Rock Physics and Quantitative Wavelet Estimation

for Seismic Interpretation: Tertiary North Sea

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ABSTRACT

A case study from the Tertiary of the North Sea is presented in which a well tie is improved through the application of zero offset processing and well log velocity prediction. The well ties are quantified using the techniques of White (1980) and White and Walden (1984) and log conditioning employs the Xu-White sand/clay velocity model (Xu and White, 1995 and 1996). A well tie of a migrated stack section to a zero offset synthetic, produced with minimal data conditioning, gave a poor tie and event identification was in doubt. Additional data conditioning improved the tie dramatically (from 43% to 72% energy predicted and a reduction in phase error on the wavelet estimation from >20^o to <10^o). These enhancements in the well tie are important in justifying decisions to perform wavelet deconvolution, zero phasing or seismic trace inversion to acoustic impedance as well as correctly identifying the top reservoir reflection. This study also demonstrates that detailed log conditioning is crucial in this area to predict a diagnostic AVO response related to the presence of hydrocarbons. This study uses a Tertiary example from the North Sea to illustrate the importance of data conditioning (both logs and seismic) not only to achieve good well ties which enhance the confidence in seismic interpretation but also to enable recognition of subtle hydrocarbon indicators.

It is common practise to perform well ties by visual matching of synthetics to seismic. Traditionally, the synthetic has been created by convolving the log derived reflection series with an idealised wavelet of similar bandwidth and phase to that posted on the seismic section side label. This technique has resulted in a large degree of ambiguity. It is often not possible to distinguish whether the best tie is made using normal polarity minimum phase synthetics with minimal time shift or time shifted reverse polarity zero phase synthetics. Without adequate quantitative measures of phase, polarity and timing of the seismic wavelet there will always be this ambiguity with an associated uncertainty in the seismic interpretation.

Two important factors impact the accuracy of well ties in this area of the Tertiary in the North Sea. The first is that the impedances of sands and shales are quite similar (particularly where the sand is saturated with medium grade oil and a reasonable component of dissolved gas) and zero offset synthetics are very sensitive to small changes in impedance. Log conditioning, not only in terms of applying the standard borehole and tool corrections but also corrections for invasion, is very important. The second factor is the effect of AVO. There is a subtle (Class II, Rutherford and Williams, 1989) AVO effect which comprises a low amplitude intercept at zero offset and a phase reversal with offset. This has the effect of significantly reducing the amplitude on the migrated stack compared to the normal incidence trace. This study demonstrates that matching a normal incidence synthetic to the migrated stack data is, in this area, inappropriate. These subtle AVO effects are difficult to detect as they have a similar appearance to residual moveout on NMO corrected gathers. Reliable forward modelling evidence is crucial for their recognition.

Well tie methodology

This study tracks the accuracy of a well tie in a Tertiary sequence as different processes are applied to the data. The approach to quantifying well ties followed here is that published by White (1980) and Walden & White (1984), in which well logs are used together with a least squares fitting technique to derive a wavelet from seismic data and a statistical description of the goodness-of-fit and accuracy of the tie. The strength of this method is that it is pragmatic (requires no assumption concerning phase), quantitative (gives measures of accuracy that can be used to evaluate for example the basis of zero phasing or seismic inversion) and is interpretation-oriented (it makes sense of what is found in the borehole in terms of the seismic response). The working philosophy is one of starting simply with the primaries-only synthetic and adding other components (such as surface multiples) as needed to evaluate the effect on the tie.

Initial well ties

The data comprise a 2D sail line (from a 3D survey) through a well with a full suite of logs (including a shear wave log handpicked from monopole array sonic waveforms). Coherence analysis showed that both the seismic data have high signal-noise ratios (in excess of 10dB) and a broad bandwidth (10-70Hz). The data were initially processed through to migrated stack in the following sequence:

Pre-processing (desig., edit, pred. decon., mute)
Velocity Anlaysis
DMO
Pre Stack Time Migration (with single velocity function)
Multiple attenuation
Velocity Analysis
NMO
Full Offset Stack
Inverse Migration
Post Stack Migration (with laterally varying velocity function)

Figure 1 illustrates the initial migrated stack section through the well location. The top of the reservoir is around 2310ms. Standard environmental corrections were applied to the logs. An erroneous portion of log (above the reservoir) was edited using straight line interpolation between good data segments. The sonic log was calibrated using a minimum number of linear drift lines with knee points located at major breaks in the sonic log.

