Application of Cutting-Edge 3D Seismic Attribute Technology to the Assessment of Geological Reservoirs for CO2 Sequestration

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Submitting Organizations:	Department of Earth and Atmospheric Sciences Reservoir Quantification Lab University of Houston Houston, Texas 77204-5505
Preparers:	Prof. Christopher Liner - P.I. Dr. Jianjun (June) Zeng Phone: 713-743-9119 Fax: 713-748-7906

CONTENTS

Executive Summary

Three major tasks have been conducted on Dickman Field data. Stratigraphic and structure modeling, fault modeling and gridding, and data preparation for property modeling. The former two tasks have been done in two cycles that included quality checking of data and editing of missing information caused by data transfer from GeoFrame to Petrel.

A graduate student, Heather King, begins work on the project in January 2009. The emphasis of her work (leading to an MS degree) will be structural and flow integrity of the seal rocks in the field, with particular emphasis on the Fort Scott.

Pending DOE concurrence, Dr. Po Geng will be joining the project in February as lead of flow simulation studies. Initial background investigation into CO2 flow simulation for geologic sequestration has begun and is included in this report.

Activities in Quarter

Stratigraphic Modeling

Three seismic horizons were carried from the earlier GeoFrame project to Petrel and two new horizons were interpreted. This forms our first cycle model (M1). Interpreted horizons in M1 were gridded into surfaces and refined using well tops and well logs to form a second cycle model (M2). From all the data in M2, the structure model was built from gridded surfaces.

Figure 1-1 shows a sketch of the stratigraphic units recognized in the Dickman Field area and referred by figures in the rest of the text. Also shown in Figure 1-1 is a map identifying the critical log control that allows detailed seismic interpretation: sonic, density, and time-depth curves. The Fort Scott horizon forms the top of the structure model and serves as a regional hanging datum. Immediately above the Mississippian Unconformity are the Lower Cherokee Sandstone and Mississippian carbonate shallow modeling targets. The basal Gilmore City serves as the lowermost extent of the deeper saline aquifer modeling zone. These three horizons were loaded from previous GeoFrame interpretation work. The level denoted by B in Figure1 is a phantom horizon picked in Petrel to serve as the base of the structure model. The Fort Scott and B horizons are not cut by faults that penetrate the intervening strata, thus satisfying a key requirement for a Petrel structure model.

These horizons were re-interpreted in Petrel based on seed points provided by a previous seismic attribute and velocity study that used Kingdom software, along with Lower Cherokee Sandstone and the local oil water contact. These were, again, based on seeds resulting from the above study. Figure 1-2 is a series of maps showing subsea depth and interpreted reflection time for the Fort Scott, Lower Cherokee Sandstone, Mississippian Unconformity, and oil-water contact. Due to sparse sonic control and few time-depth curves, the time values must be considered approximate. For major lithology changes, such as shale-to-limestone, these approximate time correlations are refined by picking the reflection event that most logically represents the lithologic boundary.

The GeoFrame horizons that had earlier been imported into Petrel were revised based on these time-depth pairs. Figure 1-3 is a representative a comparison of the new Petrel horizon interpretation compared to the earlier GeoFrame picks. The shallowest horizon track in light blue is a peak event now identified as top of the Fort Scott (note light blue arrows and FS label). The previous GeoFrame Fort Scott horizon pick is shown in red dots and now re-interpreted as the top Mississippian (note red arrows and M label). The deeper unmarked purple pick is the new Gilmore City horizon based on time-depth information from the Sidebottom 6 well. This replaces the older GeoFrame interpretation of Gilmore City shown as an unmarked thick red line. The revised horizon interpretations in Petrel are 10-20 ms shallower than previous interpretations carried from GeoFrame work. Also, two more horizons immediately above and below the Mississippian were added to the Petrel interpretations. Lower Cherokee Sandstone (based on time-depth in Figure 1-2B) is the top of the stratigraphic interval containing the sandstone oil reservoir. The oil-water contact (Figure 1-2D) separates the Mississippian carbonate reservoir from the underlying deep saline aquifer.

To QC and refine these interpretations, time-depth pairs in Figure 1-2 were used to create 21 local pseudo-check shots for the log-seismic overlay. To define horizons at well locations, up-scaled 30-point average logs (gamma, neutron porosity, sonic) were posted in the 3D project space together with stratigraphic tops loaded from GeoFrame. The gridding of these horizons into surfaces is controlled by well tops as shown in Figs 1-4, 1-5, 1-6, and 1-7 constituting the second cycle results.

In Figure 4, only the top (Fort Scott) and the base (B horizon) of the structure model are shown. Figs. 1-5, 1-6 and 1-7 show the Lower Cherokee Sandstone, Mississippian, and Gilmore City horizons as internal stratigraphic boundaries.

Based on the above stratigraphic framework, a 3D gridded structure model was established (Figure 1-8). The structure model is frequently up-dated using the results from fault modeling, discussed below.

Fault Modeling

Previous fault interpretations on the Dickman 3D seismic volume in GeoFrame were limited to a couple of boundary faults. Research on maximum negative curvature suggested the existence of a structural framework with NW- and NE-oriented faults/fractures in the north part of the survey area (Nissen et al., 2006). A Study of 5-year oil and water production data (Goloshubin, personal communication) suggested that the NW-oriented faults/fractures are open and those oriented NE are closed, acting respectively as fluid conduits and barriers. These studies did not differentiate individual reservoirs or stratigraphic units, and therefore are not well-focused on the targeted reservoirs and saline aquifer. It is important to address whether such a fault/structure framework exists within targeted zones of the refined stratigraphic model, its vertical extension, and effects. This will be used to set the top and base of the structure model, control the propagation of reservoir properties, and set physical constraints in flow modeling.

Several efforts were made to determine and select the fault/fracture features to be built into the structure model. These include:

1. Hand-picking of faults seen on selected seismic lines;
2. Fault extraction from key lines with the aid of advanced tools in Petrel;
3. Study of additional seismic volume attributes, such as variance and chaos to enhance detection of discontinuities (faults, fractures, channels, and sinkholes);
4. Tracking all discontinuities using Petrel "ANT" technology, including analysis ANT plane dip and azimuth;
5. Comparison of volumetric attributes with the previous maximum-negative curvature analysis on GeoFrame to determined the geological meaning of the linear features revealed by all the above studies.

Robust faults selected for inclusion to the structural model are those with a combination of indicators from the above steps.

Figure 2-1 shows variance time slices through a structurally smoothed seismic volume. The slices represent time surfaces roughly corresponding to the stratigraphic tops of Fort Scott, Mississippian, and Gilmore City horizons. Away from edges of the image area, strong (red) events indicate sharp lateral variations associated with structural or stratigraphic features. The Fort Scott is relatively devoid of features except at the north corner of the survey where a NE-trending fault is clearly indicated. The Mississippian shows the same fault, and a curved feature representing the edge of an erosional channel cut into the Mississippian limestone (black arrow). The Gilmore City again shows the fault and a deeper expression of the channel (white arrows). Since the channel itself does not extend down to this level, the variance is likely indicating karst features such as sinkholes.

Figure 2-2 shows the same time slices from a chaos volume. The chaos data indicates features similar to those seen in the variance result. Fort Scott horizon is less chaotic (more laterally continuous), while Mississippian and Gilmore City are indicated to be more chaotic. It is clear from Figs. 2-1 and 2-2 that some features with high variance/chaos exist at the deeper Gilmore City horizon and continue upward to the Mississippian, but not to the Fort Scott which is relatively free from faulting and fracturing. Therefore, we will use Fort Scott as the top boundary of the fault model. We also need an undisturbed horizon below Gilmore City to serve as the base of the fault model. We designate this horizon B (indicated in Figure 1-1) and it was chosen below all faulting to ensure stability of the gridding calculations.

The ANT tracking process is a patented Petrel tool, based on an edge-enhanced variance volume, that locates seismic discontinuities for all directions and dip angles. Figure 2-3 shows time slices slicing into an Ant Tracking volume at the same time levels as Fig. 2-1. In Figure 2-3A, the dark black lines are the ANT tracks indicating discontinuities. We observe far greater density of features and range of orientations than indicated in either variance or chaos. Features already discussed, including the northern fault and channel bend, are clearly seen in the ANT result. However, there is no obvious way to judge the relative importance (amplitude, throw, displacement) of ANT features, unlike the gradational indications in other attributes. This suggests it may be useful to combine attributes in some way. An overlay of the ANT track patterns with time-structure contours (Figure 2-3 B) provide further evidence that some features correspond to the edges of the Mississippian channel on top of horizon and Gilmore City sinkholes.

The ANT tracking results are compared in Figure 2-4 with previous work on maximum negative curvature at the same time levels. The curvature features carry through all three horizons to a high degree, indicating poor vertical localization. The vertical localization is controllable in the ANT calculation by sampling every 2 ms (rather than10 ms as in maximum negative curvature computation), revealing different structural patterns for each level. Horizontally, the curvature shows a rather faint framework of intersecting NW-NE dark bands. The ANT slices clearly show localized features, some lying on or parallel to dark curvature bands. However, the ANT results show few NW trending features, at odds with a strong NW grain in the curvature.

In an earlier part of this project, Nissen, Carr, and Marfurt (2006) interpret negative curvature 25 ms below the Mississippian to infer a fault/fracture system that has influenced the flow pattern in the Dickman Field reservoirs (their Figure 2). However, analysis of ANT event dip angles challenges this interpretation. In Figure 2-5A, ANT tracks are displayed in 3D to remove spurious effects caused by seismic survey data boundaries. In Figure 2-5B, a steronet shows dip and azimuth of all ANT planes with vertically exaggerated seismic dips. The corresponding histograms (Figure 2-5C) show dip statistics for all ANT planes computed using three different algorithms. The histograms revealed that over 70% of the linear features seen in ANT time slices are in fact very low angle planes with less than 5 degree dip. This is roughly equal to regional stratigraphic dip of 0-2 degrees. A fair amount of these low angle planes are overlaying linear features mapped on maximum negative curvature. If not due to data or computation errors, such low angle planes, even representing some sort of geological fractures or boundaries, can not cut the target reservoirs into sub-segments laterally or to act as vertical conduits or barriers to the flow. It is possible that depth conversion will reveal more meaningful structural dips associated with these features. But for now, they are deleted from the ANT results as suspect features.

At least one observation on the northern fault challenges the dip representation in the ANT histograms. From seismic interpretation, this boundary fault shows significant throw, whereas the ANT results imply an improbable 6-7 degree low angle thrust. Further study is planned to find our whether these low angle planes reflect geological features or artifacts. If validated, a study of the structural deformation and the stress field history will help to understand their formation and effects on fluid flow in the carbonate reservoir and saline aquifer. A fracture model was built based on all ANT planes for this purpose.

After eliminating edge effects and low angle planes, the remaining ANT planes were compared with faults hand-picked from seismic lines. Only ANT planes that cut the targeted stratigraphic units with greater than 5 degrees dip were selected (Figure 2-6A) to serve as input to the fault model. A skeleton of the fault model with the Fort Scott and B horizons as top and base is shown in Figure 2-6B. The selected fault planes were gridded between the skeleton top and base (Figure 2-6C). In Fig, 2-6C (right), the NE-oriented boundary fault is clearly shown with the down-thrown hanging wall to its NW side.

The fault model was merged with the stratigraphic model described earlier to form the final structure model (Figure 2-7). This will constitute the gridded property model. Figure 2-7A shows an overview of the entire fault and property model. From top down, the light blue mesh is a phantom horizon defining the top of the fault model, the green mesh is Fort Scott, the property model is shown as solid layers (Cherokee Sandston, Mississippi carbonate, and deep saline aquifer), and the yellow-green mesh is the base of the fault model (horizon B). The interbedded shale/carbonate seals between the Cherokee Sandstone and the Fort Scott will be modeled in a separately. The targeted zones are cut by fault walls into sub-segments as shown in Figure 2-7B. Each sub-segment will be treated as an individual geo-body for rock/fluid property propagation. In Figure 2-7C, well log traces with gamma ray (blue) and neutron porosity (pink) are shown inserting into the structure model to serve as seeds for property propagation.

The property model requires a transfer of the above structure model from time to depth domain. The structure model is converted to depth using 21 wells with pseudo-check shots as time-depth curves (Figure 2-8). This is the structural model to hold the reservoir property propagation.

The display in Figure 2-8 suggests that a further zonation within the deep saline aquifer, and possibly the Mississippi carbonate reservoir will be needed to a cell height that best fits the vertical property distribution. This will be done after the data analysis step on log property in Section 3.

Property Modeling

The work flow for the Property modeling in Petrel includes three steps. First, geometrical modeling in which properties are built based on the geometrical properties of the grid cells themselves without interpolation of input data. Second, facies modeling involving interpolation or simulation of discrete data as facies that can guide the property propagation with preferences. And, third, petrophysical modeling to interpolate or simulate continuous data, e.g. porosity, permeability and saturation based on the log data analysis/up-scaling.

