PS Mapping Lower Austin Chalk Primary and Secondary Porosity Using Modern 3-D Seismic and Well Log Methods in Zavala County, Texas*

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Abstract

Establishing fracture distribution and porosity trends is key to successful well design. The Austin Chalk has historically been referred to as an unpredictable producer due to high fracture concentration and lateral variation in stratigraphy, however recent drilling activity targeting the lower Austin Chalk has been very successful. The Upper Cretaceous Austin Chalk (AC) and Eagle Ford (EF) units are considered by many to act as a single hydrocarbon system so both units are investigated. Communication between these two units is largely through expulsion or dewatering fractures, extensional faults or along the AC/EF unconformity. Total porosity for the Eagle Ford is composed of a primary matrix component and secondary fracture porosity. For the Austin Chalk, the secondary porosity includes both dissolution and fracture components which complicate wireline and seismic interpretation.

The current study interprets 40 square miles of modern 3D seismic data for horizons and faults using amplitude, coherence and ant tracking seismic attributes. Post stack acoustic impedance (AI) inversion is applied to the time migrated seismic volume with control from two wells; this input data is similar to that available to independent operators active in the area. Wireline acoustic impedance plotted against density-porosity reveal strong correlations that allow calibration of seismic AI into primary, secondary and total porosity from which time slices and surface maps are created. Relationships are identified between porosity and geological features of interest, such as faulted and brittle zones, that may prove useful in guiding future well development in the lower Austin Chalk.

Mapping Lower Austin Chalk Primary and Secondary Porosity Using Modern 3-D Seismic and Well Log Methods in Zavala County, Texas

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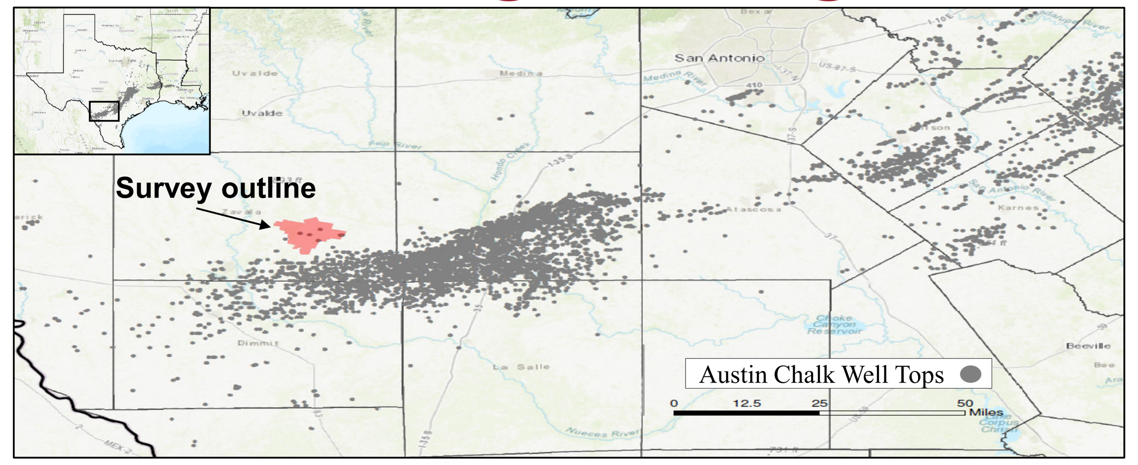
Data Provided by Stephens Production Company

