Intrinsic and apparent seismic attenuation in VSP data

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Summary

This paper investigates transmission loss contributions to seismic attenuation in VSP data from the Ross Lake heavy-oil field, Saskatchewan. We compensate for transmission losses when estimating seismic attenuation (Q) by the analytic signal method. Major Q-estimate changes are not observed when compared to results obtained from the analytical signal method without this compensation. 1D scattering is not a major contributor to apparent attenuation. 2D scattering shows offset dependent stratigraphic "attenuation/amplification". Stratigraphic "amplification" is one possible explanation for the peaking of shallow depth Q-estimates from actual VSP data.

Introduction

Attenuation factors are of interest in seismic exploration because they can be useful for amplitude recovery, improving resolution, stabilizing wavelet phase, defining lithology and perhaps providing indications of hydrocarbon saturation. Thus, we seek robust and accurate ways to estimate attenuation or quality factors (Q) and applications for them. One technique we have employed for Q estimation is the analytic signal method (Haase and Stewart, 2005a). However, when applying the analytical signal method to estimate Q in some actual VSP data from the Ross Lake heavy-oil field in Saskatchewan, we found an offset dependence in the results (Figure 1). Furthermore, our Q-factor estimates increase from about 500m towards shallower depths, and this trend is emphasized with increasing offset. Applying moveout compensation to account for the difference between plane waves and spherical waves leads to insignificant changes in Q-estimates (Haase and Stewart, 2005b). We anticipate that there is another mechanism at work. At the 75th Annual SEG Meeting several authors (e.g. Chichinina et al., 2005; Gray, 2005; Maultzsch, 2005) presented their investigations of Q-anisotropy. Could some of this observed offset dependence be explained by Q-anisotropy? It was also noted previously that the assumption of unity transmission coefficients could cause errors in Q-estimates. Before invoking Q-anisotropy, the contributions of reflection and transmission effects (as predicted from modeling and the actual well-logs) to apparent attenuation should be investigated. Q-factors compensated for transmission losses are estimated in this study by computing running transmission coefficient products derived from a well-log acquired at the Ross Lake oil field. High Q-values at shallow depths appear to be even more emphasized now. What, then, could be the cause for these over-estimated Q-values? The Q-factors estimated here are apparent Q, which is a combination of the desired intrinsic Q of the rock layers, the stratigraphic Q caused by reverberations between layer interfaces, and a gain component. When comparing results from a 1D wave equation model to the running transmission coefficient product, a good match is observed. One-dimensional scattering, though present in this case, seems to not be a major contributor to apparent attenuation. Because offset dependence is observed, a 2D model seems more appropriate in this case. We have adapted a 2D elastic wave equation method (Virieux, 1986) to the VSP case. Both P- and S_v - source VSP sections have been computed. P-source VSP sections are presented below.

Transmission loss compensation

Figure 1 shows that, with increasing source offset, Q-factors estimated at shallow depths also increase. Moveout compensation attempted in previous work (Haase and Stewart, 2005b) did lower Q-factors for some intermediate depths but could not account for high Q-values at shallow depths. For these investigations, unity transmission coefficients had been assumed. Are the estimation errors caused by this assumption significant and is transmission loss compensation required? The instantaneous amplitude display in Figure 2 shows an amplitude increase with depth at approximately 700m (before smoothing, green curve). In previous work (Haase and Stewart, 2004) Q-estimation is done with smoothed amplitudes (red curve in Figure 2) because such an amplitude increase with depth leads to negative Q. However, depending on acoustic impedance changes, amplitudes can increase with depth, and Q-estimation must take this effect into account. The blue curve in Figure 2 displays a running product of transmission coefficients versus depth, computed from a well log. At approximately the 800m mark, an upward trend is observed, which constitutes a decrease of transmission loss or, in this case, an amplitude gain. Weighted instantaneous amplitudes are computed from the green curve and the blue curve in Figure 2 by applying transmission loss/gain compensation and smoothing. A shift parameter is introduced here to account for a depth misalignment. Q-factor estimation with these weighted instantaneous amplitudes gives the results shown in Figure 3 together with the best previous estimate (following moveout compensation). There are changes in detail, but the general character of the new Q versus depth curve did not change significantly. However, high Q-values at shallow depth are even more exaggerated now.

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1D wave-equation model

The Q-factors estimated in this study are apparent Q, which is a combination of the desired intrinsic Q of the rock layers and stratigraphic Q caused by reverberations between layer interfaces. The running transmission coefficient product employed in the previous section only accounts for amplitude changes across interfaces on downward transmission. A first step beyond this simple transmission model is to consider all transmission and reflection coefficients of the stratigraphic column which includes reverberations (O'Doherty and Anstey, 1971). It is reported in the literature (see e.g., Richards and Menke, 1983) that stratigraphic filtering means low-pass filtering. Therefore, rejected higher frequencies could reverberate at shallow depths and mimic larger apparent Q-factors. Figure 4 gives the result of numerical wave equation modelling for a flat-layer earth with vertical incidence plane waves. The same well log as before is employed to compute these plane wave amplitudes. Also shown is the cumulative transmission coefficient. When comparing the two curves in Figure 4, a reasonably good match is observed. 1D scattering, though present in this case, is not a major contributor to apparent attenuation.

