Using Seismic Inversion and Net Pay to Calibrate Eagle Ford Shale Producible Resources

Bo Chen[1], Dhananjay Kumar[1], Anthony Uerling[2], Sheryl Land[2], Omar Aguirre[2], Tao Jiang[1], and Setiawardono Sugianto[1]

[1]BP America, 501 Westlake Park Blvd., Houston, Texas 77079

[2]BP America, 737 N. Eldridge Pkwy., Houston, Texas 77079

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ABSTRACT

The production outcome of an Eagle Ford well depends on many factors including reservoir properties. This paper discusses an utilization of seismic attributes to predict them and identify the high production potential areas. Multiple studies have identified the sweet spots in unconventional plays, however not many have been directly correlated with and confirmed by the production data. We studied the production data and analyzed the reservoir characteristics associated with it taking into account the operation procedures. It was found that the producible resources lie in the thicker and more porous intervals. Both thickness and porosity can be determined with seismic data. Seismic inversion is utilized for porosity prediction and seismic net pay for 'net' thickness prediction with higher porosity. The seismic net pay, confirmed by the blind well log data, has been used to predict the producible resources for future wells in the Eagle Ford shale in South Texas. The study includes the following four steps. First, a correlation between the petrophysical net pay and the estimated production volume is established. Well logs are analyzed to establish a method to predict net pay from seismic data. Second, post migration seismic data conditioning is applied to improve seismic data quality, by attenuating noises, flattening the gathers, and balancing the frequency spectrum and amplitude across offsets. Good quality seismic data are required for seismic net pay estimation. Third, using the conditioned seismic data, colored inversion is applied to invert the reflectivity data to relative acoustic impedance. Acoustic impedance is inversely proportional to porosity and is used to predict porosity in the lower Eagle Ford Shale. Finally, seismic net pay is calculated by detuning the relative acoustic impedance and integrating over the gross thickness intervals. To quality control (QC) the results, the predicted seismic net pay is compared with well log data and estimated production data. We found that seismic net pay in the lower Eagle Ford as an indicator of its reservoir quality. The reliable estimation of seismic net pay requires an understanding of the rock properties, good quality well data, seismic data conditioning, well calibrated horizons, and accurate seismic inversion for impedance followed by porosity prediction.

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BP America Inc.

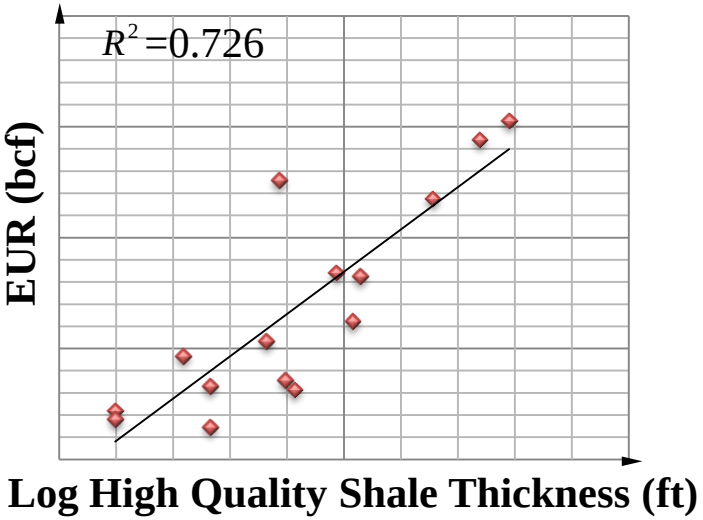
Objectives

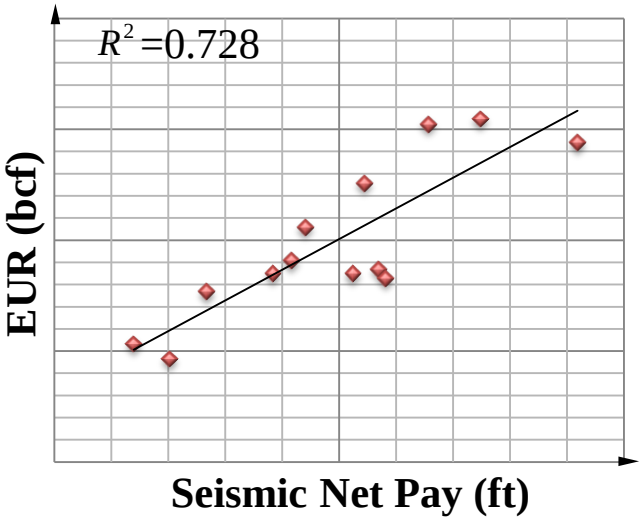
- Identify key petrophysical properties driving production
- Predict such rock properties from seismic

Outline

- Studied area
- Petrophysical analysis
- Seismic data conditioning
- Seismic (coloured) inversion
- Seismic net pay
- Conclusions