Three sub-tasks were planned for the targeted zones to partially satisfy this work flow: (1) upscale well logs, (2) log/core data analysis, and (3) porosity curve calculation from logs and core data analysis. The facies modeling process requires detailed lithology data and information on clastic and carbonate depositional environments in the studied area. Both are not easily accessible to this research group.

Well log upscaling. Logs loaded from GeoFrame include both original logs. derived logs, such as logs after “up-scaling” (averaging based on different window sizes with or without spike-removal), and porosity logs calculated from neutron logs using different methods and matrix densities. For consistency with the data to be computed from Petrel, all these derived logs were re-evaluated and most will be re-computed by Petrel log computation tools. Gamma ray and neutron porosity logs that will be used for lithology and porosity calculations are already inserted into the model as shown in Figs. 2-7 and 2-8.

Data analysis. Only two wells near the boundary of the survey area (actually outside) have both density logs that read the total porosity and sonic logs that read the interconnected porosity. Another four wells within the survey area have core porosity and permeability measurements for a small portion of the targeted zones. The data analysis was originally focused mainly on the relationship between raw log values and core porosity measurements. However, the correlation between core porosity and neutron porosity values are poor. Computation of water saturation from resistivity logs is possible only for two wells outside the survey area.

Because of the lack of good quality logs, especially for the deep saline aquifer with very limited well penetration, seismic data will be a major contributor to the data analyses. For this purpose, a comparison of seismic thickness and true subsurface thickness of the stratigraphic interval between Fort Scott and Mississippian horizon was done using “Surface Calculation” tools in Petrel, in the hope of identifying the contribution of rock properties to the seismic time thickness. The Fort Scott-Mississippian interval is well-sampled (over 80 wells and gridded seismic tops) for computation of the interval thickness in both time and depth. This interval also contains one of the modeling targets, the Cherokee Sandstone reservoir, at its base. The concept for the analysis is that measured depth thickness (isopach) represents true interval thickness and the two-way time thickness (isochron) depends on two factors: true thickness and seismic velocity. It is possible to identify the contribution of rock property to the isochron by removing the isopach thicknesses and isolating lateral changes in interval velocity.

The isochron and isopach values of the Fort Scott to Mississippian interval were normalized to lie between 0 (minimum) and 1 (maximum) at each well. The normalized isochron was subtracted from the normalized isopach to make a residual (Figure 3-1A). If time and depth thickness were perfectly correlated, this map would be zero everywhere. The observed variability is due to lateral velocity changes in the interval studied.

Figure 3-1B is an isopach of the Cherokee Sandstone which lies in the interval under consideration. Thickness ranges from 0-75 ft and bears a strong visual correlation with the residual map. When absent, the missing sandstone is replaced by either shale or carbonate both of which are of significantly different velocity. This implies that lateral lithology changes are the dominant cause of isopach-isochron disagreement. We suspect that lateral porosity changes are present but have much less influence.

Figure 3-2 shows a cross with normalized isochron values along the x-axis and normalized isopach along y. Points above the blue line correspond to the red areas in Figure 3-1A and white area in Figure 3-1B. Points near the curve are correspond to the white area in Figure 3-1. Points below the line are correspond to the blue areas in Figure 3-1A and brown areas in Figure 3-1B. If lateral velocity variation is very small in the Fort Scott to Mississippian interval, this plot would show a linear relationship with a high correlation coefficient. However, the plot in Figure 3-1 B yields a linear relationship with a 0.3 correlation coefficient indicating significant lateral variation.

<u>An Initial Report on the Application of Reservoir Simulators in CO2 Sequestration</u>

A literature search aiming to understand the application of simulators to CO_2 sequestration was conducted on several web sites (Society of Petroleum Engineers, Society of Exploration Geophysicists, etc.). The initial investigation indicated that the following five simulators were reportedly used in recent research:

GEM Computer Modeling Group (CMG) of Calgary offers a generalized equation-of-state model compositional reservoir Simulator (GEM). UT Austin and CMG conducted a series of research using GEM for CO_2 sequestration simulation in deep saline aquifers (Navanit and Bryant, 2008; Kumar et al., 2005; Nghiem e al, 2004; Noh et al, 2004). GEM also can be used in CO_2 enhanced oil recovery (EOR), CO_2 storage in depleted reservoirs, and enhanced coal bed methane simulation. GEM can model multi-component gas in the coal bed methane problem.

STARS Computer Modeling Group also offers a steam, thermal, and advanced processes reservoir simulator (STARS) which is the company's most successful product. It is the only commercial simulator that includes thermal and chemical reactions. STARS has been used widely in steam and thermal EOR simulation, and has been applied to a carbonate CO_2 sequestration simulation (Izgec et al., 2006).

TOUGH This is a research simulator developed by Laurence Berkley National Lab (Pruess et al., 2002) who conducted a comparison of TOUGH with several other simulators (GEM, Eclipse & etc) for many different cases. TOUGH2 adds rock/fluid interaction including porosity and permeability changes over time.

ECLIPSE Schlumberger's ECLIPSE black oil simulator is one of the company's most successful products. It is reliable, fast and a dominate commercial simulator. ECLIPSE CBM (coal-bed methane) has been developed to simulate the enhanced coal recovery problem (Wei et al, 2006). It inherits Eclipse's advantages, but can only model two components: CH_4 and CO_2. Mo and Akervoll (2006) conducted interesting flow simulation research on deep saline aquifers for CO_2 sequestration by using the ECLIPSE black oil simulator. Schlumberger's ECLIPSE EOS (equation of state) compositional simulator is similar to GEM. We have found only one article (Karsten et al., 2002) that compares ECLIPSE EOS with other simulators in relation to the CO_2 sequestration problem.

Work Plan for Next Quarter

Geology

June Zeng

The final goal for the work from January 1 to Mar. 31, 2009 is to provide a property model with fault and fracture information (dip, azimuth, open or closed) ready for flow modeling. New results from each of the following modeling steps in the workflow will be used to up-date the other models.

Stratigraphic modeling
Up-date after each cycle of the Fault and Property modeling.

Fault modeling
Fault identification is difficult because of the lack of true field evidence for subsurface faults (e.g., well bore fault intersections, or flow compartments evidenced by pressure/production data). Also, linear features indicated by seismic curvature and ANT analysis does not support a vertical fault/fracture system, although vertical fractures are reported in a similar stratigraphic interval of the nearby Schaben Field. Challenges further relate to the NW-trending open fault/fracture network suggested by an earlier curvature study (Nissen et. al, 2006, Fig.15), which is not well-resolved by any of the other seismic attributes.

More field structure data will be collected from KGS web site and other sources to support the "Fracture modeling". Re-evaluate the different attribute study tools to resolve the uncertainties by comparing with hand-interpretation. Finalize fault and structure modeling based on integration of manual amplitude interpretation, volumetric attributes, and ANT analysis.

Property Modeling
Property modeling will be the major focus. Challenges include the lack of a relationship between core porosity and the log measurements (mainly neutron porosity), sparse log data for the deeper saline aquifer, and few permeability measurements (two cores) across the entire survey area. Seismic data will be used to fill the gaps, while understanding it's

resolution and accuracy limitations. The final property model for flow simulation will be constructed after the following steps.

1. *Data analysis*. Generate numerical relationships between density and sonic logs for the dolomitic deep saline aquifer, and also as a reference for porosity relationships in the shallower carbonate and sandstone reservoirs. The expected result is the generation of computed porosity logs for 17 additional wells.
2. *Up-scale logs.* Find the optimized sampling interval for the up-scaling by variance plots on computed porosity logs. Results will also be used as constraint on vertical cell size in the structure model.
3. *Facies analysis*. Focus on deep saline aquifer to further divide the stratigraphic unit into 2 or 3 property sub-zones based on picks in the SideBottom 6 well. This step may have to be skipped depending on log data availability in the saline aquifer interval.
4. *Time/Depth thickness.* Clarify the relationship between seismic time thickness and measured depth thickness for the deep saline aquifer to control the later propagation of properties to areas with no well penetration.

Heather King

Compile all available information on well logs and seismic data from the Dickman Field including acquisition and processing parameters. This will require contacting Kurt Marfurt and others to find acquisition and processing reports and updating the current well log data chart.

Gather information about the Fort Scott formation, focusing on lithology and depositional environment near Ness County. This will require contacting someone with the KGS to obtain all relevant data on Dickman Field and Ness County and any available, unpublished theses or dissertations.

Regenerate synthetic seismograms from all the wells that have density, sonic, and time-depth curves.

Gather all of the data I am missing (Humphrey 4-18 tops, pre-computed seismic attribute data) so all of the data will be in one location which can be considered the official SMT Dickman Field project.

Engineering

Po Geng

The immediate task is to complete Kingdom production data import and pass it to Heather. The files are not in Kingdom standard file format. I have to copy and paste the data into Kingdom, which may take some time to complete.

After completing the production data import, if there is no other urgent task, I will continue to do simulation preparation. I will work with June to get grid and property model ready for the upcoming simulation job.

Cost Status

Baseline Costs Compared to Actual Incurred Costs

2008			
Oct 1 – Dec 31	**Plan**	**Costs**	**Difference** (Plan-Costs)
Federal	$33,333.33	$6480.00	$24,853.33
Non-Federal	$12,563.58	$0	$12,563.58
Total	$45,896.91	$6480.00	$37,416.91

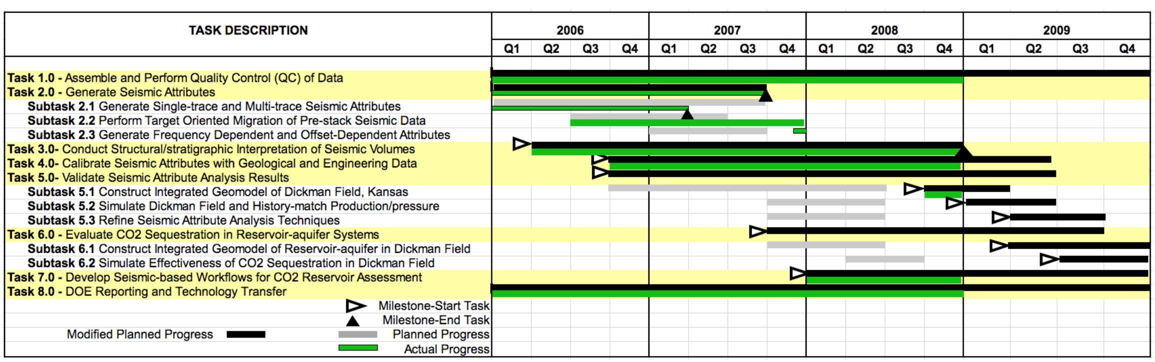
Forecasted cash needs vs. actual incurred costs

Notes:
1. Federal plan amount based on original award of $400K averaged over 12 reporting quarters.
2. Cost this period reflects Petrel training for June Zeng and one month of her salary.
3. Non-Federal plan amount based on original budget cost share of $150,573 averaged as above.

Analysis of Variance

Cost this period reflects Petrel training for June Zeng and one month of her salary. Going forward spending will increase with June Zeng, Heather King, and Po Geng all drawing pay for most of 2009. The P.I. has other sources of funding and will not be paid out of this project.

<u>Actual Progress Compared to Milestones</u>



Summary of Significant Accomplishments

<u>Problems and Significant Events</u>

We are happy to report no problems in this reporting period. The final installment of funds was received from DOE in this period, and we were granted a 12 month no-cost extension through Dec. 31, 2009.

Aside from the work reported here, the most significant event was the identification of Dr. Po Geng to join the team as lead flow simulation scientist. This will allow us to proceed to the next important phase.

Continuing Personnel

Prof. Christopher Liner is Principle Investigator and lead geophysicist. He is a member of the SEG CO2 Committee and Director of the U Houston Reservoir Quantification Lab.

Dr. June Zeng has been working exclusively on this project since Dec 2007 and is lead geologist. She will be funded through the end of 2009.

Heather King is a graduate MS student in geophysics who will join the project in January 2009 as a research assistant. She will be funded out of the project Jan-May and Sept-Dec 2009, when she anticipates graduating. Her thesis will focus on the Fort Scott to demonstrate the integrity of this formation as a seal for injected CO2. This will involve subtle structure and stratigraphy inferred by interpretation of multiple seismic attributes.

New Personnel

The original subcontract arrangement with Kansas University and Kansas Geological Survey (KU/KGS) called for work related to petrophysics and flow simulation at the Dickman Field. This involved DOE funding and $50K cost share. Part of the work (petrophysics) was completed by early 2007 then, for a variety of reasons, progress and payment ceased. To that point, KU had contributed cost share to the amount of $30,427.33. Negotiations between P.I. C. Liner and KU/KGS personnel in summer 2008 revealed that this subcontractor preferred to withdraw from the project to focus resources and effort.

Further, previous communications with DOE indicated that Texas A&M Petroleum Engineering would be involved in the flow simulation work. After discussions with Dr. Behnam Jarfarpour in November 2008, it became clear that the time frame for the flow simulation study (2009 only) would present difficulties in identifying personnel to do the work. It was agreed that a private contractor in Houston would be the preferred solution.