Matching of the reflectivity series to the seismic data was done over two time gates, a shallow zone from 750ms to 1250ms and a deeper zone from 1850 to 2350ms. Inputs to this process are the seismic data, a specified time gate (not less than 500ms) and a wavelet length (ms twt). A good tie is a compromise between the wavelet length (any synthetic can be matched to seismic by using unrealistically long wavelets), the frequency of the estimated wavelet and the goodness-of-fit and accuracy of the match. The data are scanned for the best match location. Outputs that describe the match include:

B - statistical bandwidth (Hz) of the seismic data

b - analysis bandwidth (Hz) (a smoothing parameter, directly related to the wavelet length, which should be <B/2)

T - data segment length (bT should be in the range of 5-12)

PEP - percentage of energy predicted (a measure of good-ness-of-fit) (where energy is calculated as the sum of squares)

NMSE - normalised mean square error (a measure of accuracy) (NMSE relates to phase error in the wavelet estimation such that the standard error in phase = (NMSE/2)0.5 radians)

It was found that the initial tie at the shallow gate was good whereas the tie at the deep gate was poor. Well tie results are shown in Table 1. The shallow tie has a very low NMSE of 0.06 (equating to a phase error of <100) and 76% of the energy in the trace is predicted by the synthetic. In contrast, the deeper tie has an NMSE of 0.25 (equating to a phase error of >150) and only 43% of the seismic trace energy predicted by the synthetic (Table 1). Figure 2 shows the tie for the deep gate (tie 'deep 1' in Table 1) . The figure shows the reflectivity series, the estimated wavelet, a comparison of the filtered synthetic with the seismic data from the best location and the residual or difference trace. The time series representation of the wavelet illustrates a response to an increase in acoustic impedance. The wavelet is very symmetrical with time zero located at the zero crossing between the trough and the peak. Thus, a positive reflection such as that from the top of the reservoir sands would be picked as a black peak. It was found in this study that all the estimated wavelets looked similar yet the ties varied in their fit and accuracy. The prominent reflector at 2260ms is the Top Balder. A comparison of the filtered synthetic trace and the seismic trace (labelled 'data segment') reveals a poor match at the top reservoir, with a prominent reflection and on the synthetic a low amplitude peak set in a generally low amplitude, and apparently higher frequency, zone of peaks and troughs on the seismic trace. Event identification on the basis of this tie is quite difficult.

Improving the well tie

A first improvement to the tie was made by replacing the erroneous section above the reservoir with sonic velocities derived from a velocity model (the Xu-White sand/clay model, Xu-White 1995) (Figure 3). This model uses petrophysical estimates of porosity, shale and water saturation, an implementation of Kuster-Toksoz theory, assumptions concerning the aspect ratios of sand-related and clay-related pores and their distributions, and Gassman's equation to predict the (low frequency) velocity over the whole continuum from sands to shales. As such it is a very useful tool for quality control of the sonic log in siliclastic sequences. The effect of replacing the erroneous sonic log above the reservoir on the well tie is to improve the tie to the migrated stack section by increasing the spectral bandwidth (B) of the estimated wavelet from 62 to 67Hz, decreasing the NMSE to 0.11 from 0.25, and increasing the proportion of predicted energy from 43% to 61% (tie 'deep 2' Table 1).

Further improvements in the tie were made by processing the seismic to zero offset and applying fluid substitution corrections to the sonic log to account for the effects of invasion. The zero offset processing was accompanied by closer attention to velocities, pre-stack migration and multiple attenuation. Fluid substitution was performed using a predicted shear velocity log and a trial and error approach to the problem of determining the 'log' fluid parameters. It is a common feature in hydrocarbon bearing zones that velocities derived from the sonic are too high, due to the replacement of compressible hydrocarbon with filtrate of lower compressibility. Invasion effects can also occur in the water zone, though the magnitude of the effect (sonic velocities too low) is generally less than in the hydrocarbon zone. Figure 4 illustrates that the correction for invasion is up to 10% of the measured velocity. The shear velocity prediction (using the Xu-White model, Xu-White 1996) highlights the fact that the shear wave velocities in the shales are erroneous, resulting from p wave mud arrivals obscuring the (slower) shear wave velocity arrival of the shales (Figure 4). The effect is also illustrated in Figure 5 where the shale velocities from the array sonic are crossploted, together with an empirical Vp/Vs relation for mudrocks taken from Castagna et al (1985).

