How accurate can a well tie be?

ROY E. WHITE, Birkbeck College, University of London, U.K.
TIANYUE HU, Chinese Academy of Sciences, China

There appears to be a body of opinion among geophysicists that well-log synthetic seismograms and seismic data cannot be expected to match one another very closely. For example, Simmons and Backus (GEOPHYSICS, 1996), in a paper on impedance estimation, state "...as is most often true, well-log-based synthetic seismograms do not agree well with observed seismic data." Norman Neidell, in conjecturing on the conditions that generate coherent multiple reflections (*TLE*, November 1993) comments that explorationists often encounter synthetic seismogram fits that are less than satisfactory. That may be true, but it is not inevitable. We wish to counter these pessimistic views by showing an example of how good a well tie can be.

It would be a misfortune for seismic exploration, and especially for reservoir geophysics, if poor matches between synthetic seismograms and seismic data became an accepted fact of life. Although there is more to validating an interpretation than producing a close well tie, a poor tie invariably diminishes one's confidence in an interpretation. And the ability to model seismic data accurately in the vicinity of a well must always be the primary concern in establishing the scientific credentials of transformations to impedance.

By any measure, the well tie we present is a very accurate one, but it is exceptional only in the duration (900 ms) over which it closely matches the seismic data. It also gives a reasonably good match over the remaining 400 ms of logged section. With the advent of 3-D seismic data acquisition and continuing improvements in acquisition and processing, examples of comparable accuracy can be found in other areas of the North Sea, although they would more typically extend over 500 ms. Some of these were shown in a poster ("The accuracy of well ties: practical procedures and examples") at SEG's 1997 Annual Meeting in Dallas.

Phase errors from the best ties were of the order of 7°. When one of us (REW) began measuring well tie accuracy in the late 1970s for BP, phase errors were rarely less than 15°. At the very least, well ties with data from most marine surveys should be routinely satisfactory. And they can often be very good indeed.

The seismic data. The well tie comes from a dip line shot through well 44/29-1A in the southern North Sea. Figure 1 shows part of the migrated seismic section, in the center of which are spliced three identical synthetic seismogram traces. The exploration target was a sequence of sands, shales, and coals marked by the reflections beginning at 2.4 s. The sands are gas bearing, although not in commercial quantities at this location. Above them is the Lower Permian Rotliegendes shale, which underlies 220 ft of Zechstein evaporites, marked by the flattish reflections just before 2.3 s. The quiet zone above this corresponds to a firmly compacted Lower Triassic shale, the Bunter shale, on top of which at 2.05-2.10 s is the Bunter sandstone, a fine- to medium-grained sandstone interbedded with thin layers of shale. This sandstone is overlain unconformably by 45 ft of shale followed by a 210-ft layer of salt (2.02 s). The well is on the wing of a syncline formed between two salt features, one of which appears on the right of Figure 1. Above the salt is a sequence of Lower-Middle Triassic shales. The Speeton clay formation lies unconformably on these shales, above which is the Upper Cretaceous chalk. The dipping reflection at 1.87 s marks the base of the chalk, which is more than 3000 ft thick. The reflections within the chalk above 1.73 s correspond to variations in porosity (see Figure 4).

The seismic data were acquired from a water-gun array shooting into a 132-group cable at offsets ranging from 199 to 2236 m. A source signature was supplied for this array. An initial study starting from a stack tape produced in 1983 showed a good match with the well-log synthetic seismogram. Because we wanted to analyze the data before stack, the data were reprocessed from the field tapes.