PI Liner has discussed this change with DOE Program Representative Dr. Karen Cohen (1/30/09) who suggested consultation with DOE Contract Specialist Ms. Dona Reese. Assuming concurrence with DOE personnel, Dr. Po Geng will join the project in Februay 2009 as flow simulation lead. He will be partially supported from the project Feb-Dec 2009. Dr. Geng's credentials are impressive, including work with IBM, Shell, and Seismic MicroTechnology. He educational details are:

- Master of Petroleum Engineering: The University of Houston, 2008
- Ph.D.: Computational Mechanics, The University of Texas at Austin, 1994
  Dissertation: *Parallel HP-Methods for Coupled BE/FE Analysis of Structural Acoustics*

Problem.

- B.S.: Mathematics & Mechanics, East China Institute of Technology, 1984

Technology Transfer Activities

Under this heading, we can include data that was transferred to Dr. John Anderson of DOE's Rocky Montain Oilfield Testing Center. Text of the transmittal explains the purpose and contents of this transaction:

Letter of Transmittal

November 3, 2008

Dr. John Anderson
Chief Scientist, Rocky Mountain Oilfield Testing Center
U.S. Department of Energy
33250 N. Hwy. 259
Casper, WY 82601

Dear John,

As you may recall, we met on May 19 at the University of Houston and discussed the Teapot Dome 3D data set which was being studied as part of a CO2 sequestration DOE project DE-FG26-06. I hope that you will forgive this tardy reply, but the last several months have been occupied with reorganizing the project budget, subcontractors, and scope of work. One outcome of this effort has been to focus our efforts on the Dickman, Kansas site as the best candidate area to make meaningful progress with limited budget, time, and personnel.

Having said that, I also realize that the seismic data work initiated by Dr. Kurt Marfurt while at UH is important to RMOTC and future collaborators who will work on the field. Therefore, please find the enclosed a set of 5 DVDs containing the following SEGY data (number corresponds to DVD number):

1. Migrations
    a. Post stack depth migration (PostSDM)
    b. Post stack time migration (PostSTM)
    c. Prestack depth migration (PreSDM)
    d. Prestack time migration (PreSTM)
2. Attributes computed on PostSDM
3. Attributes computed on PostSTM
4. Attributes computed on PreSDM
5. Attributes computed on PreSTM

The attributes in each case consist of : Crossline gradient, Principal component filter, Energy ratio, Fractional derivative, Inline gradient, Negative curvature, Positive curvature, and Outer product For a discussion of many of these attributes, I refer you to : Curvature attribute applications to 3D surface seismic data by S. Chopra and K. Marfurt (The Leading Edge, 2007).

Thank you for your patience in receiving this requested data, and for your support of research efforts at the University of Houston.

Respectfully yours…

Contributors

University of Houston
Christopher Liner (P.I, Geophysics)
Jianjun (June) Zeng (Geology)
Po Geng (Flow Simulation)

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10. *Modeling Long-Term CO2 Storage in Aquifer With a Black-Oil Reservoir Simulator*, S. Mo, SPE and I. Akervoll, SINTEF Petroleum Research , SPE 93951, 2006

Figures

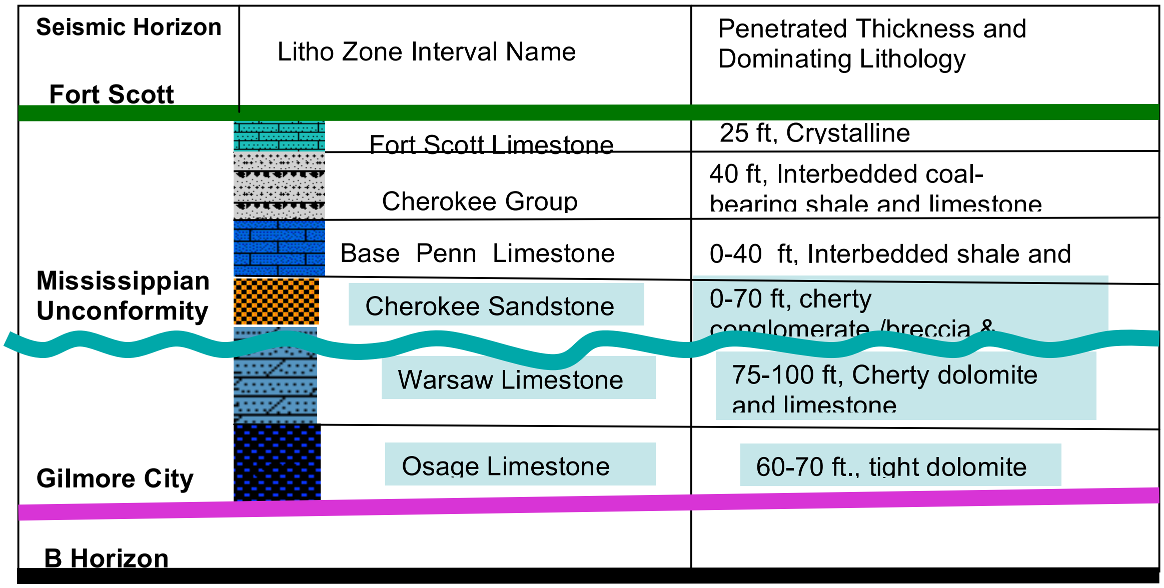

Figure 1-1 Stratigraphic diagram showing the Fort Scott Horizon (green) as the hanging datum of the structure model, the B Horizon (black) as the base of the structure model, and target zones for the property model (shaded in light blue) separated by the Mississippi Unconformity.

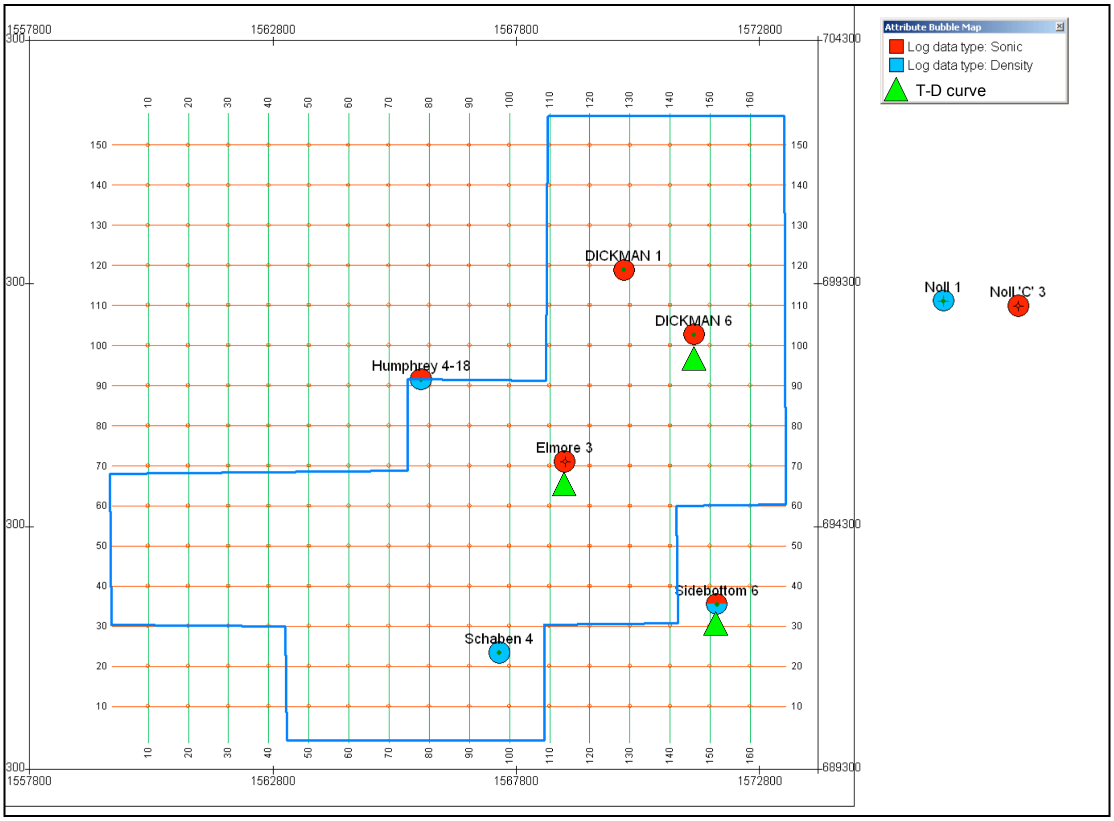

Figure1-1. Cont. Maps showing all wells with key logs for seismic interpretation: sonic (red), density (blue), time-depth curve (green).

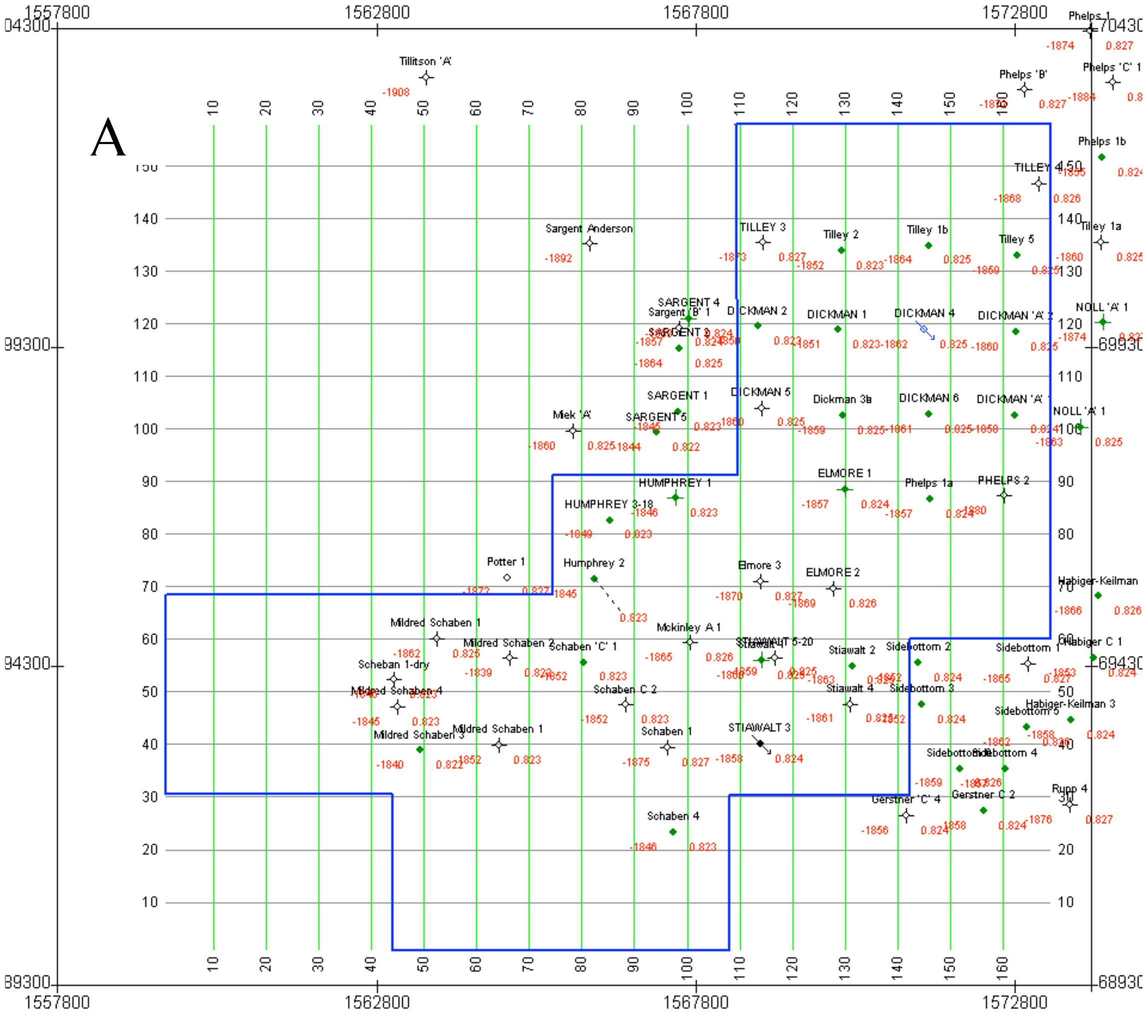

Figure 1-2. Maps generated in Kingdom software with posted subsea depth and migrated reflection time of selected horizons. These served as seed points for porting horizon interpretation to Petrel software. On each map, only those wells with a picked top for the relevant horizon are shown. Blue line indicates limit of 3D data coverage. (A) Top of Fort-Scott.