Table 1 shows the effect of all this data conditioning. The deep tie ('final deep' in Table 1) now has very good accuracy (an NMSE of 0.05) and a very good fit (a significant proportion (72%) of the energy is predicted by the synthetic model) and the bandwidth of the estimated wavelet is high (67Hz). Figure 6 shows the 'final deep' well tie. The prominent reflection at 2320ms on the synthetic, related to the top reservoir, is now matched clearly by a similar reflection, albeit with a slightly different amplitude, on the seismic trace. There is no mistaking the correct event identification in this case.

Recognising and modelling the AVO effect

A gather from the re-processed dataset is shown in Figure 7. A Class II AVO effect is evident at a time of 2320ms, where a peak on the near traces (representing a compression) changes polarity with offset. This is a subtle effect and can easily be mistaken for residual NMO. The low amplitude normal incidence reflection is due to the effect of hydrocarbon significantly lowering the impedance of the sands. The phase reversal occurs because there is a marked decrease in amplitude with offset, resulting from a significant contrast in poissons ratio at the top of the reservoir. Figure 8 shows a comparison of single interface AVO models for the top reservoir reflection based on recorded velocities and density and those with corrections applied. The AVO response predicted using the raw log data is relatively flat and does not show a phase reversal with offset. On the other hand, the response derived from the conditioned logs shows a lower zero offset amplitude and a steeper gradient, giving rise to a phase reversal with offset. It is quite clear that without the log conditioning, the AVO effect related to the presence of hydrocarbons would not be predicted.

Conclusions

This study has shown that the application of zero offset processing and log QC and conditioning (in the form of velocity prediction) can improve the accuracy of well ties. A tie of a migrated stack section to a zero offset synthetic, produced with minimal data conditioning, gave a poor tie and event identification was in doubt. Additional dataconditioning improved the tie dramatically (from 43% to 72% energy predicted and a reduction in phase error on the wavelet estimation from $>15^o$ to $<10^o$). This enhancement gives confidence in performing seismic inversion and the mapping of impedance changes related to changes in lithology and fluid. This study has also shown that detailed log conditioning is crucial in predicting a diagnostic AVO response related to the presence of hydrocarbons.

References

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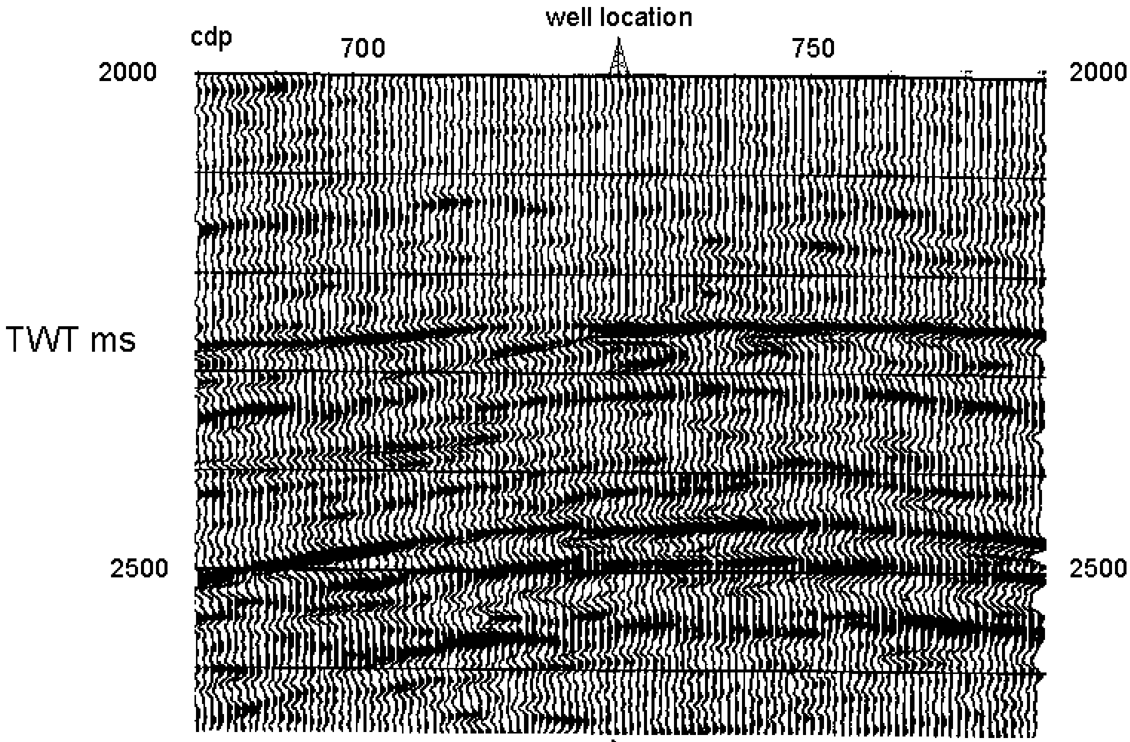

Figure 1. Initial migrated stack section.

