Crosswell seismic waveguide phenomenology of reservoir sands & shales at offsets >600 m, Liaohe Oil Field, NE China

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SUMMARY
Crosswell seismic data recorded at 620–650 m offsets in an oil-bearing sand/shale reservoir formation at the Liaohe Oil Field, northeast China, provide robust evidence for waveguide action by low-velocity reservoir layers. Crosswell-section velocity models derived from survey-well sonic logs and further constrained by observed waveguide seismic wavegroup amplitudes and phases yield plausible evidence for interwell reservoir–sand continuity and discontinuity. A pair of back-to-back Liaohe crosswell vector-seismic surveys were conducted using a source well between two sensor wells at 650 and 620 m offsets along a 200-m-thick reservoir formation dipping 7° down-to-east between depths of 2.5 and 3 km. A downhole orbital vibrator generated seismic correlation wavelets with frequency range 50–350 Hz and signal/noise ratio up to 5:1 over local downhole ambient noise. The sensor wells were instrumented with a mobile 12- to 16-level string of clamped vector-motion sensor modules at 5 m intervals. Using 5 m source depth increments, crosswell Surveys 1 and 2 cover source/sensor well intervals above and through the reservoir of, respectively, 600 m/600 m (13 000 vector traces in 9 common sensor fans) and 300 m/560 m (7000 vector traces in 7 common sensor fans). Survey 1 common sensor gathers show clear, consistent high-amplitude 20 ms waveletgroup lags behind the first-arrival traveltime envelope. Such arrivals are diagnostic of seismic low-velocity waveguides connecting the source and sensor wells. Observed Survey 1 retarded wavegroup depths tally with source and sensor depths in low-velocity layers identified in sonic well logs. Finite-difference acoustic model wavefields computed for waveguide acoustic layers constrained by well-log sonic velocity data match the observed waveguide traveltime and amplitude systematics. Model waveforms duplicate the observed m-scale and ms-scale sensitivity of waveguide spatio-temporal energy localization. Survey 2 crosswell data, in contrast, provide no comparable evidence for waveguide action despite a sensor-well sonic well log similar to that of Survey 1. Instead, acoustic wavefield modelling of Survey 2 data clearly favours an interpreted waveguide model with 10° downdip interrupted by a 75–100 m throw down-fault near the sensor well. The absence of clear waveguide arrivals is adequately explained by dispersal of waveguide energy at the fault discontinuity. Auxiliary well sonic velocity and lithologic logs confirm the model-implied 75–100 m of down-throw faulting near the sensor well.

Key words: borehole geophysics, guided waves, reservoirs, waveform analysis.

1 INTRODUCTION
Oil production problems in the Liaohe field in northeast China mirror oil production problems world wide: surface seismic profiling and generalized reservoir modelling are often (usually?) insufficient to find many (most?) reservoir-scale flow-discontinuity structures. Without reliable spatial locations for reservoir discontinuities, production well siting and operation decisions are generally reduced to guess work at the price of increased production inefficiency.

The Liaohe reservoir, located in Fig. 1, holds heavy oil in a 150- to 200-m-thick sequence of sand bodies interlayered with shale units along a 7° dipping trend between depths of 2.5 and 3.2 km. The sand/shale reservoir formation lies beneath relatively low velocity, lossy (seismic Q ≈ 40–50) lacustrine and deltaic sediments. Sonic well logs illustrated in Fig. 2 attest to 30–40 per cent velocity contrasts across sand/shale interfaces.

The Liaohe sand/shale pair sequence is repeated four to five times at 30–40 m intervals across the reservoir. Despite the large sustained
sand/shale acoustic contrasts, however, surface seismics throughout the production locale fails to image both the reservoir sequence, and more particularly, major reservoir structural heterogeneities (e.g. through-reservoir faulting, severe folding and/or sand-layer pinchouts) that can cripple production plans. With no reliable information on reservoir structural heterogeneities, Liaohe oil field production engineers cannot usefully plan around reservoir flow segmentation, and well siting and in-fill drilling remain high-risk operations with much revenue lost to ill-placed and under-performing production wells.

In response to the surface seismic-imaging deficiency at the Liaohe oil field, Geospace Engineering Resources International (GERI) was contracted to conduct a series of exploratory crosswell surveys in existing production wells at offsets between 600 and 850 m. Higher-frequency and lower-power (300 versus 30 Hz, 500 W versus 500 KW) seismic-wave generation made possible by downhole reservoir-proximate sourcing and sensing (Leary et al. 2003; Walter et al. 2003; Leary & Walter 2005a,b) offer an option to surface seismic imaging if far-offset crosswell seismic signals can be detected and accurately interpreted in terms of reservoir-scale heterogeneity structures lying below the resolution of surface seismic imaging.

The 600–850 m crosswell offsets surveyed at Liaohe are typical of many oil fields. Despite the far offsets, the crosswell seismic signals recorded at Liaohe appear to be sufficiently strong to permit some form of imaging (e.g. Figs 3–6). However, attempts to obtain tomographic transmission-seismic and reflector-inversion

Figure 1. Location of Liaohe Oil Field in the Liao-Ning province of north-east China. The oil field lies on a tectonically-active north-east striking structural trend hosting most of eastern Chinas oil fields.

Figure 2. Sonic velocity well-log data for Liaohe crosswell Surveys 1 and 2. Vertical scale is well depth in m. The reservoir sand/shale sequence begins at 2520 m in well 2727, dips to 2570 m in well 2629, and reaches 2750 m in well 2531. Apparent interwell reservoir dips are respectively 8 per cent for Survey 1 (well 2629 to well 2727), and 30 per cent for Survey 2 (well 2629 to well 2531). Asterisks denote sonic log data used to generate crosswell velocity fields for finite-difference acoustic model wave field computation.
seismic images from the Liaohe far-offset crosswell seismic data failed badly. Appendix A illustrates the degree of failure encountered with Liaohe crosswell seismic data.

The failure of far-offset crosswell seismic tomography and reflection imaging is not surprising. Transmission data tomography generally fails at all but the smallest crosswell offsets because tomographic inversion works only when there is an adequate, usually large, range of ray angles through the grid elements of the interwell velocity section (Peterson et al. 1985; see also numerous reports in Expanded Abstracts, SEG 60th Annual Meeting & Exposition, San Francisco, 1990). Cheng et al. (2004) present the limited results of modern computationally intense inversion using crosswell seismic synthetic data for data sections equal horizontal and vertical dimension; they do not, however, attempt inversion for sections with horizontal dimension greater than the vertical dimension, or in the presence of the seismic and structural noise common to all field data. Most oil field well pairs do not afford an adequate range of ray angles through the velocity grid. In the Liaohe crosswell surveys, the maximum ray angle to the horizontal is $\approx 30^\circ - 45^\circ$, but typically 85 per cent of ray angles are $< 5^\circ$ from the horizontal.

Reflector inversion attempts to remove first-arrival energy in order to image reflected energy obscured by first arrival wavelets in common source or common sensor gathers. Crosswell reflection processing can succeed for subnormal reflections available at near offsets, but the technique quickly runs into difficulty with the low signal-to-noise ratios and insufficient time separation between direct and reflected wave packets that characterize far-offset data (e.g. Rector 1995 and following articles; Yu et al. 2003; Yu et al. 2004). Rowbotham & Goulty (1994) institute a spatial filter cutoff for crosswell seismic rays propagating at angles greater than $60^\circ$ to the vertical. This cutoff rules out the majority of crosswell ray paths for data acquired at Liaohe on strictly geometric grounds. Further, the downhole orbital vibrator source used at Liaohe (Leary et al. 2003; Walter et al. 2003; Leary & Walter 2005a,b) has a radiation pattern that highly favours horizontal over vertical radiation, and does not generate source energy within the processing angular passband considered acceptable by Rowbotham & Goulty (1994). Finally, at far offsets the ray theoretic basis for reflector inversion is increasingly suspect as the source wavefield is spherical rather than pseudo-planar, and high-angle (far-offset) reflection of spherical waves is physically far more complex than low-angle (near-offset) reflection of plane waves. Appendix A illustrates that even when prominent reflectors can be clearly distinguished from the first arrival energy, the far-offset geometry does not yield a reliable image.