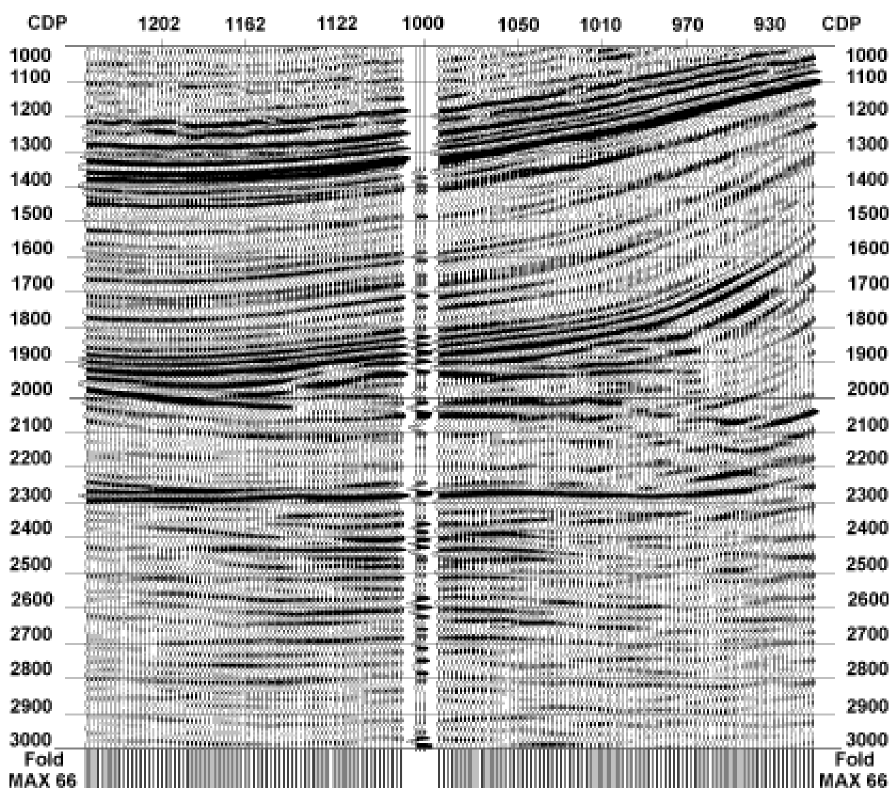

Figure 1. Part of the migrated seismic section through well 44/29-1A. Three synthetic seismogram traces are spliced into the data at the location of best match over the interval 1.4-2.0 s.

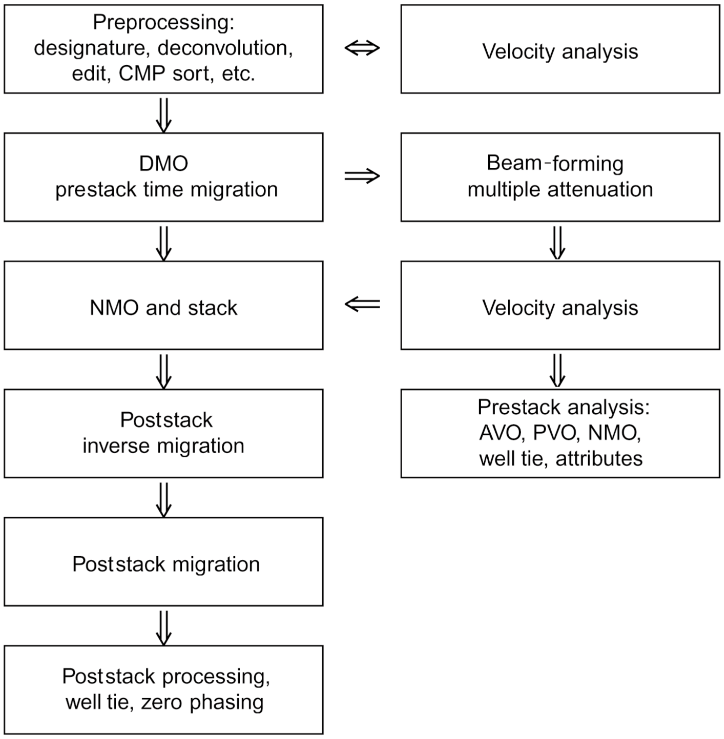

Figure 2. Outline of processing sequence.

Figure 2 outlines the processing sequence.

The main effort went into velocity control and the production of a good quality prestack migration. The prestack migration was a Stolt time migration that used an average velocity field centered on the well. This was intended to produce a volume of data that was sufficiently well focused on CRPs for subsequent refinement of the velocity field.

Following signature deconvolution, water-bottom multiples were attenuated by 80-ms gap predictive deconvolution. After prestack migration a beam-forming technique, applied to enhance the primaries on the CMP gathers, was found to be beneficial to the prestack well tie. Figure 3 shows a prestack CMP gather close to the well on the line before and after DMO plus prestack migration, and after beam-forming multiple attenuation. The benefit from the beam former was no longer evident in the stacked data, however. The final section of Figure 1 was pro-

