Borehole acoustic reflection survey (BARS) using full waveform sonic data

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From borehole-sonic data, strongly dominated by modes refracted along the borehole, we can generate images of the formation around the well. This is achieved by using adaptive algorithms which separate the components of the wavefield refracted along the wellbore from the components escaping the wellbore and subsequently reflected at bed interfaces, fractures, and possible faults. The reflection data are converted into images of the formation using synthetic-aperture processing. We show how the information provided by the sonic images at decimeter resolution can contribute to significant changes in the understanding of a reservoir.

Sonic tool
A sonic tool makes acoustic measurements related to the formation surrounding the wellbore with resolution along the well of 1 ft (0.3 m). The radial depth of investigation may be as large as 33 ft (10 m). Figure 1 shows schematics for the sonic tool used for acquiring the data described in the present paper. The tool has 104 acoustic receivers, located in 13 radial arrays, spaced one every 6 in (15.24 cm). Each array consists of eight receivers spaced every 45° around the tool’s circumference. The tool and, consequently, all the receivers, are oriented in space by included azimuthal and inclinometry sensors.

Energy is provided by transmitters (two near-monopole and one far-monopole) as well as two orthogonal dipole transmitters. The monopole transmitters emit clear high amplitude waves of both high and low frequencies for formation evaluation as well as the high frequency waves required for cement evaluation. The crossed-dipole transmitters provide a multi-frequency sweeping signal transitioning from 300 Hz to 8 kHz each time they fire. They generate the flexural waves needed for characterization of shear wave slownesses in slow and anisotropic formations. Together, the transmitters excite high and low frequency P- and S-waves, low frequency Stoneley waves, and fast and slow flexural waves with excellent signal-to-noise ratios. The tool can be used in both open holes and cased holes and is combinable with higher resolution investigations (e.g., for complete cement evaluation).

Images from sonic data
The acoustic waves emitted from the sonic tool are scattered and reflected from inhomogeneities in the formation outside the wellbore (see Figure 2). The idea of sonic imaging has been through a number of different implementations since the original work by Hornby (1989), using a tool with 12 axial receiver stations.

The wellbore is an excellent guide for acoustic waves. This means that the reflected energy would normally be overpowered by energy trapped in the wellbore. Much of the early work on sonic imaging (e.g., Esmersoy et al., 1998 and Yamamoto et al., 1999) concentrated on finding ways to separate these trapped modes from the reflected wavefield components by means of different hardware contraptions. More recent work by Haldorsen et al. (2005), Haldorsen et al. (2006), and Hirabayashi et al. (2008) achieve this separation by new powerful data-adaptive algorithms (borehole acoustic reflection survey, or BARS), allowing the use of sonic imaging data acquired by the tool in its standard configuration.

Several potentially severe problems are solved by using the sonic tool in its standard configuration:

- The large dynamic range of the sonic tool (giving digitized data at 16-bit resolution) allows weak reflections to be recorded in the presence of powerful modes trapped in the wellbore.
- The simply shaped construction of the sonic tool makes it possible to apply powerful model-guided adaptive filters to separate the strong guided modes from the weak reflections.

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transmitters [two offset by 1 ft (0.3 m) on either end of the receiver section (Figure 1, MU and ML) and one that is 11 ft (3.35 m) below the receiver array (Figure 1, MF)] and the entire receiver array to determine the distance and direction to acoustic reflectors, boundaries characterized by distinct changes in acoustic impedance. These can be the result of lithology changes, faults, and fractures, or gas/liquid contacts. It is not necessary for the boundary to intersect the borehole to be imaged, nor is it necessary for the boundary to be parallel to the regional dip.

Data processing

The data processing methods and procedures are summarized as follows:

- Adaptive filters based on the acoustic properties of the near-wellbore formation are used to separate reflected waves from powerful refracted and trapped waves.
- The estimated acoustic slowness determines the transformation of the reflection data to images.
- Thirteen receivers, each with eight separate azimuths (Figure 3) make it possible to determine at which side of the wellbore a reflector is located.

The ‘standard’ analysis of the sonic waveforms will give propagation velocities for the formation. The BARS technique, as laid out by Haldorsen et al. (2005), is essentially a processing tool: a way of extracting formation properties from acoustically reflected components of the wavefield, and, as such, BARS does not require a special run. The imaging technique uses ‘triangulation’; the location of a reflecting body is calculated using the formation velocities in combination with the measured propagation times from a variety of different tool settings. Thus, a fundamental requirement for accurate BARS logging is good depth control. Also, the maximum distance one can see into the formation will be determined by the length of the recording time window: one will not see an acoustic reflector when the propagation time from the source to the reflector and back to the receiver is longer than the time window of the recorded data.

In the following we will show the results from applying BARS analysis to data acquired using the sonic tool. The waveforms were generated by the three monopole transmitters [two offset by 1 ft (0.3 m) on either end of the receiver section (Figure 1, MU and ML) and one that is 11 ft (3.35 m) below the receiver array (Figure 1, MF)] and the entire receiver array to determine the distance and direction to acoustic reflectors, boundaries characterized by distinct changes in acoustic impedance. These can be the result of lithology changes, faults, and fractures, or gas/liquid contacts. It is not necessary for the boundary to intersect the borehole to be imaged, nor is it necessary for the boundary to be parallel to the regional dip.