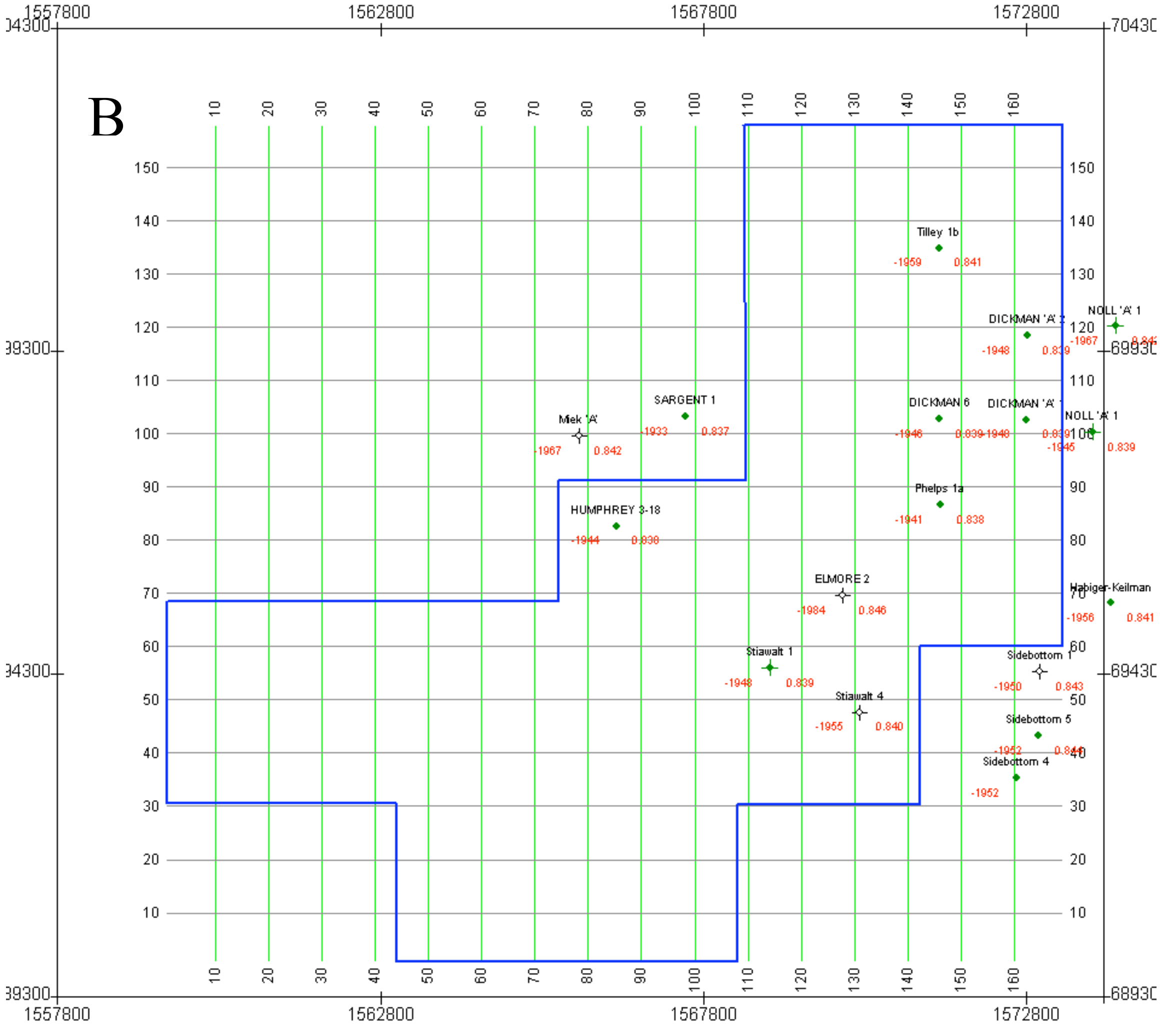

Figure 1-2. Continued. (B) Time-depth postings for top of Lower Cherokee Sandstone

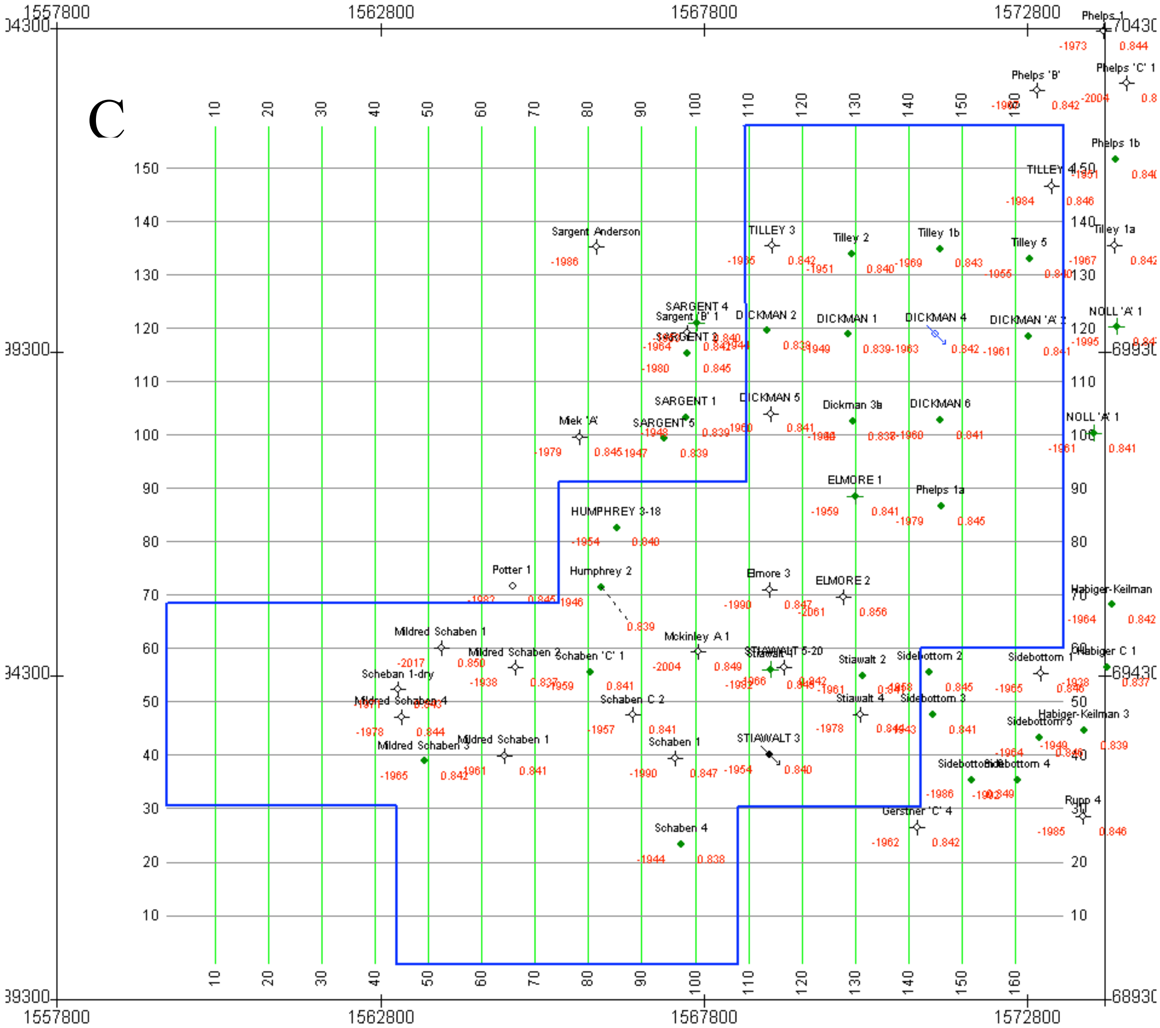

Figure 1-2. Continued. (C) Time-depth postings for Mississippian Unconformity.

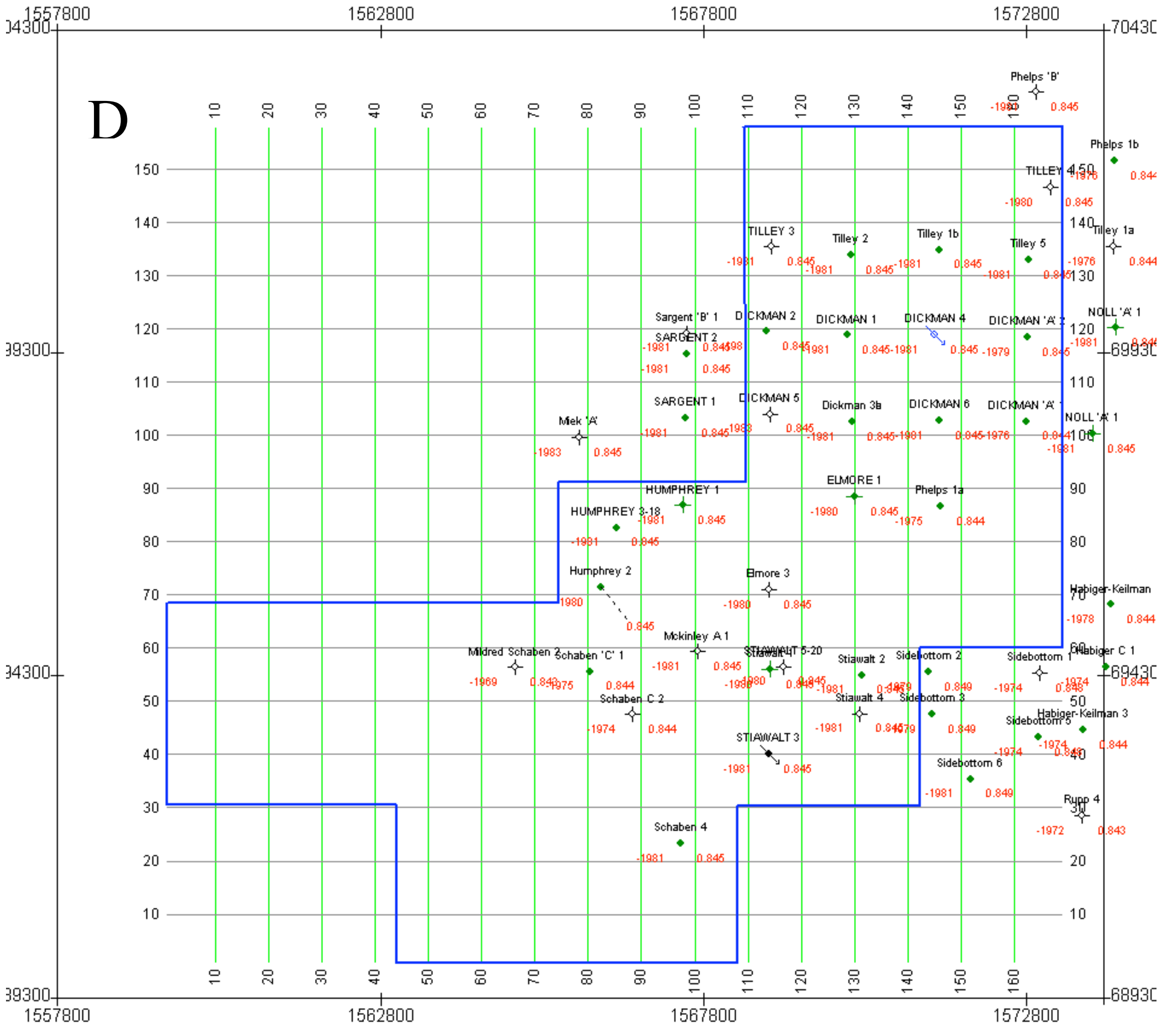

Figure 1-2. Continued. (D) Time-depth postings for top Oil-Water contact.

