Borehole Seismic Surveys: Beyond the Vertical Profile

Today's borehole seismic methods create new opportunities for investigating formations penetrated by a borehole. From well construction and 3D subsalt imaging to stimulation monitoring and high-pressure, high-temperature acquisition, borehole seismic surveys reduce operator risk and help improve recovery.

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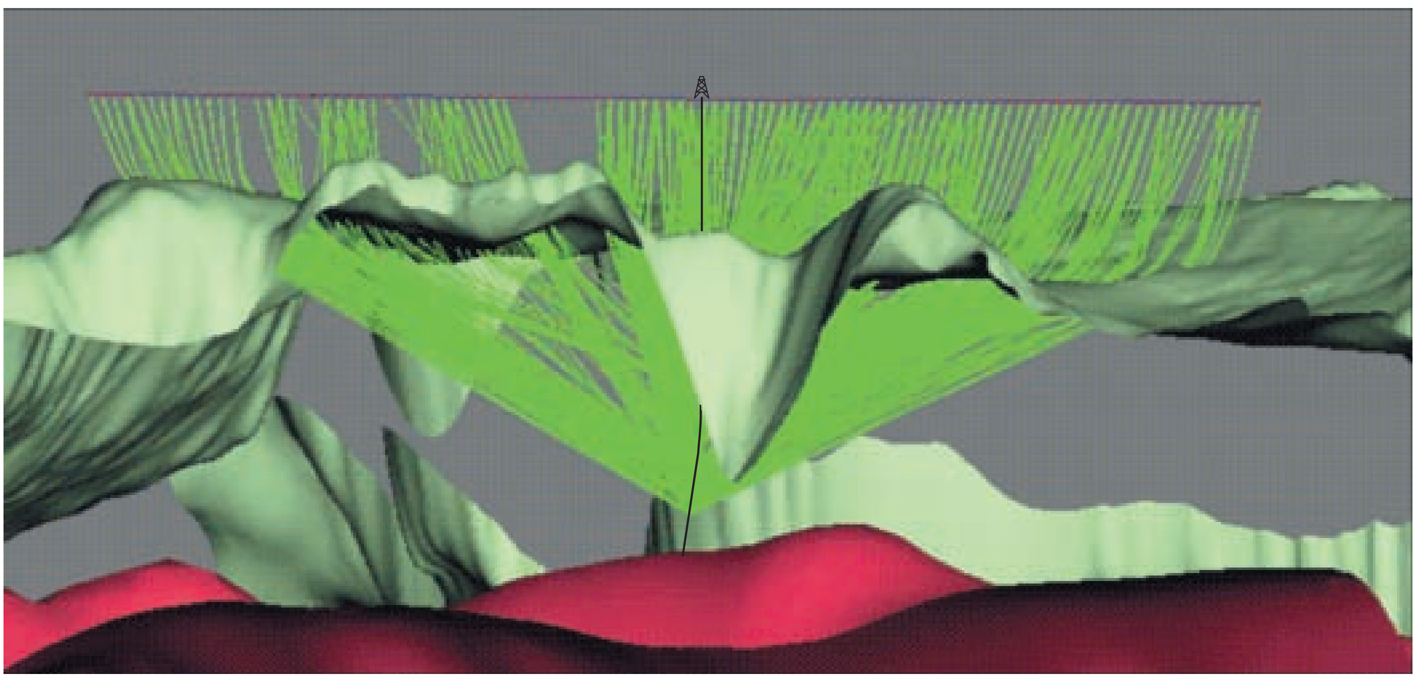