Abstract

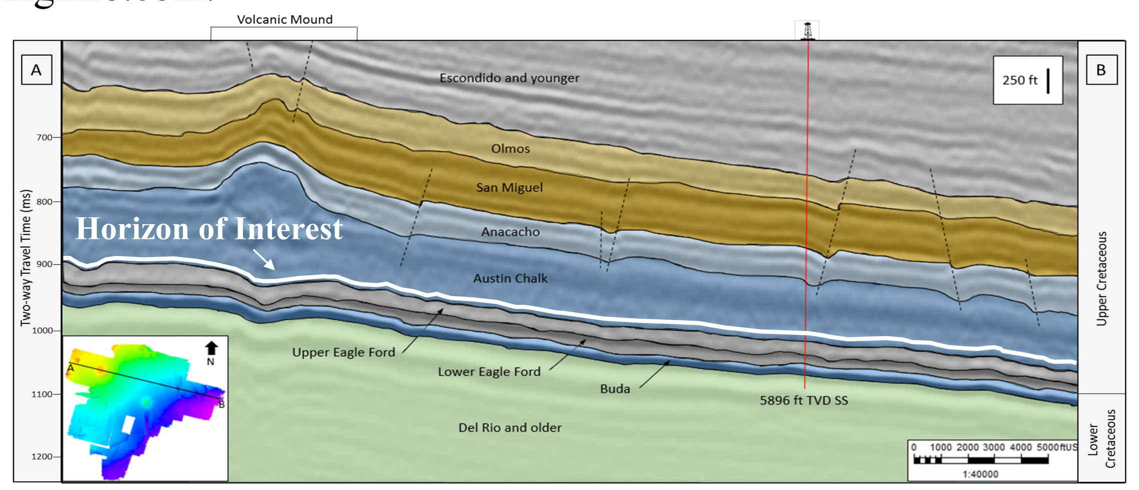
Establishing fracture distribution and porosity trends is key to successful well design. The Austin Chalk (AC) has historically been referred to as an unpredictable producer due to local fracture density and lateral variation in stratigraphy. Total porosity for the AC is comprised of a primary matrix component and a secondary component including fracture and/or dissolution porosity which complicate wireline and seismic interpretation.

A post stack acoustic impedance inversion (AI) was applied to the time migrated seismic volume with control from two wells; input data is similar to that available to independent operators active in the area. Wireline acoustic impedance plotted against log properties revealed strong correlations that allow calibration of seismic AI into primary, secondary and total porosity from which time slices and surface maps are created. Relationships are identified between porosity and geological features of interest, such as faulted and brittle zones, that may prove useful in guiding future well placement in the Lower AC.

Geologic Setting

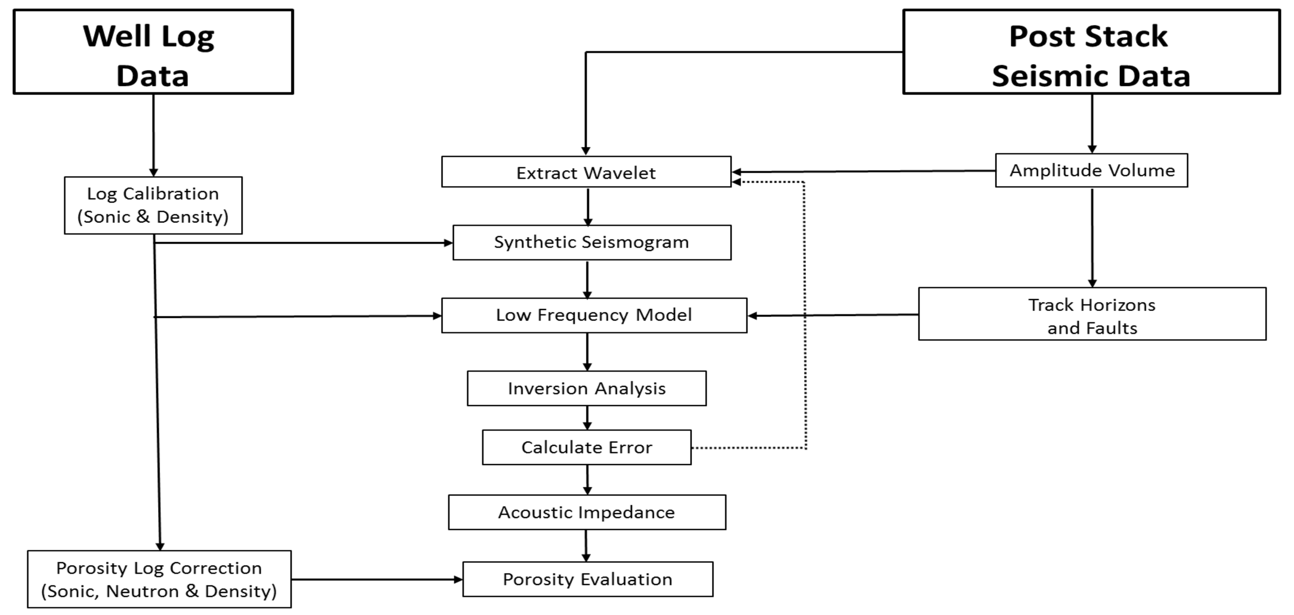


40 sq. mile PSTM seismic survey lies immediately to the north of the Austin Chalk producing trend, on the northern perimeter of the Pearsall Field. Both vertical and horizontal wells displayed, with well top data taken from Drillinginfo.com.



