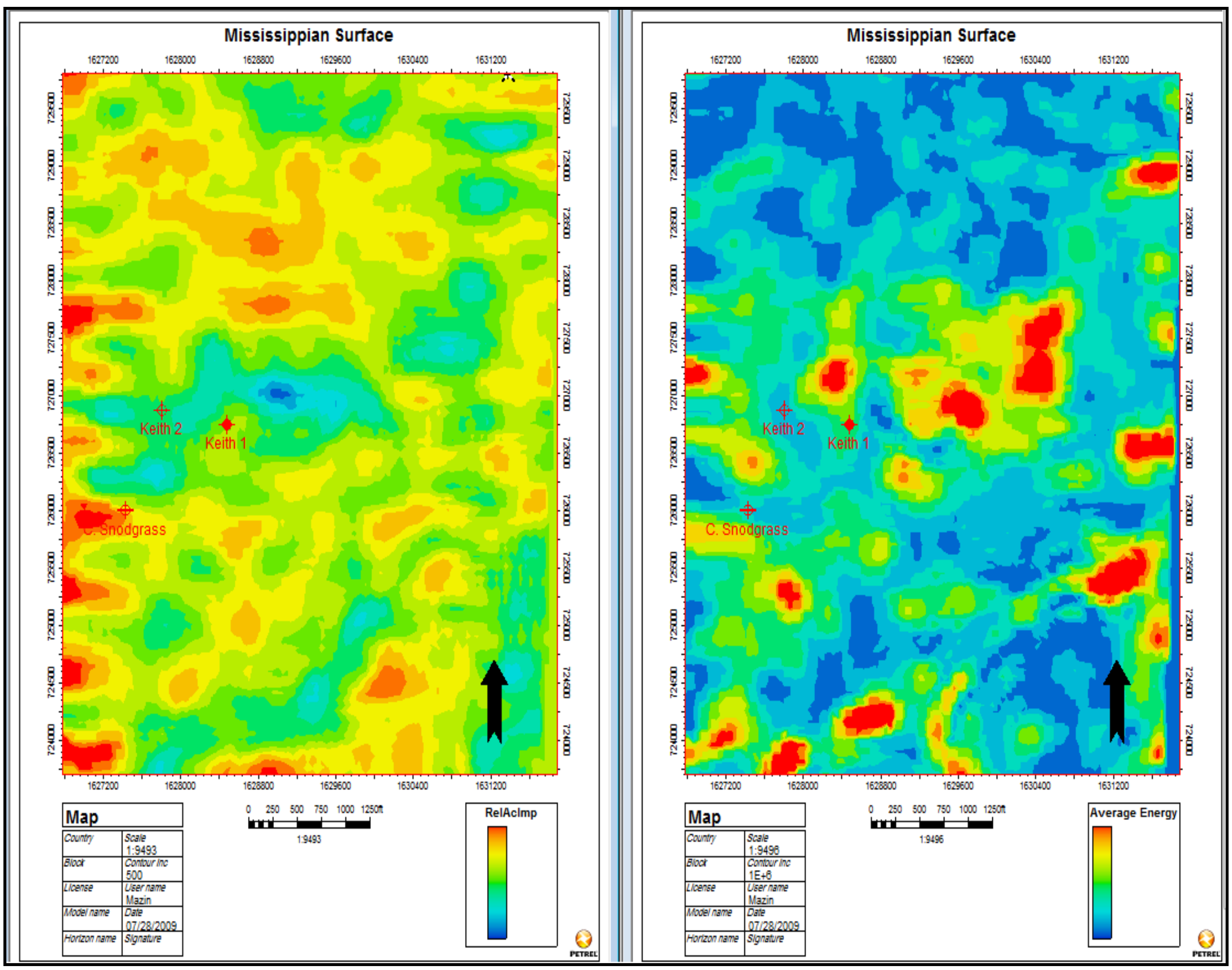


Figure 4-2 shows relative AI map on the left and again the average energy map on the right. Unlike the other attributes, AI attribute map is interpreted as lower values reflecting better reservoir quality and higher values indicates poorer reservoir quality. Reservoir quality here could mean lower porosity and/or no fluid content. Therefore, AI attribute's values generally should show the opposite representation of the energy attribute's values. This means, areas with higher energy should match with areas with lower AI values and vise-versa. This is based on the fact that the lower values in AI are reflected by higher amplitude which in return reflects higher energy values. For areas where this fact does not hold, contribution from other factors may be possible. For example, areas where bed thickness is less than the dominant wavelength, variation in thickness would lead to tuning effects resulting in changes in wavelet shape and amplitude. Those tuning thickness related changes can occur independent of AI variation. Looking at the maps in the figure, all wells in the area are falling in relatively higher AI and lower energy spots.