Elastic wave-equation model with offset sources

Because offset dependence is observed in Q-estimates from actual VSP-data, a 2D model seems more appropriate than a 1D approach in this situation. When expanding to a 2D elastic wave equation model a completely different picture emerges, even for a 1D earth. A great richness of wave types and complications are generated. We have adapted Virieux's (1986) 2D elastic wave equation method to the VSP case. Horizontal and vertical particle velocities are computed on a staggered grid from P-velocities, S-velocities and densities for a given source type and a given source wavelet. The vertical particle velocity of a synthetic VSP generated for a source offset of 54m (P-wave source) is shown in Figure 5. Note that surface effects are ignored and that this model includes an offset dimension (2D wave propagation) but is based on well log data (flat-layer earth). The first arrival slope steepens with faster velocities at depth. Reflections and multiples are clearly visible. A 399m offset equivalent is displayed in Figure 6. First arrival times are delayed when compared to Figure 5 because of increased travel distances. There is also clear evidence for energy converted on reflection as well as transmission. Instantaneous first arrival amplitudes are displayed in Figure 7. At a 54m source offset, trace maxima of instantaneous amplitudes decay quite smoothly with depth. At a 399m source offset, however, there are significant instantaneous amplitude increases at certain depths. Furthermore, this effect is enhanced by a decrease in the V_p/V_s-ratio (which means by an increase in shear velocity V_s). The curves in Figure 7 appear to indicate the existence of an offset-controlled energy partitioning effect which could explain (at least in part) the peaking of shallow depth Q-estimates from actual VSP-data. The stratigraphic Q-factor estimated from the black curve in Figure 7 (following smoothing) is shown in Figure 1. Note that intrinsic attenuation is zero for this elastic model.

Conclusions

Q-estimates obtained by the analytical signal method do depend on VSP-source offset to some degree. Transmission coefficient compensation does not substantially change Q-estimates. High Q-values estimated at shallow depths appear to be even more emphasized with transmission compensation. A 2D elastic wave-equation method is adapted to the VSP case in this study to investigate the offset dependence of Q-estimates. At small source offsets, trace maxima of instantaneous amplitudes decay quite smoothly with depth. At large offsets, however, significant depth regions of instantaneous amplitude increases are observed. This offset dependent energy partitioning (stratigraphic "amplification" ?) is one possible explanation for the peaking of shallow depth Q-estimates from actual VSP-data.

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Acknowledgments

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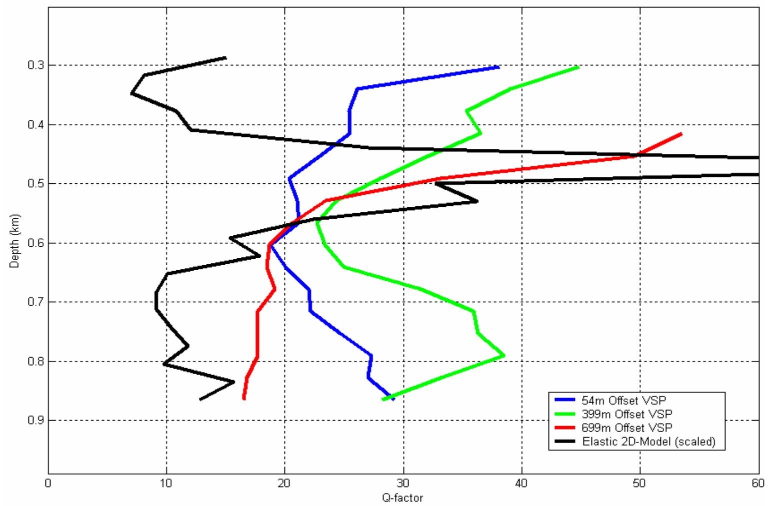

Figure 1: Seismic attenuation as determined from VSP data in the Ross Lake oilfield, Saskatchewan.

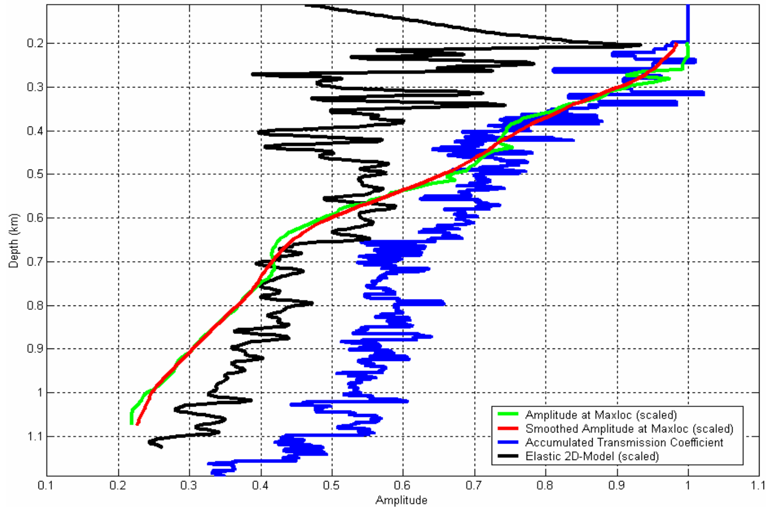

Figure 2: Instantaneous amplitude as determined from first breaking P-waves in 399 m offset VSP data.