In contrast to imaging difficulties encountered by tomography and reflector inversion, waveguide signals illustrated in Figs 3–6 appear to offer good chances to achieve the imaging goal of accurate interwell velocity models and plausible estimates of the continuity...
Figure 4. Survey 1 Fan 6 gathers for sensors 1 and 2 in the low-velocity sediments above the top reservoir-defining high-velocity layer. Vertical arrows point to low-velocity layers above the reservoir (left) and in the reservoir (right). Inclined arrows point to direct (lower) and refracted (upper) traveltime arrival curves in for sources above the reservoir.

or discontinuity of interwell sand/shale reservoir layers at offsets of at least 620–650 m. Wavefield structures noted by arrows in Figs 3–6 are traveltime and wavelet amplitude anomalies in common sensor gathers recorded in crosswell Survey 1 by successive horizontal geophones at 5 m intervals in a sensor well offset 650 m from the source well. Figs 3–6 wavefields are plotted in trace-normalised mode. Larger signal/noise ratios for the delayed waveguided energy are seen in terms of smaller pre-signal background seismic noise fluctuations. Relative traveltime differences of 20 ms are seen between the first arrival envelope and waveguide-retarded arrivals. The amplitude and time delay definition of waveguided energy can vary significantly between successive sensor levels at 5 m spacing. Referring to well-log velocity data in Fig. 2, this degree of signal variation is expected for a waveguide structure with characteristic half-width of ≈15 m. The Figs 3–6 retarded wavelet signals in specific source-level traces are spatially correlated with the well-log sand/shale velocity lows and highs of Fig. 2.

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The amplitude and traveltime systematics of waveguide-like signals illustrated in Figs 3–6 can be compared with finite-difference (FD) model acoustic wavefields computed for waveguide velocity structures derived from survey-well sonic logs (the FD computation is discussed in Section 4.3). Fig. 7 shows the essential fact that intact model waveguides based on Fig. 2 velocity sequences act to localise wave energy spatially and temporally on the scale of 3–10 m and 3–10 ms as seen in the Liaohe oil field data. The Survey 1 waveguide signals of Figs 3–6 and the close spatial correlation of common sensor gather waveguide signals with well-log low-velocity layers (LVLs) suggest that coherent waveguide signals are evidence for interwell LVL continuity. By inference, absence of coherent waveguide signals in the presence of strong well-log sand/shale structures is evidence for a discontinuity in the LVL. Liaohe crosswell Survey 2 data, for the Survey 1 source well but with sensor well offset 620 m in the opposite direction, provide an example of apparent LVL discontinuity.

This paper discusses the phenomenology of Liaohe far-offset crosswell seismic waveguide signals in Survey 1 and their absence in Survey 2. We first put the Liaohe oil field velocity structure and crosswell signals of Figs 2, 3 and 7 in the context of recent seismic waveguide observations in oil fields and fault zones. In Section 3 we contrast the presence and absence of waveguide signals in Surveys 1 and 2, and in Section 4 present FD acoustic wavefield modelling that can explain Survey 1 and 2 observations in terms of a continuous waveguide between Survey 1 wells and a discontinuous waveguide between Survey 2 wells. We draw two main conclusions from these results: (1) FD acoustic modelling of crosswell seismic waveguide signals can effectively provide significant evidence for interwell reservoir continuity and discontinuity at offsets of 650 m and probably up to 1 km; and (2), that crosswell seismics offer an excellent opportunity to monitor oil production from waveguide reservoirs via time lapse crosswell seismic data and modelling to track changing layer wave speeds as the oil/water ratio falls.
Figure 5. Survey 1 Fan 7 gathers for sensors 1 and 2 in the second high-velocity layer below the top reservoir-defining high-velocity layer.

2 WAVEGUIDE SEISMIC OBSERVATIONS & LIAOHE OIL FIELD VELOCITY STRUCTURE

Seismic waveguide observations are well developed in the coal industry where the high velocity contrast between coal and host rock make an nearly ideal waveguide (Buchanan & Jackson 1986; Dresen & Ruter 1994). However, while most coal seam seismic data are acquired with coal-seam discontinuity detection in mind, surveys are typically conducted without benefit of a crosswell transmission geometry. Beginning around 1990 a number of observations of seismic waveguide transmission were recorded for both surface sources and borehole sensors, and earthquake sources and surface sensors (Li & Leary 1990; Ben-Zion & Malin 1991). Observed fault-zone waveguide signals were modelled analytically (Ben-Zion & Aki 1990) and numerically (Leary et al. 1991; Igel et al. 1997; Jahnke et al. 2002). The fault-zone waveguide modelling established that waveguide transmission tends to persist through a considerable range of geometric and material heterogeneities, so that waveguide transmission may be regarded as a robust rather than fragile phenomenon provided the wave lengths are sufficiently long. Ben-Zion et al. (2003) give a recent and comprehensive account of numerical modelling and observations of fault zone waveguide transmission.

With the advent of borehole seismic sources and multisensor arrays (Hardage 1992), a strong potential arose for observing seismic waveguide action in georeservoir formations. However, despite the obvious incentive to acquire and exploit such data (Krohn 1990, 1992, 1993; Kurkjian et al. 1992, 1994; Lines et al. 1992; Lou & Crampin 1992; Turpening et al. 1992; Parra 1998; Liu, Queen & Cox 2000; Parra et al. 2002), previously reported observations do not match the waveguide spatio-temporal localization of seismic energy observed at the Liaohe oil field.

Kurkjian et al. (1994) study fault-offset phenomenology in model elastic wavefields computed for realistic borehole-sourcing computations. Parra et al. (1998) show two field examples of common source gathers recorded at ≈1-m-depth intervals in a sand sequence at 100 m offset; the gathers are sensitive to sensor and source depths relative to a 4 m thick low-velocity sand embedded in higher-velocity sands. Pump tests have indicated that the low-velocity porous sand is flow-continuous across the crosswell interval (Turpening et al. 1992). Elsewhere far-offset crosswell data have been recorded in shale and sand/shale formations, but the field evidence presented for waveguide action has been more oblique. Liu et al. (2000) report crosswell seismic signals at 600 m offsets in shallow-lying gas-producing marine shales obtained with a prototype of the orbital vibrator source used at Liaohe. While the far-offset signal was strong, the LVL was 50 m broad and not particularly well defined, and does not appear to have provided spatio-temporal energy localization that can be clearly tied to sonic well-log low-velocity intervals. Instead, evidence for waveguide action was inferred from waveform dispersion. More recently, Parra et al. (2002) recorded air-gun-sourced crosswell seismic data at 530 m and 840 m offsets in sand/shale formations of a gas reservoir. However, these data do not yield the conspicuous spatio-temporal energy localization tied to LVL depths reported by Parra et al. (1998) for 100 m offsets in sands. Instead, continuous and discontinuous waveguide effects observed at 530 m are analysed in terms of velocity dispersion and dispersion.
synthetic amplitude curves; the 840 m offset data did not permit conclusive analysis.