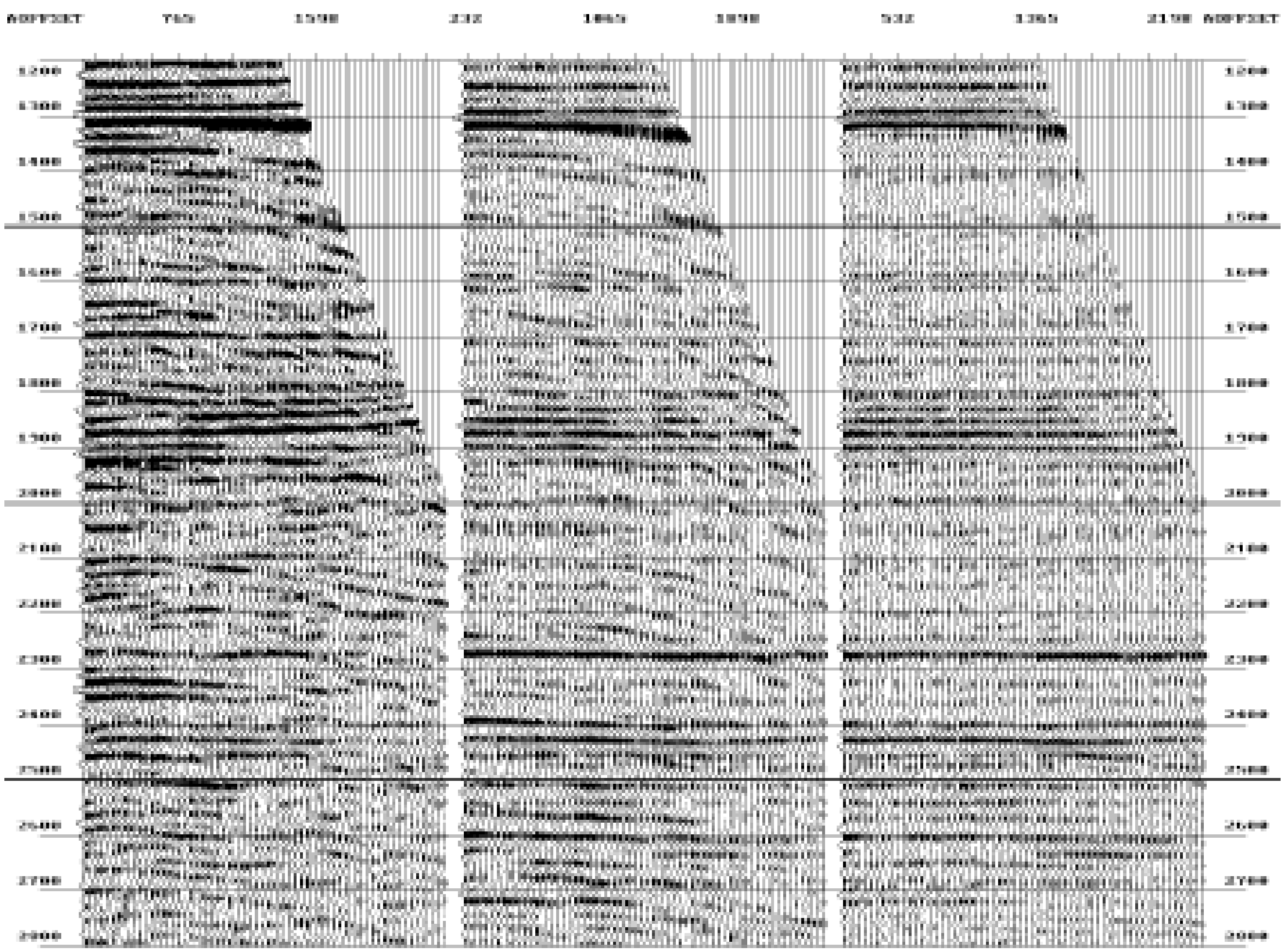

Figure 3. A prestack CMP gather close to the well on the line showing the data (left) before and (center) after DMO and prestack migration and (right) after beam-forming multiple attenuation.

