The well tie problem: from seismic source to seismic stratigraphy

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Summary

We present an approach for the consistent tying of wells to marine seismic data. The process begins in data acquisition, with the source signature, and ends in interpretation, with the reliable identification of stratigraphy. The key step in acquisition is the measurement of the source signature. The key step in processing is the deconvolution, using the wavelet *calculated* from the acquisition step. In constructing the synthetic seismogram at the well location, we employ the wavelet shaped during processing, and ensure that check-shot times are honoured at each depth level during the time-to-depth conversion of the logs. The result is a good well tie for timing and polarity, except where attenuation is a problem, in which case we have to include a causal attenuation step to compensate.

Introduction

Conventionally the well-tie problem is this. The seismic data are processed to a "known" phase, typically zero-phase. This means the phase of the seismic wavelet that was assumed to be in the data has been removed. At the well position the seismic data should then tie, that is, strongly correlate, with the synthetic seismogram calculated by convolving the primary reflection series with an appropriate zero-phase wavelet. Normally there is a **mis-tie,** and the synthetic seismogram is then adjusted to make the tie (e.g. Nyman et al., 1987; Richard and Brac, 1988). This approach essentially admits that the so-called zero-phase seismic data are not zero-phase, as pointed out by Nyman et al. (1987). An almost perfect tie can be made at any well with this approach. However, if such a "tie" is made at one well, and a marker horizon is followed from this well to the next well, there is normally a mis-tie of, typically, 30 ms at the next well. A new wavelet must be found to "tie" the seismic data at the new well. It follows that "the wavelet" is unknown unless there is a well and the interpretation of the seismic data for stratigraphy between the wells or beyond well control can be unreliable. Poggiagliolmi and Alldred (1994) have developed a method that forces the seismic data to tie with the same zero-phase wavelet at every given well, but requires processing of both the synthetic seismogram and the seismic data. There are problems with these approaches.

Proposed Methodology

For consistent tying of wells to seismic data, and for reliable stratigraphic interpretation to be successful, it is essential that the data be acquired and be processed with this as a major goal. We have developed an approach to this process for marine seismic data which begins with data acquisition and follows a well-defined processing scheme to facilitate the desired interpretation. Our methodology allows accurate identification of stratigraphy away from well control by ensuring reliable ties between surface seismic data and well data where wells exist.

Acquisition

The key step in acquisition is the measurement of the source signature. The *cost* of acquiring the necessary additional data is of the order of 1% of total data acquisition costs (Hones, 1996). The theory for calculating the source wavefield of an airgun array from nearfield pressure measurements is well established (Ziolkowksi et al., 1982 and Parkes et al., 1984). Ziolkowski and Johnston (1997) presented an approach using this theory which permits a *quality control* estimate on the calculated wavefield. This involves mounting 1 or 2 extra hydrophones on the airgun array which are not required in the calculation of the wavefield, to allow a check on the accuracy of the calculated source signature. This allows any shot-to-shot variations to be monitored during acquisition, and their effect on the data to be subsequently removed during processing.

Processing the surface seismic data

A key step in processing is the deconvolution. The wavelet is determined using the source measurements obtained in acquisition, including source and receiver ghosts, and compressed to the shortest possible (zero-phase) wavelet within the bandwidth available. Any shot-to-shot variations in the source are incorporated into this (wavelet shaping) step, and subsequent processing is constrained to introduce no uncontrolled distortions to the wavelet. Trace-to-trace variations which remain in the final seismic section then result from variations in the earth. This is described in more detail in Ziolkowski et al. (1997).

Making the well tie

The wavelet calculated during processing is convolved with the normal-incidence reflection coefficients to construct a synthetic seismogram for comparison with the seismic data. We apply no arbitrary time shifts or phase-rotations to the synthetic seismogram, but ensure instead that check-shot times are honoured at each depth level during the time-to-depth conversion of the well logs. Both the *polarity* and arrival *time* of events in the real data are now the same as synthetic data at the well location.

In areas where attenuation (of high frequencies) is a problem we have to include a causal attenuation step. Because all waves travelling from source to receivers travel different paths, each is attenuated by a different amount. This effect is not convolutional and cannot, therefore, be removed by deconvolution. We assume that the arrivals within a target window have travelled more-or-less the same distance. Assuming a constant Q earth (Carpenter, 1966), each frequency ω in the surface seismic data is attenuated by an exponential factor $exp(-\alpha\omega)$ (Trorey, 1962). We simply have to find the single value α that does the best job of balancing the amplitude spectrum of the synthetic seismogram after filtering, with the amplitude spectrum of the data in the target window. The value of α is found in this way by trial and error. We constrain the filter to be minimum phase and apply it in the time domain.

Interpretation for stratigraphy away from the well

The key step in interpretation is the well tie. We know the phase of the wavelet from acquisition throughout processing to interpretation and therefore there is no ambiguity over the polarity of the final stacked section. Stratigraphic interpretation of seismic data is essentially the correlation of seismic amplitudes with changes in acoustic impedance in the subsurface (Figure 1). We argue that this correlation requires the absolute arrival times of the reflections to be known at a well. With our methodology of constructing synthetic seismograms we expect the polarity and timing to be correct between seismic and synthetic data. Key horizons can easily be mapped from the well data onto the seismic section. Because we have eliminated shot-to-shot variations in the wavelet, all lateral variations are caused only by the earth and may be reliably interpreted for stratigraphy.

Results

We will illustrate this methodology with data from a speculative well-tie survey shot in October 1992 by the Seismograph Survey Limited (SSL) *Seisventurer* in the Inner Moray Firth, at the Western end of one of the main rift arms in the North Sea. In this case, attenuation was not too severe at the target and we tied 25 wells to the seismic data (Ziolkowski et al., 1997). Figure 2 shows the layout of this survey including the well locations. Figures 3 and 4 show the tie at two of these wells, which are linked by seismic line 1D1R. Our processing sequence also allowed us to image an unconformity on seismic data for the first time.

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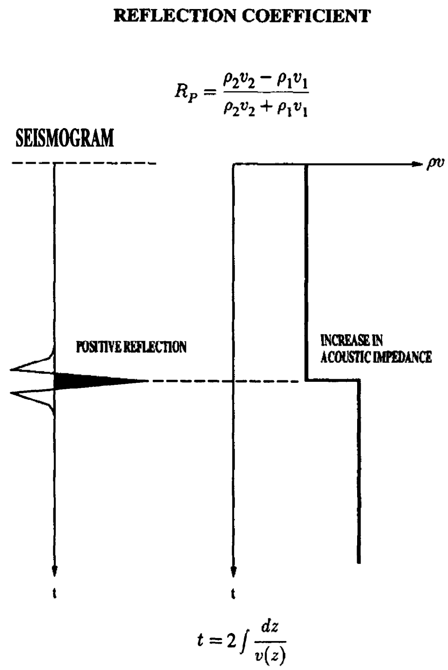

Figure 1: The essence of the well tie.

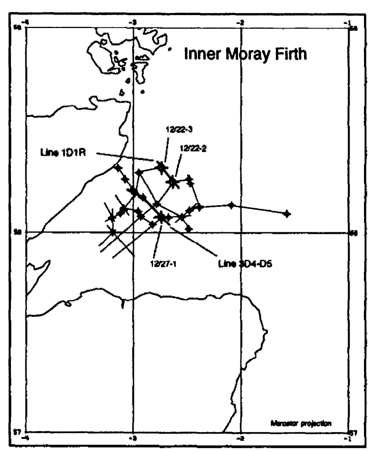

Figure 2: Map of the Inner Moray Firth showing the well-tie survey.