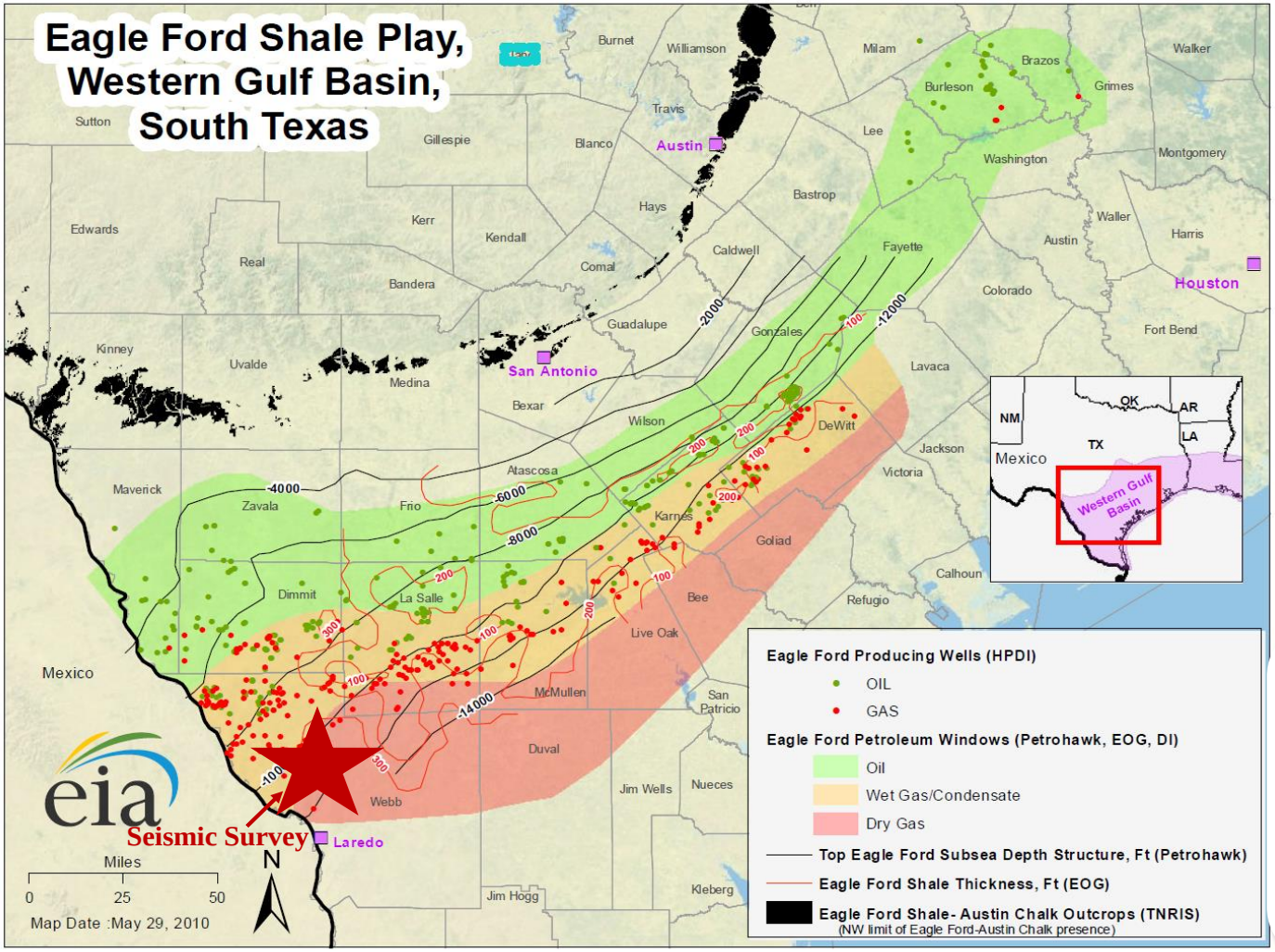
Production Potential Prediction





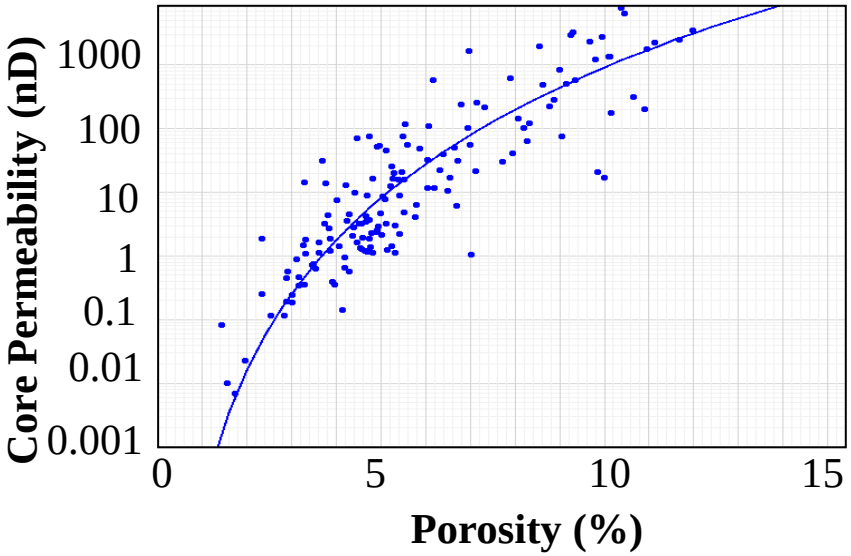
Log and seismic derived high quality shale (HQS) thickness correlate well with EUR when operation is the same.