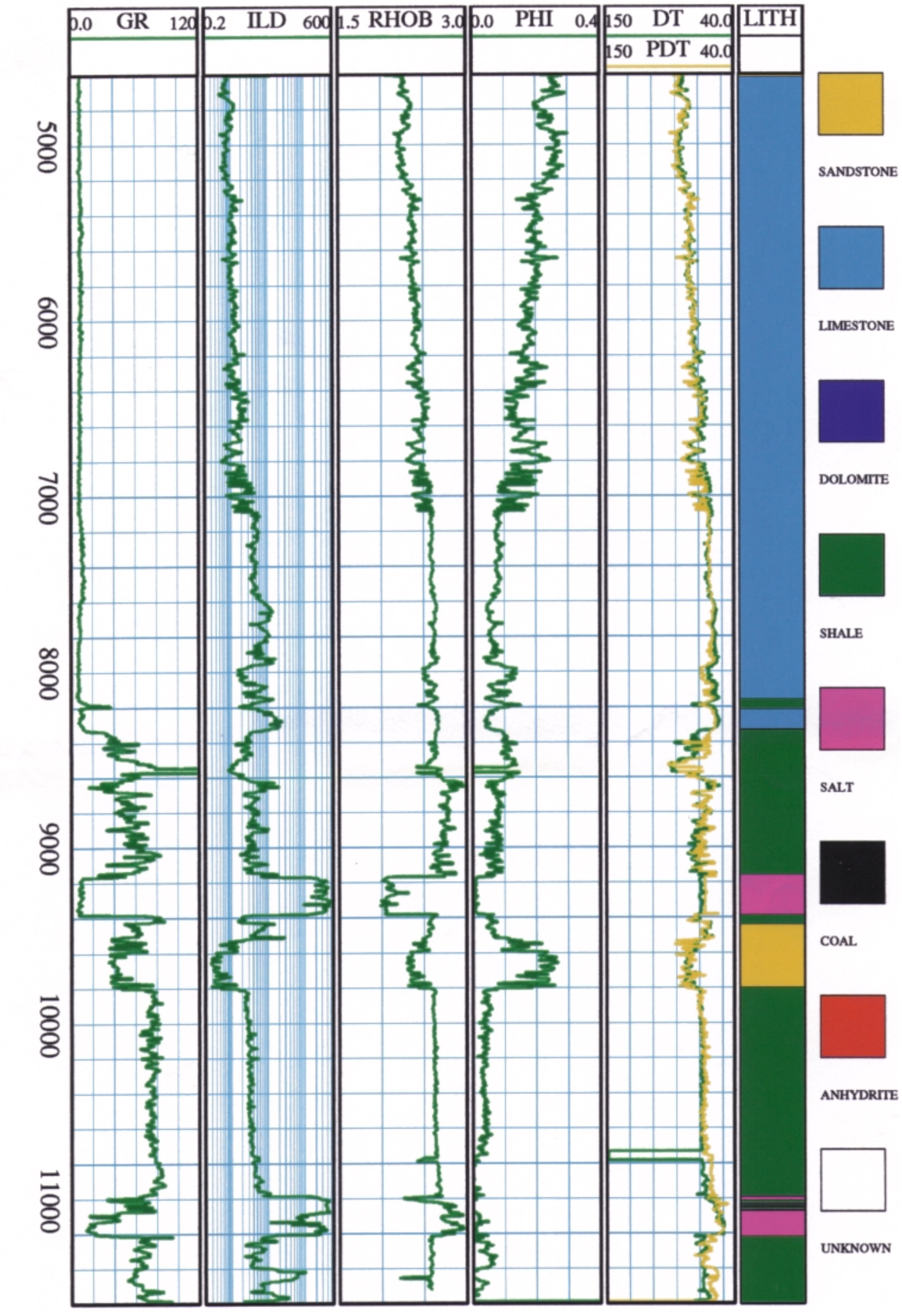

Figure 4. The logs used in constructing synthetic seismogram at well 44/29-1A. Panel 1: gamma-ray; panel 2: deep (ILD) induction log; panel 3: density; panel 4: porosity estimates; panel 5: *P*-wave sonic log and the *P*-wave log predicted using the Xu-White model. Depths are in feet.

duced by stacking, demigrating with the velocity function applied during prestack migration, and then remigrating with a laterally varying velocity function using a finite-difference time migration.

The well logs. Figure 4 shows the well logs used in constructing synthetic seismograms. The display runs from nearly the top of the chalk down to the Lower Permian Rotliegendes shale (11 200 ft); the other formations described earlier can be readily identified on it. Some spikes were identified and edited on the sonic and density logs. To highlight possible discrepancies in the logs, we employ a petrophysical model (see "A new velocity model for clay-sand mixtures" by Xu and White, *Geophysical Prospecting*, 1995) to predict the *P*-wave sonic from lithology and porosity estimates and then compare the measured and predicted logs (DT and PDT, panel 4, Figure 4).

Apart from two obvious errors from the tool sticking, the logs were of good quality. The model was very useful in automating the identification of coals beneath 11 600 ft, where no density log was recorded. In constructing synthetic seismograms, it is most important that coals are assigned the correct density.

The sonic and density logs were calibrated using first arrival times from a VSP and blocked using the procedure described in Walden and Hosken (*Geophysical Prospecting*, 1985). A suite of broadband plane wave normal incidence synthetic seismograms was computed from the blocked logs, including the primary reflection coefficients, the attenuated primaries (p), the primaries plus internal multiples (p+im), and the surface multiples.