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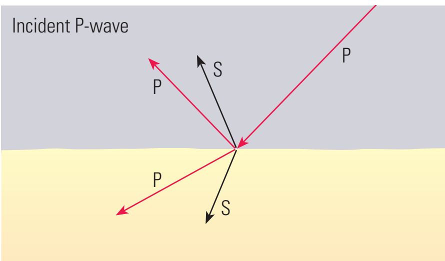
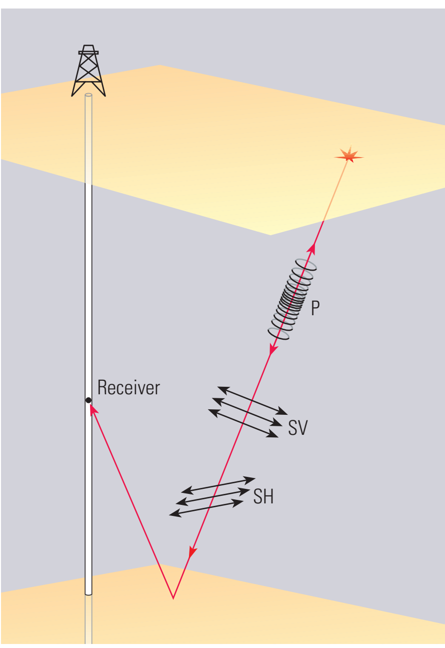
1. Point sources are implosive or explosive sources, such as dynamite or airguns. Sweep sources are vibroseis trucks or other vibrating sources.
2. Marine vibrating sources have been attempted: Fischer PA: "Seismic Source Offerings Provide Options for Operators," *World Oil* 227, no. 6 (June 2006), http://www.worldoil.com/magazine/MAGAZINE_DETAIL.asp?ART_ID=2913&MONTH_YEAR=Jun-2006 (accessed October 8, 2007).
3. Arroyo JL, Breton P, Dijkerman H, Dingwall S, Guerra R, Hope R, Hornby B, Williams M, Jimenez RR, Lastennet T, Tulett J, Leaney S, Lim T, Menkiti H, Puech J-C, Tcherkashnev S, Burg TT and Verliac M: "Superior Seismic Data from the Borehole," *Oilfield Review* 15, no. 1 (Spring 2003): 2–23.

Borehole seismic surveys are now among the most versatile of all downhole measurement techniques used in the oil field. Historically, the main benefit derived from these surveys, also known as vertical seismic profiles (VSPs), has been to link time-based surface seismic images with depth-based well logs. However, today's borehole seismic surveys have expanded beyond a simple time-depth correlation. The wide spectrum of seismic energy that is now recorded and the various geometries currently possible with borehole seismic surveys combine to deliver results not previously available. From these data, E&P companies derive important information about reservoir depth, extent and heterogeneity, as well as fluid content, rock-mechanical properties, pore pressure, enhanced oil-recovery progress, elastic anisotropy, induced-fracture geometry and natural-fracture orientation and density.

Originally, VSPs consisted of receivers deployed in a vertical borehole to record the most basic signals from a seismic source at the surface. The innovations delivered by modern VSPs have come about by recording more information and expanding survey geometries with improved acquisition tools. This article describes the types of waves that can be recorded in the borehole, and the tools that record them. We then briefly catalog the many types of surveys that can be acquired, along with the information they can provide. We continue with case studies demonstrating advances in borehole seismic surveys, including 3D VSPs and VSPs acquired while drilling, optimizing hydraulic fractures, monitoring perforation operations, and VSP acquisition in high-pressure, high-temperature conditions.





^ Propagation and reflection of compressional and shear waves. At normal incidence, compressional *P*-waves reflect and transmit only as *P*-waves. However, at incidence other than normal, such as when the source is placed some distance from the rig, an incident *P*-wave can reflect and transmit *P*-waves and shear *S*-waves (*top*). *P*-waves have particle motion along the direction of propagation, and *S*-waves have particle motion orthogonal to the direction of propagation (*bottom*). *SV*-waves are polarized in the vertical plane and *SH*-waves are polarized in the horizontal plane. Incident *SV*- and *SH*-waves are generated by shear-wave sources.