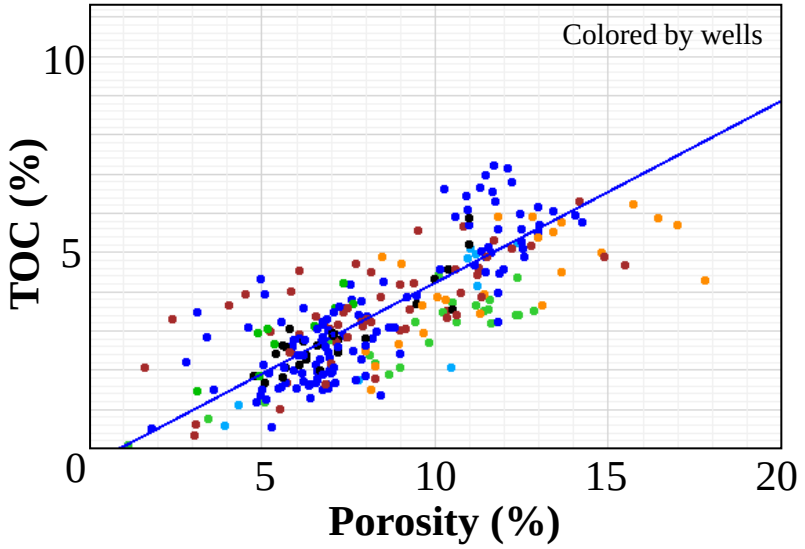
Studied Area



Studied area is located in the dry gas window, western portion of Eagle Ford play.

Petrophysical Analysis

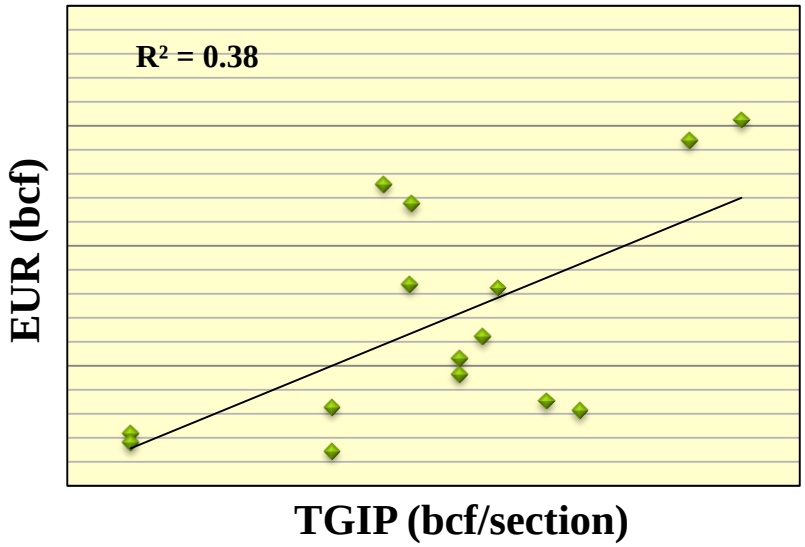




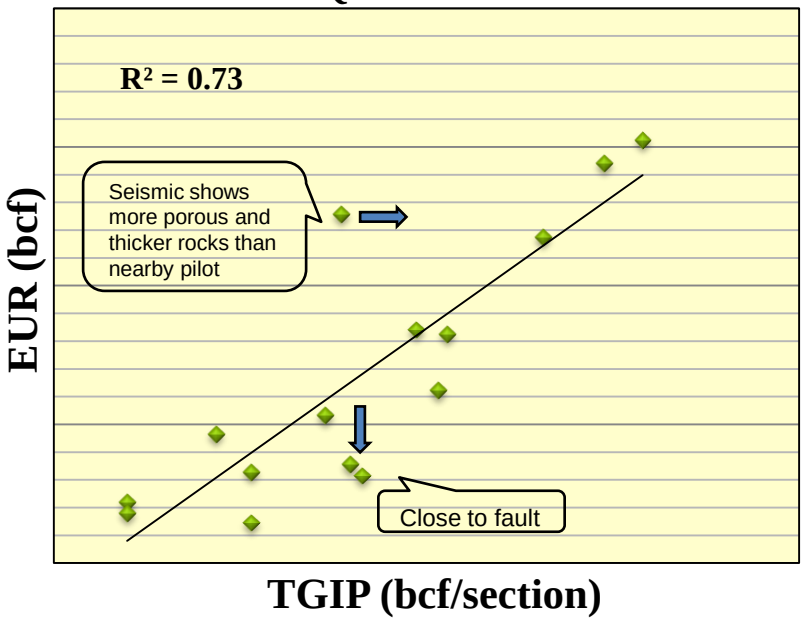
High quality shale (HQS) interval: shale intervals with higher porosity, higher permeability, higher TOC, higher gas saturation, lower clay content.

