Calibrating FWI image amplitudes: Insights from Deepwater GoM

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Summary

We evaluated various shallow Miocene amplitude anomalies on 11 Hz full-stack acoustic Full Waveform Inversion (FWI) derived reflectivity (FDR) data from the Deepwater Gulf of Mexico. Based on seismic well ties, fluid substitution and 2D seismic forward modeling, we concluded that five out of the five penetrated amplitude anomalies are mainly a response of fluid (~30 API & 800-1500 scf/bbl GOR) on high porosity (~33% avg) unconsolidated Miocene reservoirs. Our modelling shows that substituting the fluid from brine to oil in these reservoirs causes approximately a ~15% reduction in compressional velocity (Vp) and only ~5% in bulk density (Rhob) resulting in observable amplitude anomalies on the FDR. Furthermore, our synthetic model suggests that the amplitude ratio from oil to brine bearing sands is ~2.5x, which matches our observations on the FDR when comparing the oil leg to the aquifer.

Introduction

FWI has now become much more practical because of the increased computer power (Shen et al., 2017). It has become increasingly popular in recent years because of its ability to produce higher-quality images in challenging subsalt areas using full wave propagation modes including diving waves, multiples, and reflection waves (Wang et al., 2021). Whereas standard migration algorithms, such as Kirchhoff migration, one-way migration, and reverse-time migration (RTM), use only the primary reflection data. (Buist et al., 2023). Although multiple FWI studies focus on improving the image quality of the subsurface (Zhang et al., 2020), not much has been published on the significance of the FDR (derivative of the FWI velocity model) amplitudes. Our study shows how we calibrated a set of amplitude anomalies on FDR seismic data in DW GoM using seismic well ties and 2D forward models.

Data and Method

We used WAZ towed streamer data as underlying digits that had been processed by a 3rd party using their proprietary algorithms to obtain an 11 Hz acoustic FDR which significantly improved the illumination of the reservoir subsalt (Fig 1 and 2). We then conducted seismic well ties on wells that have good quality compressional velocity (Vp), bulk density (Rhob) and shear velocity (Vs) data and penetrated the amplitude anomalies in the FDR. We created full stack synthetics seismogram using Acoustic Impedance, Vp only and Rhob only to compare against the FDR data (11Hz FDR) at the well locations (Fig 2a & 2b). Noticeably, the Vp only synthetic gives a better correlation with the FDR, showing dim amplitude on the thicker (180ft) wet sand and strong amplitude at the thinner(~50ft) oil sand. In contrast with the Rhob only synthetic which shows the opposite (high amplitude at the thicker wet sand and low amplitude at the thinner oil sand). Consequently, the AI synthetic shows a slight better correlation with the 11Hz FDR compared to the Rhob only, although still not as good as the Vp only synthetic.

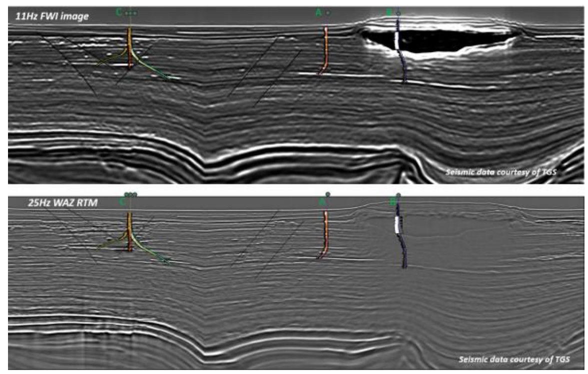

Figure 1: Upper FDR and Lower 25Hz WAZ RTM seismic section showing the shallow Miocene amplitude anomalies. The phase is rotated to -90deg. Trough =soft, Peak=hard.