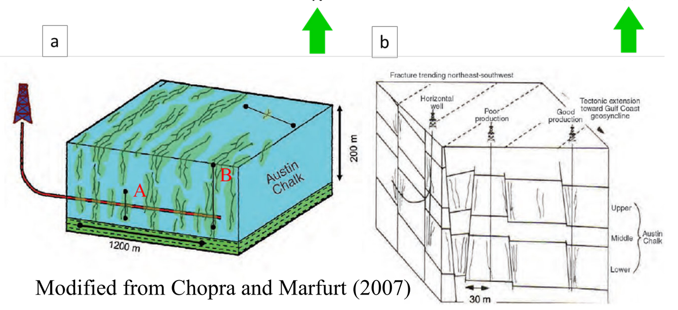
The AC is divided into 3 lithological units. The Lower AC is an interbedded marl and chalk unit and is the focus of this study. It is a laminated wackestone, deposited during a regressive cycle in water depths up to 300ft.

Model based Inversion Workflow



Seismic Interpretation

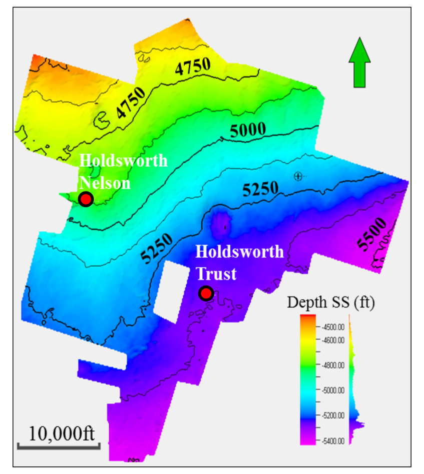
Fractures not confined to the Lower AC are typically leaky or water bearing. Greater production is correlated with the increasing numbers of fractures intersected.



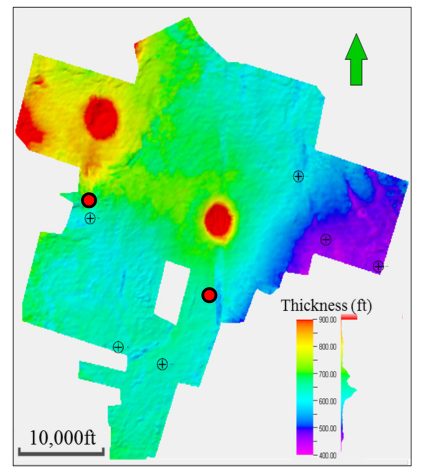
Modified from Chopra and Marfurt (2007)

No fault offset on the Lower AC surface is seen. The thickness map shows multiple areas of faulting, but these are shallower events. Either fault offset terminates or offset drops below the vertical resolution of the data (109 ft).