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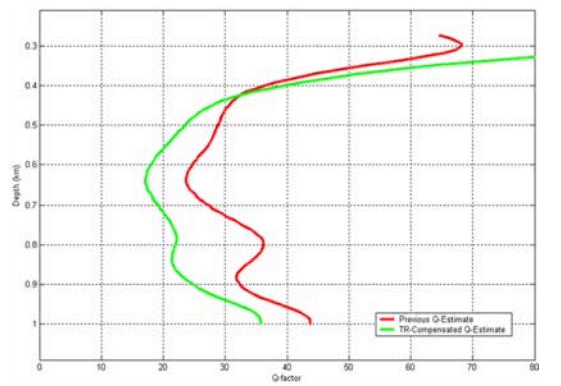

Figure 3: Q versus depth. Note high Q-values at shallow depths.

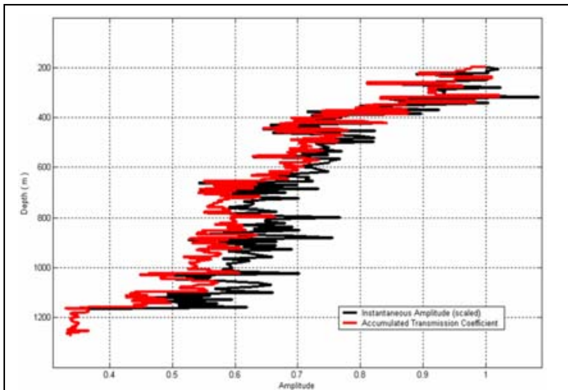

Figure 4: Maximum amplitudes picked from traces generated in a 1D model.

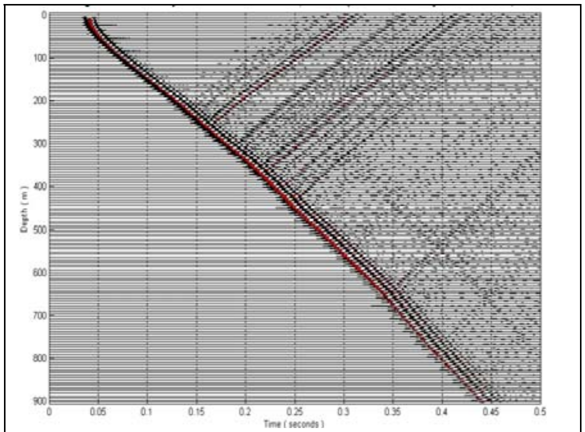

Figure 5: 2D velocity-stress model VSP (vertical particle velocity, 54 m offset).

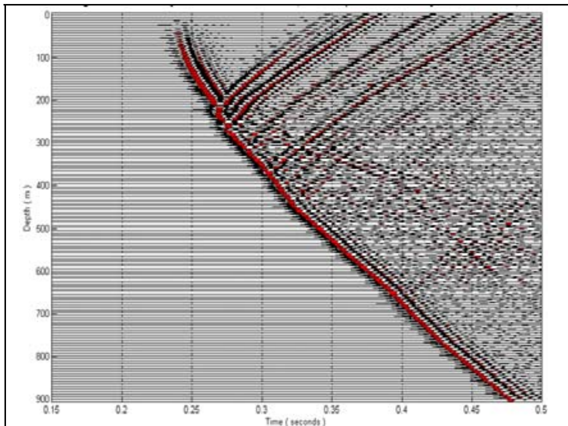

Figure 6: 2D velocity-stress model VSP (vertical particle velocity, 399 m offset).

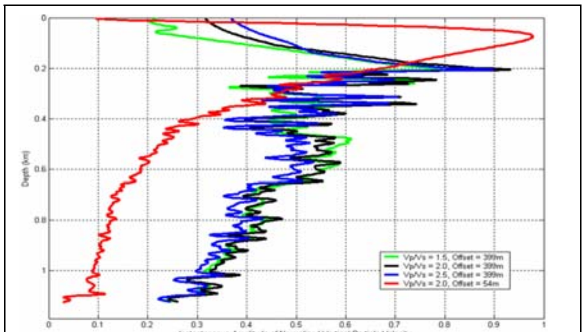

Figure 7: 2D velocity-stress model VSP (vertical particle velocity).