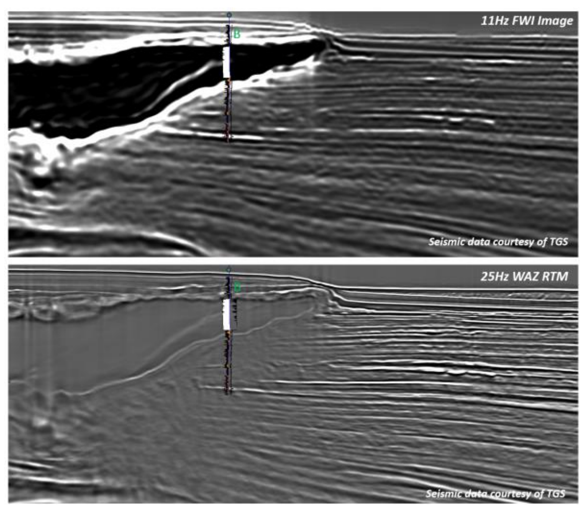

Figure 2 Upper 11Hz FDR and Lower 25Hz WAZ RTM seismic section showing the improvement of the imaging subsalt. SEG standard polarity, the phase is rotated to -90deg. Trough=soft, Peak=hard.

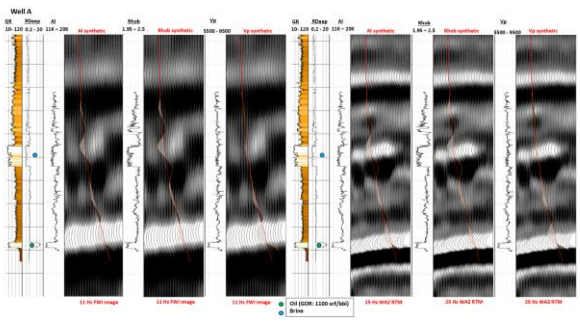

Figure 3: Seismic well ties using AI, Vp only and Rhob only wavelet used is an orbmsy filtered (2-5-8-15) that macthed the FDR frequency spectrum. Left panel shows the FDR data as background vs RTM data on the right.

Results

The insitu fluid at Well A is brine in the upper sand while it is oil charged at lower reservoir. For this study, we applied the fluid substitution (Smith et al., 2003) to these reservoirs to model the sonic and density response for brine to oil (upper reservoir) and for oil to brine sands (lower reservoir). Both the upper and lower reservoirs are sensitive to fluid substitution in terms of the Vp, and Rhob at the log scale. These shallow reservoirs are very soft and are highly sensitive to pore fluids. Figure 5 shows quantitatively the change in Vp, Rhob and AI from BR to Oil. In the upper reservoir this median change is about 13% (Vp_{BR}=7700 ft/s and Vp_{Oil}=6700ft’s) and about 16% for lower reservoirs (Vp_{BR}=7550 ft/s and Vp_{Oil}=6300ft’s) whereas is ~ 5% for the changes in Rhob (2.05 g/cc BR and 1.95g/cc Oil) for both reservoirs. Using the modelled set of logs and Ormsby wavelet, we generated AVO synthetics for brine, oil, gas and in situ fluid (Figure 4). Both upper and lower zone show a trough leading reflector with flat gradient; class III (the BR sands exhibit a slight positive gradient making it a Class IV in theory; however, this change is small enough that we interpret it as a flat gradient). The synthetic shows that for the upper reservoir the stacked amplitude is ~ 2.5 times brighter when charged with oil versus when saturated with brine, similarly the gas saturated sand appears 5.0 times brighter than brine sands. We compared to the stacked trace because our FDR is fullstack. Furthermore, the stacked amplitude of the lower oil-bearing reservoir is ~1.5x the amplitude of the upper wet zone even though the lower reservoir is about 50ft. gross and the upper reservoir is ~180ft. gross. Tuning thickness ($\lambda/4$) for the oil-bearing reservoirs at the dominant frequency of the FDR data around these depths (10Hz) and median velocity of ~6300ft/s is ~160ft. and detectability limit ($\lambda/25$) (Sheriff 2022) is ~25’ft. This suggests the lower reservoir (gross thickness ~ 50ft. > 25ft.) is detectable on the 11 Hz FDR data.

The strong change in amplitude between the brine and oil saturated sands is primarily driven by the change in compressional velocity (~15%) and has only small contribution by the density change (~5%).