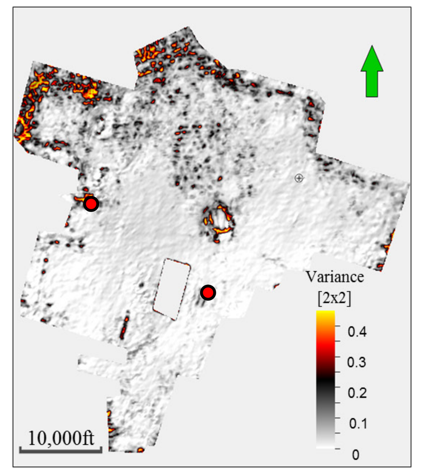
AC Base



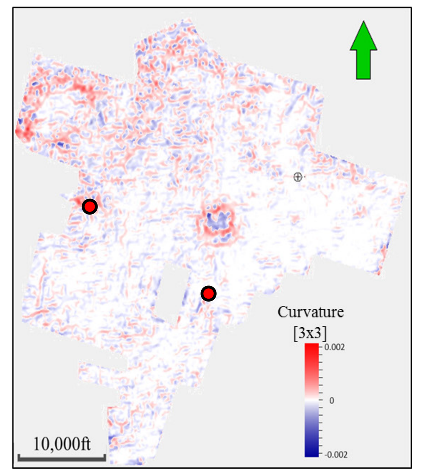
AC Thickness Map



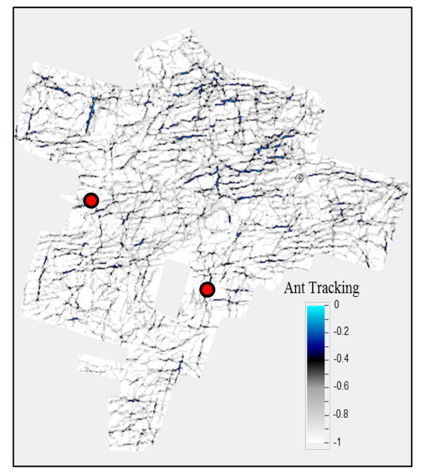
Variance



Most Pos. & Neg. Curvature

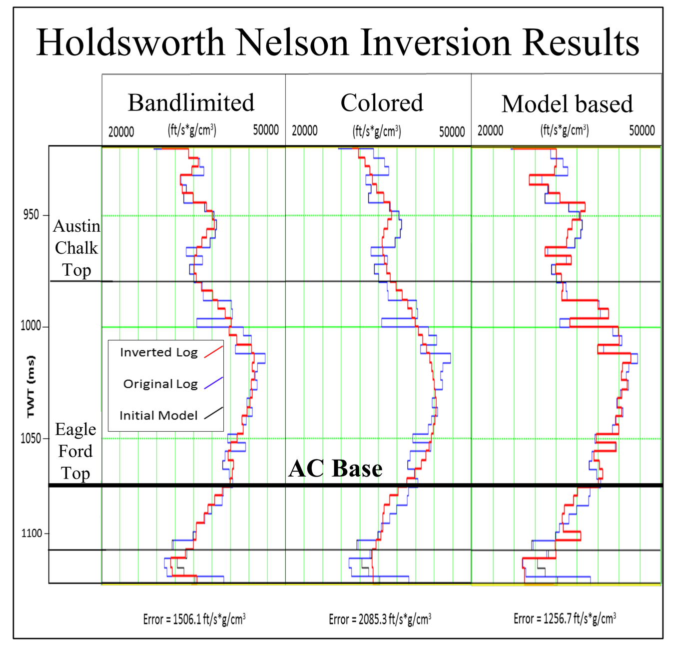


Ant Tracking



Attributes were extracted over a 20 ms up window to capture vertical and sub-vertical faulting. Edge effects are responsible for high variance values seen in the northwest. 3 fault/fold trends identified; N20E, N80E and N35W.