Rock Quality versus EUR

Gross intervals

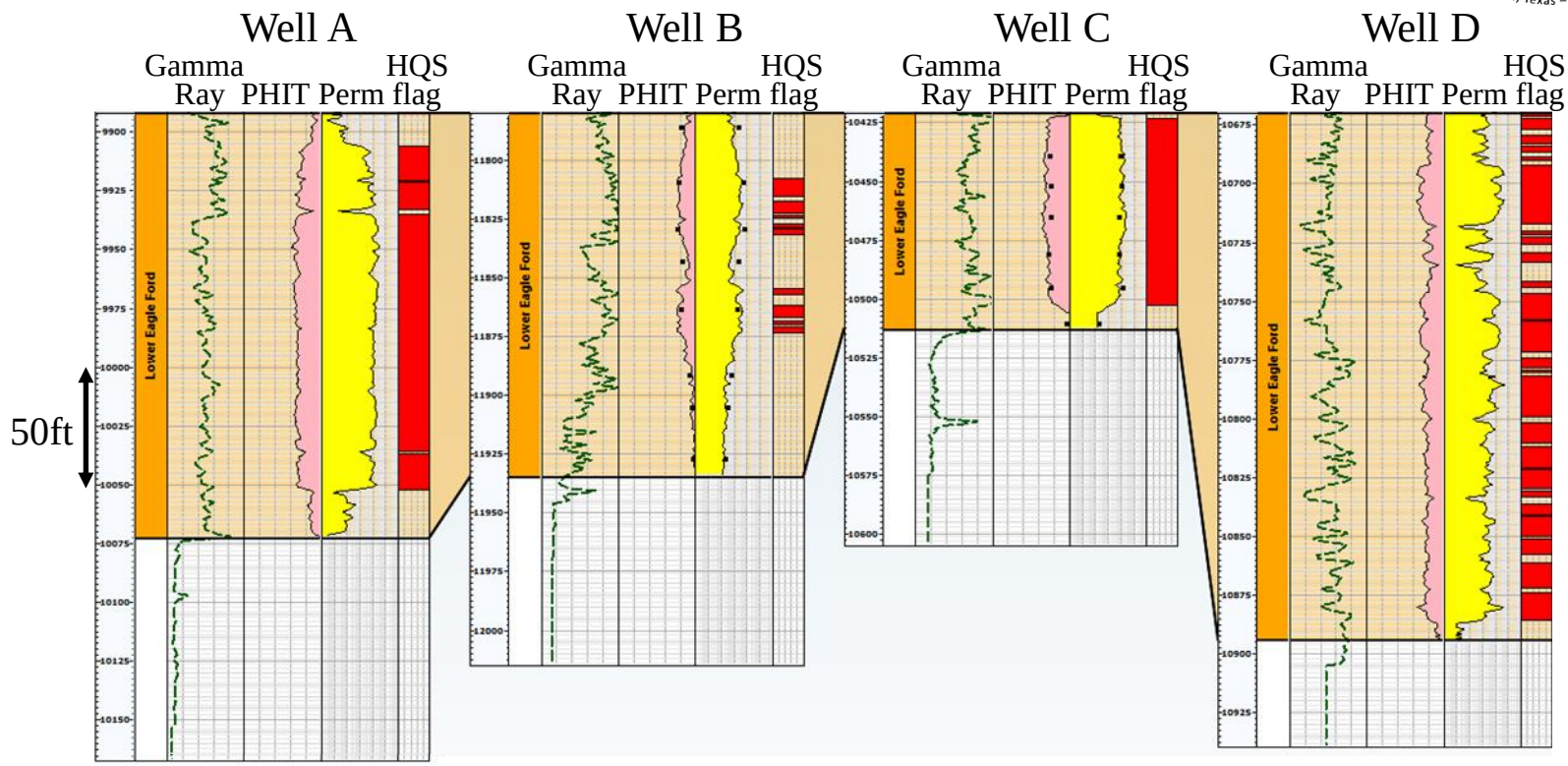


HQS intervals



Resources in High Quality Shale form stronger correlation with EUR with the same completion designs.

Petrophysical Analysis

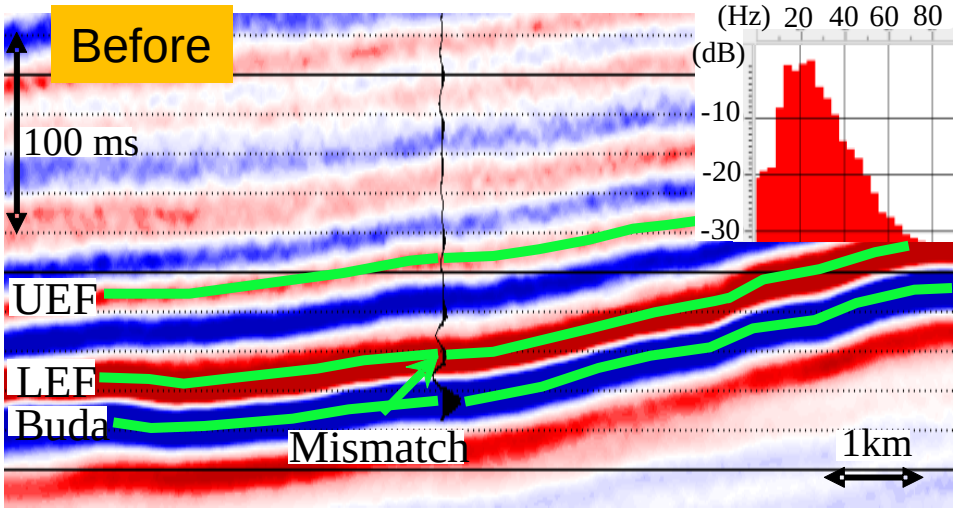


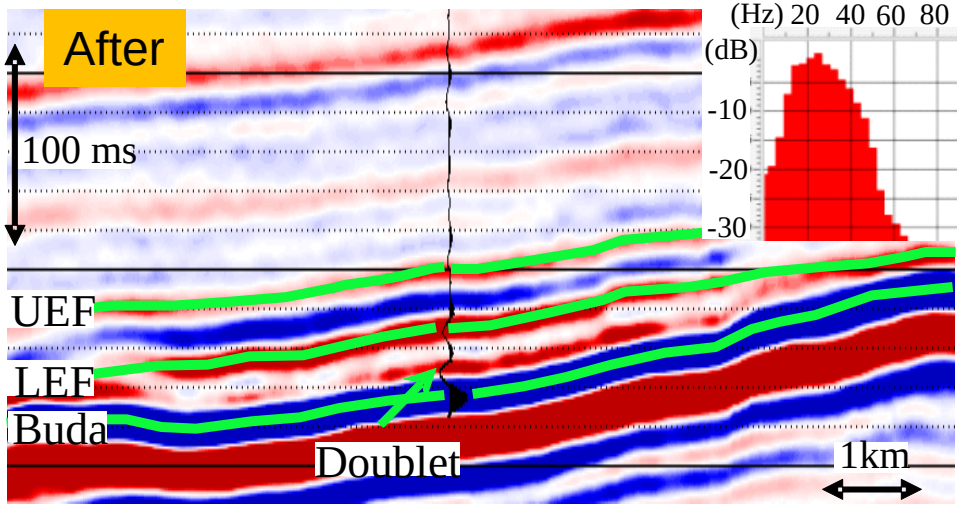
	Well A	Well B	Well C	Well D
TGIP (bcf/section)	154	68	76	165
	137	22	74	134