Matching procedure. If the synthetic seismogram is to model the waveforms observed in the seismic data, some form of matching is required in order to estimate the effect of the overburden on the seismic wavelet. To achieve reasonable accuracy, it is essential to match a seismic data segment having a bandwidth-duration product of 25 or more and containing a number of reasonably coherent reflections. In the North Sea, this typically means using 500 ms of data, which must of course be accompanied by a corresponding length of good quality logs. There is no real likelihood of a good fit being forced on this much data, and in any case there are diagnostics to flag this likelihood. What is more important, and cannot be emphasized too strongly, is that the accuracy of the tie is measured and monitored throughout the testing of the tie (see the cited poster paper in SEG's 1997 *Expanded Abstracts*). Apart from quality control of the testing, quantifying the accuracy of well ties allows their utility to be assessed relative to, say, the accuracy required for inversion to impedance, and, with the accumulation of results, the significance of improvements in technique can be put into perspective.

What if one simply does not have the required 500 ms of data and logs? If there are several wells within the survey, it may be possible to work with shorter segments, although well-to-well validation becomes more questionable. With just one well, it may be possible to start from a model wavelet and estimate a very simple trimming filter to represent the overburden. In either situation, the case for monitoring accuracy becomes even stronger. For example, there is not much point in comparing wavelets from well ties, or any other approach, without some measure of their accuracy. Similarly rou-

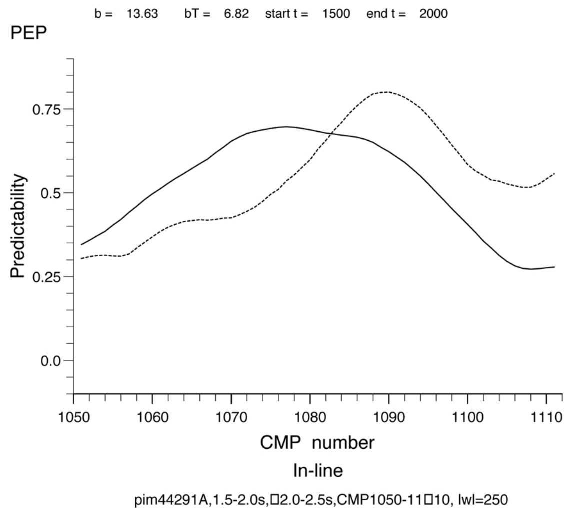

Figure 5. Results from scanning the migrated seismic section through well 44/29-1A for the location of best fit with the broadband well-log synthetic seismogram over two time intervals: 1.5-2.0 s (dashed line) and 2.0-2.5 s (solid line). The vertical axis is P the proportion of trace energy predicted by matching; the horizontal axis is CMP number.

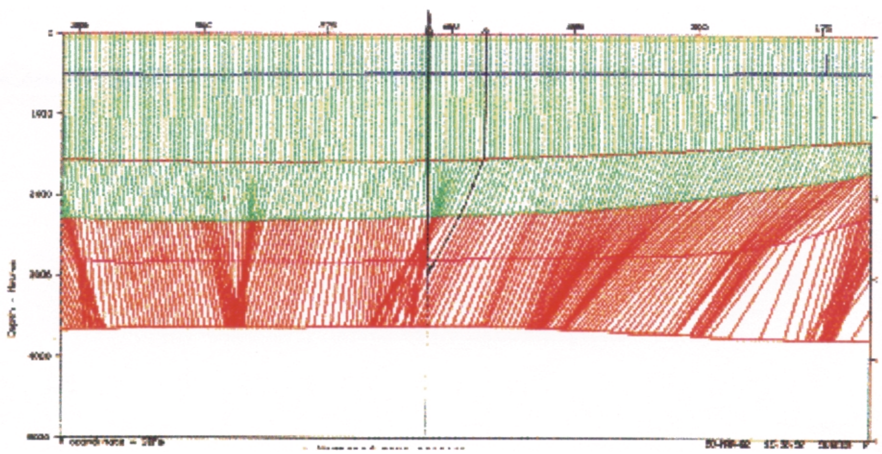

Figure 6. Image ray tracing of a depth model constructed from the migrated seismic section through well 44/29-1A showing the reflection points corresponding to CMP locations at the surface. The separation of the starting points of the rays at the surface is 16.67 m.

tine monitoring of accuracy would immediately reveal the unsatisfactory nature of the many well ties one sees based on data segments that are too short (e.g., 200 ms) to yield reliable results.