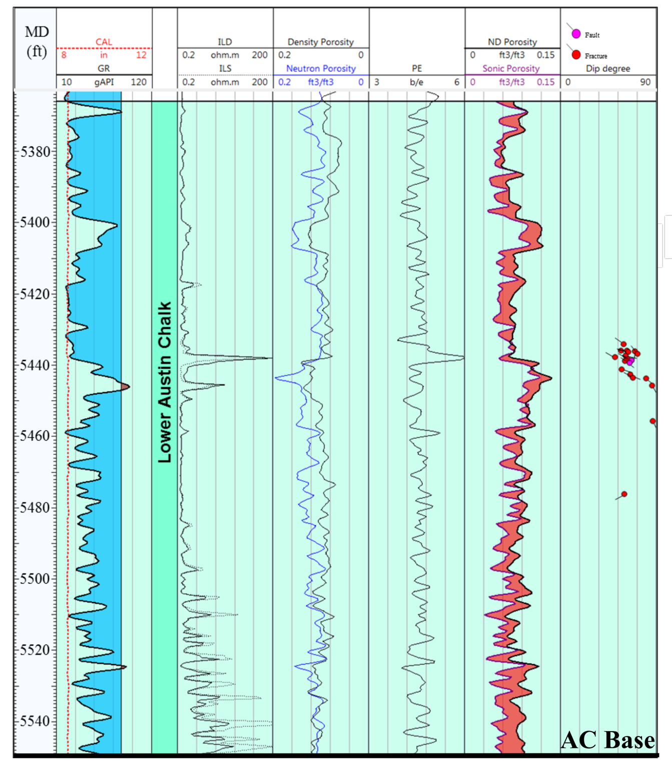
Seismic Inversion



AI is the product of density and P wave velocity. Resolution is increased and wavelet side lobes are removed, reducing the risk of false geological structures.

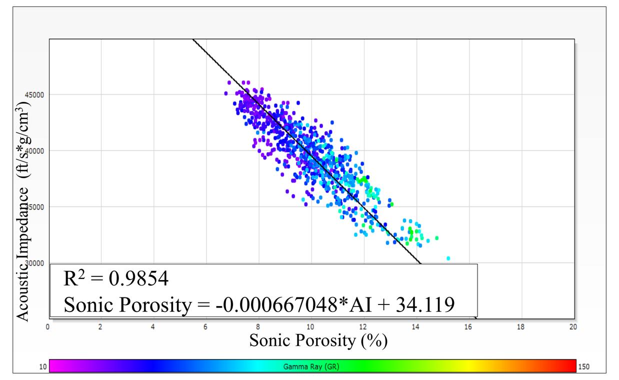
A synthetic seismogram was performed on the Holdsworth Trust (92% corr.) and Holdsworth Nelson (95% corr.), using a wavelet extracted from a 3x3 radius around the well, over a time window of 600 ms centered on the Lower AC.

Well Log Analysis - Holdsworth Nelson

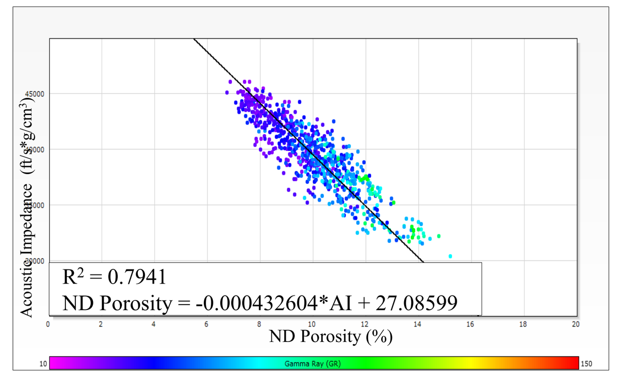


- Neutron-Density porosity (ND) was used as an analogue for total porosity and sonic porosity was used as an analogue for matrix porosity
- Secondary porosity is seen throughout the interval, most likely due to vug development
- A cluster of features are seen near 5440 ft on the FMI, with a spike in the PE curve. When combined with minimal secondary porosity, it appears these are healed fractures