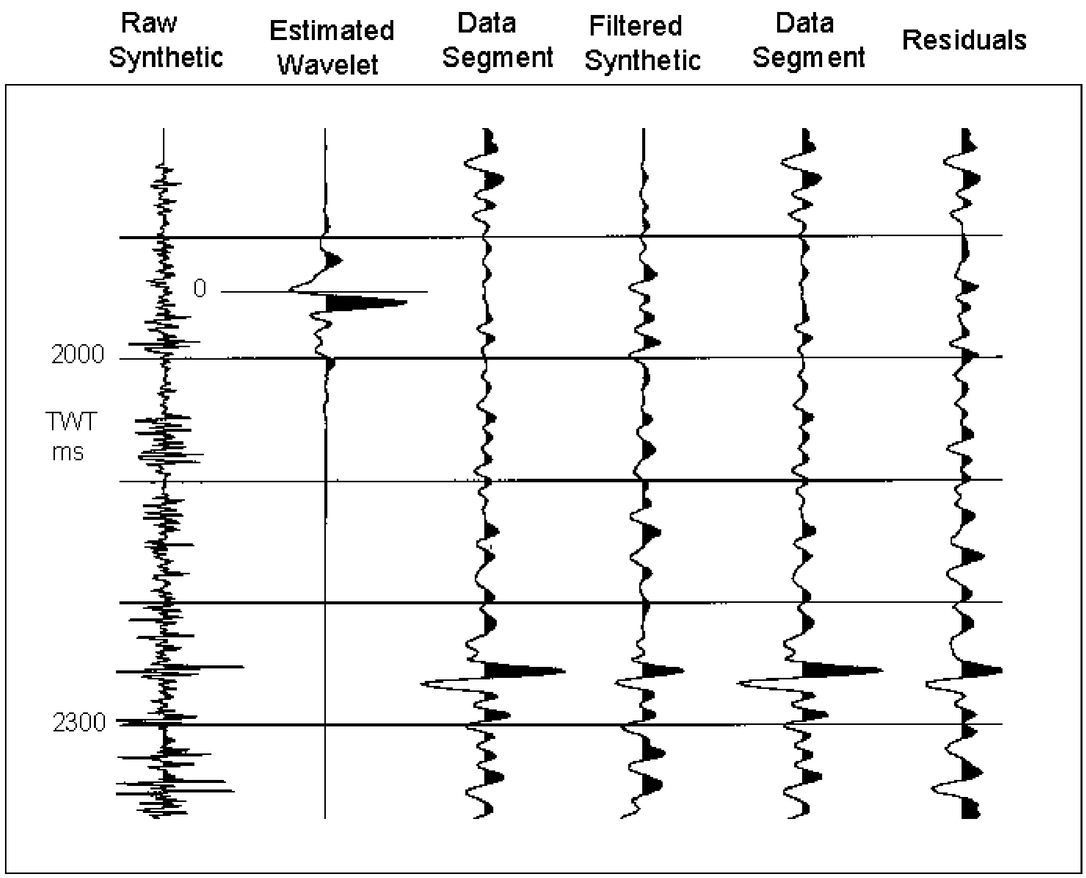

Figure 2. Initial well tie ('deep 1') over the reservoir section, matching the zero offset synthetic to the migrated stack data. Wavelet time zero is at 1950ms