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Figures 5–8 show sonic full-waveform data from about 300 ft (90 m) of a mostly horizontal well shown in Figure 4. In Figure 5 we show a fixed-receiver section of raw, unprocessed data. The wavefield separation is done at fixed-azimuth records for each monopole source separately (Figure 6). This is the domain in which the refracted wavefield components are most readily identified. The slowness values from the sonic logs are adaptively adjusted to optimally remove the refracted waves. On the filtered data (Figure 7) one can
already see a feature near the wellbore, changing at about 8675 ft (2644 m). The wavefield migration gives a clear image of this feature (Figure 8), seen to be about 5 ft (about 1.5 m) from the wellbore.

**Image focusing**

After applying adaptive noise-cancellation filters, and wavefield migration, we may have eight images, each centred on the corresponding set of azimuthal receivers. An azimuthally focused image is formed by applying a high resolution adaptive beam former to these images. The focusing technique could use all the waveforms or an adequate subset of them. Although the tool has eight sets of hydrophone receivers arranged around the perimeter of the tool, we often use only four of these. The BARS image will be best be only quasi 3D because of the acquisition geometry in which the sources and receivers are all within a mostly linear borehole, giving reflections mainly from the point of a formation feature nearest to the sources and receivers. The calculated images offer information about the fine structure of the reservoir, information otherwise not read-

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**Figure 5** Raw waveforms of a fixed receiver. The horizontal and vertical axes show the measurement depth and recording time, respectively. The borehole guided waves (e.g., compressional, shear, and Stoneley waves) are dominant, and the reflected event signals are hard to distinguish.

**Figure 6** Filtered waveforms of a fixed azimuth at varying stages of wavefield separation. The filtering process proceeds from left to right. The left- and right-end figures show the raw and final filtered waveforms. In the right-end figure, the event signal is separated from the strong borehole-guided waves.

**Figure 7** Filtered waveforms of a fixed receiver (same section of Figure 5). A feature found near the wellbore changes at a depth of about 8675 ft (2644 m).

**Figure 8** Wavefield migration image for a fixed azimuth. The wavefield migration gives a clear image of this feature, seen to be about 5 ft (1.5 m) from the wellbore.
for the purpose of formation imaging. In principle, any multi-azimuth, high quality, full-waveform sonic dataset (such as the data acquired by the sonic tool) can be used for imaging.

**Azimuthal focusing**

A separate image is generated for each of the eight receivers around the perimeter of the tool, each measuring a slightly different distance to a scanner. Using all or a subset of the eight images, at each depth setting of the tool, we can generate a map of reflected energy versus distance and azimuth to the reflector shown in Figure 9. In this case we used four receivers, and the indication is that at a depth of 8700 ft (2651.7 m) there is a reflector about 5 ft (1.5 m) away from the wellbore, directly overhead.

Figure 10 Maps of reflected energy versus distance and azimuth to the reflector. The vertical and horizontal axes show distance from the wellbore and azimuth, respectively, in the left figure, and the 2D section is shown in the right figure.

Figure 11 Reflector image containing subseismic faults. The box in the left figure is zoomed in the right figure. The throw of each of the two faults is about 0.3 m.
How good the azimuthal separation is depends to a varying degree on the frequency of the source and the source/receiver offset relative to the distance to the reflector, as well as on the diameter of the tool. From Figure 10, it can be seen that the distance to the feature 5 ft (1.5 m) above the wellbore is better determined than the azimuth to the nearest point on the reflector.

**Application 1**
Figure 11 shows sections of the image obtained from the data used for illustration in the preceding section. The vertical section along the wellbore shows details of subseismic faults in the roof of the reservoir. The throw of each of the two faults is about 0.3 m.

**Application 2**
The images shown in Figures 12 and 13 were generated to confirm the placement of a well supposed to be placed within 0 to 3 m from the reservoir shale cap. The data were acquired in a well that had been geosteered using an omnidirectional resistivity tool. The BARS image shows how the cap rock disappears out of range. In this case, the tool had been set to record 5 ms of data (512 samples at 10 ms). In this formation, 5 ms of data gives a range limit of about 7 m. The tool can be configured to record up to 1000 samples (at 20 ms, this would have extended the limits of this image to close to 30 m).

**Application 3**
Figure 14 shows a BARS image from Campos Basin, Brazil (from Maia et al., 2006). The objective for the imaging was to confirm the well placement and to better define the turbidite reservoir geometry. The image extends horizontally about 600 m and vertically about 20 m. Figure 15 shows the
surface-seismic image used for planning the well, together with the planned and drilled well trajectories. The well was steered by measuring formation dips and assuming that the turbidite sand reservoir had a constant thickness of 4 m. The solid green and the blue dashed lines in Figure 14 indicate the top and bottom of the reservoir as interpreted from the BARS image. At about 1 m above the well, on the right near the toe of the well, one can see a horizontal, flat event – an indication of a density separation of the hydrocarbons, possibly a gas/oil interface.

Conclusions
The relatively short-range sonic-scale images generated from full waveform borehole-sonic data, showing several orders of magnitude higher resolution compared to seismic data, reveal detailed information of the rock formations up to 20 m from the wellbore. We have shown how this information – hitherto not available to the reservoir engineer – can be used to improve the understanding of a reservoir.

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References