We also created a 2D forward model with a known Oil water contact (OWC) where the beds dip 20 degrees to investigate the reflectivity response to fluid in the lower reservoir Figure (6). In this model, the overburden has been simplified to be homogeneous so that the amplitude changes are only a response of the fluid effect. The oil leg is modelled using Vp, Rhob, and Vs subbed to oil from well A. Well A is then positioned downdip using the Brine logs to model the aquifer. The lower part of Figure 6 shows the 0-40deg stacked seismogram using Zoeppritz algorithm (Shuey 1985) and different wavelets. Our model shows a clear amplitude contrast from the oil leg to the aquifer even at frequencies like our FDR data (2-5-8-15 Hz). We extracted the amplitudes of the synthetic model by mapping trough and peak (like we would interpret on real seismic data) and extracting the max absolute amplitude of the interval. We then cross plotted the extracted amplitude vs trace to show the location and impact of the OWC which we placed at trace 140 (middle of the model). The inserted amplitude vs trace crossplot on the lower left and right corners on Figure 6 shows that this Oil/Brine ~ 2.5 which is consistent with the ratio from the in-situ fluid (oil) to Brine.

Figure 7 upper shows a dip-oriented FDR seismic section across well A. We observed an amplitude shut off that is most likely an OWC because of the amplitude conformance in 3D (not shown here) and the amplitude ratio of ~ 2.2 times from the oil leg (6.3 units) to dimmer amplitudes below our interpreted OWC (2.8 units). Similarly, Figure 7 lower shows a dip-oriented FDR across well B. It found a gross reservoir of about 150ft and ~ 60ft of net pay with similar avg porosity of 30%. Although subsalt, the structure is well illuminated due to acquisition design and exhibits a similar amplitude ratio of ~ 2.7 of the oil leg (5.4 units) to the downdip aquifer (2.0 units). Well C consists of three well pads(C1-C2-C3), none of them have good quality Vp, Rhob, Vs logs, therefore we did not conduct fluid substitution but are still able estimate the gross pay interval to be ~ 100ft and a GOR range of about 800-1500 scf/bbl on the three different amplitude anomalies, (Figure 8) demonstrating that these amplitudes are responding to oil-bearing reservoirs. We are unable to estimate an amplitude from oil leg to aquifer because of the trap type- well C seems to be a faulted trap with stratigraphic edges which make it difficult to determine the aquifer (if any) on seismic data.

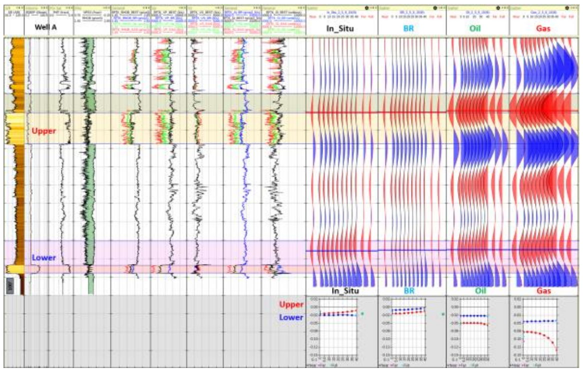

Figure 4: AVO Synthetic seismograms using different fluids : In_situ is the original fluid found in the well, BR is fluid sub to water and Oil is fluid sub to oil with GOR= 1100 scf/bbl. Wavelet is zero phase ormsby 2-5-8-15. Syntethics used Zoeppritz equations.

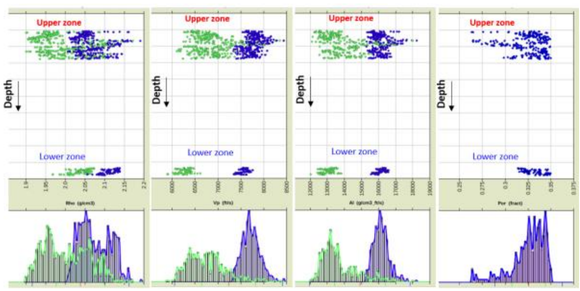

Figure 5: from left to right: Vp, Rhob, AI and porosity in well A Green dots are oil bearing sands whereas blue dots represent Brine.