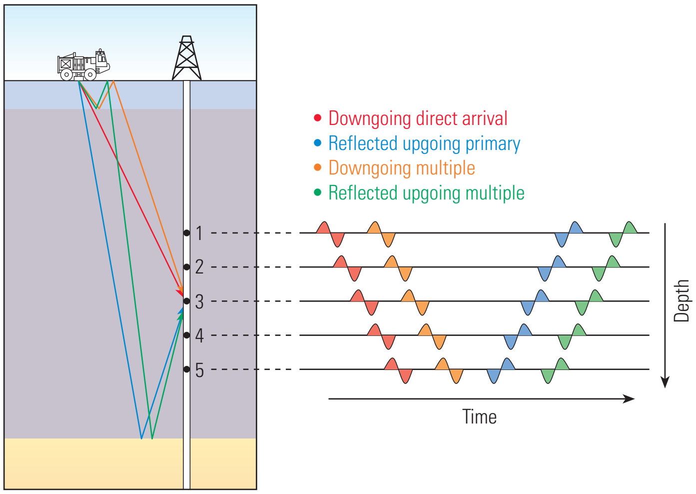
Types of Waves

The main types of waves generated and recorded in borehole seismic surveys are body waves emitted by point sources or frequency-sweep sources, and consist of compressional, or primary, *P*-waves and shear, or secondary, *S*-waves.[1] These waves propagate from man-made sources near the surface to borehole receivers at depth. In the case of marine VSPs, and where land VSPs deploy airguns in a mud pit, typically only *P*-waves are generated. However, depending on the receiver geometry and formation properties, both *P*-waves and *S*-waves may be recorded if *S*-waves have been generated by conversion from a reflecting *P*-wave (below left). For land VSPs with sources coupled directly to the earth, both *P*- and *S*-waves are generated and may be recorded.[2]

The signals recorded by borehole receivers depend on the incoming wave type, the survey geometry and the type of receiver. Most modern downhole hardware for recording VSPs consists of clamped, calibrated three-component (3C) geophones, which are able to record all components of *P*- and *S*-wave motion, including *SV*- and *SH*-waves.

The Schlumberger borehole seismic tool, the VSI Versatile Seismic Imager, offers up to 40 three-component receivers, called shuttles, that can be spaced up to 150 ft [46 m] apart to form an array 6,000 ft [1,830 m] long (below).[3] The 40-shuttle tool has been deployed several times for VSP acquisition in the Gulf of Mexico. The VSI tool

^ VSI Versatile Seismic Imager. Each of the 40 VSI shuttles contains three orthogonally oriented geophone accelerometers in an acoustically isolated sensor package that can be clamped to the borehole wall.



^ Upgoing, downgoing, primary and multiple arrivals. Upgoing waves reflect at interfaces below the receiver and then travel upward to be recorded (blue and green). Downgoing waves arrive at the receivers from above (red and orange). A wave that arrives at the receiver without reflecting is called the direct arrival (red). Waves that reflect only once are called primaries. The reflected upgoing primary (blue) is the arrival that is desired for imaging reflections.

can be run in open hole, cased hole or drillpipe, and is clamped into position to provide optimum coupling. Options for conveyance include wireline, downhole tractor or drillpipe.

An advantage that borehole seismic surveys have over their surface seismic counterparts is their capability to record direct signals in a low-noise environment. The direct signal travels downward to the receivers, and so is referred to as a downgoing signal. Waves that reflect at deeper interfaces and then travel up to a borehole receiver are recorded as upgoing signals (above). Upgoing signals contain reflection information, and are used to create seismic images of subsurface reflectors. Both upgoing and downgoing signals can contain multiples, or energy that has reflected multiple times, which can interfere with the desired signal. Signals without multiples are called primaries. Downgoing signals can be used to distinguish multiples from primary arrivals, and to enable more reliable processing of the surface seismic upgoing wavefield.

In conjunction with *P*- and *S*-waves, which propagate from a near-surface source to the receiver, different types of source-generated noise arise. Tube waves are formed when source-generated surface waves transfer energy to the borehole fluid. The resulting fluid-guided wave travels down and up the borehole, forcing the borehole wall to flex radially. Receivers clamped to the borehole wall record tube-wave energy on horizontal geophone components. Tube waves are sensitive to changes in borehole dimension, which can cause them to reflect. Another form of noise that sometimes contaminates recordings is casing ringing.

The majority of VSPs use compressional and shear waves from airguns, vibrating trucks or dynamite sources for imaging reflectors, but energy from other sources can be recorded and processed to yield information about the subsurface. For example, the drill bit can act as a downhole source, generating vibrations that are detected by sensors deployed at surface or on marine cables.[4] These recordings require specialized processing, but can provide critical answers in time for decisions to be made while drilling, such as changing mud weight or setting casing.