Gross Interval

HQS Interval

Seismic Data Conditioning



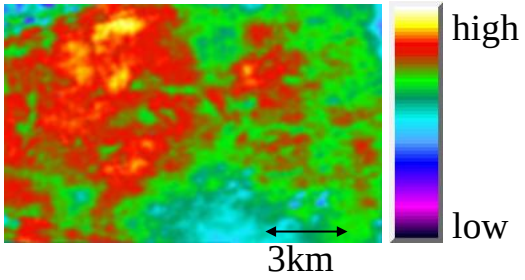


Red: trough

Blue: peak

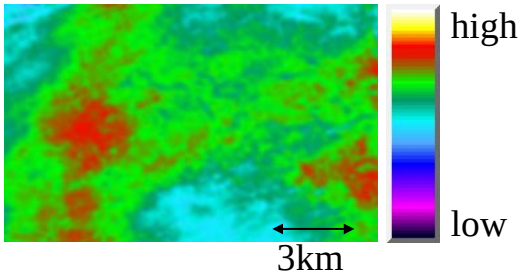
Before

LEF Instantaneous Amplitude



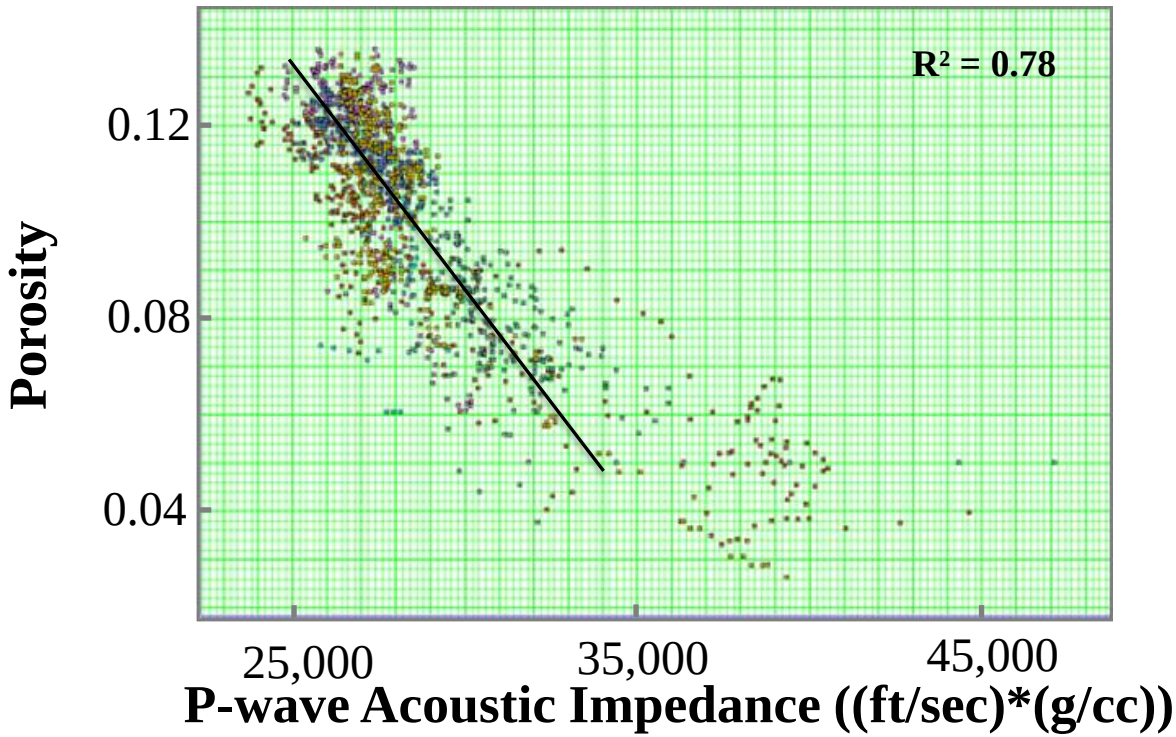
After

LEF Instantaneous Amplitude



Post-migration seismic data conditioning reduced noise, increased the resolution and improved the amplitude fidelity.