It is not clear why the Liu et al. (2000) and Parra et al. (2002) far-offset crosswell seismic data do not appear to provide evidence for seismic-waveguide action comparable to the 100 m offset data of Parra et al. (1998) or the present 600 m offset Liaohe data. In the case of Liu et al. (2000), perhaps the waveguide is simply not well enough defined; or perhaps the layer is, unknown to the investigators, offset or otherwise discontinuous. Further waveguide modelling may disclose whether the dispersion evidence of Liu et al. (2000) is consistent with the broad LVL of moderate velocity contrast exhibiting relatively weak energy confinement. A possible complication arises because the shale formations have strong layering anisotropy. In the case of Parra et al. (2002), air-gun source tube waves have contaminated the waveguide signal; processing the tube waves may have obscured waveguide energy localizations or otherwise perturbed the waveguide signal. The Parra et al. (2002) data have apparent surface seismic control that has been interpreted to eliminate the possibility of lateral discontinuity.

The difference in far-offset (>500–600 m) waveguide signals between those recorded at Liaohe and those recorded by Liu et al. (2000) and Parra et al. (2002) may be due to different degrees of physical property heterogeneity in the waveguide structures. Numerical simulations of 3-D fault-zone waveguide phenomena conducted by Leary et al. (1991) and Igel et al. (1997) suggest that heterogeneity within a waveguide LVL can destroy a waveguide signal. In contrast, the present acoustic 2-D computation of Section 4 and prior 3-D numerical computations for a variety of fault-zone geometries indicate that boundary irregularity does not significantly disturb waveguide energy propagation. Roughly speaking, diffraction at complex boundaries tends to preserve wave energy channelling, while scattering at LVL heterogeneities tends to disperse wave energy from the energy channel. The recent study of Ben-Zion et al. (2003) sustains this observation. We may, therefore, tentatively suggest that waveguides subjected to complex histories may be sufficiently disturbed to scatter trapped energy even if the large-scale layer geometry appears intact. It may be pertinent that both Liu et al. (2000) and Parra et al. (2002) are working in shallow gas reservoirs. The high mobility of gas may allow commercial production of internally heterogeneous gas-bearing formations that would be less productive for liquid hydrocarbons.

The geometric and material heterogeneities that appear to characterize fault zones and degrade many georeservoir low-velocity structures seem to be largely absent in the Liaohe oil field sand/shale reservoir sequence. The waveguide-like signals of Figs 3–6 suggest that the sonic velocity well-log data of Fig. 2 can be directly incorporated as numerical interwell section velocity grids for Survey 1 and 2 waveguide FD acoustic modelling as illustrated in Figs 8–11.
Fig. 7. Examples of model common source acoustic wavefields for Survey 1 velocity model (upper panels) and sample Survey 1 seismic common sensor wavefields (lower panels). All model and all field traces are plot-normalised to common reference values. Model and data wavefields vary strongly in time and space with source/sensor location within the wave guide. Traveltime envelopes on the data plots clearly distinguish first-arrival move-outs for the well-log velocity model (smaller radius of curvature) with move-outs for a uniform medium (larger radius of curvature).

Fig. 8 shows the Survey 1 and 2 crosswell seismic well geometry in relation to the top and bottom of the Liaohe reservoir. Thin lines mark well trajectories, with thick lines denoting survey depth coverage in the source well (2629, centre), Survey 1 sensor well (2727, left) and Survey 2 sensor well (2531, right). The reservoir top at each well is marked by small darker planes. The mean bottom reservoir is marked by the large lightly-shaded plane. A fourth well trajectory shows that there is an abrupt difference in reservoir depth just east (left) of the Survey 2 sensor well. The fourth well provides the auxiliary well logs, which confirm the near-sensor-well location of the waveguide discontinuity inferred from Survey 2 wavefield modelling.

Figs 9–11 picture the interwell velocity grids used for FD acoustic wavefield modelling. The velocity grids have 500 nodes on a side at 2 m spacing. Prominent sonic velocity structures identified by asterisks in Fig. 2 are shown as model well logs superposed on the model velocity fields. Velocity log data are transferred to the model grids as velocity gradients rather than as velocity interfaces. Velocity gradients more naturally capture the sonic log sequence, and are more stable for numerical computations. Successive velocity-depth pairs for each source and sensor well fix a model velocity gradient within the velocity grid. Bilinear gradient interpolation over the four velocity model points fills in the grid for each model layer. Darker shades denote high velocities and lighter shades denote low velocities.

Fig. 10 shows a Survey 2 initial interwell velocity model directly derived from sonic well data. The much steeper Survey 2 model waveguide dip of Fig. 10 compared with that of Survey 1 in Fig. 9 illustrates the tentative nature of the initial velocity models derived from well logs. While the Survey 1 interwell velocity model is sustained by acoustic wavefield modelling, the Survey 2 initial model immediately runs into conflict with Survey 2 data. Fig. 11 shows how the Fig. 10 initial model is altered to agree with Survey 2 wavefield data.

In principle the interwell layer continuity of Figs 9 and 10 initial velocity models can be arbitrarily violated. In practice, the Liaohe initial velocity models contain a high degree of validity. Waveguide data can then be used to steer initial velocity models into adapted velocity models that provide numerical wavefields more consistent with observation. At a high degree of confidence, Survey 1 crosswell seismic data require only modest adjustments of the initial model velocity layer parameters to achieve satisfactory agreement between model and observed wavefields. Survey 2 data are consistent at a lower degree of confidence when the Fig. 10 initial model is structurally altered to the model of Fig. 11. Survey 2 model alterations comprise

1. reducing the initial-model dip of 30 per cent to a dip of 10–15 per cent;
2. restoring the reservoir depth in sensor well with 75–100 m of localised down-faulting and
Figure 8. Crosswell acquisition geometry of Liaohe seismic Surveys 1 (left pair) and 2 (right pair). Plot axes are scaled in metres relative to an arbitrary surface wellhead position. Thin lines mark well trajectories; source/sensor coverage is given as thick line segments. Sourcing is from the central well (2629), with Survey 1 sensors in the left well (2727) and Survey 2 sensors in well right (2531). The fourth well, without source/sensor data, provides direct evidence for 75 m of localised down-faulting inferred from wavefield modelling to exist near Survey 2 sensor well 2531. Darker planar sections mark individual reservoir tops above the lighter mean-reservoir bottom plane.

Figure 9. Survey 1 interwell velocity grid derived from sonic well data of Fig. 2. Grid is 1 km on a side; velocities shown in sidebar are in km s$^{-1}$. Sensor well 2727 is left; source well 2629 is right. Interwell grid velocity gradients are determined for each layer by bilinear interpolation of the four selected sonic log velocities at well positions in the grid. Velocity model is fine-tuned from well-log data shown by solid line with dots to match finite-difference traveltime model to observed data.

Figure 10. Survey 2 interwell velocity grid derived from sonic well data of Fig. 2. Grid is 1 km on a side; velocities shown in sidebar are in km s$^{-1}$. Sensor well 2531 is right; source well 2629 is left. Well-log data are shown by solid lines with dots. Interwell grid velocity gradients are determined for each layer by bilinear interpolation of the four selected sonic log velocities at well positions in the grid.

Figure 11. Revised Survey 2 interwell velocity grid. Grid is 1 km on a side; velocities shown in sidebar are in km s$^{-1}$. Sensor well 2531 is right; source well 2629 is left. Steeply dipping continuous waveguide layer of Fig. 10 is replaced by a more moderately dipping layer with additional vertical offset of waveguide layers attributed to localised down-faulting in vicinity of sensor well 2531. Velocity model is fine-tuned from well-log data shown as solid lines with dots to match finite-difference traveltime model to observed data.