The first step in making the well tie is to run pilot analyses, the purpose of which is to establish the parameters needed for estimating the wavelet as accurately as possible. A key step is to scan time gates and traces around the well for the best match location. Figure 5 shows how the goodness-of-fit of the tie at 44/29-1A varies with CMP location in two disjoint time gates. The well is at CMP 1110. In the 1.4-2.0 s gate, the best-fit location is 380 m away at CMP 1087; in a 2.0-2.5 s gate, it moves to CMP 1076, and in a 2.3-2.8 s gate to CMP 1071. Much of the bulk shift is likely to be positioning error. The systematic drift is caused by raypath effects in time-migrated data: The best match location is tracking the starting point at the surface of image rays that end on the well bore. Image ray tracing from a simple depth model (Figure 6) shows how the drift originates. A depth of 2000 m at the well corresponds to a two-way reflection time of 1.66 s. The surface locations of image rays emerging from the well move systematically in an updip direction. Although the drift from this crude model does not agree exactly with that observed, they are similar. It is generally observed that the best match location moves updip from the well when tying time-migrated sections in which velocity increases with depth.

Once the best-fit location has been found, other analysis parameters can be tested. In the interests of brevity we skip the details of this. In addition one can test, for example, whether internal multiples should be included with primaries in the synthetic seismogram, and whether surface multiples are contributing significantly to the data. These are often not critical decisions for modern data from the North Sea.

Well tie. The most accurate tie at 44/29-1A was obtained from matching the 1.4-2.3 s segment at CMP 1087 with the (p+im) synthetic seismogram. Within this time gate, the synthetic seismogram predicts 85% of the trace energy; that is, the mean square of the residuals is 15% of the mean square value of the trace segment. This translates into an estimated normalized mean square energy in the wavelet of 0.015, or a standard error in phase within the seismic bandwidth of about 6°. The tie is shown in detail in Figure 7.

The best match location varies with two-way time. Matching over shorter time windows, such as 1.4-2.0 s and 1.5-2.1 s, produces virtually the same wavelet and predicts the same proportion of trace energy in the 1.4-2.3 s gate. Although the predictabilities rise to 87% and 88% respectively in the 600-ms intervals, the estimated wavelet accuracies are slightly less.

Reflections from 2.4 s to near the end of the log at 2.8 s originate within the sand-shale-coal sequences. The ties of Figures 1 and 7a do not match this sequence well. The best tie location is really 16 CMPs updip, but the main change appears to be that the wavelet has become more narrow band and phase shifted by approximately 40°.

Figure 7b shows the tie over the interval 2.3-2.8 s at CMP 1071, the best match location. This is still a respectable tie. The normalized mean square energy in the wavelet is 0.08; the standard error in phase is 12°. The (p+im) synthetic was significantly better than a simple primaries-only synthetic in matching the 2.3-2.8 s data. Within the 1.4-2.3 s interval, it made little difference which synthetic was used.

The wavelet of Figure 7b has lost both high- and low-frequency energy relative to the one in Figure 7a. The attenuation is not consistent with a constant-Q loss. It is doubtful whether our log blocking was good enough to model a finely layered sand-shale-coal sequence and the wavelet could be compensating for that. However, frequency attenuation is also detectable within the 1.4-2.3 s interval, and this too deviates from a constant-Q model by more than the errors of estimation. Without going into details, it is clear that testing whether the wavelet varies with time has to take account of image ray effects (and the log calibration). While