Hydraulically induced fractures emit energy in much the same way as natural earthquakes, and these microseisms can be recorded by sensors in neighboring boreholes. Similarly, production of fluids or injection of fluids for enhanced recovery or waste disposal all induce stress redistribution that in turn can cause detectable microseismicity. And finally, borehole sensors can be used to record natural seismicity.[5]

Types of Surveys

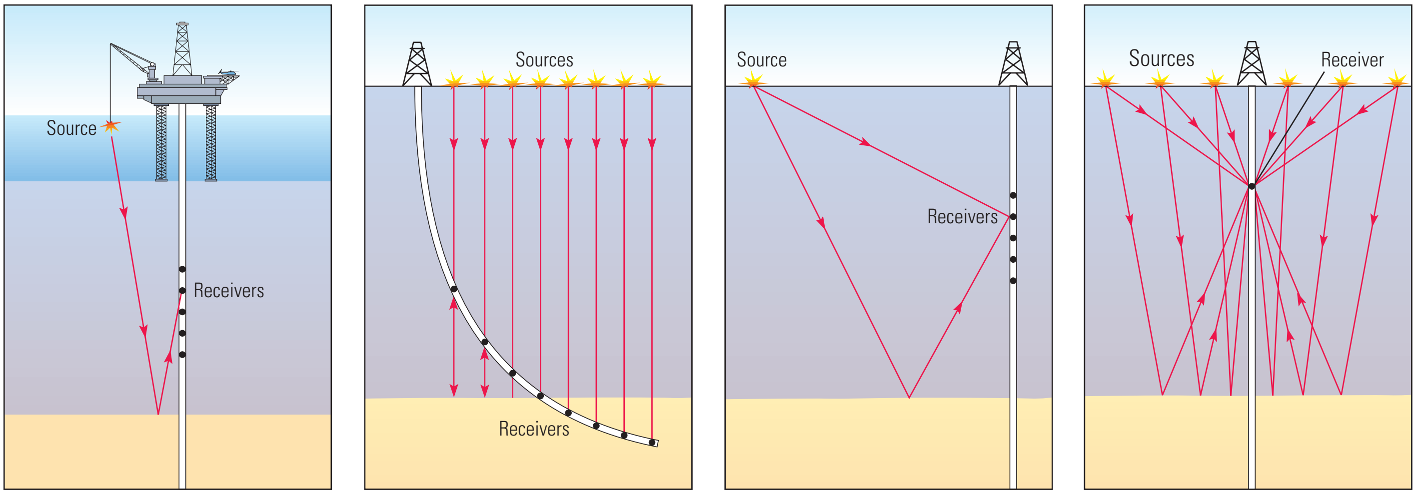
Borehole seismic surveys are usually categorized by survey geometry, which is determined by source offset, borehole trajectory and receiver-array depth. The survey geometry determines the dip range of interfaces and the subsurface volume that can be imaged.

The simplest type of borehole seismic survey is the zero-offset VSP. The basic zero-offset VSP features a borehole seismic receiver array and a near-borehole seismic source (next page, top). In most cases (unless formation dips are very high), this survey acquires reflections from a narrow window around the borehole. The standard output from a zero-offset VSP is a corridor stack, created by summing the VSP signals that immediately follow the first arrivals into a single seismic trace. That trace is duplicated several times for clarity and comparison with surface seismic images. Processing yields velocities of formations at different depths, which can be tied to well log properties and interpreted for detection and prediction of overpressured zones. The velocity model can also be used to generate synthetics to identify multiples in surface seismic processing.

Another type of zero-offset VSP is known as a deviated-well, walkabove, or vertical-incidence VSP. It is designed to ensure that the source is always directly above receivers deployed in a deviated or horizontal wellbore. This survey acquires a 2D image of the region below the borehole. In addition to formation velocities and an image for correlation with surface seismic data, benefits of a walkabove VSP are good lateral coverage and fault and dip identification beneath the well.

Offset VSPs are acquired using a source placed at a horizontal distance, or offset, from the wellbore, again producing a 2D image. The receiver arrays are deployed at a wide range of depths in the borehole. The offset increases the volume of subsurface imaged and maps reflectors at a distance from the borehole that is related to the offset and subsurface velocities. The added volume of illumination enhances the usefulness of the image for correlation with surface seismic images, and for identification of faulting and dip laterally away from the borehole. In addition, because the conversion of *P*-waves to *S*-waves increases with offset, an offset VSP allows shear-wave, amplitude variation with offset (AVO) and anisotropy analysis. The degree to which *P*-waves convert to *S*-waves depends on offset and on interface rock properties.