(3) locating the fault near the sensor well. In the case of Survey 2, data from the auxiliary well shown in Fig. 8 validate the model alterations. The post-modelling agreement between model and auxiliary helps calibrate the predictive power of acoustic waveguide models based on sonic well-log data. In the next section, we illustrate a range of waveguide signal phenomenology observed in the Liaohe crosswell seismic data. Survey 1 data systematically show high-amplitude retarded wavegroups with detailed spatial relation to low- and high-velocity layer (HVL) depths recorded in the source and sensor wells. Survey 1 gathers also show traveltime retardation and refracted-path arrivals generated by the broad LVL lying above the reservoir layers. The detailed crosswell seismic waveguide systematics of Survey 1 are in clear contrast with the virtual absence of waveguide signals in Survey 2 data.
3 CROSSWELL SEISMIC PHENOMENOLOGY—EVIDENCE FOR CONTINUOUS & DISCONTINUOUS WAVEGUIDES

3.1 Survey 1—Continuous waveguide

Liaohe crosswell Survey 1 was conducted westwards up-dip from source well 2629 to sensor well 2727. Nine sensor-array fans were acquired, each comprising approximately 120 source positions at 4.85 m intervals between 2200 and 2800 m and recorded by 12 levels of vector motion sensors spaced at 4.85 m intervals. Fans 1–5 lie above the sand/shale formation and Fans 6–9 traverse the sand/shale formation as diagrammed in Fig. 12. More than half the 48 Fan 6–9 gathers showed significant evidence for two or more waveguide arrivals. Sample arrivals are illustrated in Figs 3–6. Table 1 keys the waveguide arrivals of these figures to LVLs labelled in Fig. 12.

Table 1 clearly illustrates the tendency for significant Survey 1 waveguide signals to be associated with the same or adjacent LVLs labels a–d in Fig. 12.

Fig. 4 plots Fan 6 common sensor gathers for two sensors at 2520 m in the broad LVL above the reservoir. For source points above 2500 m in the source well the common-sensor gathers have a direct-ray traveltime envelope that approximates the standard hyperbolic traveltime curve of a quasi-uniform velocity structure. For source points below 2500 m the gather travel times noted by the vertical arrows become increasingly retarded at up to 35 ms to 40 ms behind a nominal 200 ms travel time until the source reaches the top shale layer at 2560 m, when the travel time quickly returns to 200 ms. Also present in these gathers is the refracted arrival from the top shale noted by the subhorizontal arrows. The refracted arrival beats the direct arrival because there is a slight horizontal velocity gradient from the sensor to the source well that favours a steeper ray path that reaches the high-velocity top shale quickly enough to arrive at the sensor before the direct wave. This ray path is stronger on the vertical component than on the horizontal component, indicating it provenance as vertically moving energy.

Fig. 5 shows sensor gathers for levels 1 and 2 of Fan 7 within the HVL between LVLs a and b. These waveguide arrivals are relatively muted compared with the well-developed Fig. 3 signals recorded by the Fan 7 sensors 8–10 located in the succeeding LVL. Note further the evidence in Fig. 5 for reverse-move-out energy as if reflected by source-well velocity structures at 2450 m.

Prominent 20–25 ms retarded wavelets corresponding to LVLs b, c near Fan 8 source depths 2625 and 2665 m appear at sensor levels 8 and 9 near LVL-c at 2650 m.

3.2 Survey 2—discontinuous waveguide

Liaohe crosswell Survey 2 was conducted downdip to the east between source well 2629 and sensor well 2531. Details of the well-log velocity structure and waveguide source/sensor coverage are given in Fig. 13. Source coverage comprises some 60 source positions at 4.85 m steps, with sensor coverage provided by 16 levels of vector-motion sensors spaced at 4.85 m intervals. As in Fig. 12 for Survey 1, the four main reservoir sand/shale low-velocity zones are denoted a–d.

Representative gathers of y-component motion are plotted in Figs 14–16. The corresponding x-component gathers show similar results at somewhat less signal amplitude. Two Fan 4 gathers illustrate the wavefield for well 2531 sensors above the sand/shale waveguide layer. The remaining four gathers are from Fans 5–6 for sensors within the well 2531 reservoir sand/shale layers.

Despite the similarity of Survey 2 velocity logs in Fig. 13 with those of Survey 1 in Fig. 12, Fig. 14 shows that the Survey 2 Fan 4 first-arrival envelope is poorly defined, the first-arrival signal is smaller compared with pre-signal noise levels, and there is little evidence for a systematic retarded wavegroup due to the broad LVL above the reservoir as seen for the Survey 1 gathers of Fig. 4 and on the sonic well-log data of Fig. 2. The poor first-arrival envelope

### Table 1. Spatial linking of waveguide traveltime events identified in the six gathers of Figs 4–6 and three gathers of Fig. 3 with well-log sonic low-velocity layers a–d in Fig. 12. Data fan numbers, sensor depths and well-log low-velocity layers (LVLs) are from Fig. 12; common source-gather event depths and traveltime delays are from Figs 3–6.

<table>
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<th>Fan–Sns</th>
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Figure 12. Acoustic well logs and source/sensor coverage for Survey 1 sensor well 2727 and source well 2629. Sensor and source coverage is marked by solid bars next to acoustic logs; fans progress from Fan 6 (outside) to Fan 9 (inside). Acoustic logs scale from V_{min} = 2400 m s^{-1} to V_{max} = 3700 m s^{-1}; velocities increase left to right. Low-velocity layers labelled a–d are associated with bounding high-velocity layers.

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Wavefield definition improves somewhat further for Fan 6 gathers shown in Fig. 16, but localised wavegroup energy is more haphazard than systematic from sensor to sensor. Acoustic wavefield models discussed in the next section begin to elucidate the nature of the difference between the Survey 1 and 2 observations.

4 MODELLING CROSSWELL SEISMIC WAVEGUIDE DATA

Acoustic wave modelling of Survey 1 intact waveguide data in Section 4.1 establishes a good general level of agreement between data and models of intact waveguide structures. Such data-model agreement is, however, less important for what it adds to our understanding of Survey 1 waveguide structure than for what it promises to add to our understanding of Survey 2 waveguide structure. Systematic trial modelling is likely to be the best, perhaps only, means of extracting useful reservoir information on how and where a well-defined waveguide structure such as that of Fig. 9 breaks down. In the case of the Fig. 10 Survey 2 starting model, we seek to determine if the 200 m vertical offset in reservoir depths occurs over a broad, continuous downward depression of the reservoir sediments, or if it involves significant localised faulting. And if there is localised faulting, where does the faulting occur? If the faulting is up-dip near the source well, then oil may be trapped oil in the downdip reservoir section. On the other hand, evidence for downdip faulting implies that up-dip production wells 2727 and 2629 can have drained the Survey 2 reservoir interval. The Survey 2 modelling results of Section 4.2 seen in the down-faulted velocity model of Fig. 10 support the hope that acoustic wavefield simulations can yield valid structural interpretations of crosswell seismic data acquired for discontinuous waveguides. Section 4.3 reviews aspects of the FD acoustic model wavefields displayed in Sections 4.1 and 4.2, in particular the use of computationally efficient common source wavefields to model common sensor data wavefields.

4.1 Modelling continuous waveguide data

First cut modelling of crosswell seismic data computes the model acoustic wavefield for a sequence of source points located near each
sensor depth for which a model gather is required. Model common source gathers are then compared with the data common sensor gathers and appropriate model adjustments are made to secure satisfactory fits.