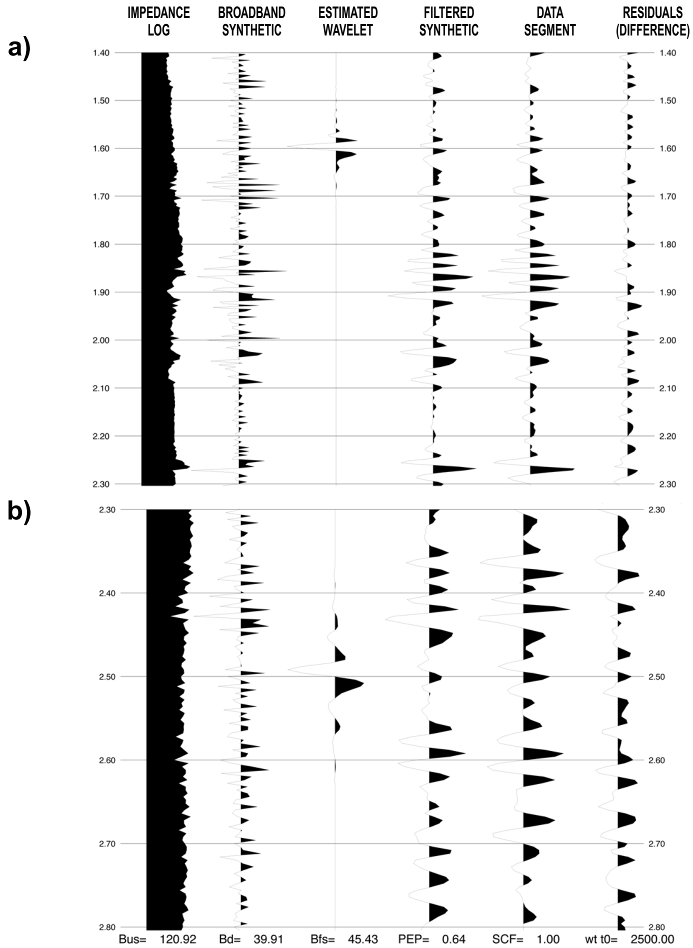

Figure 7. The match between the trace at (a) CMP 1087 from the remigrated section and the primaries-plus-internal-multiples synthetic seismogram at the well over the time interval 1.4-2.3 s, and at (b) CMP 1071 over the time interval 2.3-2.8 s.

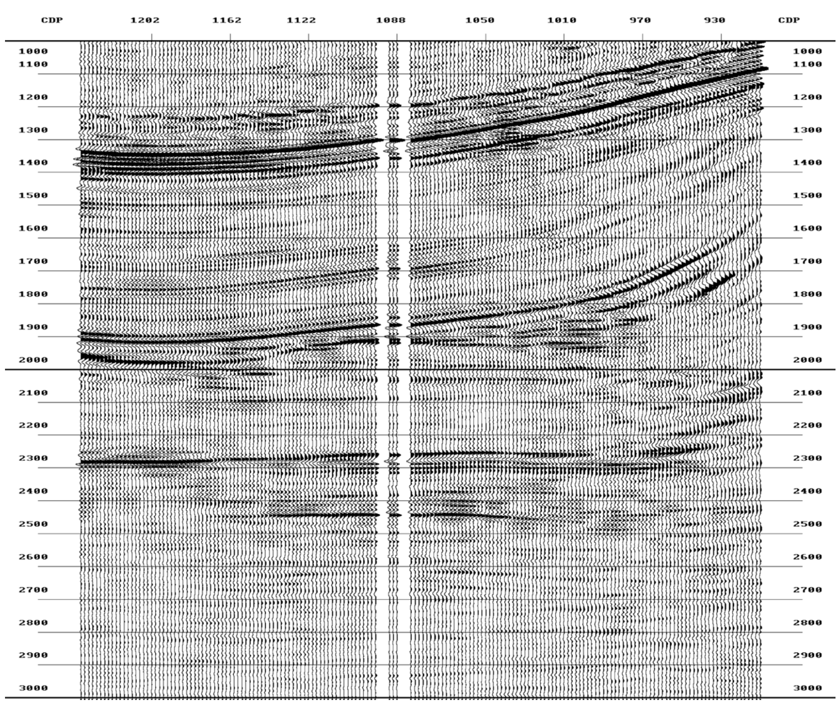

Figure 8. Part of the whitened zero-phase seismic section. Three synthetic seismogram traces are spliced into the data at the location of the best match over the interval 1.4-2.0 s.

parsimonious modeling of the time-varying spectral decay improves the tie, the gain is not great, and it raises other issues that we leave for discussion elsewhere.

The section of Figure 1 was zero-phased and whitened using the seismic wavelet from Figure 7a. Figure 8 shows the resulting zero-phase section. Improved resolution of this kind had not been seen before from these data.

Wavelets from the prestack data. After beam forming was applied to attenuate multiples, various weighted and unweighted substacks of the moveout corrected CMP gathers were matched with the normal incidence synthetic seismogram. Figure 9 is a contour plot of goodness-of-fit over a 1.5-2.0 s time gate from six simple disjoint 11-trace substacks. It appears that the CMP gather at the well is focused on the well over the first four offset bands. Muting (Figure 3) affects the fifth and sixth offset bands.

The prestack wavelets are very similar to the wavelet in Figure 7a, except that they become increasingly stretched with increasing offset.

Conclusions. In general, data from the North Sea yield reasonable-to-good well ties. Why is this and why, in other places and other situations, are well ties often poor? Because many factors contribute to the making of a well tie, there is no simple answer to these questions, but Neidell was surely right in emphasizing that geology plays an important role. In the North Sea, well ties in the Tertiary are usually poorer than those from the Cretaceous and below. It is unlikely to be a coincidence that the Tertiary rocks are softer and more prone to generate AVO anomalies and nonhyperbolic moveouts. These last two factors were raised by Denham, in his response to Neidell's conjecture, together with the requirements of strong multiple attenuation and precise migration.