Figure 4-3 Zoomed attenuation map around Keith #1 area

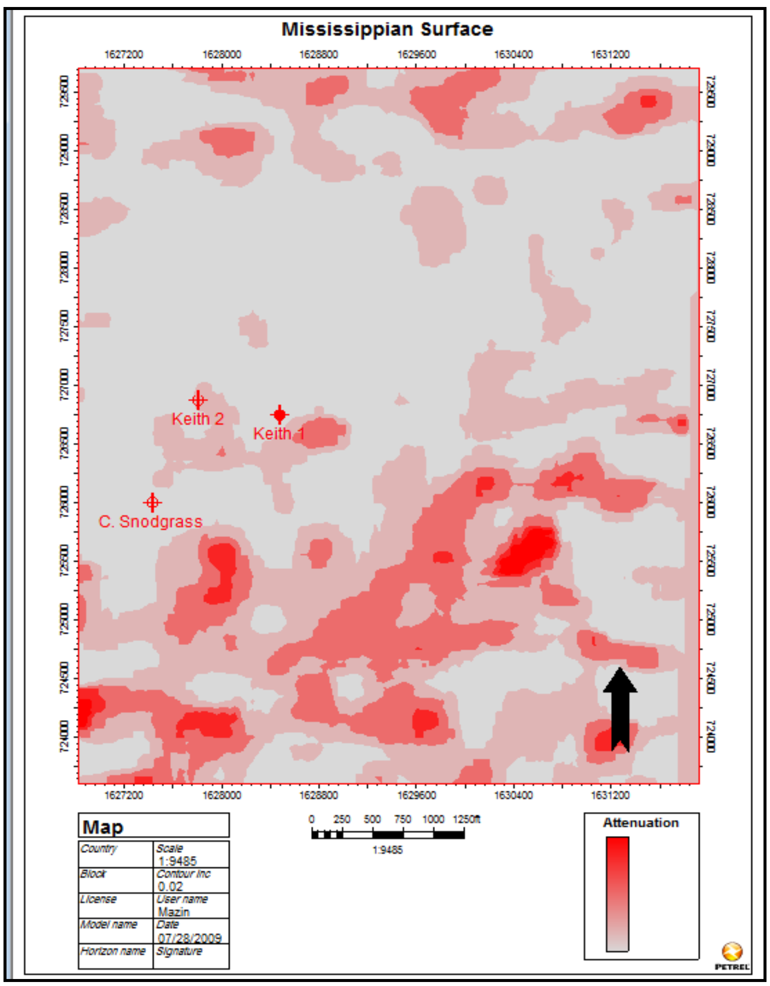


Figure 4-3 shows the attenuation attribute map. Higher attenuation values indicate areas with possible fractures zones and greater fluid movements. At the same time, lower attenuation values indicate non-porous areas and poor fluid movements. Therefore, the attenuation map may indicate areas with higher reservoir quality in terms of porosity and/or permeability. Looking at the wells in the area, it is evident that all wells are positioned in areas with low attenuation values which mean poor or no reservoir quality.

Combining information from the extracted attributes maps zoomed on the region of Keith #1 suggest the following. Keith #2 and C. Snodgrass wells were positioned on low amplitude, low energy, relatively higher AI and low attenuation areas. This means the wells were targeting zones with no lithological contrast, no positive hydrocarbon indication, poor reservoir quality, and the lowest permeability. These observations correlate with the status of the two wells which were dry holes. On the other hand, Keith #1 well was positioned on an area with a slightly higher amplitude and energy values, which could be interpreted as slight contrast in lithology and low hydrocarbon indication. This could explain the presence of the sand signatures shown by the well logs and the initial production from the well before it was plugged. The poor reservoir quality and low permeability resulted in low cumulative production, but certainly better than the two dry holes that were not completed for production at all.

Figure 4-4 shows the average energy map where the rest of the wells. These were positioned on areas with low energy except for the Wanda Judeen. Figure 4-5 shows the RMS amplitude map where the wells were positioned on areas with low amplitude, also except for Wanda Judeen. Figure 4-6 shows relative AI map where the wells were positioned on areas with relatively higher values. Figure 4-7 shows attenuation map where the wells were positioned on areas with low attenuation values.

