Using relative seismic impedance to predict porosity in the Eagle Ford shale

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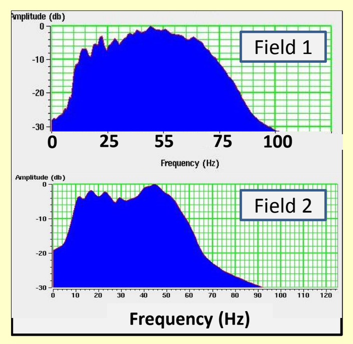
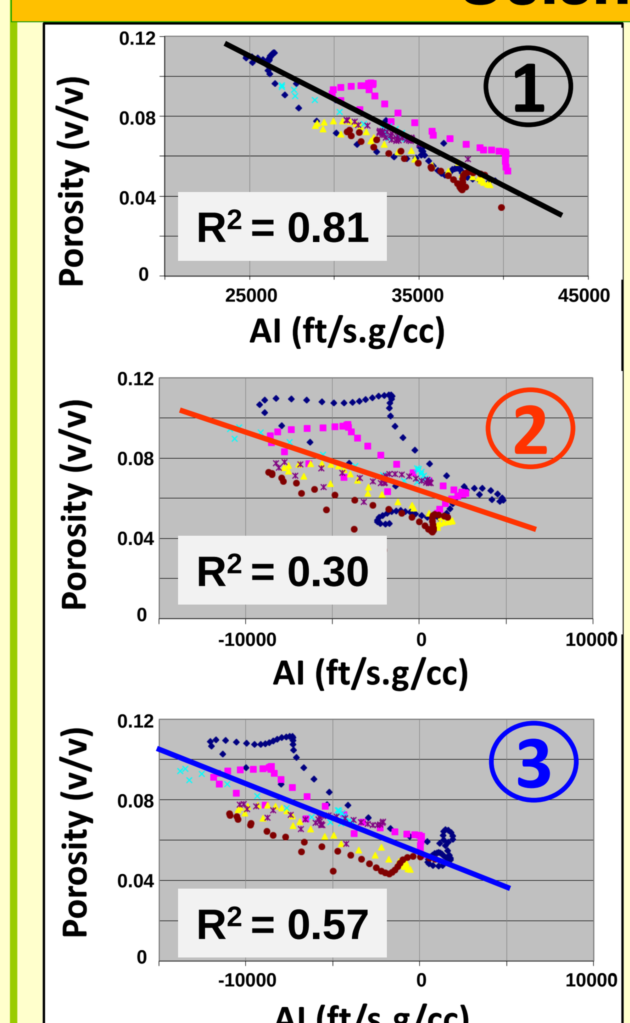
Problem

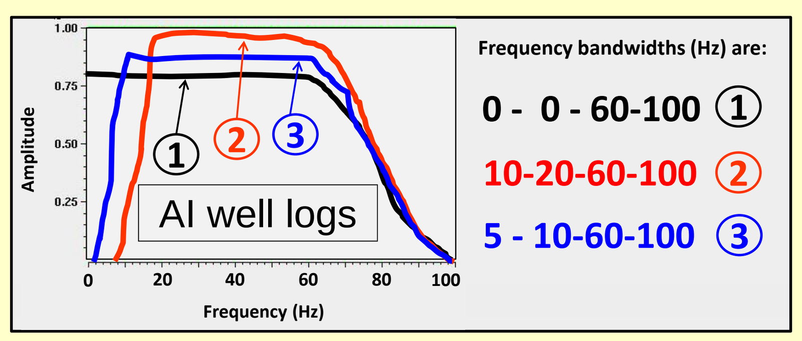
Porosity prediction in Eagle Ford shale from seismic

- Porosity prediction from seismic is a key aspect of reservoir characterization.
- Objective is to evaluate porosity prediction from relative seismic AI at the two fields in the South Texas.
- Relative AI has been used as a seismic attribute in the past (Coke et al., 1999).