Figs 17–19 illustrate model and data gathers for nine sensor positions from a total of 48 sensor gathers acquired for Survey 1 Fan 6–9 coverage diagrammed in Fig. 12. Fig. 17 begins at the top of the reservoir section with the transition in low-velocity zones across the reservoir top HVL at depth 2510–2520 m in the sensor-well velocity log and depth 2560 m in the source-well velocity log of Fig. 12. For source/sensor depths above the reservoir top reservoir, Fan-6 Sensor-2 panel in Fig. 17 shows a deep bay of retarded but high-amplitude wave motion in both data and model due to the large LVL above the reservoir. Sensors 6 and 10 show the transition of wave energy from above the HVL to arrival energy dominated by the high-velocity top reservoir layer. There is general agreement between the limbs of the data and model traveltime curves. However, discrepancies between data and model are evident. All panels show that the velocity model does not capture the full structural sensitivity of the in situ velocity field. On the limbs of the traveltime curves in the Sensor 2 and 6 panels, the data wavefield limbs are more energized for the Sensor 2 panel while the reverse is true for model wavefield limbs in Sensor 6 panel. The Sensor 10 panels shows that the data central-bay retarded wavefield is more persistent than the model wavefield. It is not clear

Figure 15. Survey 2 Fan 5 with sensors 9 and 10 below the top reservoir-defining high-velocity layer.

Figure 16. Survey 2 Fan 6 with sensors 11 and 12 well within the reservoir layers.
Figure 17. Survey 1 common sensor data-gathers (grey) and common source acoustic wavefield model gathers (black) computed for model sources at Fan 6 field sensor levels 2, 6 and 10. Significant observed and model energy clusters agree in time, space and relative amplitude, indicating that the Fig. 9 interwell model velocity field is a useful approximation for these source and sensor positions.

that data-model discrepancies at this level can be effectively clarified by extended modelling. Perhaps more to the point, it is not clear that it is important to devise models that achieve this superior level of agreement. The overall data-model agreement establishes a highly plausible level of confidence in waveguide continuity between the Survey 1 wells, giving a first-order presumption that interwell fluid flow is not interrupted. Such data and modelling conclusions are likely to be robustly testable by auxiliary observations such as well production data and, ultimately, by time lapse seismic monitoring. More detailed questions of model-data agreement may be both less important and far harder to decide.

Fig. 18 shows somewhat improved data-model agreement than Fig. 17. The large-amplitude arrivals agree well for the complex waveforms at the heart of the upper reservoir LVLs. Energy is again largely confined to the waveguide layers. However, the limbs of the gathers show better model-data agreement since the Sensor 3 panel shows relatively high energy in both model and data limbs, while the Sensor 7 panel shows relative absence of energy.

Fig. 19 continues the level of data-model agreement at the level of where wavefield energy appears. The central role of the waveguide is again confirmed with good data-model agreement in space, time and amplitude. The most obvious discrepancy in Fig. 19 is seen on the limbs of the traveltine curve. The discrepancy is, however, due to such inessential model aspects as different source-radiation patterns, absence of model intrinsic attenuation, and model 2-D geometric attenuation. Each of these model features could be included in the acoustic model, but nothing important about the waveguide structure would be gained.

The model common source gathers of Figs 17–19 support the associated initial acoustic velocity model with its continuous waveguide. On the scale of tens to hundreds of metres, the model travel-time envelopes closely reproduce the main structural features of the data. Below the scale of tens of meters, the model accurately locates the high-amplitude guided wave energy where it is observed in the data. In general there is a good correspondence between energy amplitudes throughout the gathers. The greater complexity of the data wavefield is not surprising, not least because the data are recorded in a 3-D structure for which out-of-plane energy can arrive behind the first arrivals. Conversely, the greater uniformity of the model data and the larger amplitudes at the limbs of the traveltine curves are due among other things to the 2-D computation.

For completeness, Fig. 20 illustrates the complex model and data wavefield at greater resolution. It is difficult to assess the degree which agreement or disagreement between data and model can be exploited to understand details of the waveguide structure. It is not, for instance clear whether individual LVL can or cannot be moderately interrupted in the crosswell section. For the present, it is concluded that

(1) the data/model agreement of Figs 17–20 lays the ground work for accepting the simple, essentially continuous, model velocity connection between source and sensor well pictured in Fig. 9,
(2) the acoustic wavefield can provide an useful account of seismic energy propagating in well-defined geological waveguides and
(3) the use of model common-source gathers to model data in common-sensor gather format does not appear to produce significant problems when applied to continuous waveguide data.

4.2 Modelling discontinuous waveguide data

We have noted that aspects of acoustic waveguide modelling of Survey 2 data imply significant down-drop faulting occurs near the sensor well 2531, and that auxiliary well evidence validates this reservoir model. We illustrate here the model acoustic wavefield evidence that (1) a continuous waveguide does not exist between wells 2629 and 2531, and (2) waveguide discontinuity is more likely to be expressed in fault-disruption of reservoir rock near the sensor well 2531 than near the source well 2629.

Figs 21–24 compare representative field data with synthetic waveforms for the two velocity models pictured in Fig. 10 (continuous steeply dipping waveguide) and Fig. 11 (moderately dipping discontinuous waveguide). In addition, each waveguide model is computed for two directions of wave propagation. The two directions of wave propagation efficiently measure the wavefield effect of source proximity to the fault-discontinuity versus the source distance from the fault discontinuity. The efficiency factor enters because both propagation directions compute common source wavefields rather than common sensor wavefields, hence neither model gather duplicates the common-sensor gather of the field data.

The model/data wavefield display format of Figs 21–24 has a data gather in the centre flanked by two panels with the two model gathers in each panel. The continuous waveguide model (Fig. 10) is shaded black, the discontinuous waveguide model (Fig. 11) is shaded grey. Left-hand panels are ‘forward’ computed for the model source at the field source well. Right-hand panels are ‘reverse’ computed for the model source as the field sensor well.

The first, and negative, modelling conclusion is that the black model wavefields in Figs 21–24 show consistent and substantial data-modelling disagreement, hence ruling out a continuous waveguide between Survey 2 wells. Model waveguide continuity leads to the temporally and spatially localised wavegroups seen in black in both the left-hand and right-hand panels. Such spatially and temporally restricted wavefields are not observed in the corresponding centre-panel data gathers.

The second, and positive, modelling conclusion is that grey model wavefields in Figs 21–24 computed for the discontinuous waveguide model velocity field of Fig. 11 are more like the central-panel data gathers. Unlike the continuous-waveguide model wavefields in black, the discontinuous-waveguide model wavefields in grey are far less spatially and temporally localized. The broad and somewhat irregular distribution of wavefield energy is consistent with the central panel observations. Not surprisingly there is no detailed agreement between model and observed wavefields such as obtained for Survey 1 data, but the similar ranges of wavefield variation makes the discontinuous velocity model of Fig. 11 more or less consistent with data.
The final, and again positive, modelling conclusion is that the right-hand-panel grey wavefields in Figs 21–24 agree less well with field data than do those of the left-hand panels. Left-hand panel wavefields show the result of encountering the disruptive faulted section of the velocity field near the sensors, while right-hand panel wavefields show the result of encountering the fault near the source. The systematics of the left- and right-hand grey-shaded wave fields computed for the discontinuous waveguide show that wave energy can propagate through a disrupted waveguide and enter (or re-enter) waveguide structures if the source is near the discontinuity (right-hand panels), but is far more dispersed if the waveguide discontinuity is near the sensor well (left-hand panels).

If waveguide disruption is near the source, as for the right-hand panel grey wavefields, wave energy passes through the discontinuous zone and responds to the remaining waveguide structures in a relatively orderly manner. The nature of the right-hand panel grey wavefields is thus that of group energy at sensors 50–75 m below sensors registering the black wavefield. In the continuous waveguide computation, energy travels along the LVL near the source, while for the disrupted waveguide energy travels along deeper LVLs located 50–75 m below the layer transmitting the continuous waveguide wave energy. As the model source point moves down the well, more of grey energy field appears as travelling below rather than in the waveguide. This transition from within to below the waveguide does not occur for the black continuous waveguide model wavefields because the model source is always within the waveguide interval of the well.