Sonic Porosity Vs AI



Neutron-Density Porosity Vs AI

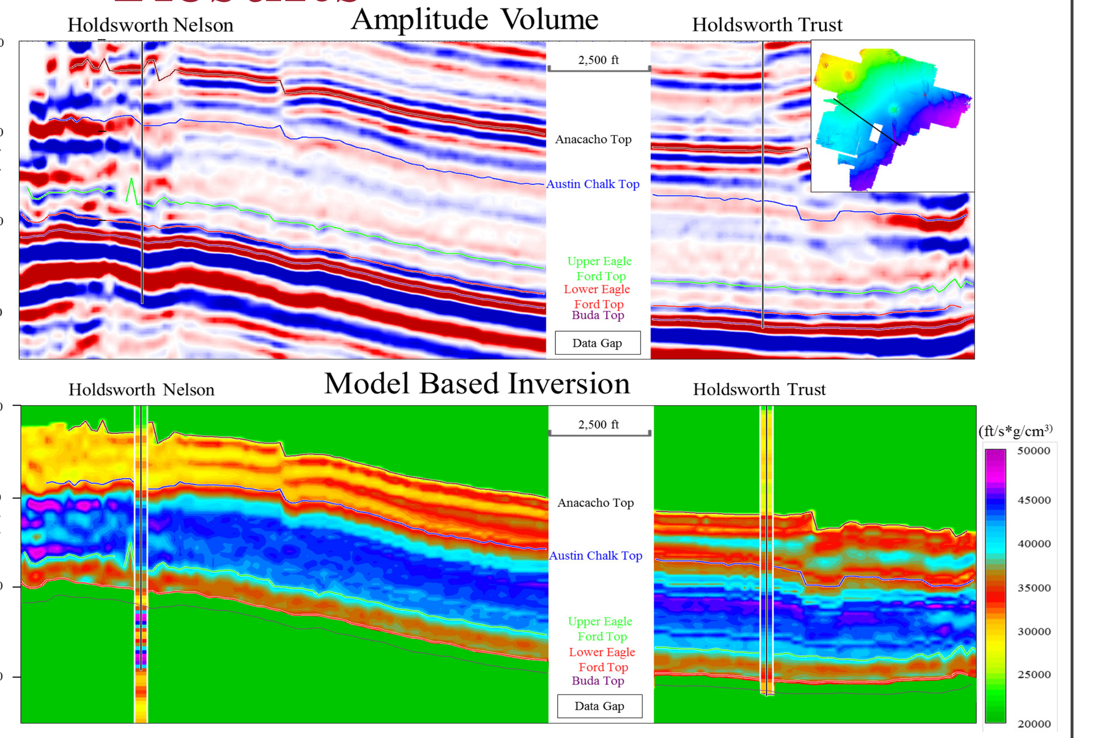


Wireline AI from the Lower Austin Chalk from both the Holdsworth Trust and Holdsworth Nelson wells combines were plotted against sonic and ND porosity respectively using both wells. Using regression, sonic and ND volumes were calibrated form the AI volume. The secondary porosity cube were created by subtracting the sonic from ND volume. Surfaces were extracted over a 20 ms up window.

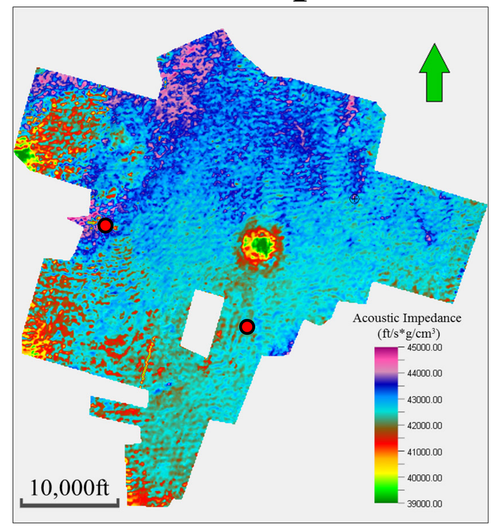
Results

The amplitude volume shows faulting in the younger units but no offset within the AC. Higher AI is associated with brittle rocks and lower AI with ductile units. Good correlation between wireline AI and the surrounding AI volume is seen from both wells.

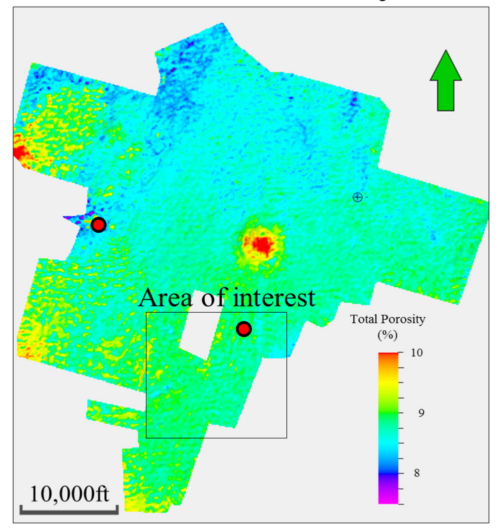
Values close to 46000 ft/s*g/cm^3 make up most of the Lower AC in the Holdsworth Nelson, however from the FMI, this is known to be relatively fracture and fault free.