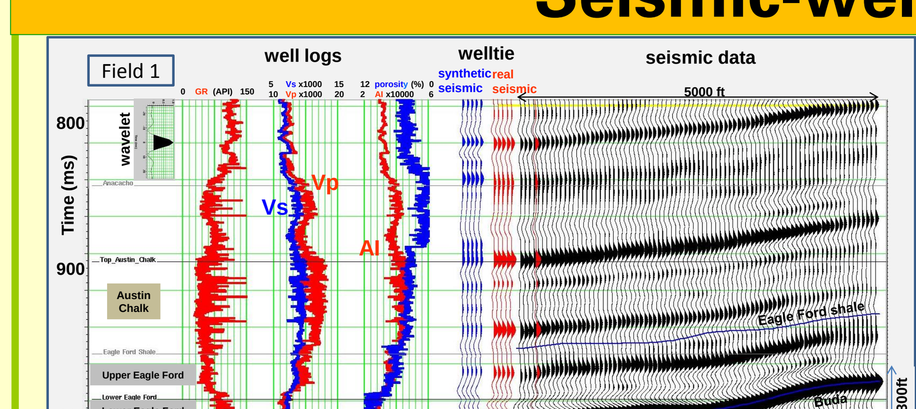
Seismic rock physics





- Well log crossplots (colored by wells) for AI and porosity are shown at left. Each plot has a different filter applied to the AI log.
- Porosity best correlates to fullband AI as expected (case 1), but even for a bandlimited AI (case 3) there is an acceptable correlation.
- Porosity could be predicted from relative seismic AI, given a good bandwidth seismic data with sufficient low frequency.

Seismic-well-tie



- Well tie quality is good.
- There is a good correlation between AI and porosity.
- Well tie provides: I) QC of data, II) calibration of wiggle to geology, III) wavelet, IV) a time-depth relationship.

Terminology

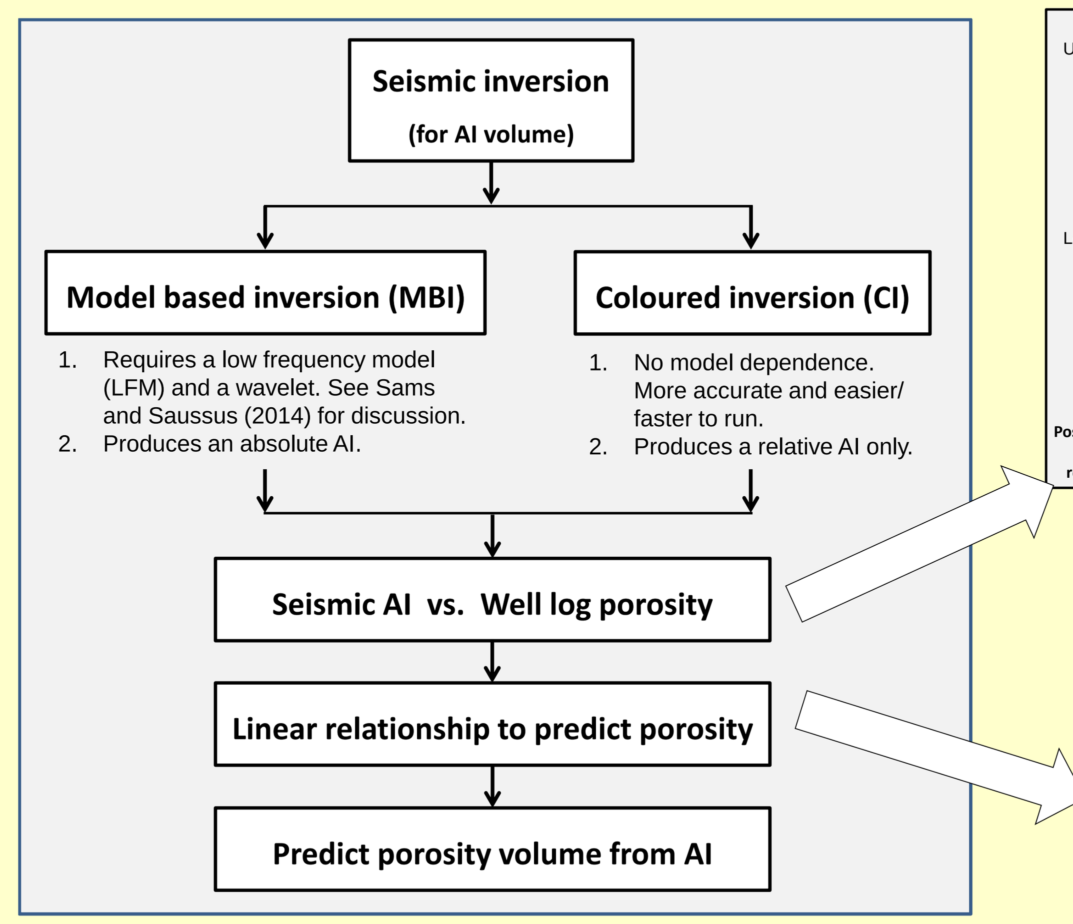
AI: acoustic impedance (P-wave velocity x density)
CI: coloured inversion (inversion of seismic data to relative impedance by deriving a convolutional operator that shapes the average spectrum to a representation of that observed in the impedance well log [Lancaster and Whitecombe, 2000])
MBI: model based inversion (inversion of seismic data to absolute impedance by perturbing starting model to match synthetics to real seismic and adding missing low frequency information from a model [Russell and Hampson, 1991])
Fullband (absolute) AI: AI with frequency content from zero to what is available in seismic data (e.g., 0-0-60-100 Hz)
Bandlimited (relative) AI: AI with frequency content same as what is available in seismic data (e.g., 5-10-60-100 Hz)