4.3 FD acoustic modelling considerations

Waveguides are essentially interference phenomena for which coherent interference creates significant amplitude localised amplitude variations that are equally or more important discriminators than traveltimes. Hence, observations and model gathers benefit from true-amplitude wavefield plots rather than trace-balanced or AGC-balanced wavefield plots. While trace-balanced and/or AGC-balanced wavefield displays provide a well established means of pattern recognition for much seismic data, the potent information in waveguide signal amplitudes should not be ignored. Accordingly, all model and data plots preserve relative trace amplitude information throughout each plot. All model/data comparisons use a single overall relative scaling parameter. It should thus be noted that, unlike most model seismic sections, the acoustic waveguide model wavefields meet an amplitude agreement criterion as well as a traveltime criterion. The amplitude effect of Q can be computed with elastic FD code (Carcione 2001) but is not warranted for the present modelling; while an overall Q effect is seen in depressing higher-frequency amplitudes relative to lower-frequency amplitudes, the effect is not keyed to waveguide versus non-waveguide formations, and is hence of secondary interest in this study.

Waveguide modelling of crosswell seismic data faces several procedural questions. First, is an acoustic waveform computation a suitable approximation to what is formally an elastic problem? Second, does it matter if waveguide models are computed as
common-source gathers instead of common-sensor gathers? Third, what level of model agreement and/or discrimination can be sought? We can shed indirect light on these questions.

First, our model scalar waveform data appear to have amplitudes and phases that agree satisfactorily with Survey 1 observations, and that structural deductions from the Survey 2 model were borne out by auxiliary evidence. One is therefore prompted to ask what more can be gained from an elastic computation. It remains to be seen whether elastic wave equation modelling on these or more refined future crosswell seismic waveguide data can justify the considerable extra computational time and resources (each increased by at least a factor 3 to accommodate the vector wave equation), the extra parameters (P- and S-wave velocities), and the potentially more tricky numerical stability considerations (more spatial derivatives), required by a elastic computations.

In this regard, it is useful to point out the simplicity and accessibility of the acoustic FD algorithm. The model wavefields were conveniently obtained with a 2-D acoustic wave equation FD algorithm (Dablain 1986) simply implemented in Matlab (igel, igel@geophysik.uni-muenchen.de) and performed on a standard PC for wave high temporal-resolution frequencies up to 200 Hz for a high spatial-resolution 500 x 500 node numerical velocity grid representing a convenient 1 km by 1 km crosswell crustal section. Velocity gradient models derived from sonic logs defined 15-m-wide low- and high-velocity waveguide structures with seven to eight nodes. At frequencies of 200–250 Hz waveguide computations on 12 m to 15 m waves were likewise defined by 6 to 8 nodes. Computed wavefields were stable for at least 40 wavelengths using a fourth-order version of the Dablain (1986) algorithm. This combination of high precision, good stability, ready accessibility, and productive model-data agreement indicates that there should be a very good case made before resorting to elastic computations. Expressions for suitable elastic FD computations, including the effects of Q, are given by Carcione (2001).

The second question arises since much or most crosswell seismic vector field data are acquired using a fixed sensor string recording signals generated by a mobile source. Vector sensors require time consuming clamping and often involve variable sensor orientations at each clamping, hence it is more efficient and reliable to fix the sensors and move the source. Because of sensor orientation and clamping variability, field data are often most simply and completely displayed as common-sensor gathers. Model data, on the other hand, are vastly more efficiently generated as common-source gathers. One source wave can be measured at, say, 100 sensor locations, while the comparable reverse computation for a fixed sensor requires 100 wave propagations. While there is probably little conflict between the common-source and common-sensor formats in the case of intact waveguides, there is little or no reciprocity between common source and common sensor gathers in the case of broken waveguides. For instance, wavefields broken up by diffraction and

Figure 20. Details of Fan 6 Survey 1 common sensor gathers (grey) at 3 sensor depths from 544 m to 553 m versus model common source acoustic wavefields (black) computed for model sources at depths 540 m and 550 m. The data and model show a sharp transition between high-velocity layer transmission and low-velocity layer transmission at depths near 650 m. The corresponding sonic well-log high- and low-velocity zones are marked a in Fig. 12.
Figure 21. Comparison of observed wavefield (central panel) with model wavefields (left- and right-hand panels). Black-shaded model wavefields are computed for the continuous waveguide velocity field in Fig. 10, grey-shaded model wavefields for the discontinuous waveguide velocity field in Fig. 11. Left-hand panel wavefields are computed for sources in well 2629 and sensors in well 2531; for these wavefields, the source is distant from the model waveguide disruption while the sensors are adjacent to the disruption. Right-hand panel wavefields are computed for the reverse source-sensor geometry. The difference between left- and right-hand panel wavefields is due to the difference in wavefield disruption by waveguide discontinuities near and far from sensors.

Questions about significant model resolution would appear to be premature. It is straightforward if tedious to generate a formal assessment of model parameter resolution for velocity or velocity gradient, layer widths and locations, layer slopes, and layer discontinuities based on the number of sensors, traveltime errors, and wavelet-amplitude errors. It would be far more difficult to convert such a resolution study into an assessment of what really matters, deciding whether fluids flow between two wells along nominal waveguide-like structures identified in sonic well-log data. It seems more useful to aim for a broad-based practical answer to the relevant question, even if that will take considerable time and experience involving a number of production well sites. The most useful lesson suggested by the Liaohe crosswell seismic data and their simulation with well-constrained acoustic FD modelling, with a few added comments related to possible oil field exploitation of seismic waveguide phenomenology.

1. Waveguide signals in crosswell seismics. Seismic waveguides exist in sand/shale reservoir formations and can be robustly observed at 650 m crosswell offsets with seismic waves in the frequency range of 100–400 Hz. Frequencies higher than 300–400 Hz are probably a poor investments at these ranges unless the effective Q of the rock is higher than 60. For dedicated observation at a limited range of source and sensor depths, it is reasonable to suppose that the waveguide wavelet S/N ratio can be adequately enhanced to extend the crosswell offset range to 1 km.

2. Velocity conditions for crosswell seismic waveguide signals. Systematic sonic well-log sequences of 20–40 per cent velocity contrast that persist over 650 m (up to 1 km?) intervals form legitimate targets for crosswell seismic investigation. Waveguide signal amplitudes and traveltime delays drop off when the waveguide velocity contrasts fall below about 20–25 per cent.

3. Robustness of crosswell seismic waveguide signals. When seismic waveguide arrivals are systematically observed, well-log
sonic velocity logs can generate initial velocity models that can in principle be adjusted to the details of wavefield. However, due to diffraction at obstacles waveguide energy propagating in structures 15–30 m wide at frequencies <200 Hz is robust rather than fragile. Modelling experience with the present continuous and/or discontinuous-waveguide structures does not encourage expectation that detailed modelling of waveguide signals will significantly refine the details of reservoir continuity.

(4) Spatial sampling of crosswell seismic waveguide signals. Waveguide signal complexity can arise from a number of physical effects, among which are source and sensor positions within the waveguide structure. To eliminate ambiguities due to the inherent spatial complexity of source and sensor position, and to insure the greatest likelihood of capturing an optimal waveguide signal in the 100–400 Hz range for waveguide structures on the order of 15–30 m, it is probably best practice to record crosswell seismic data at a minimum of 5 m source and sensor intervals, with 3 m intervals perhaps better still.