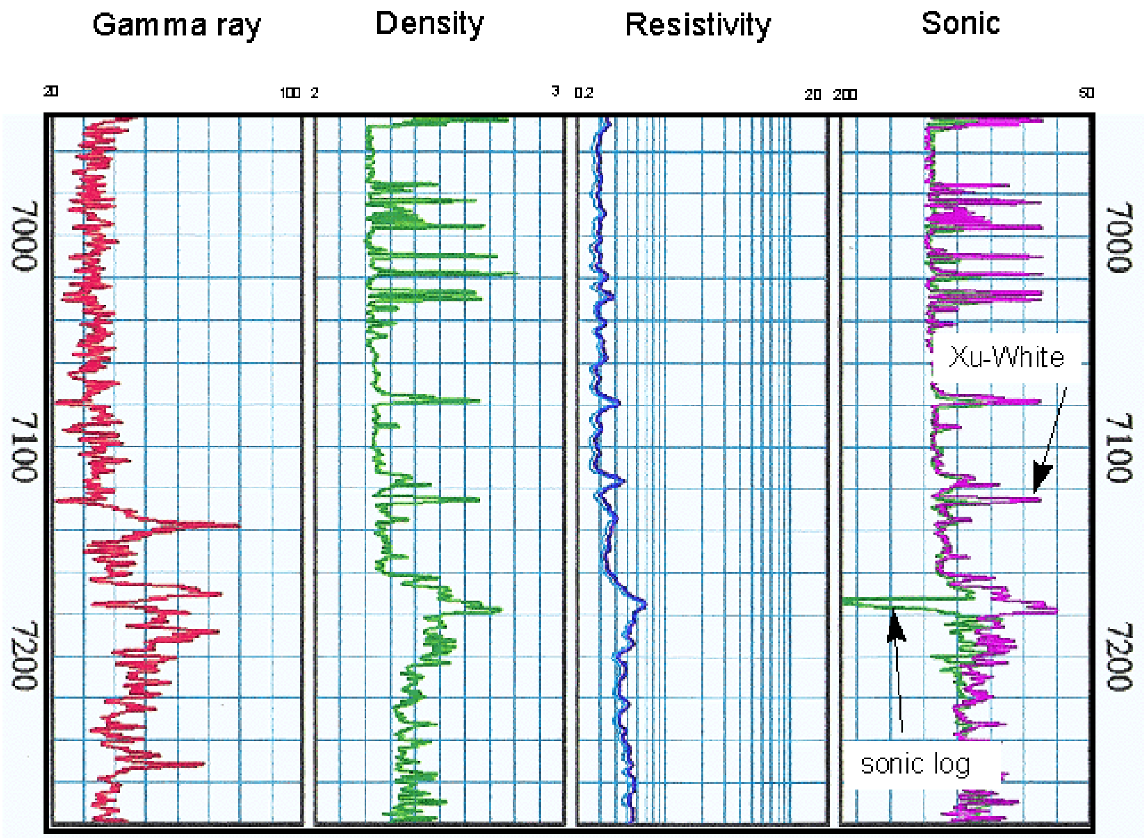

Figure 3. An illustration of the use of the Xu-White model for sonic log QC.

Note the erroneous log readings at around 7175ft.