Walkaway VSPs are similar to offset VSPs in that the source is offset from vertical incidence, but the acquisition geometry is somewhat reversed. The borehole receiver array remains stationary while the source moves away from it, or "walks away" at a range of offsets. The range of offsets acquired in a walkaway VSP is particularly useful for studying shear-wave, AVO and



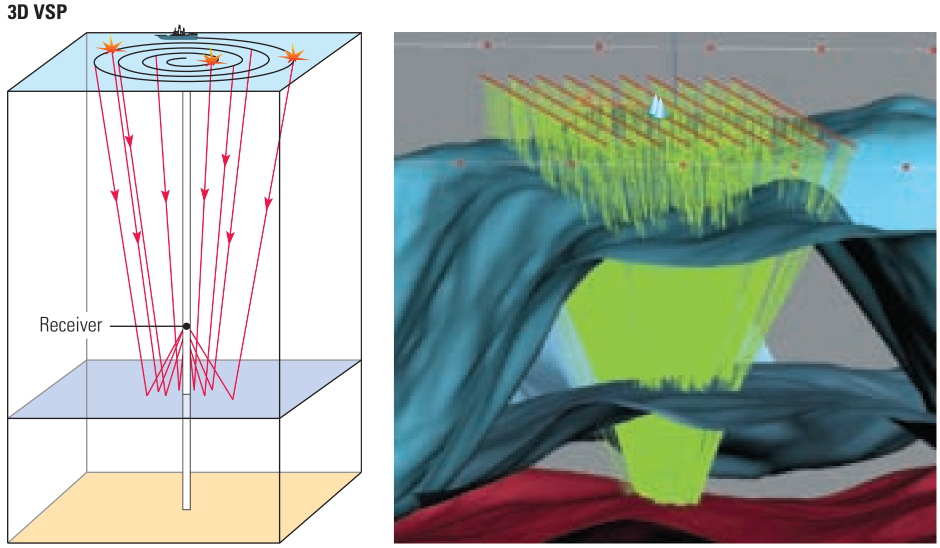
^ Variations on a theme of VSPs (*left to right*). The original acquisition geometry, with no offset between source and wellbore, creates a zero-offset VSP. Seismic waves travel essentially vertically down to a reflector and up to the receiver array. Another normal-incidence, or vertical-incidence, VSP is acquired in deviated wells with the source always vertically above each receiver shuttle. This is known as a deviated-well, or walkabove VSP. In an offset VSP, an array of seismic receivers is clamped in the borehole and a seismic source is placed some distance away. The nonvertical incidence can give rise to *P*- to *S*-wave conversion. In walkaway VSPs, a seismic source is activated at numerous positions in a line on the surface. All these survey types may be acquired onshore or offshore.

anisotropy effects. And, because they can illuminate a large volume of subsurface, offset and walkaway VSPs are useful elements in the design of surface seismic surveys.

The surveys described so far are all designed to provide information and images in one or two dimensions. To adequately illuminate 3D structures requires 3D acquisition and processing. In the same way that surface seismic surveys have progressed from 1D and 2D to 3D, so have VSPs.

Three-dimensional VSPs can be acquired on land or offshore. Acquisition of 3D marine VSPs is similar to that of 3D marine surface seismic surveys and can follow parallel lines or concentric circles around a borehole (right). On land, source positions typically are laid out in a grid. Three-dimensional VSPs deliver high-resolution subsurface imaging for exploration and development applications, and require detailed prejob modeling and planning. In addition to producing images at higher resolution than surface seismic methods, 3D VSPs can fill in areas that cannot be imaged by surface seismic surveys because of interfering surface infrastructure or difficult subsurface conditions, such as shallow gas, which disrupts propagation of *P*-waves.