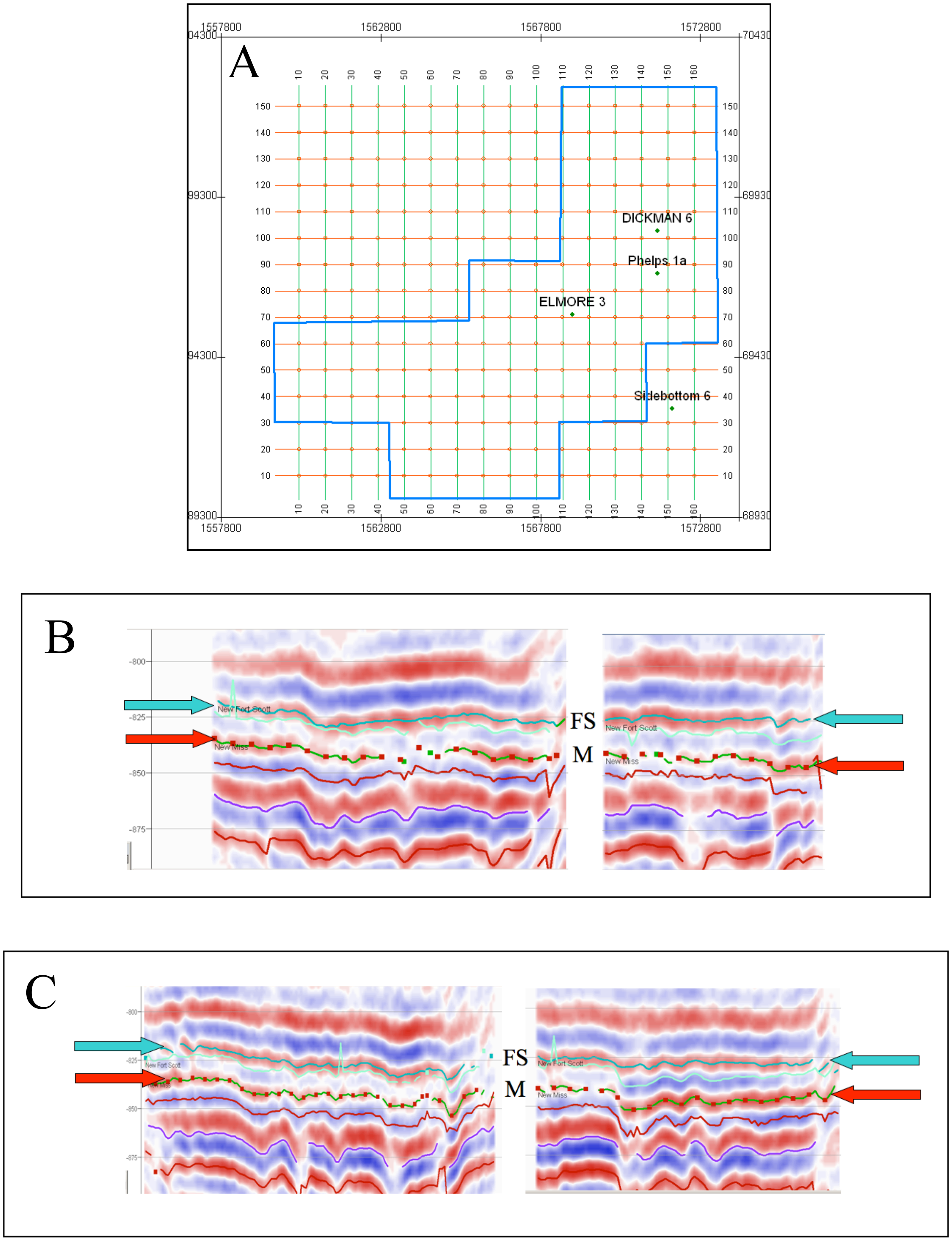

Figure 1-3. Illustration of revised Fort Scott and Mississippian horizon interpretations. (A) Base map showing wells whose formation time-depth values contributed to the seismic profiles shown. (B) North-South seismic line through the Dickman 6 and Phelps 1a wells. Light blue arrow indicates new Fort Scott pick (previous pick at red arrow). Red arrow and M indicate new Mississippian pick. (C) Northwest-Southeast line through Elmore 3 and Sidebottom 6 wells with same indicators.

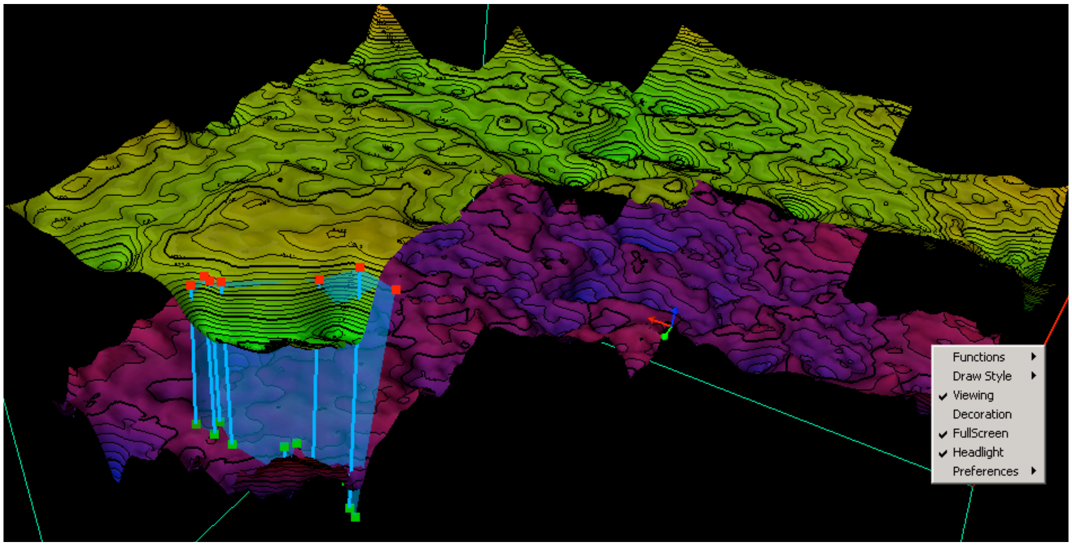

Figure 1-4. The geologic property model extends from the Fort Scott (green upper surface) to phantom horizon B (dark purple). The near vertical blue plane is a NW fault surface at the north boundary of the survey cutting through the entire Mississippian to Gilmore City strata. Vertical axis is reflection time and viewpoint is from the North.

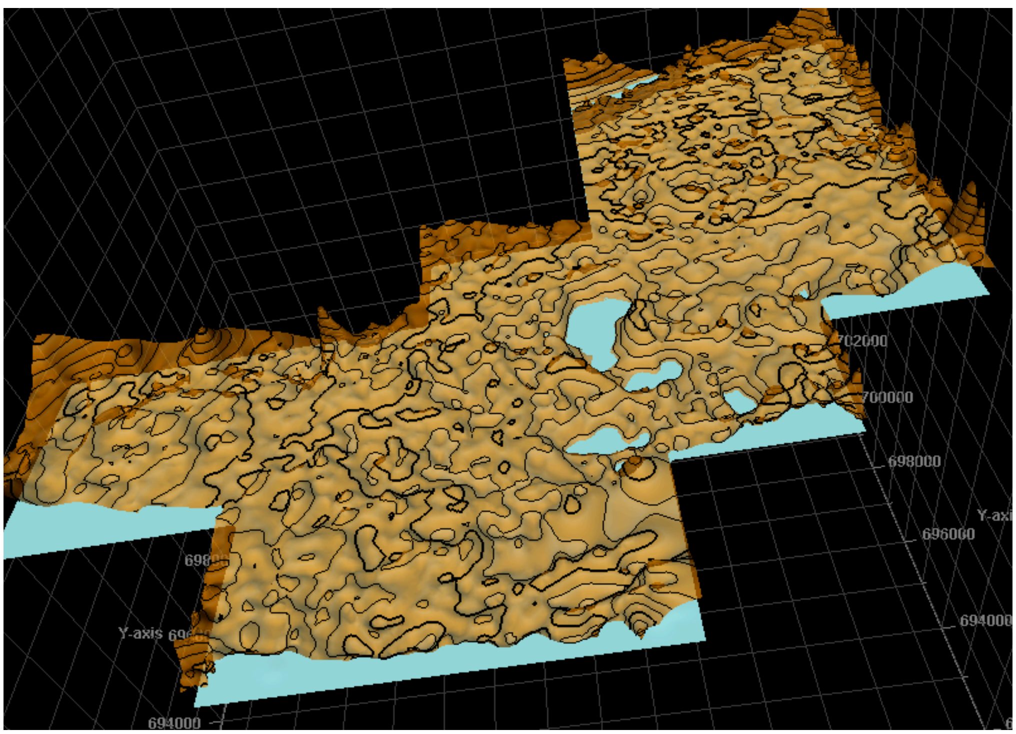

Figure 1-5. Gridded Lower Cherokee sandstone top surface (brown) with oil-water contact (light blue). The vertical scale is in time and the picture looks from south.

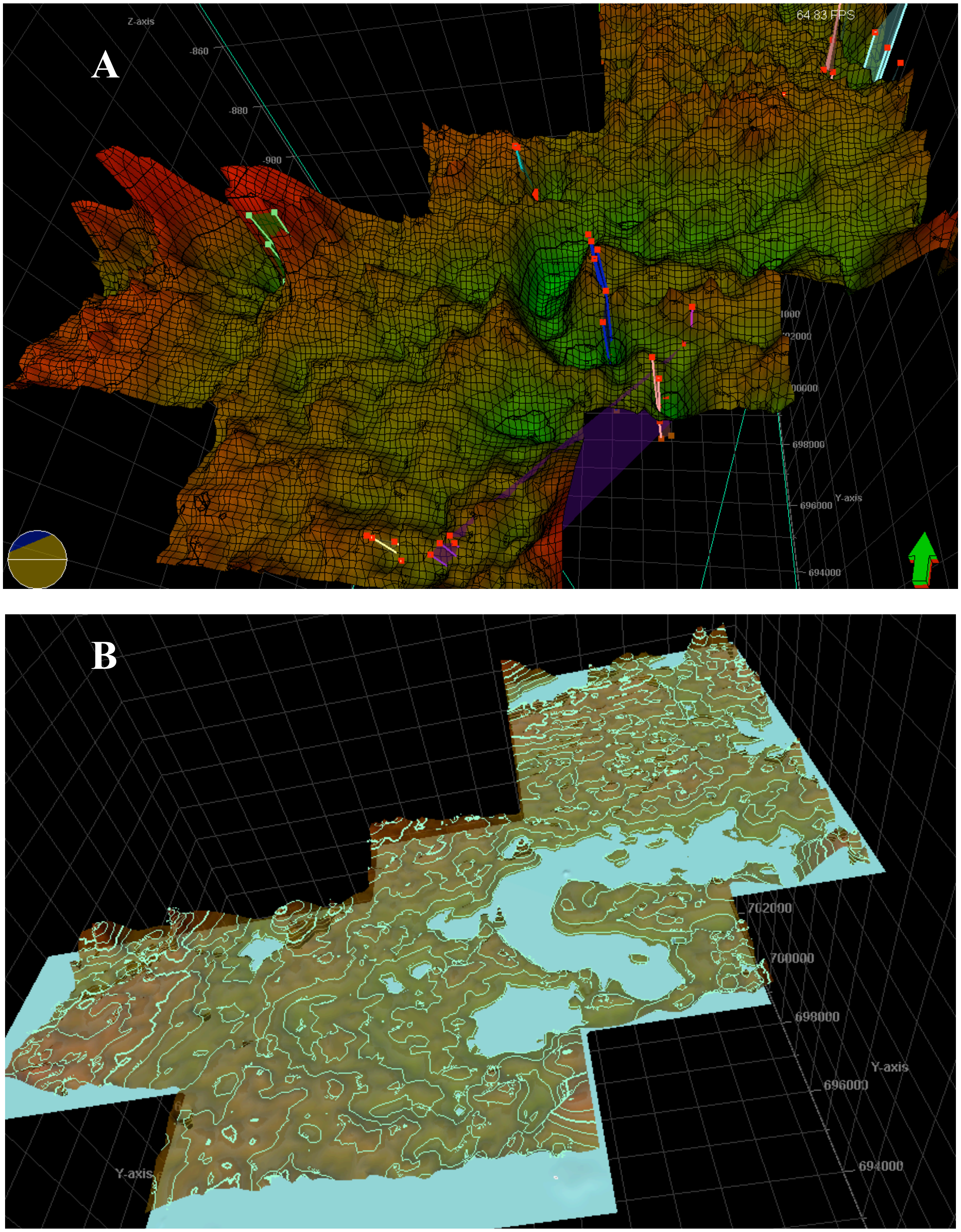

Figure 1-6. Gridded Mississippian Unconformity. A. the first cycle result without oil-water contact and with faults. B: the second cycle results with oil-water contact (light blue). The vertical scale is in time and the picture looks from south.