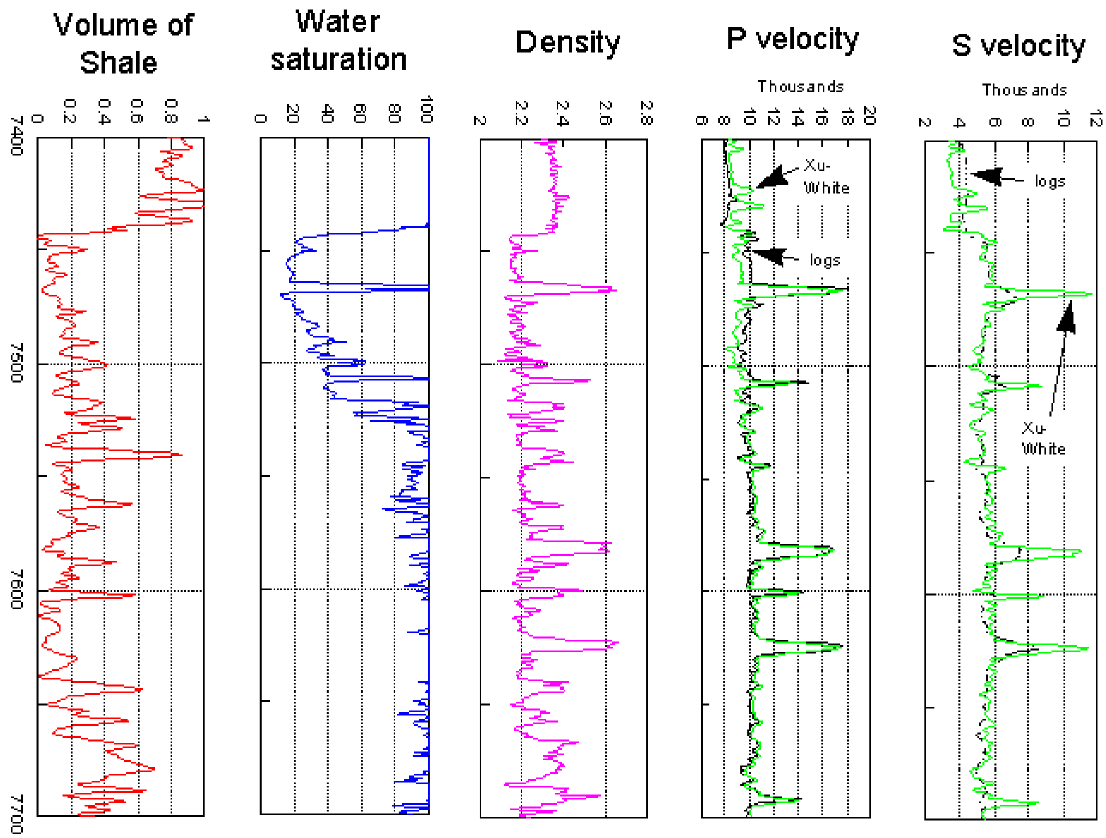

Figure 4. Illustrating the effect of fluid substitution (using the Xu-White model) on the sonic velocity, together with the difference between predicted and log shear velocity

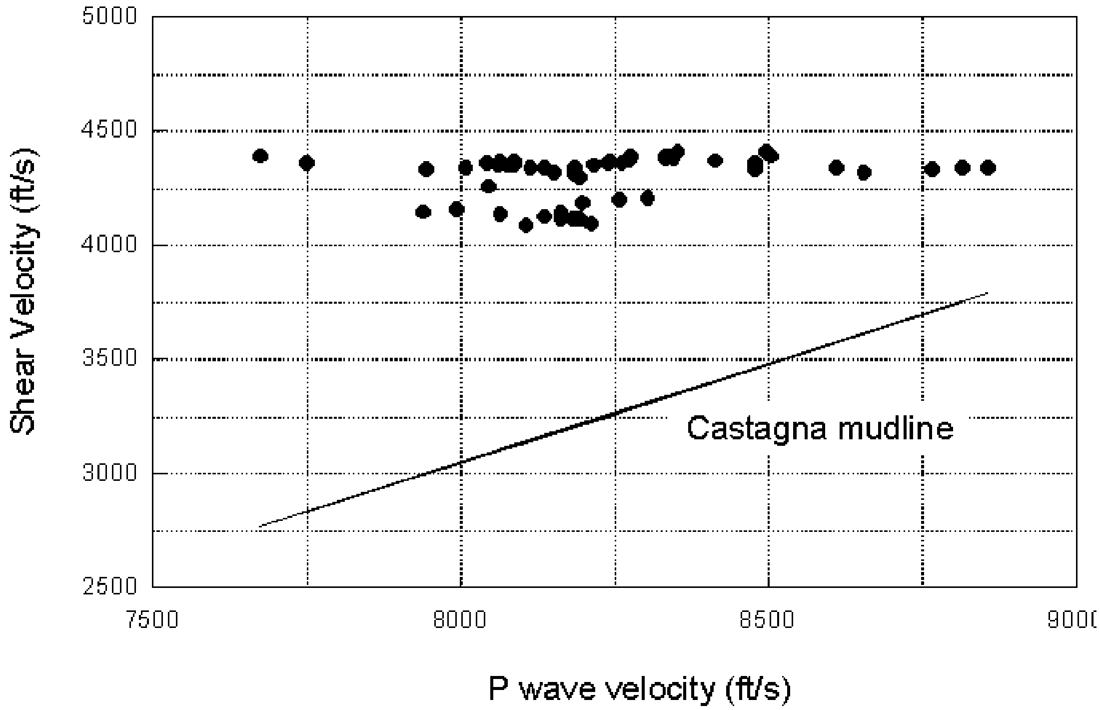

Figure 5: Vp/Vs crossplot for shales, showing that where the shear velocity of the shales is lower than the mud wave it is the mud wave which is recorded by the monopole array sonic tool.