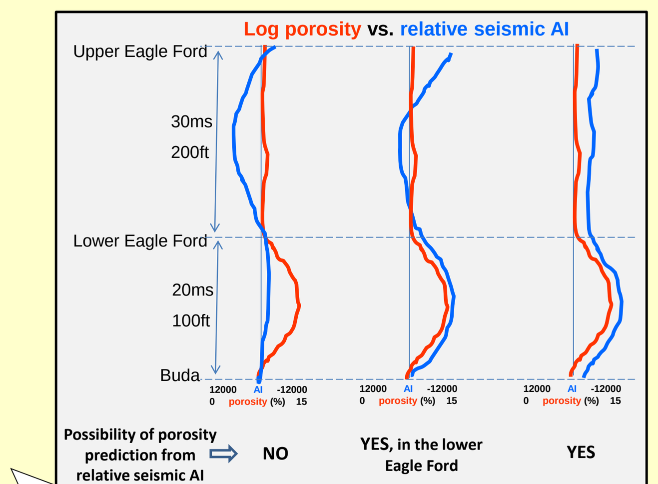
References

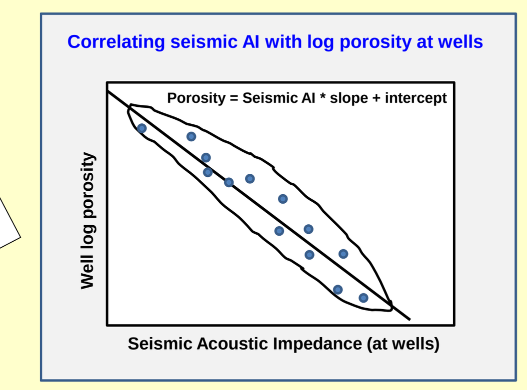
Coke, et al., 1999, What is the best seismic attribute for quantitative seismic reservoir characterization: SEG expanded abstract.
Lancaster, S., and D. Whitecombe, 2000, Fast-track coloured inversion: SEG expanded abstract.
Russell, B., and D. Hampson, 1991, Comparison of poststack seismic inversion methods: SEG expanded abstract, 876-878.
Sams, M., and D. Saussus, 2014, Practical implications of low frequency model selection on quantitative interpretation results: SPG-India expanded abstract, 10th Biennial Int. Conf.

Solution

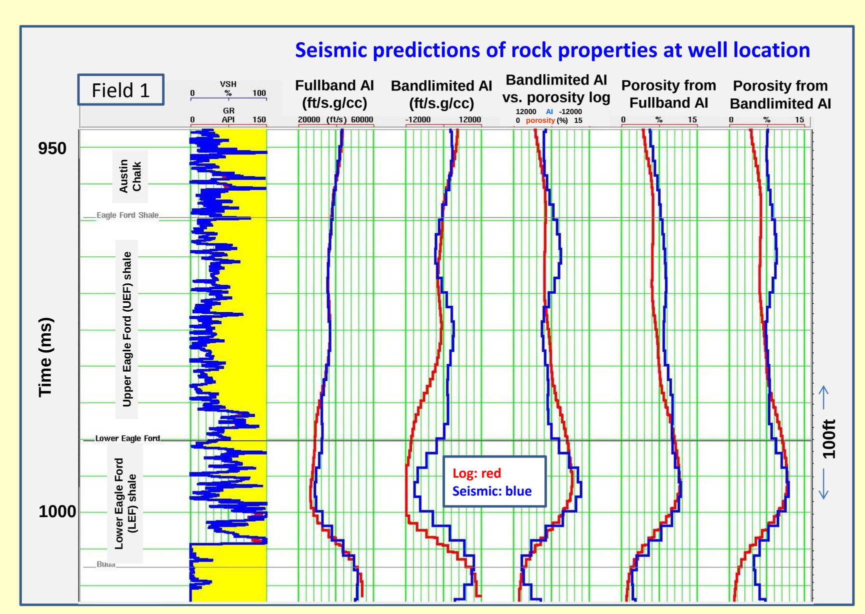
Seismic inversions (with and without model) for impedance