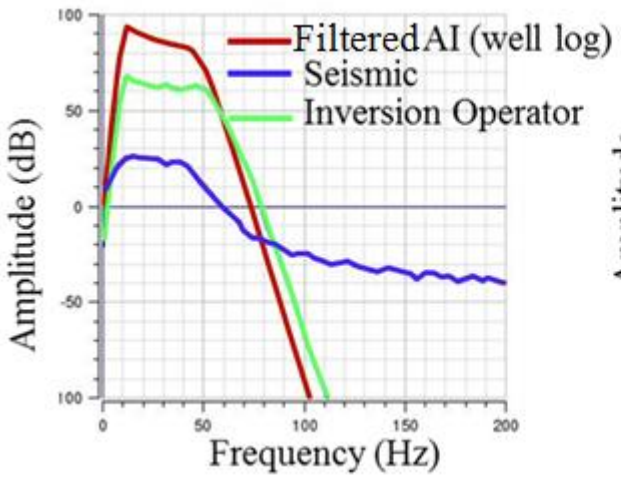
Rock physics relationships

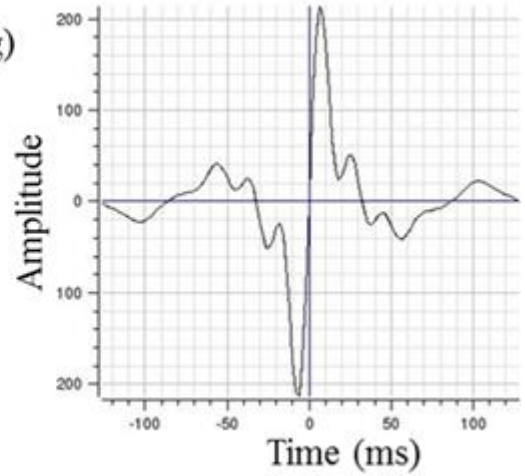


Porosity forms a good correlation with P-wave acoustic impedance (AI), which can be derived confidently from seismic data.

Seismic (coloured) Inversion

Inversion operator

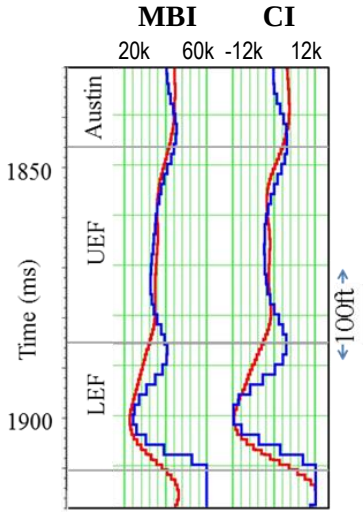




Coloured inversion (CI) provides bandlimited (relative) impedance

(Lancaster & Whitecombe, 2000)

Inversion QC with wells

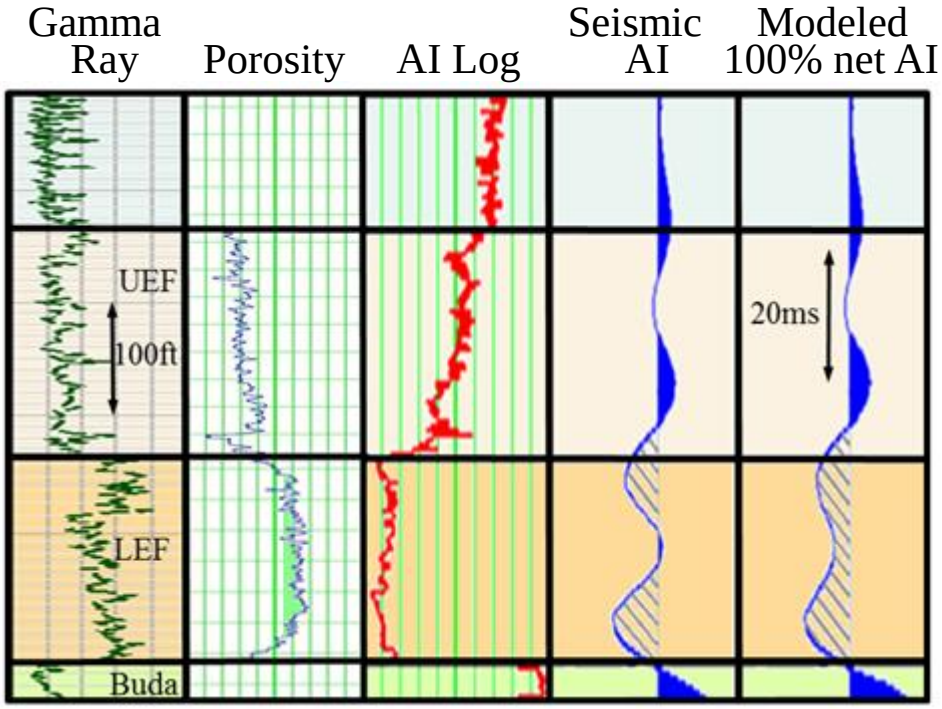


Log: red
Seismic: blue

(Kumar et al., 2014)

Coloured inversion (CI) and model-based inversion (MBI) generated similar results.

Seismic Net Pay



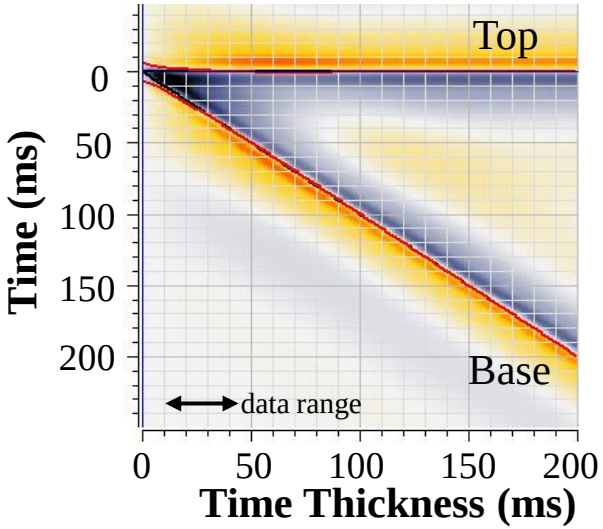
$$\text{Petrophysical net-to-gross} = \frac{\text{HQS thickness}}{\text{gross reservoir thickness}}$$