(5) Acoustic wavefield modelling of crosswell seismic waveguide signals. Acoustic waveguide simulations appear to validate the physical principles of waveguide action applied to geological materials. Broadly speaking, energy in both the Survey 1 continuous waveguide model wavefield of Section 4.1 and Survey 2 discontinuous waveguide model wavefields of Section 4.2 appears where and how it should appear and does not appear where it should not appear. Acoustic simulations probably cannot add significant detail to the general velocity model. While it is an open question whether elastic wave guide simulations can improve model resolution, it seems more likely that naturally occurring earth heterogeneity is sufficient to defeat attempts to extract significant and reliable information about detailed waveguide structure through elastic wavefield modelling.

(6) ‘Non-uniqueness’ of crosswell seismic waveguide signal modelling. Velocity model results at the level of Figs 9–11 are probably well determined, with questions of ‘model non-uniqueness’ being not very challenging. However, at 650 m offsets, even operating under good observational constraints, it would be easy to over-interpret the data, quickly raising serious questions of ‘model non-uniqueness’. The real question is, perhaps, how important are these difficult-to-resolve waveguide details for the purpose of producing oil.

(7) Identifying waveguide discontinuities from crosswell seismic waveguide data. Significant and persistent mismatches between well-developed sonic-log-constrained acoustic models and observed wavefields should prompt wavefield modelling attempts to find substantial structural information about how the crosswell interval deviates from the straightforward velocity model produced from sonic logs. The waveguide structure most probably exists through much of the crosswell section, but is substantially interrupted at some point. Evidence of significant vertical discontinuities in the crosswell section may be detected with detailed modelling of energy arriving along the limbs of the traveltime curve, that is, arrivals for large vertical-offset source positions. In the case of no crosswell seismic waveguide signal where one may be expected, it is also useful to identify the mean dip of the waveguide structure by modelling data from extended source and sensor positions above and if possible below the reservoir.

(8) Reverse crosswell seismics for near-well discontinuity location. Modelling indicates that significant vertical layer offsets near
the sensor well tend to disturb the waveguide signal far more than the same offsets located far from the sensor well. In the absence of an expected crosswell seismic waveguide signal, reversed crosswell data may be able to establish that waveguide signals are more deteriorated in one direction than the other. Modelling should then be able to establish if the more deteriorated signal is likely to be due to, say, fault disruption near the sensor well for the more deteriorated data. If the crosswell seismic data are equally deteriorated in both directions, it can be concluded that the discontinuity is not near either well.

(9) Modelling inversion of crosswell seismic waveguide signals. At present only trial forward modelling yields structural information; there is as yet no formal inversion process based on acoustic waveguide models for crosswell seismic data. As there are a large number of interacting model parameters involved in specifying a crosswell waveguide model, formally assessing the ability to resolve details for even the most significant of these parameters could be a formidable task.

(10) Traveltime resolution of crosswell seismic waveguide signals. At present 3:1 to 5:1 signal-to-noise ratios over ambient seismic background, waveguide wavelet traveltimes can be reliably measured to perhaps 0.25 ms (5 per cent of a 5 ms wavelet) if the source and sensor conditions are stable. Acoustic model tests suggest that under Liaohe waveguide conditions, this traveltime resolution is equivalent to sensitivity to 50–100 m movement of oil/water interface assuming 100 per cent oil/water conversion and 25 per cent reservoir porosity.

(11) Time lapse crosswell seismic waveguide reservoir monitoring. The high environmental stability, low seismic background, high source repeatability, and physically straightforward interaction of seismic wave with waveguide properties encourage use of crosswell seismics for time lapse reservoir monitoring. Changes in the make-up of reservoir fluids in the waveguide formation are likely to lead to detectable changes in waveguide arrival times. It seems only a matter of time and technology before the advantages of reservoir-proximate borehole sourcing and sensing will be employed to lower the cost of hydrocarbon production monitoring (de Waal & Calvert 2003). The prospects of time lapse seismic is conditioned by source wavelet stability and by signal strength. Extensive monitoring observations with the downhole orbital vibrator seismic source used to acquire the Liaohe crosswell seismic data yields an estimate of the time lapse traveltime source stability equivalent to traveltime sensitivity of 50–100 µs (Leary & Walter 2005a,b). Waveguide energy travelling between a source and sensor over distance $d$ comprising length $d_1$ of water saturated rock with effective wave speed $v$ and length $d_2$ of oil saturated rock with effective wave speed $v + \Delta v$ has travel time $t = d_1/v + d_2/(v + \Delta v)$. At a subsequent observation, the waveguide crosswell travel time can be altered by changing distributions of water and oil to $t + \Delta t = (d_1 + \Delta d)/v + (d_2 - \Delta d)/(v + \Delta v)$. The fractional time lapse differential travel time is $\Delta t/t \approx \Delta d/d \times \Delta v/v$, giving for $d \approx 600$ m, $\Delta d \approx 50$ m, $v \approx 3000$ m s$^{-1}$ and $\Delta v \approx 100$ m s$^{-1}$, a traveltime signal level of $\Delta t/t \approx 0.5$ ms/200 ms $\approx 0.25$ per cent. For waveguide conditions appropriate to the Liaohe field data, a 50 m interval of waveguide in which water...
Figure 24. Comparison of observed wavefield (central panel) with model wavefields (left- and right-hand panels). Figure details as in Fig. 21.

replaced oil causing a 3.5 per cent change in effective wave speed produces a 0.5 ms shift in waveguide travel times. A Liaohe waveguide signal composed of perhaps 1000 downhole orbital vibrator correlation wavelets rather than the 15–25 correlation wavelets of Survey 1 and 2 data can almost certainly achieve a similar or better accuracy at 600 m waveguide offsets.

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APPENDIX A: TOMOGRAM & REFLECTION INVERSION QUALITY FOR FAR-OFFSET CROSSWELL DATA

As noted in the introduction, velocity tomography and reflection imaging of crosswell seismic data become increasingly difficult as interwell offsets increase. For tomography, increased offsets restrict the range of ray angles through elements of the velocity tomography grid. For reflectivity imaging, increased crosswell offsets tend to merge reflected and direct arrivals. Figs A1–A2 illustrate these basic sources of crosswell seismic imaging difficulty. Figs A3–A5 demonstrate how far-offset imaging problems are manifested in Liaohe oil field crosswell seismics.

Tomographic crosswell seismic data cannot resolve horizontal velocity variations without suitably steep ray paths. For the horizontal velocity variation in Fig. A1 (left), the polar traveltome (right) shows that traveltimes for rays at angles less than 26° to the horizontal detect essentially the effective velocity $V = 7.5$ from mean slowness, $1/V = 1/5 + 1/15$. Rays at angles below 26° carry no information about the distinct blocks of velocity 5 and 15, and hence cannot be used to invert for the target velocity structure. Traveltome inversion for the block velocity structure requires ray angles in the range 25°–45° or greater. However, at crosswell separations of 400 m and 600 m, tomography traveltome data acquired for 300 m source/sensor traverses in vertical wells do not provide ray angles greater than 26.5° and 18.5°, respectively, and hence are not effectively inverted for horizontal velocity variation.

The effect of interwell offset on tomographic inversion is demonstrated in Fig. A3. The velocity model in Fig. A3(a) is used to simulate tomography traveltome data for offsets of 200, 400 and 600 m. Model velocities are, from top, 3.2, 2.9, 3.0 and 2.8 km s$^{-1}$. The velocity model is gridded in 1 m intervals over 600 m horizontally and 450 m vertically. Tomographic traveltomes are computed for vertical distributions of 60 sources and 60 sensors at 5 m intervals (295 m total well coverage) centred in the model at horizontal positions ±100, ±200 and ±300 m (model edges), respectively, in the velocity model A3(a). Subplots A3(b–d) are velocity tomograms for 200 (b), 400 (c) and 600 m (d) interwell offsets. The vertical and horizontal axes of tomograms (b–d) are scaled to the model interwell offset.