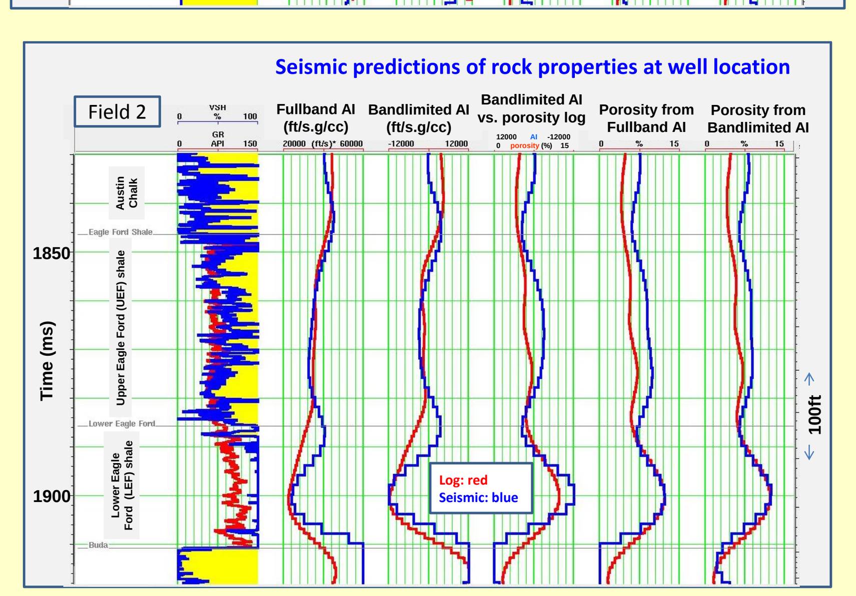






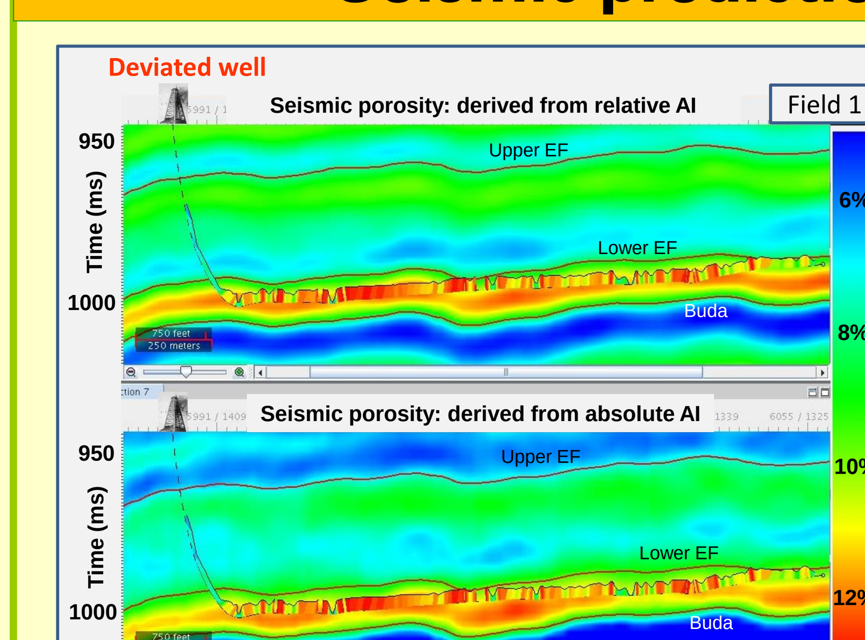
Seismic prediction: vertical wells





- Seismic is shown in blue curve and well log is shown in red curve. Well logs are filtered to seismic bandwidth.
- Prediction of AI: Good for both relative and absolute AI. In Field 1, the amplitude of relative seismic AI does not exactly match the well log AI. This is acceptable if trend is consistent at other wells, as we plan to correlate the shapes of seismic AI with porosity log.
- Correlation of relative seismic AI with well log porosity: Good especially in the lower Eagle Ford shale.
- Porosity prediction: Good, and the two seismic predictions are comparable. The study was designed for entire Eagle Ford in Field 1 and only the lower Eagle Ford shale in Field 2.