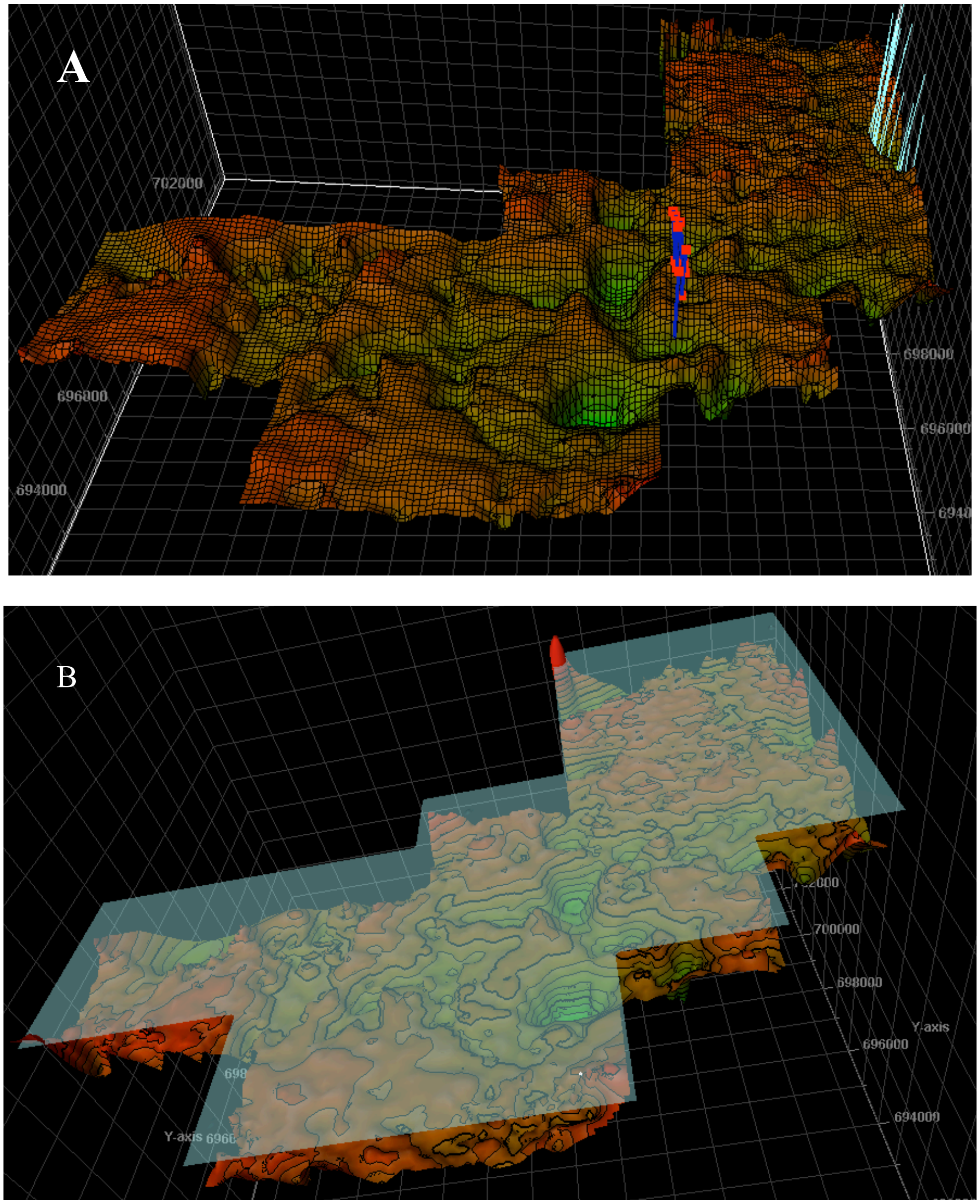

Figure 1-7. Gridded Gilmore City surface. A: grid from first cycle results and B. the grid from the second cycle results with oil-water contact (light blue). oil-water contact and Gilmore City represent the top and bottom of the deep saline aquifer, respectively. The vertical scale is in time and the picture looks from south.

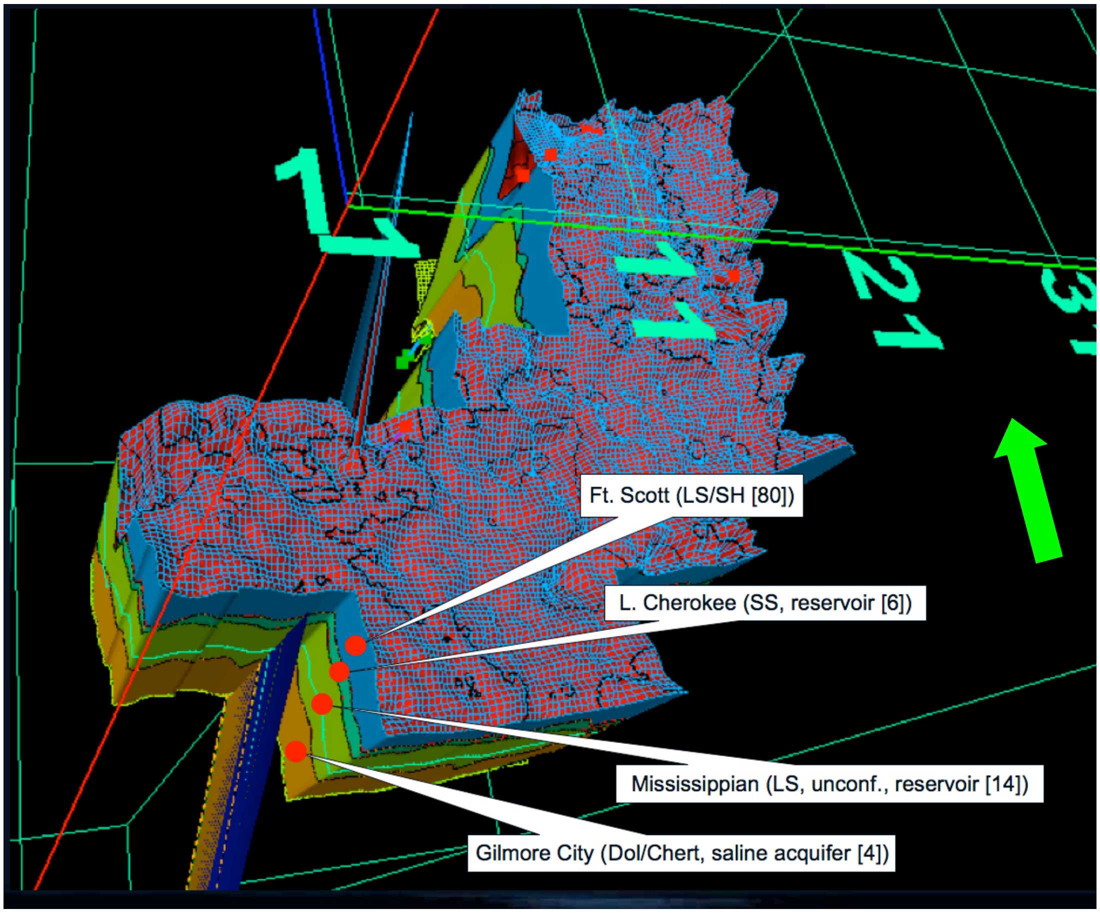

Figure 1-8. 3D grid structure model built on all revised seismic interpretations shown in Figs. 1-4 to 1-7. This will be integrated with the fault model to serve as geometry framework for property models. The vertical scale is in time. The picture looks from south west.

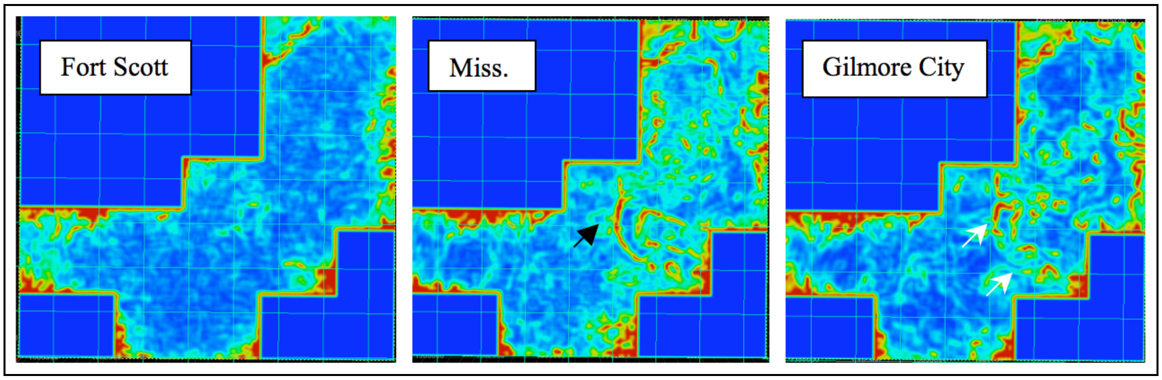

Figure 2-1. Time slices from a variance volume (blue is low value, red is high), high variance. From left to right: For Scott time slice (824 ms), Mississippian (845 ms), Gilmore City (864 ms). The same formations and slice times apply for Figures 2-4 through 2-4.

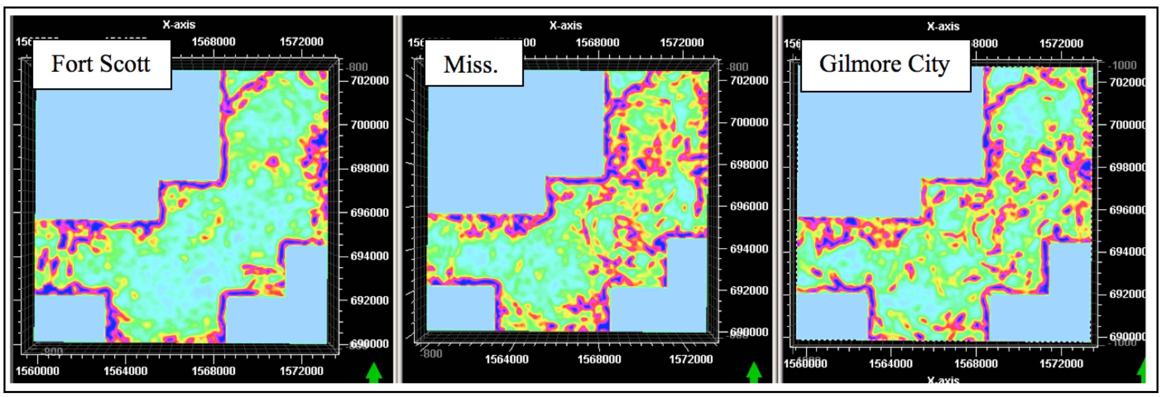

Figure 2-2. Time slices from a chaos volume, Blue-red = high level of chaos, green= low level of chaos. From left to right: Time slices at -824 ms (Fort Scott), -845 ms (Mississippian) and -864 ms Gilmore City).

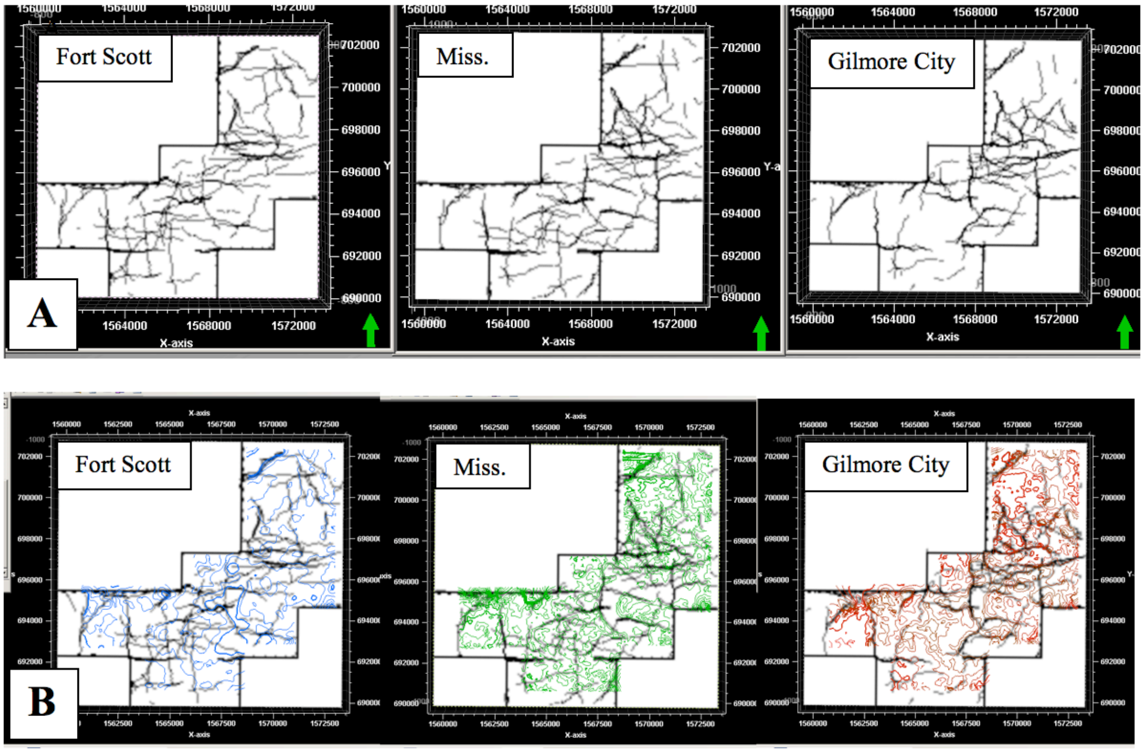

Figure 2-3 Time slices from an Ant Tracking tool. The dark black lines represent the discontinuities**.** (A) From left to right: Time slices at -824 ms (Fort Scott), -845 ms (Mississippian) and -864 ms Gilmore City). (B) Overlay of the ANT results with the relevant surface contours.