We also regard multiple attenuation and migration, preferably starting prestack, as key concerns of the processing. In the 44/29-1A example presented here, most of the reprocessing effort went into the attenuation of multiples and to building an accurate velocity field for migration. The result was that a good well tie from production processing, which predicted 65% of the trace energy, became an exceptionally good one that predicted more than 80%. Migration is beneficial for several reasons beyond its improved position-

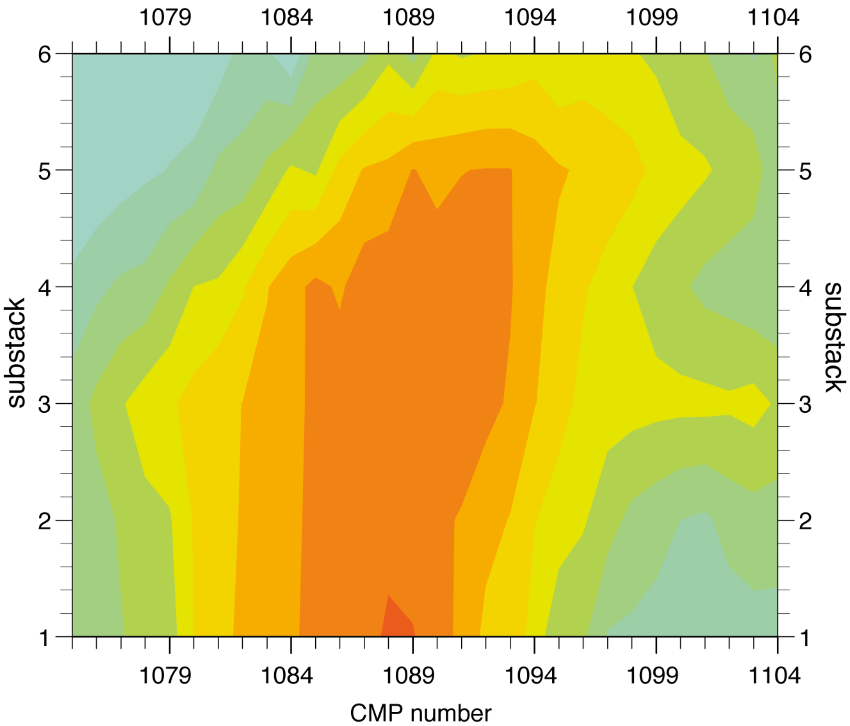

Figure 9. Contour plot from the scan of substacks of the prestack migrated CMP gathers for best fit with the normal incidence synthetic seismogram over a 1.5-2.0 s time gate. The quantity contoured is the proportion of trace energy predicted by matching the synthetic seismogram.

ing of events. It contracts the Fresnel zone, reduces timing and raypath effects relative to the stack and, when applied prestack, approximates CRP data and aids velocity control. In principle, depth migration should bring a further benefit. The practical question is whether it can be made accurate enough to yield this benefit without seriously distorting the seismic waveforms.

The basic ingredients of a good well tie are high quality seismic and log data, and near-vertical wells. Geologic factors that can stand in the way of a good tie are structural complexity, rapid lateral variations in velocity or reflectivity, seriously unconformable dips within the match gate, and finely layered sequences having severe impedance fluctuations.

To these physical factors we would emphasize the importance of an analytical approach to well ties with quantitative measures of accuracy (and not just goodness-of-fit). By providing objective quality controls, an analytical approach provides a consistent basis for testing options and for improving well ties as a matter of routine. Whenever possible, analysis for signal and noise spectra and forward modeling should be a complementary part of the exercise. Although this effort may bring only incremental improvements, experience invariably shows that following up details in the preparation of the seismic and log data bears fruit. An analytical approach brings rigor to any detailed investigation of the data. Details of implementation also need attention: optimal alignment of the synthetic and data, minimizing effects from the truncation of data segments, allowing for noise in the data, and errors in the synthetics. Sonic log calibration and timing are another area obviously deserving close attention. Of well ties, it is definitely true that "the devil is in the details."

Suggestion for further reading. The theory for estimating the accuracy of well ties was described by Walden and White in "On errors of fit and accuracy in matching synthetic seismograms and seismic traces" (*Geophysical Prospecting*, 1984). E

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Corresponding author: R. E. White, 44-171-380-7332, white@geophysics.bbk.ac.uk