Seismic prediction: deviated well



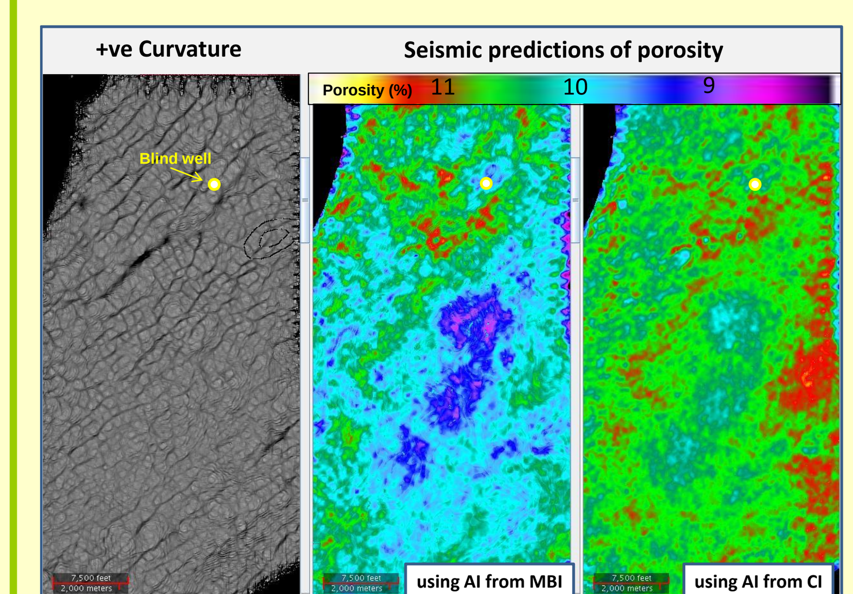
- A deviated well from Field 1 with horizontal drilling in the lower Eagle Ford shale.
- Seismic prediction is acceptable.
- The evaluation of seismic prediction is not easy due to issues in:
  - I. Well log quality
  - II. Time-depth relationship
  - III. Filtering (scaling) of two data

Discussion

Relative seismic impedance to predict porosity

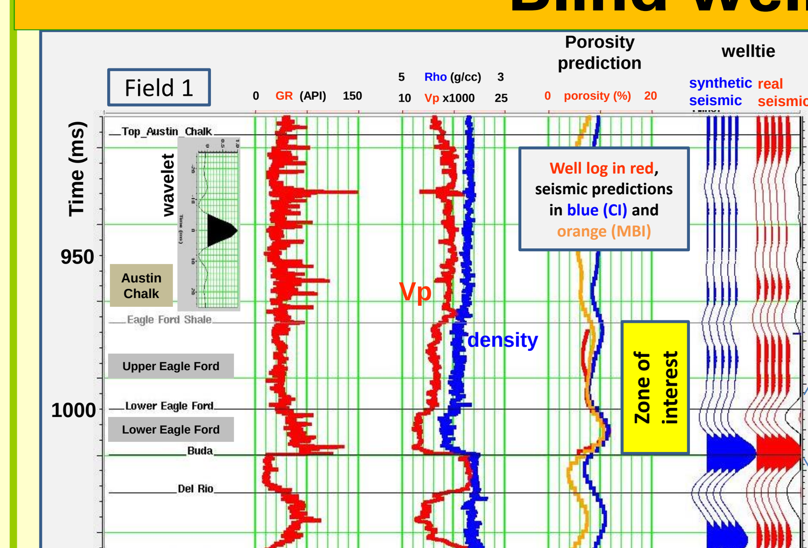
- Tried seismic impedances without model (CI) as well as with model (MBI) to predict porosity volume.
- Found a good relationship between relative seismic AI and well log porosity in the lower Eagle Ford. This is primarily because the effect of the background low frequency model (LFM) is small.
- Differences in the two porosity predictions can be used as a measure of model uncertainty.
- Blind well test will provide confidence in seismic prediction.

Seismic uncertainty



- Map view of curvature and porosity in the lower Eagle Ford shale of Field1.
- Sources of uncertainties: LFM and wavelet in MBI, quality of 3D seismic and well data.
- A measure of uncertainty: correlation between seismic AI and well log.
- Note a small dynamic range in porosity values, therefore one should look for trends only.

Blind well test



- Seismic characterization was done in 2013, and this blind well was drilled in the middle of 2014.
- Acceptable porosity prediction from relative seismic AI, compared to the one from absolute seismic AI.

Conclusions

- Seismic prediction of porosity in the Eagle Ford shale is successful.
- Porosity prediction from relative AI is more reliable and is easier to perform than absolute AI, and is possible in the case of:
  - Good quality seismic with broad bandwidth
  - Good correlation between seismic AI and well log porosity
  - Small target (half seismic wavelength), like the lower Eagle Ford shale, as the effect of background trend is small
- Recommend using multiple seismic predictions.
- Communicate uncertainties in seismic prediction to end users.

Acknowledgements

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