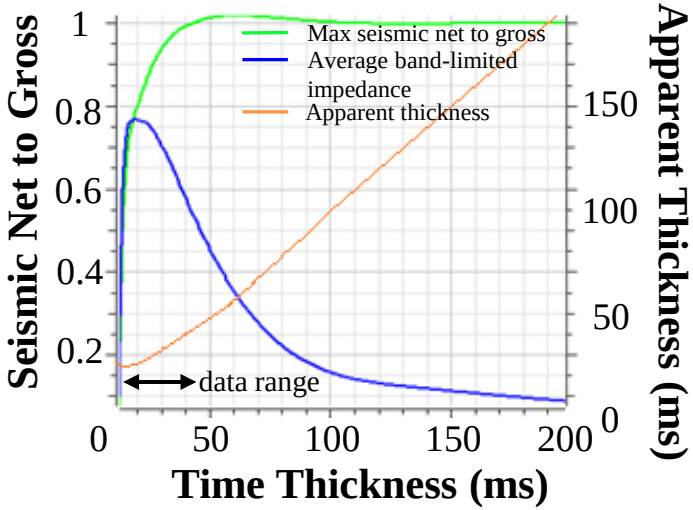
$$\text{Geophysical net-to-gross} = \frac{\text{average impedance value over reservoir}}{\text{impedance value at 100\% net (HQS)}}$$

(Connolly, 2010)

Seismic Net Pay

Wedge model





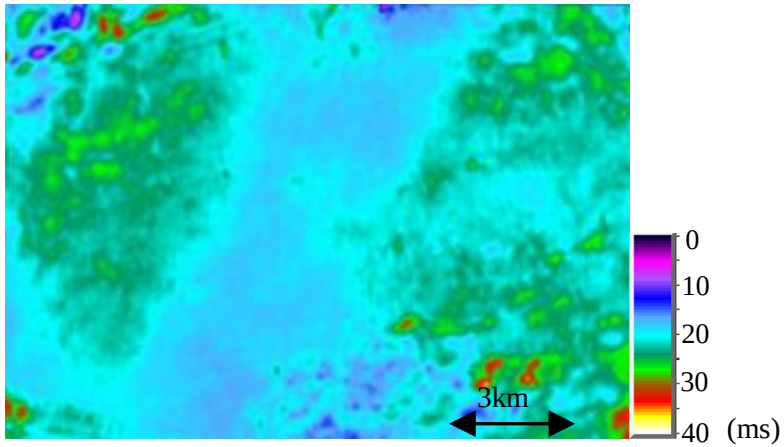
$$\text{Seismic net-to-gross} = \frac{\text{average seismic impedance}}{\text{average modeled impedance for 100\% net (HQS)}} \times \frac{\text{true thickness (ms)}}{\text{apparent thickness (ms)}}$$

Seismic net pay = seismic net-to-gross × apparent thickness

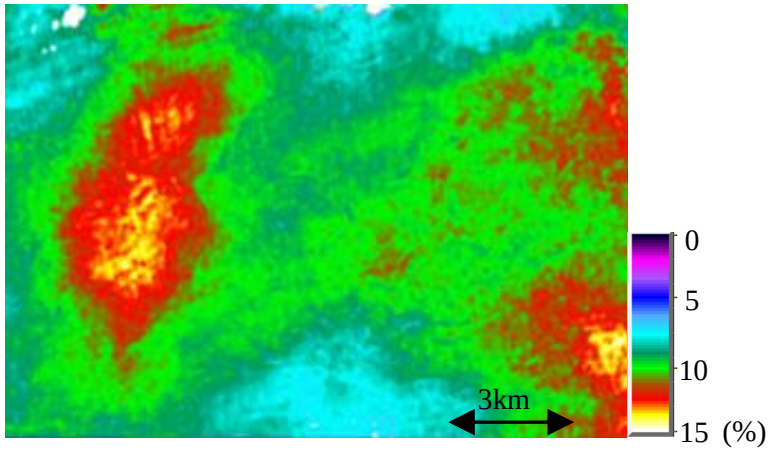
(Connolly, 2007)

