RESERVOIR SEISMIC CHARACTERISATION OF THIN SANDS IN WEST SYBERIA

PROJECT OBJECTIVES AND BACKGROUND

• Main Reservoir is Upper Jurassic, thin oil saturated sands
• Significant lateral variation in rock quality & reservoir thickness
• Previous work tried to correlate thickness to seismic with relative success
• No pre-stack data, so no option for AVO; post-stack attributes only

Key Questions to Answer:
• Why has thickness prediction failed?
• Which property controls the reservoir quality?
• Which property controls the seismic signal?
• Can we predict Reservoir quality from Seismic?
• Update the geologic model, conditioned by seismic

Prognosed thickness vs. Measured Thickness on wells drilled
Our Approach to Reservoir Characterisation. Using Petrophysics and Rock Physics to understand both the reservoir and the seismic signal.
1st Step, to perform a detailed petrophysical evaluation

Develop compaction trend global parameters to condition deterministic petrophysics evaluation. Clay porosity compaction trend determined from density log using an appropriate clay matrix density value.

Conduct deterministic evaluation for variable mineralogy.

Assess coal and cemented zones.

Use results of deterministic evaluation to constrain multi-mineral evaluation.

Validate compressional sonic logs and densities.

Petrophysical Evaluation applied consistently to all the wells with the same model and parameters.
1. A stochastic petrophysical evaluation allows us to mathematically correlate the output mineral volumes to all the input logs.

2. We can calibrate the results to the core mineralogical descriptions and we can use the deterministic model as a starting point to minimize non-uniqueness.

3. The model can be defined using global parameters applicable to all the wells.
Summary of Petrophysical Findings

• Local reductions in porosity determined to be response to poorer sorting and presence of calcite cemented intervals and carbonate stringers, which reduce porosity and permeability.

• The reservoir quality variations are highly correlated to the porosity variations in the 1-2 sands.

• The absence of hydrocarbons correlates with the presence of these cemented zones.

• The same situation is consistently observed in all the wells evaluated (24 in total).
Summary of Petrophysical Findings.
Total Porosity versus Calcite Volume as indicator of reservoir quality (All Wells)

As the volume of carbonate increases, porosity rapidly decreases and as mentioned before, the oil saturation is high when porosity is high and nonexistent in the presence of carbonates.

This indicates that porosity and the carbonate content are the main drivers of the reservoir quality.

If we can estimate accurately total Porosity from the existing seismic data, then we can incorporate this property into the geological model to update the N/G estimations.

We can also use the porosity estimation to identify in the seismic the most likely extension of the carbonated areas and use it as a risk map for the drilling campaign.
How are these reservoir changes related to the seismic signal? Synthetic Seismograms.

**Good Confidence in the well ties**

![Cross Correlation](image)
Seismic resolution analysis uses the dominant frequency to estimate the tuning thickness, however it does not incorporate amplitude changes into the model, therefore the results may be misleading and it should be used as a reference only. We analysed the trace shape change associated to the thickness changes we obtained a tuning thickness of ~9 m, however, the wedge model doesn’t detect any change in trace shape for the thickness changes modelled, but just a small amplitude change.
Are thickness changes related to the amplitude or trace shape changes? Supervised Neural Network, property: Thickness

The correlation between the net oil thickness and the seismic event thickness shown in this map gave similar results to that of the previous model when compared to the well information. This and the modelling performed demonstrates that the main driver of the seismic amplitude is not the sand/oil thickness.
What is the main driver of the observed seismic amplitudes?

- Carbonates produce high impedance contrasts that mask the seismic response of the oil sands.

- The oil sands should be represented by a negative reflection, however, the seismic shows a positive, which suggests that the amplitudes are being driven by the porosity change associated with carbonates.

- Total Porosity, which is controlled by the carbonate content appears to be the main driver of the seismic, if this is the case, we should have a strong correlation between P-Impedance and Porosity...
Is porosity the main driver of the seismic signal? How does it correlate with P-impedance?