Finally, the extended maps suggest that all the wells within the seismic survey coverage were targeting zones with no lithological contrast, no hydrocarbon indication, poor reservoir quality, and poor permeability. Again, these observations correlate with the status of the wells which show as dry wells. The exception of Wanda Judeen for the energy and amplitude maps may suggest that the well was positioned on an area of greater contrast in lithology within the extracted window. Observing and comparing the relative AI and attenuation maps show poor to no reservoir quality in the area of the well, even though there is a contrast in lithology, which when correlated to the well status show as a dry well.

Figure 4-4 Extended average energy map covering all wells within the survey

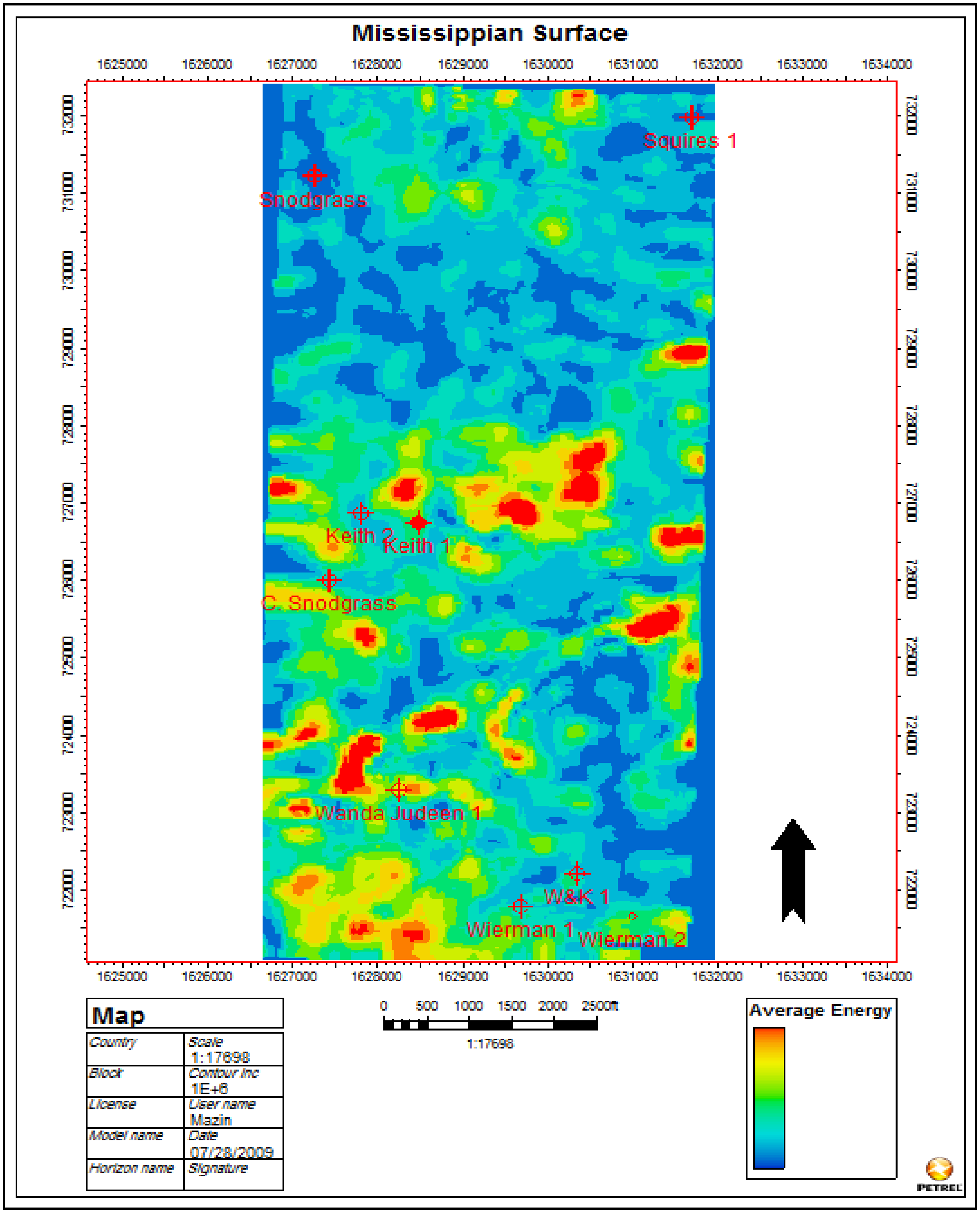