The simulation velocity model is a simple, large-scale structure with realistic (3–10 per cent) velocity contrasts but no significant small scale heterogeneity. No noise is added to the traveltome data to represent the observational errors of field data. The 200 m offset tomogram in Fig. A3(b) is moderately consistent with the model, as anticipated in the discussion of Fig. A1. However, again as anticipated in Fig. A1, the 400- and 600-m-offset tomograms are spatially-correlated numerical noise because the traveltome data do not present significant information keyed to velocity structure. Actual crosswell seismic targets are likely to be considerably more complex and noisy. Far-offset data are the most affected by seismic noise. Tomographic inversion of 600 m-offset crosswell seismic data acquired at the Liaohe oil field parallels the model results Figs A3(c)–(d).

Reflector imaging in crosswell seismics attempts to adapt simple horizon migration of upgoing wavefields in surface seismic data to reflected energy in crosswell seismics. Fundamental to the process is eliminating the ‘downgoing’ or direct wave energy from the crosswell gather to leave only the ‘upgoing’ or reflected energy. The direct/reflected wavelet separation problem for far-offset crosswell seismic data inversion is illustrated with noise-free synthetic data in Fig. A2. At moderate offsets, there is some expectation that the direct ray can be removed from the crosswell gather. At larger offsets,
Figure A1. (Left) Interwell velocity-grid elements traversed by ray paths at angles $15^\circ$, $30^\circ$ and $45^\circ$ to the horizontal (circles, dots, and pluses, respectively); grey shades mark velocity blocks $V' = 15$ and $V' = 5$. (Right) Effective ray path velocity as function of ray path angle to the horizontal, keyed to symbols of ray paths (left). Ray paths below $26^\circ$ sense effective velocity $V_{\text{eff}} = 7.5$ given by $1/V_{\text{eff}} = 1/5 + 1/15$; ray paths at angles between $26^\circ$ and $45^\circ$ sense effective velocities between 7.5 and 15; ray paths at angles greater than $45^\circ$ sense effective velocity 15. Crosswell ray paths with horizontal offset $X$ equal to maximum vertical offset $Z$ allow ray angles up to $45^\circ$; surveys with horizontal offsets $X = 2Z$ and $X = 3Z$ allow maximum ray angles $26.5^\circ$ and $18.5^\circ$, respectively. Crosswell tomography conducted at offsets $X = 2Z$ and $X = 3Z$ is not very sensitive to horizontal velocity structure such as depicted at left.

Figure A2. Synthetic crosswell seismic common sensor gathers for interwell separations $X = 200$ m (top), $X = 400$ m (middle), and $X = 600$ m (bottom). Each gather comprises direct and reflected arrivals from sources 50–350 m above a flat horizontal reflector; the sensor is 50 m above the reflector. Direct-ray first motion is followed by motion from reflected rays. At $X = 200$ m, direct and reflected wavelet arrivals cannot be separated until perhaps the source is 150 m above the reflector. At $X = 400$ m and 600 m, direct and reflected wavelet are perhaps separable when the source is 250–300 m above the reflector. The idealized gathers omit typical field data complications such as background seismic noise at the sensor, interface heterogeneity, wavelet distortion due to interwell heterogeneity and attenuation, decreasing source power at higher source-reflector distances and ray angles, and irregular source or sensor coupling. Figs A4 and 5 illustrate that these complications pose severe difficulties for reflector inversion.

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however, this expectation recedes. Generally, far-offset crosswell seismic data have reflected energy merged with direct energy.

Fig. A2, however, significantly understates the problems with reflector migration of far-offset data. Beyond the purely geometric problem of increasingly similar ray path geometries with increasing crosswell offset, problems arise with source power, source radiation aperture, source attenuation, and crustal heterogeneity. As readily seen in the main text, these aspects of crosswell seismics increasingly rob the reflector of definition. Moreover, the phases and amplitudes of reflected energy in actual data gathers are not those expected for vertically reflected plane wave energy in idealized surface seismic sections. Thus, even when reflected energy can be separated from direct energy in a far-offset gather, reflector migration is difficult.

Figs A4 and A5 illustrate the magnitude of the reflection inversion problem posed for field data even when reflected arrivals are well separated from direct arrivals.

Fig. A4 shows Survey 1 Fan 2 vector motion common sensor gathers in which direct arrivals are well separated from energy arriving from two reflectors. The reflected energy is due to the strong velocity contrasts seen in the well logs of Fig. 2 and in the velocity grid models of Figs 9–11. Reflector R1, down to the right from the left edge, arises at the large-scale velocity layer above the Survey 1 interval of Fig. 2. Reflector R2, down to the left in the centre of the section, arises at the top of the reservoir. Direct arrivals are so indicated.

Despite the unusually clear reflector definition in Fig. A4, Fig. A5 shows that application of a standard ray theoretical migration algorithm to the 650-m-offset Fan 2 data fails to accurately resolve either of the clearly visible reflectors, and implies a spurious sense of reservoir discontinuity. The image shows a down-to-the-right trend at the top of the section (loop R1), whereas the reflector R1 is known from well logs and ray trace modelling to have up-to-the-right dip. The image indicates an up-to-right dip in midsection (loop R2) whereas well logs and ray tracing establish that top-of-reservoir reflector R2 dips down to right. Finally, the image suggests that horizons are not continuous across the crosswell section A–A′, while Survey 1 waveguide phenomenology clearly indicates excellent reservoir continuity.

Reflection migration imaging failure for the Fig. A4 data is almost certainly related to the complexity of the physics of far-offset reflections, and the presence of noise in the seismograms. However, the most obvious point to make is that the clear and pronounced reflector definition of Fig. A4 is the exception rather than the rule at far offsets. In the more usual far-offset gathers seen in the main text and modelled in Fig. A2, reflector energy merges with direct energy. Attempts at reflector migration processing of standard Liaohe crosswell gathers produced reflector ‘images’ that admit of no sound structural interpretation.

While the Liaohe oil field examples of model and field data illustrate the imaging problems faced by far-offset crosswell seismic data, the examples do not ‘prove’ that it is impossible to extract valid information with sufficient modelling and interpretation effort. However, the examples indicate that the principles of crosswell seismic tomography and reflector imaging are increasingly fragile as crosswell offsets increase. In contrast, the Liaohe waveguide signals show that the principles of waveguide study with crosswell seismics are robust at the crosswell offsets required for application to oil fields worldwide.

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Figure A4. Survey 1 Fan 2 crosswell seismic raw sections for vertical and in-line horizontal components of sensor motion for Sensor 1 (upper pair) and Sensor 2 (lower pair). Reflectors R1 and R2 are clearly defined behind the direct arrival. R1 (down to the right from the left) is due to the large well-log velocity event at depth 2200 m in Survey 1 sensor well 2727 in Fig. 2. R2 (down-to-the-left in centre) is the top of the sand-shale reservoir sequence seen at depth 2525 m in the same well log. The direct arrivals form a rough hyperbolic traveltime curve across the gathers. Fig. A5 shows that at 650 m offsets the clearly defined reflectors R1 and R2 do not support an accurate reflector migration image.

Figure A5. Migration-algorithm reconstruction of Survey 1 far-offset crosswell reflectors R1 and R2 in Fig. A4. The image is essentially spatially-correlated band-limited noise. Horizontal structures may be inferred from the image, but the implied structural elements are inaccurate. Image section loop R1 shows a down-to-the-right trend at the top of the section; Fig. 2 well logs and traveltime modelling show that reflector R1 has up-to-the-right dip. Image section loop R2 shows an up-to-the-right trend in the middle; Fig. 2 well logs and traveltime modelling show that reflector R2 has down-to-the-right dip. The image suggests that horizons are not continuous across image section A–A'; Survey 1 waveguide phenomenology indicates excellent reservoir continuity.

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