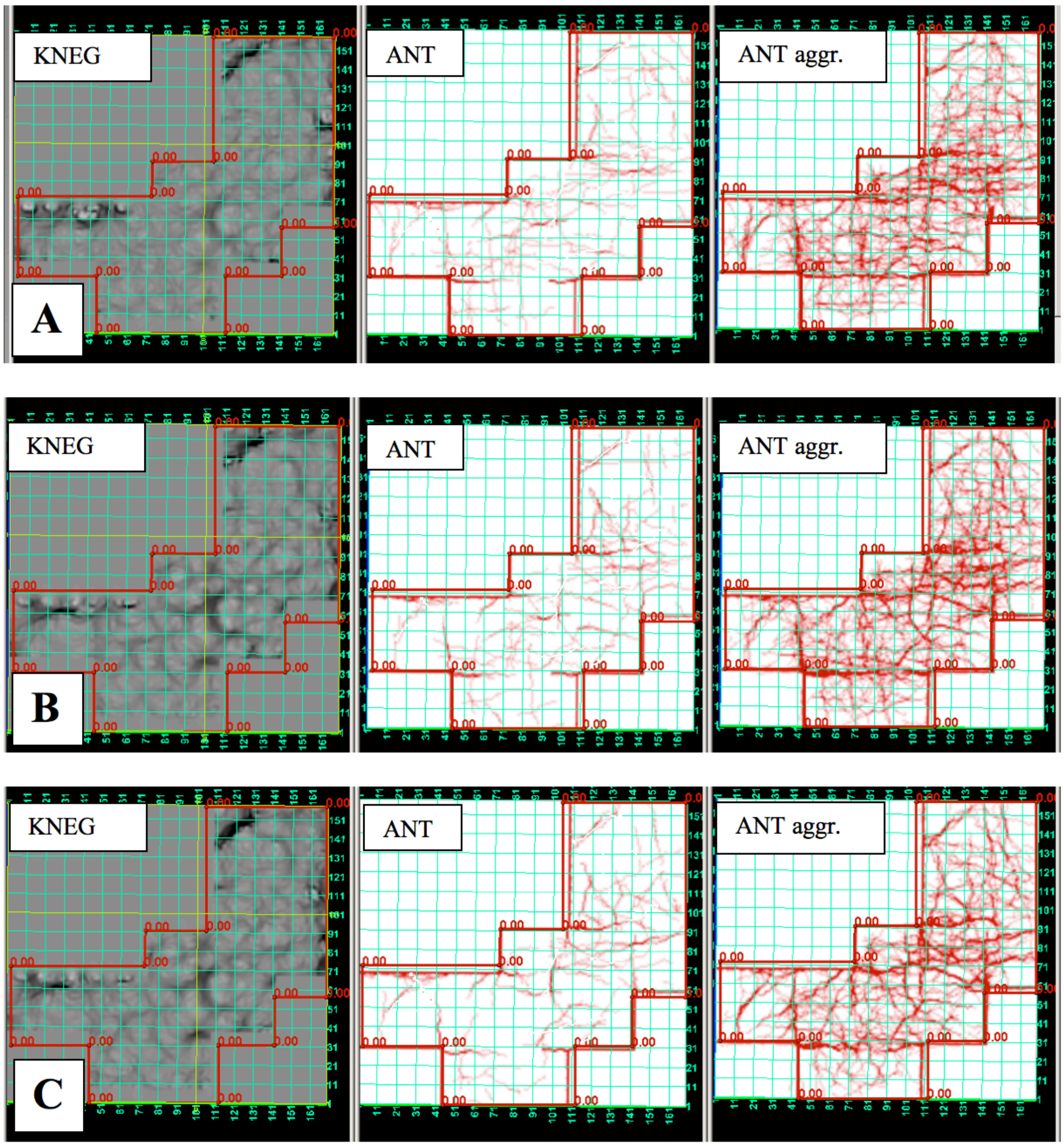

Figure 2-4 A comparison of results from max-negative curvature (KNEG) analysis on GeoFrame, ANT processing using passive (ANT) and aggressive (ANT aggr.) algorithms. (A) Fort Scott horizon. (B) Mississippian horizon. (C) Gilmore City horizon.

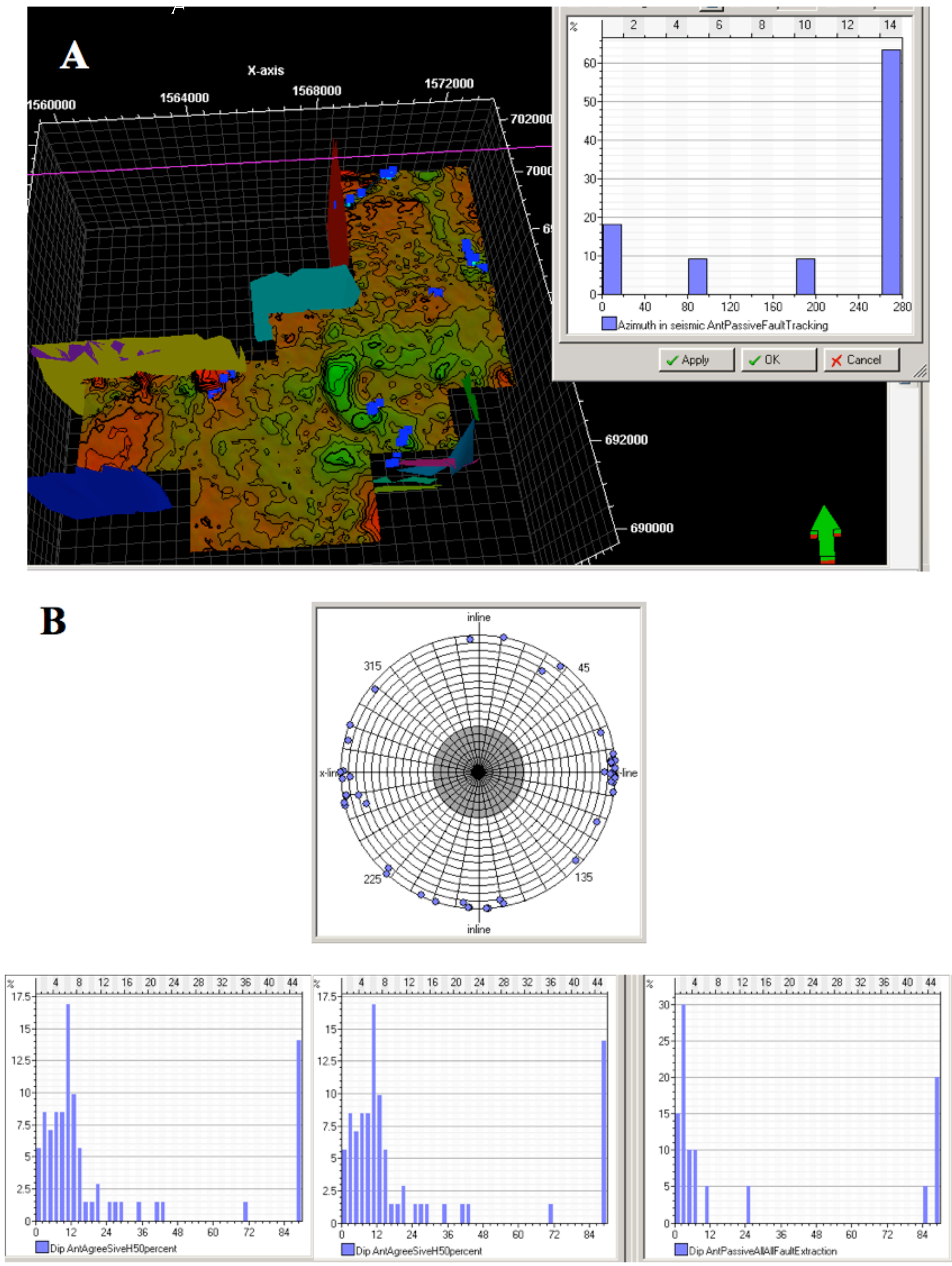

Figure 2-5. Dip/azimuth analysis of the ANT planes. (A) 3D display of ANT planes used to remove data boundary effects. (B) Steronet of ANT plane dip and azimuth (dip angles vertically exaggerated). (C) Histograms (from three ANT algorithms) showing actual dips of ANT planes. The x-axis is dip angles and y-axis is number of planes with given dip angle.

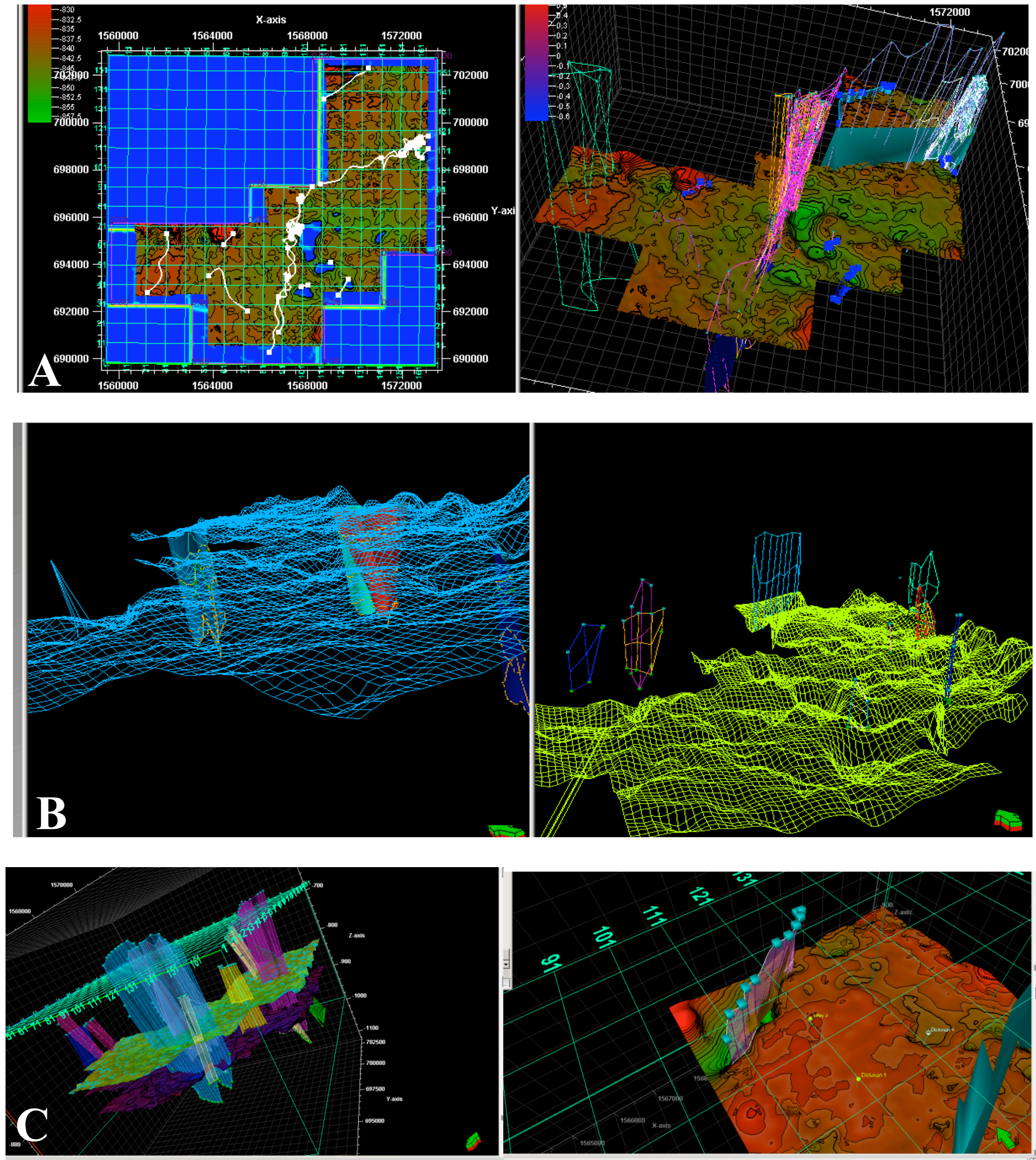

Figure 2-6. Faults selected to build the structure model. The displays are in the time domain. (A) 2D and 3D views of the selected faults. (B) Overview of the fault planes with the skeleton top (Fort Scott horizon, left) and base (B horizon, right). (C) Fault planes are gridded between the skeleton top and base (left) and the enlarged NE boundary fault is seen (right).