Figure 4-5 Extended RMS amplitude map covering all wells within the survey

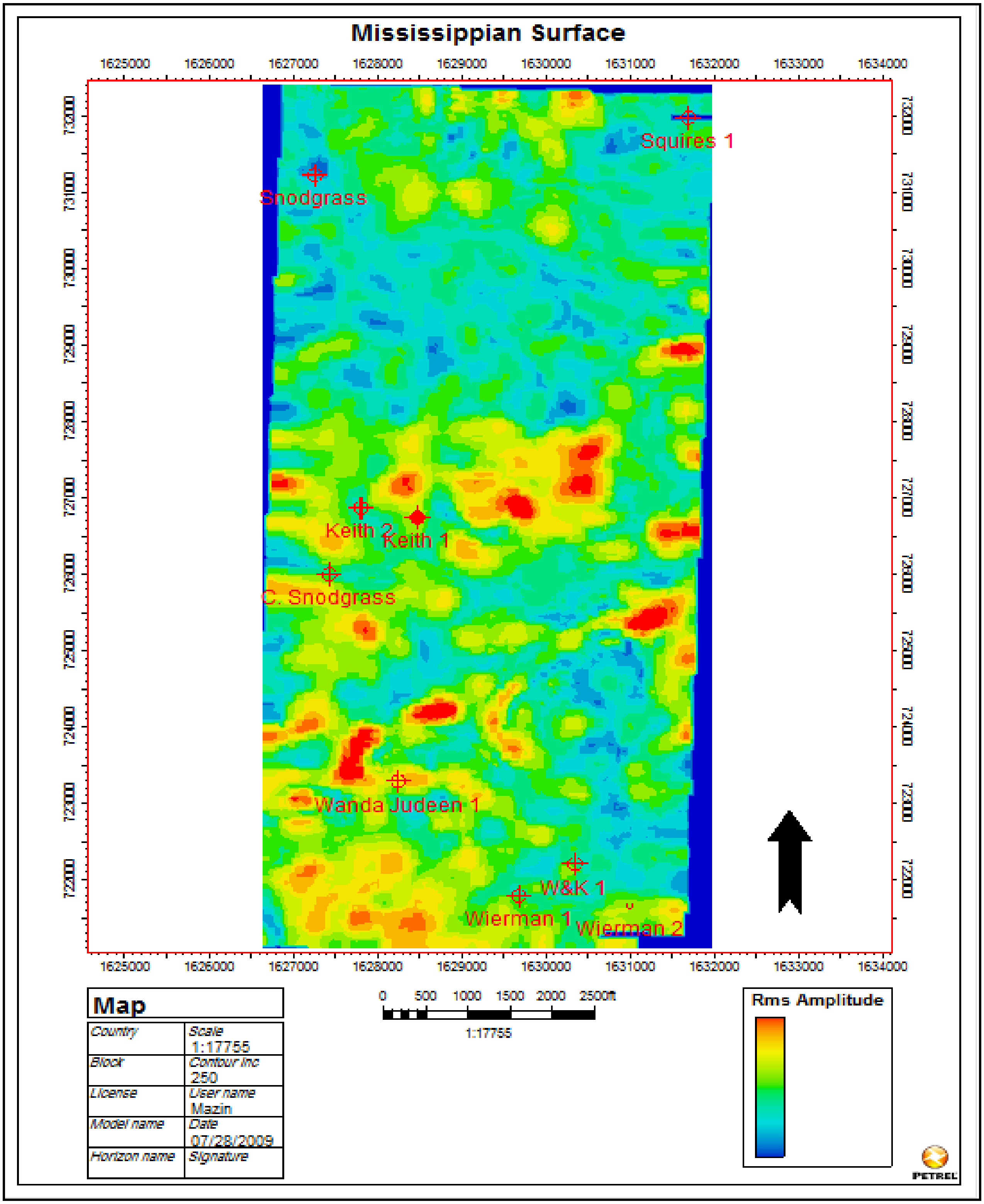


Figure 4-6 Extended relative AI map covering all wells within the survey

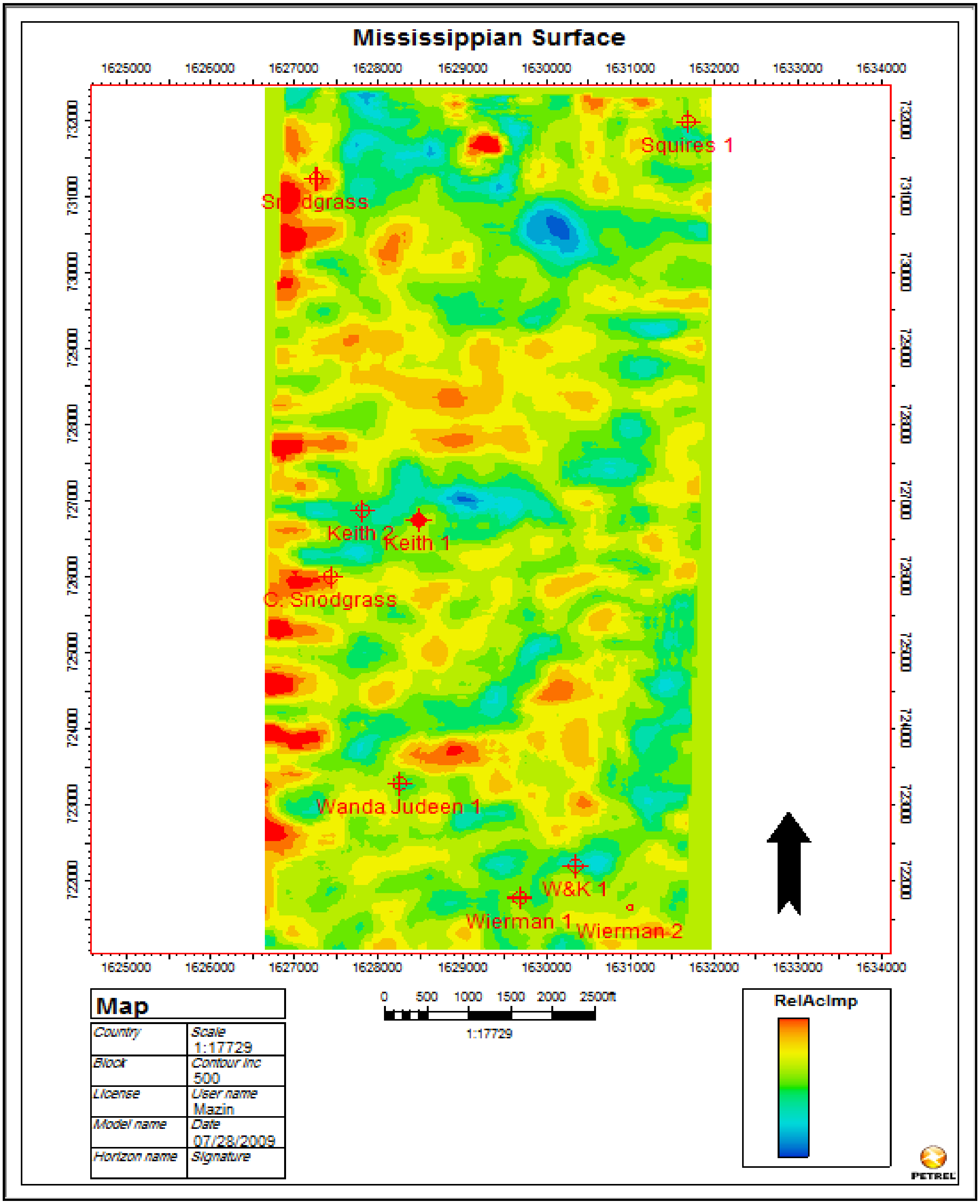
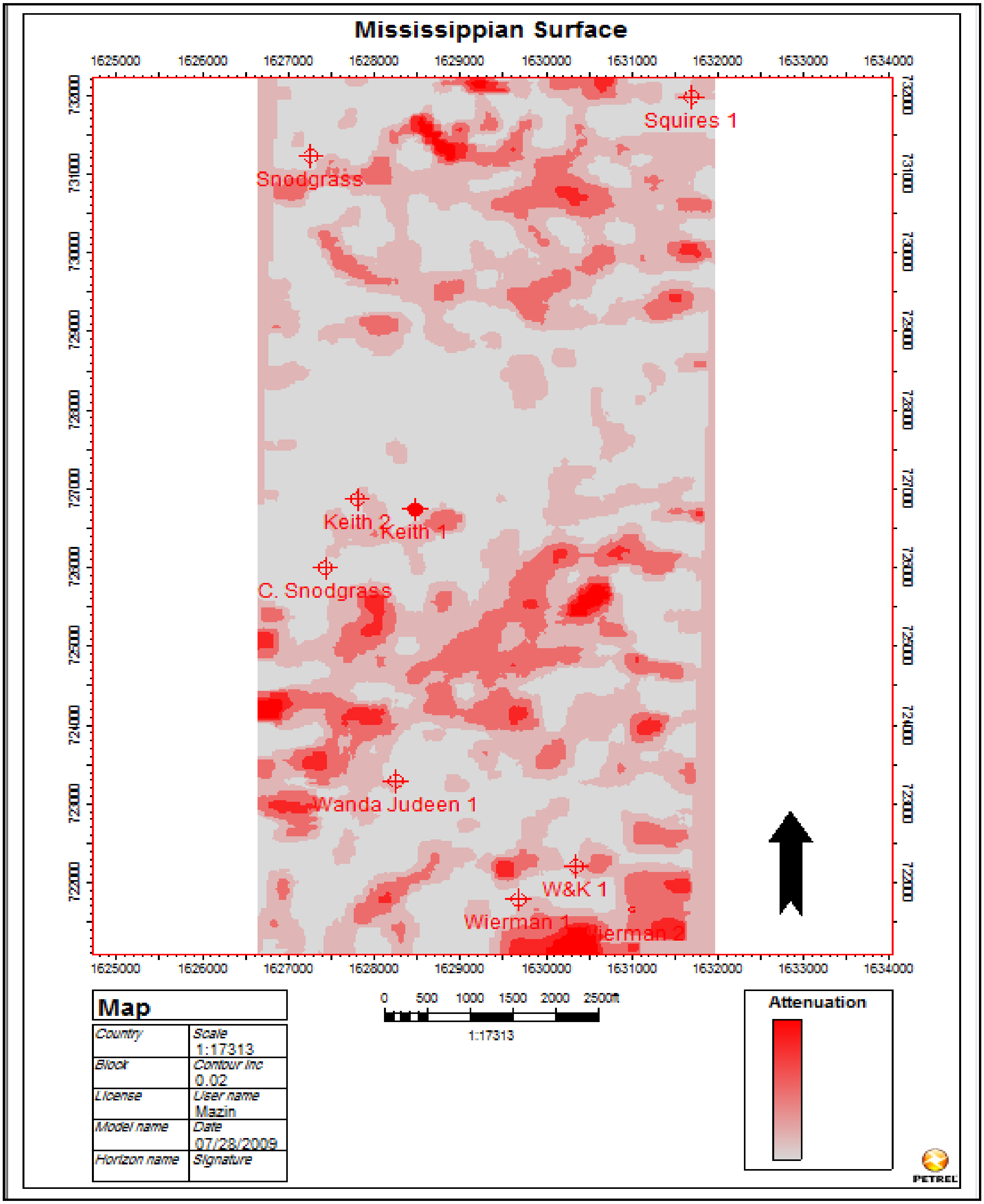