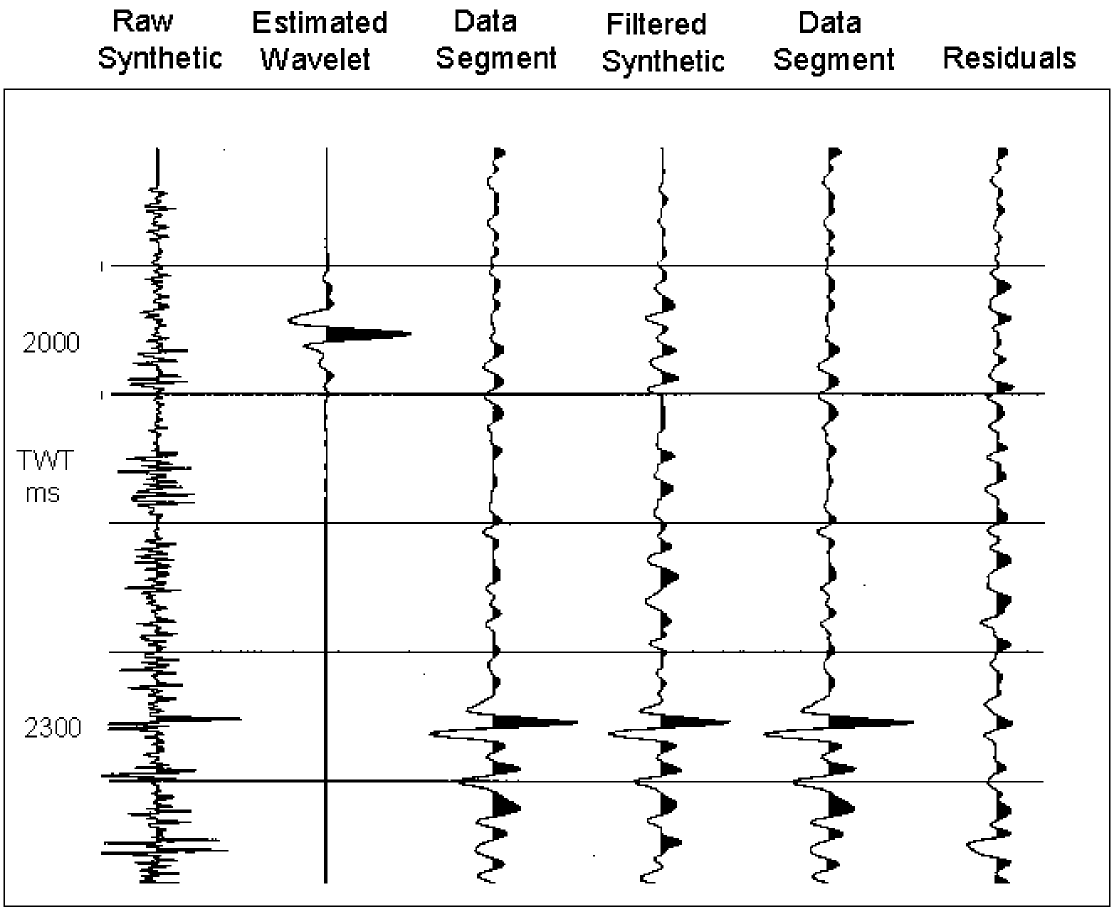

Figure 6: Final well tie ('final deep') over the reservoir section, matching the zero offset synthetic to the zero offset seismic section. Wavelet time zero is at 1950ms.