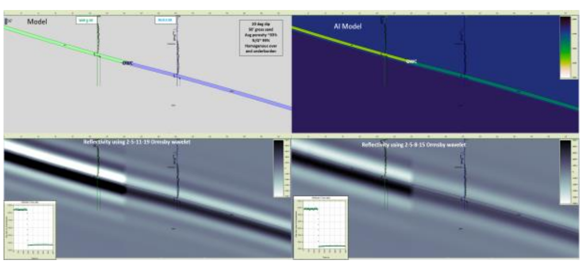

Figure 6: 2D synthetic model: Upper left to bottom right: Geometry model, AI model. Stack synthetic model using ormsby wavelet 2-5-11-19 and stack synthetic model using lower freq ormbsby walvet: 2-5-8-15.Both syntethics used Zoeppritz equations. SEG standard polarity, Trough=soft, Peak=hard.

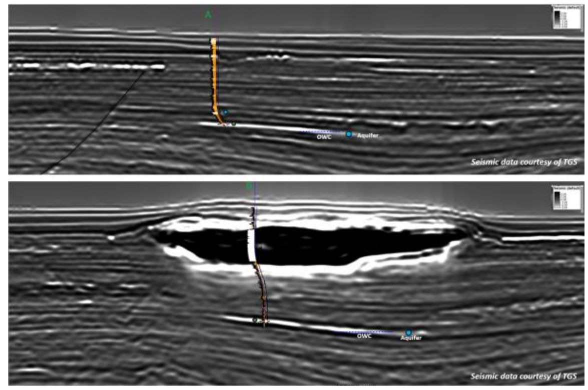

Figure 7: FDR seismic section depicting wells A and B showing the oil leg at different reservoirs and fields and the downdip aquifer. SEG standard polarity, the phase is rotated to -90deg. Trough=soft, Peak=hard.

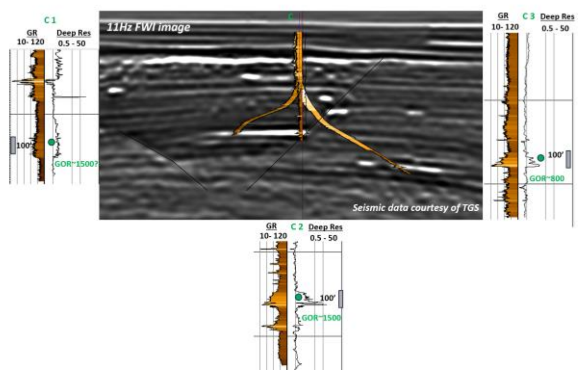

Figure 8: well section on FDR showing the gross pay at each well. Seismic vertical scale is different form the well section vertical scale. SEG standard polarity, the phase is rotated to -90deg. Trough=soft, Peak=hard.

Discussion

Our evaluation shows that these FDR amplitude anomalies are responding mainly to velocity caused by light oil-bearing clastic reservoirs that are highly sensitive to fluid. It follows then, that although not all FDR amplitude anomalies would correspond to oil-bearing sands, (a pitfall would be a highly overpressured shale sandwiched by either a normally pressured shale or sandstone or a combination of both) and assuming of course similar geology: reservoir properties, overburden, depth, pressure regime, GOR, isolated hydrocarbon bearing sands with thicknesses > $\lambda/25$ should have an amplitude anomaly on the FDR around this study area.

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Conclusions

We demonstrate that FDR amplitude anomalies studied in this paper are primarily driven by lower Vp caused by the presence of light oil in these highly porous unconsolidated clastic reservoirs. We concluded this because the fluid effect causes ~15% change in velocity (Vp) that contrasts with only ~5% change in density (Rhob). Vp is more heavily weighted on the FDR in our study area (acquisition and geology dependent) than perhaps other regions where the density leakage is more prominent (maybe at higher frequencies). We further conclude that FDR, in this case, may be used as a fluid indicator only for these shallower reservoirs in this area. Finally, we encourage other interpreters to use FDR amplitudes as a valuable seismic attribute for interpretation that should not be used in isolation, but rather in conjunction with other seismic attributes, types of data and bottom-up models.

Acknowledgments

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