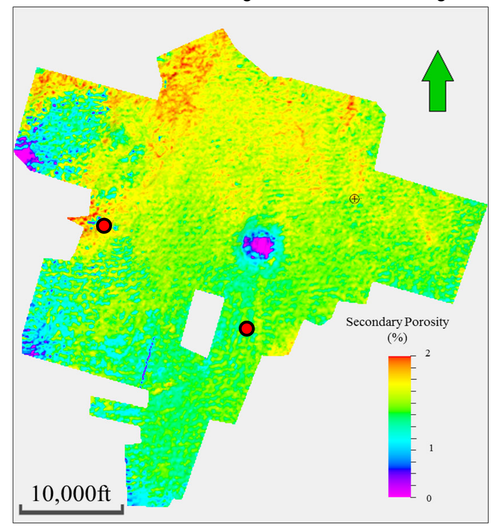
Austin Chalk Base Acoustic Impedance



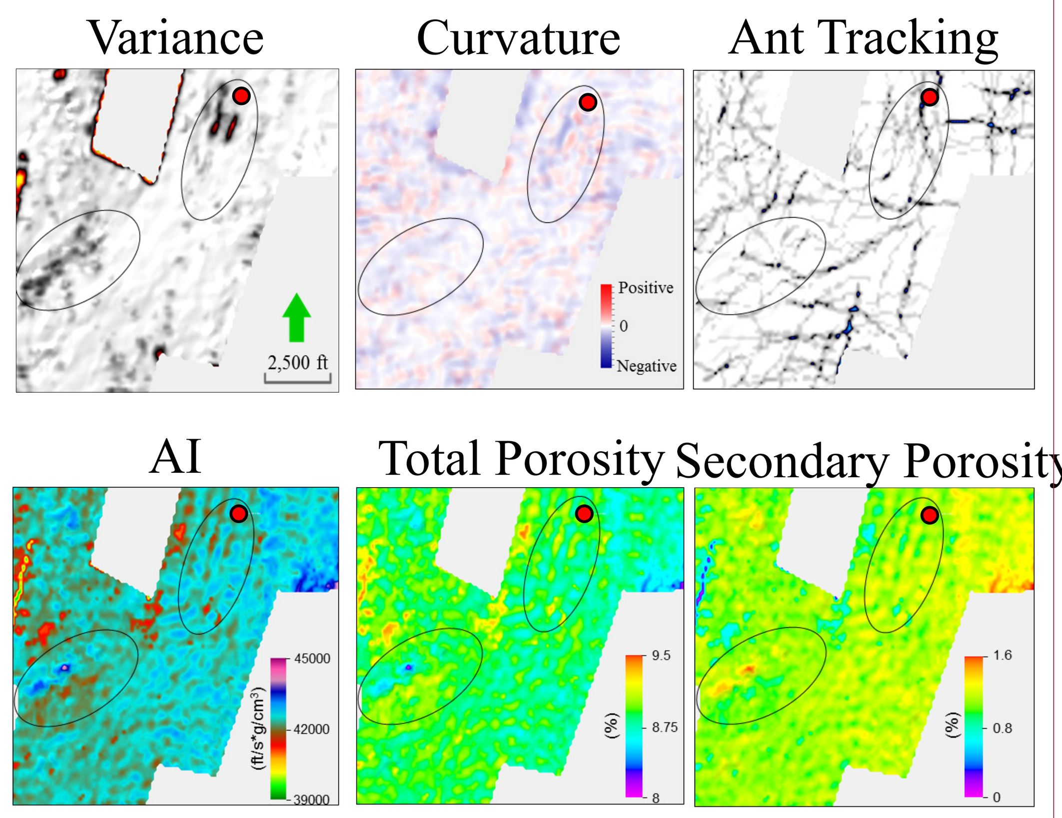
Austin Chalk Base Total Porosity



Austin Chalk Base Secondary Porosity



Area of interest



Conclusions

- A model based inversion produced the most accurate AI volume
- Higher AI correlates with higher secondary porosity
- Increased secondary porosity trends are orientated N65E, N20E and N30W
- Variance shows the best correlation with increased secondary

Selected References

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