Figure 4-7 Extended attenuation map covering all wells within the survey



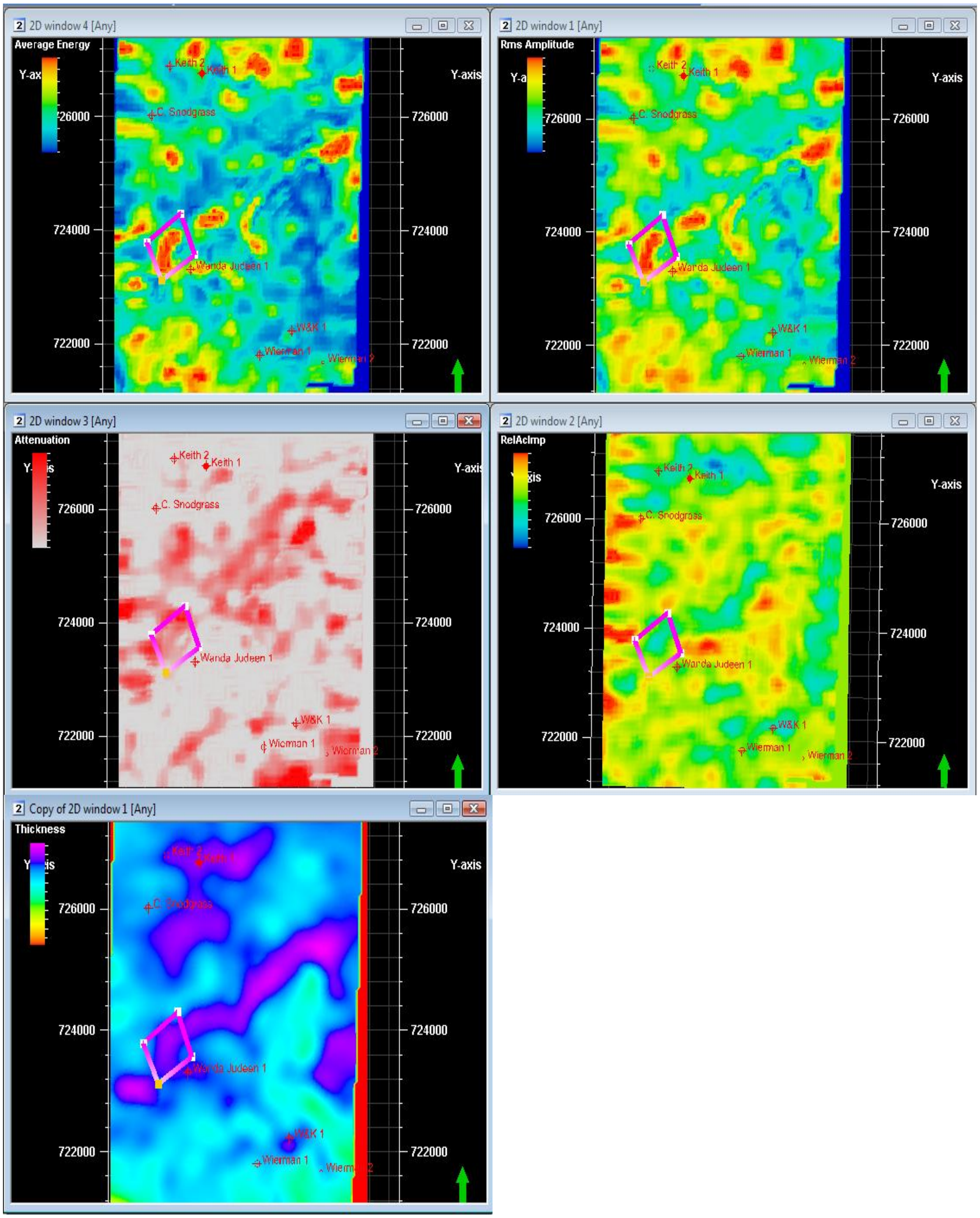
CHAPTER 5 - Conclusions and Recommendations

So, what went wrong in drilling Keith #1? and why was the target sandstone reservoir not encountered? The answer for these questions was derived from the seismic attributes workflow that suggested the following: Keith #1 was originally positioned on an area of a greater thickness and showed doublet reflections on the seismic cross section. These doublets were targeted under the impression that they may reflect a greater contrast between the underlying Mississippian surface and the lower Cherokee zone. However, analysis of the seismic attribute maps showed that these doublets were not due to development of reservoir conditions. Moreover, the isotime map shows that the thickness of the Cherokee formation at this location is within the tuning resolution of the seismic data. Hence, the duplex was likely due to tuning as the thickness approached the resolution. Moreover, the maps showed that Keith #1 was drilled on an area targeting little lithological contrast, no hydrocarbon indication, poor reservoir quality, and less permeability. This conclusion applies for all wells drilled within the limits of the seismic survey coverage. They were all positioned on areas with no incentives of profitable targets.

This study showed that running seismic attributes analysis for similar situations would provide more knowledge and understanding of geologic features. Since Coral Coast has already acquired the seismic survey, running this type of workflow would have prevented the drilling and subsequent costs of the wells in this area. At the same time it would not added any additional costs since the seismic data was already there.

Finally, Figure 5-1 shows a combination of the four attribute maps used in this study highlighting an area that could be of interest. The area shows high amplitude, high energy, relatively low AI, and higher attenuation values. This can be interpreted as higher contrast in lithology and higher reservoir quality within the extracted zone. However, more analysis needs to be carried out in order to find out if such an area is considered as a profitable target or not.

Figure 5-1 combination of the four maps highlighting a possible target



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