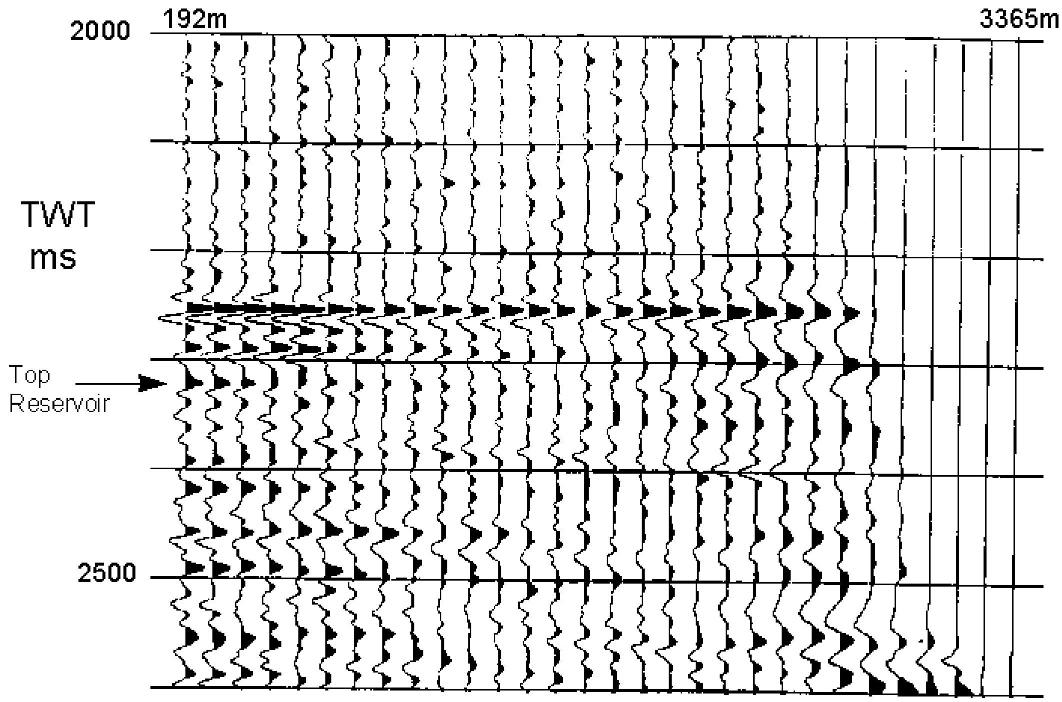

Figure 7 : Common ray point gather 735, showing a class II AVO effect at the top of the reservoir.

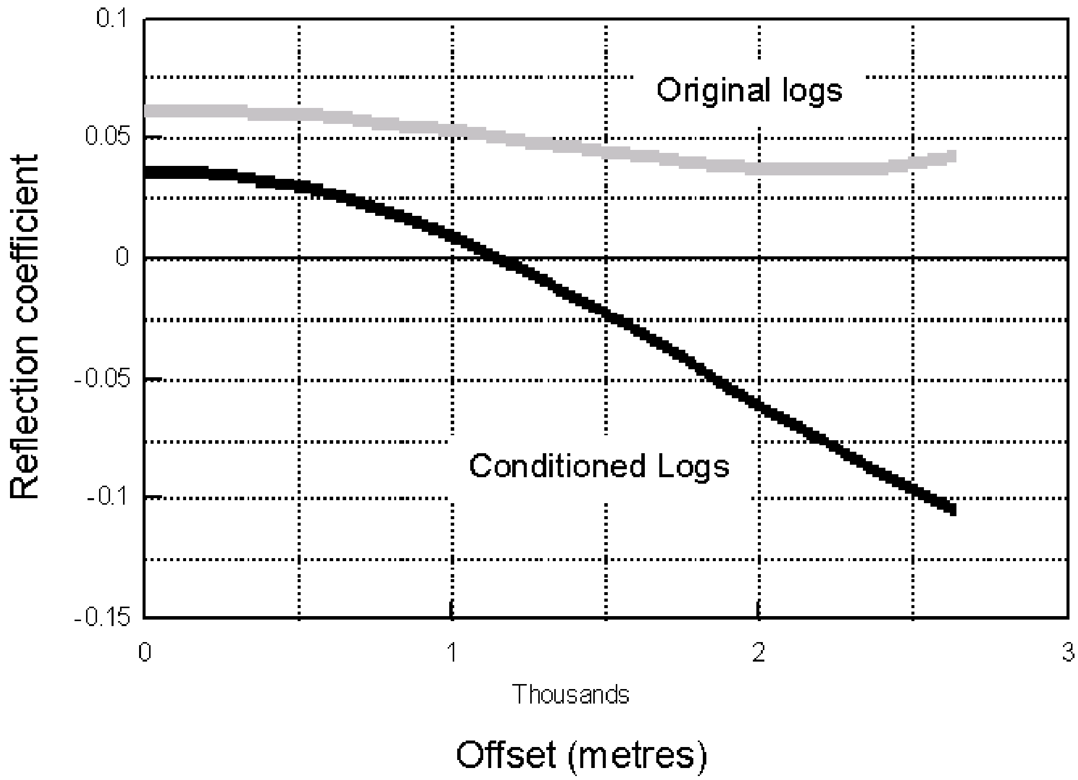

Figure 8 : AVO plot showing the effect of fluid substitution and shear wave prediction on the predicted AVO response.

Table 1. Well Tie Results.

	Initial Tie			Final Tie
	Shallow	Deep 1	Deep 2	Deep
B	57.86	62.22	67	67.25
b	17.04	17.04		17.04
bT	7.67	8.52		8.52
PEP	0.76	0.43	0.61	0.72
NMSE	0.04	0.16	0.11	0.05