Seismic Maps

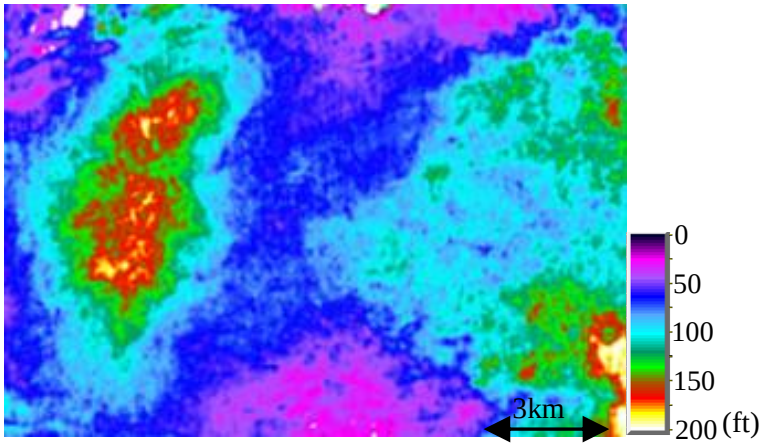
Time thickness



Inverted porosity

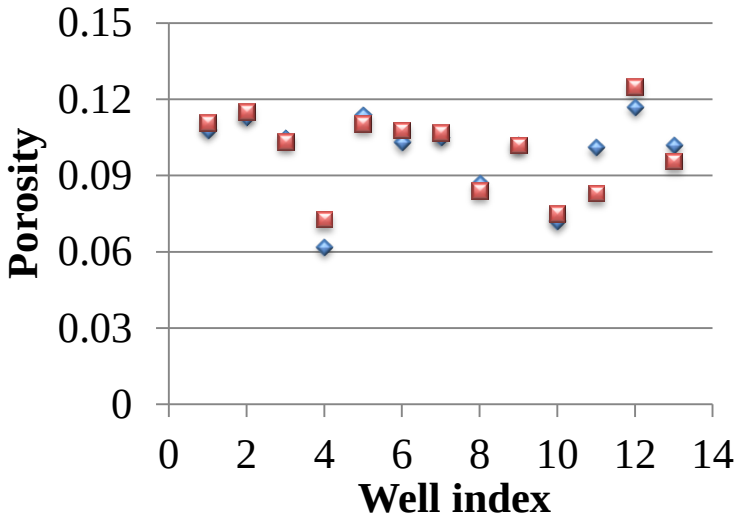


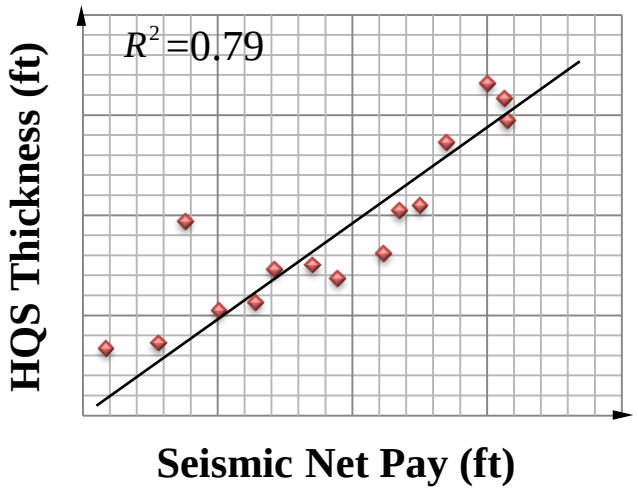
Seismic net pay



Seismic net pay more directly characterizes the sweet spot distributions than thickness or porosity maps alone.

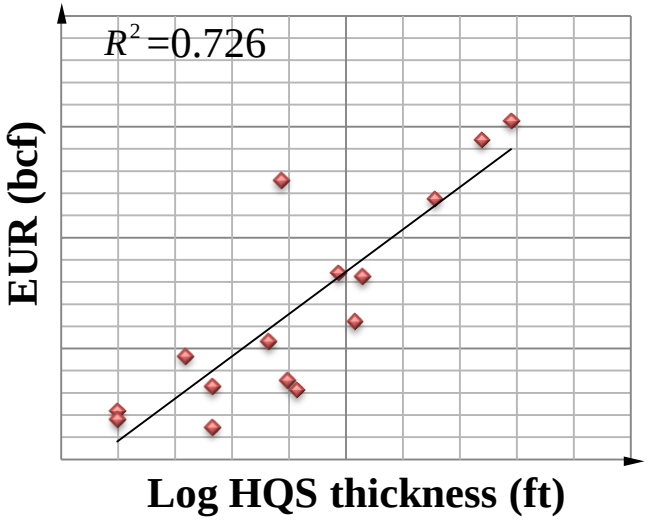
QC with Well Logs

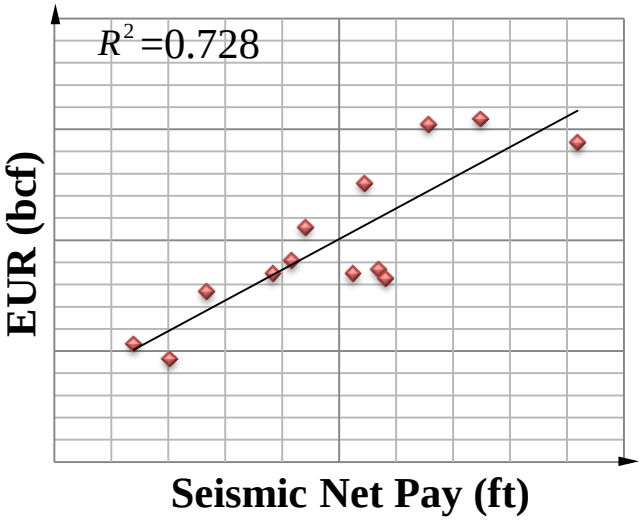




Seismic estimated porosity and net pay match with well log values with high accuracy.

Seismic Prediction of EUR





The seismic net pay correlation to EUR is as good as the correlation with well log HQS thickness.

Conclusions

- TGIP in HQS (high quality shale) intervals correlates well with EUR.

- Seismic (coloured) inversion and seismic net pay methods generate reliable porosity and HQS thickness.

- Seismic derived HQS can predict EF shale sweet spots.
  - Plan new wells
  - Identify refrac candidates
  - Appraise completion trials

Acknowledgements

- BP Lower 48 and BP Upstream Technology

- Numerous BP colleagues' suggestions and feedback, including C. Sullivan, W. Simpson, C. Lazos, A. Cunningham, J. Zhang, S. Davis, S. Li, L. Sarle, M. Blome, etc.

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Questions