- A strong relationship between Acoustic Impedance exists in the 1-2 Formation, which is consistent in all the wells.

- We can then establish an empirical relationship to obtain porosity maps from P-Impedance.

- P-Impedance can be generated from the seismic data through seismic inversion.

- The consistency of the crossplot is a direct result of the petrophysical evaluation.
2nd Step, to pre-condition the seismic using amplitude preservation techniques, to reduce the impact of noise in our results and guarantee consistency in our modelling.
We start with a log interpolation as a low frequency model (LFM), we run the inversion and check the results against the blind tests, then we improve the LFM and run the inversion again until it converges to a solution that matches all the wells, including the blind tests.
At each iteration, we filter the LFM to be between 0-10 Hz and we make sure that our inverted impedances have as much information as possible from the seismic and as little as possible from the well logs.
3rd Step: Converting the seismic amplitudes into Impedances: Validation of the results by extracting traces along the well trajectories

Well Log Impedances
(Original Sampling)

Seismic Impedances

Reservoir Section

Blind tests
3rd Step: Converting the seismic amplitudes into Impedances: Validation of the results by extracting traces along the well trajectories

Well Log Impedances
(Arithmetic Smooth, 4m)

Seismic Impedances

Reservoir Section

Blind tests
3\textsuperscript{rd} Step: Converting the seismic amplitudes into Impedances: Validation of results: Well Impedances vs Seismic Impedances. Correlation = 0.93
4\textsuperscript{th} Step, Porosity Estimation
Validation of results: Extracted seismic porosity along the well trajectories

Blind tests
4th Step, Porosity Estimation
Validation of results: Extracted seismic porosity along the well trajectories

Blind tests
4th Step, Porosity Estimation
Validation of results: Extracted porosity along the well trajectories
Additional Blind Tests (Field 2), wells without Sonic Log
4th Step, Porosity Estimation
Total Porosity Map Generated for the 1-2 Reservoir
4th Step, Property Estimations
Risk Map Generated showing the highly carbonated areas

Average Porosity from Well Logs for Zone 1-2
5th Step, Finding Evidence of the Depositional System. Theoretical Depositional Model For the Fields 1 and 2
5th Step, Finding Evidence of the Depositional System.
Seismic Facies Classification Map correlated with Well Based Sedimentological Model.

• Electric facies correlate 100% to seismic facies.
• The wells classified as Facies I and II in the well based modelling fell into the Yellow Seismic Facies (i.e. they have similar seismic character), whereas Classes IV and V have distinctive seismic signatures.
• We proposed an update of the sedimentological model based on the seismic signals but also following the well observations.
• The way the wells are clustered into 4 facies, is the same way the seismic is clustering the trace shapes. Which means that is the same sedimentological model, but driven by the seismic.
Final Step. Update of the geological Model

The Final Update of the Geological Model was performed by combining the Seismic Derived Properties with 3D stochastic modelling, enabling us to build a more consistent 3D static model which captures the spatial distribution of the seismic properties with the high resolution heterogeneity of the reservoir from log data.
Conclusions, answers to key questions:

- Why did the thickness estimation fail in those wells, can it be improved?
  - Oil Thickness and Sand thickness have little effect on the seismic signal.
  - In the reservoir modeling the thickness estimation was improved by using the seismic derived porosity and defining a porosity based cut-off for N/G.

- Which property controls the reservoir quality?
  - Porosity and Permeability are related to carbonates and cemented zones.

- Which property controls the observed seismic signal?
  - Seismic amplitude changes are related to Porosity changes.
  - A strong correlation was observed between porosity and P-Impedance.

- Can we predict Reservoir quality variation from Seismic? Which property and at what scale?.
  - Seismically derived properties matched the well log properties after applying a 4m filter to the logs.
  - In the reservoir modelling, we used seismic properties as a trend and log information as hard data.

- Can the seismic be used to update the geological model, and how?
  - Yes, if the seismically derived properties have a high correlation to the well properties (93%).
  - The use of seismic data to condition the geocellular modeling reduces uncertainty in the static model.
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