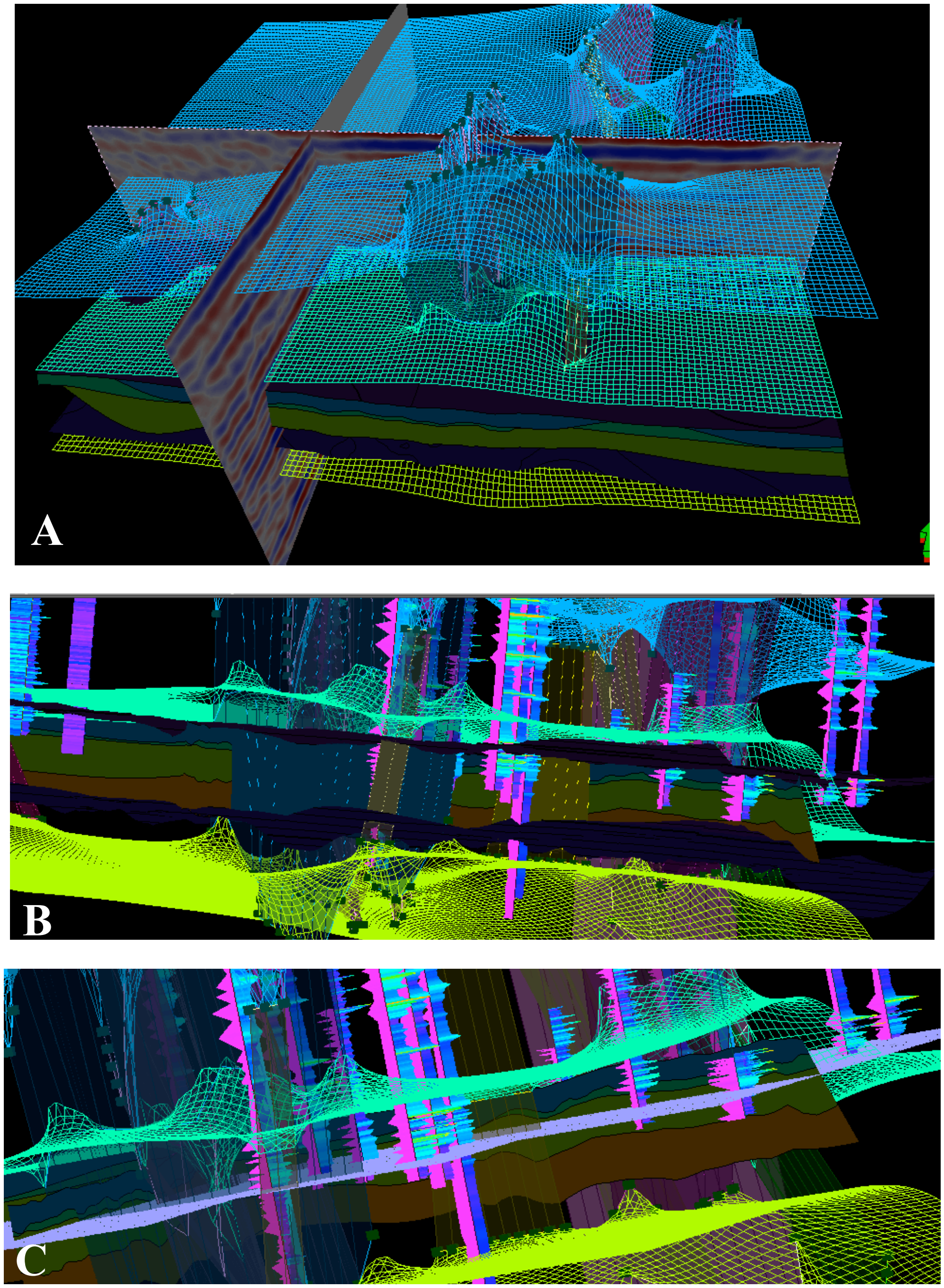

Figure 2-7. The structure model in time domain. (A) Full display with top phantom horizon (blue mesh), Fort Scott (green mesh) and B-horizon (yellow-green mesh) and the target zones for Property Modeling in solid colors. (B) The boundary of the model is removed to show fault planes cutting the modeled volume into segments. (C) The fault planes are removed to show well log curves for gamma ray (blue) and neutron porosity (pink). The oil water contact (light purple surface) separates the Mississippi porous carbonate reservoir and the underlying saline aquifer. Picture is viewed from south.

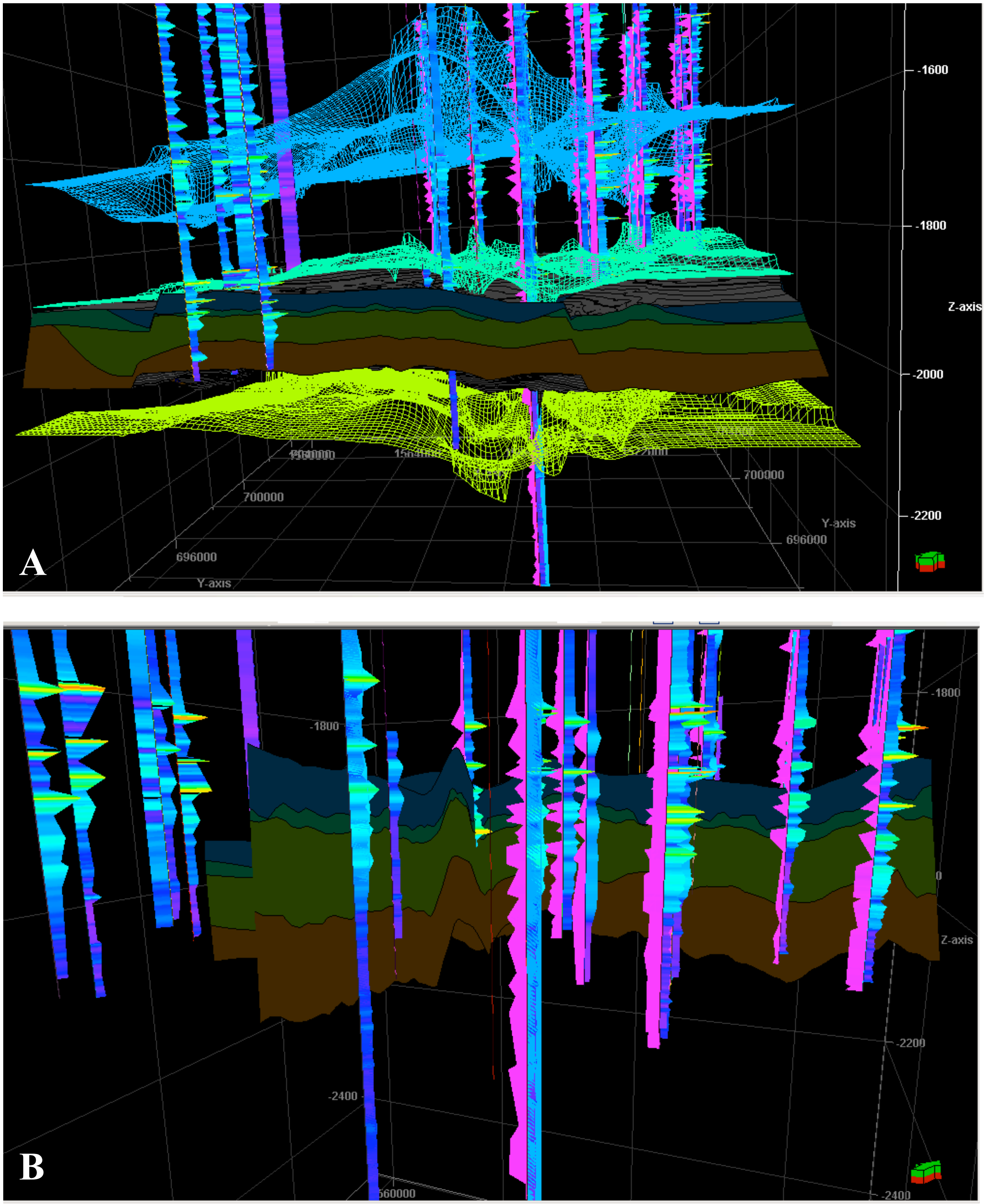

Figure 2-8. The structure model in the depth domain. (A) The skeleton of the model (meshes) and target units for property modeling (in solid colors). (B) The model boundary and fault planes are removed to show the logs and lithologic units (in solid color).

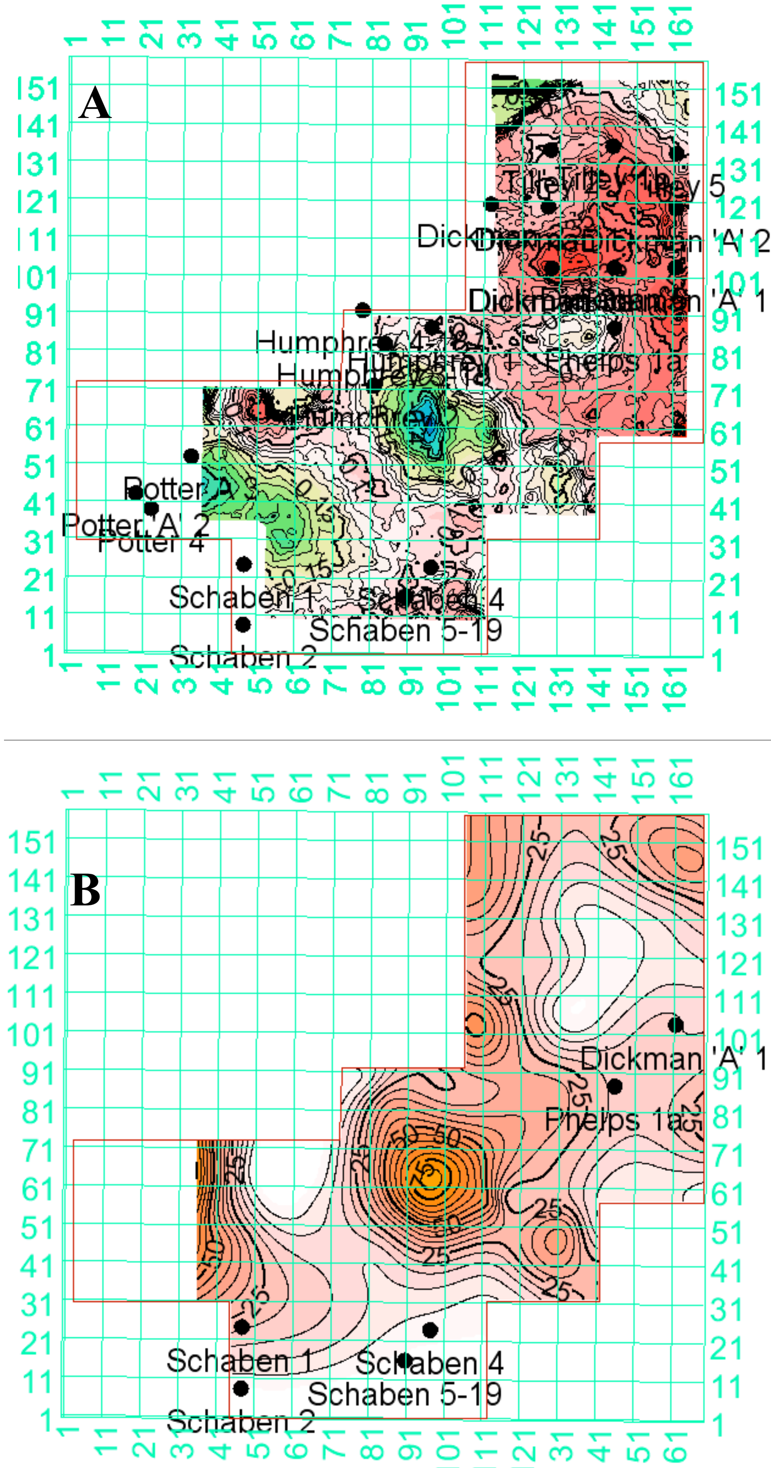

Figure 3-1. Relationship between time and depth thickness. (A) Residual formed by the subtraction of normalized isopach (Fort Scott to Mississippian) minus normalized isochron, a measure of lateral interval velocity variation. (B) Cherokee Sandstone isopach (in feet). Note similarity with patterns in the residual map.

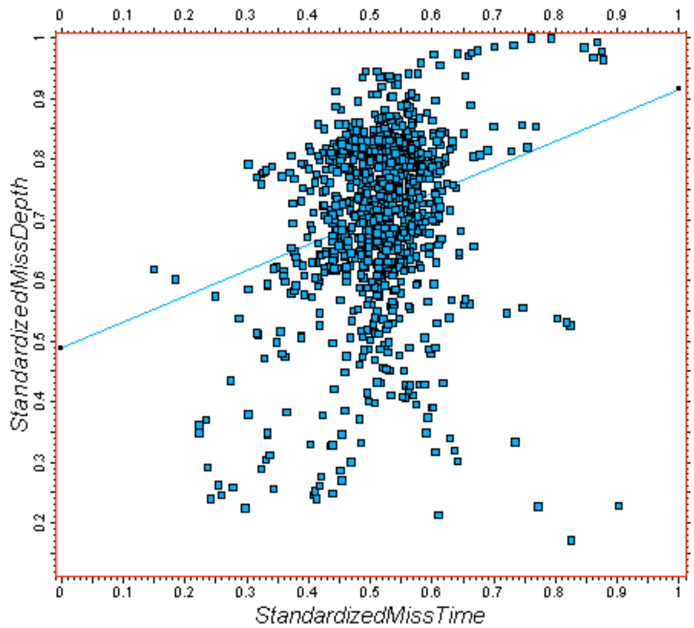

Figure 3-2. Cross plot of the normalized isopach (vertical axis) and isochron (horizontal). Data scatter implies significant lateral velocity variation in the Fort Scott to Mississippian interval.