3D VSP

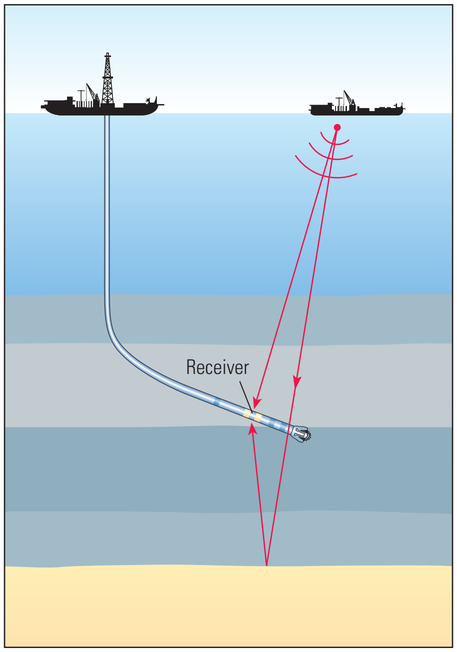


^ Three-dimensional VSPs. Onshore and offshore, 3D VSPs tend to borrow surface seismic acquisition geometries. On land, source positions usually follow lines in a grid. Offshore, source positions can be laid out in lines or in a spiral centered near the well (*left*). Ray-trace modeling prior to acquisition ensures proper coverage and illumination of the target. In this offshore example (*right*), source lines at the surface are shown in red. Green lines are rays traced from source to receiver. Wells are positioned at the light blue triangles at the surface. Blue surfaces are the top and bottom of a salt body. The target horizon is the red surface at the bottom.

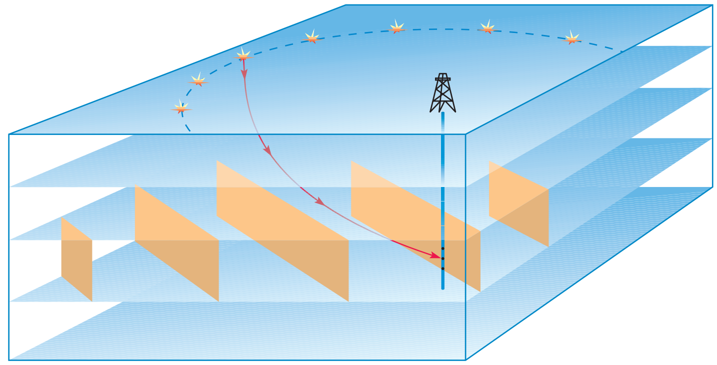
4. Breton P, Crepin S, Perrin J-C, Esmersoy C, Hawthorn A, Meehan R, Underhill W, Frignet B, Haldorsen J, Harrold T and Raikes S: "Well-Positioned Seismic Measurements," *Oilfield Review* 14, no. 1 (Spring 2002): 32–45.

5. Coates R, Haldorsen JBU, Miller D, Malin P, Shalev E, Taylor ST, Stolte C and Verliac M: "Oilfield Technologies for Earthquake Science," *Oilfield Review* 18, no. 2 (Summer 2006): 24–33.

VSP While Drilling



^ A VSP while drilling. The seismicVISION seismic-while-drilling tool positioned near the drill bit receives signals generated by a seismic source at the surface. Signals are transmitted to the surface for real-time, time-depth information.



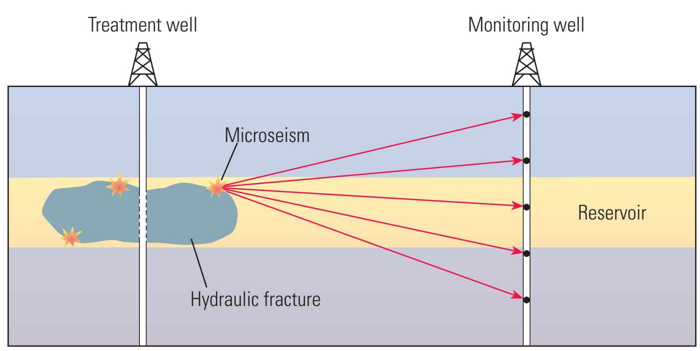
^ A walkaround VSP. With the offset source at several azimuths, this survey can detect anisotropy caused by aligned natural fractures.

VSPs have long been used to tie time-based surface seismic images to depth-based well logs. In many exploration areas, the nearest wells may be quite distant, so VSPs are not available for calibration before drilling begins on a new well. Without accurate time-depth correlation, depth estimates derived from surface seismic images may contain large uncertainties, adding risk and the cost of contingency planning to drilling programs. One way to develop a time-depth correlation is to perform an intermediate VSP: to run a wireline VSP before reaching total depth (TD). These surveys provide reliable time-depth conversions, but add cost and inefficiency to the drilling operation, and may come too late to forecast drilling trouble.

To help reduce uncertainty in time-depth correlation without having to stop the drilling process, geophysicists devised a seismic-while-drilling process (above left). This technology uses a conventional seismic source at the surface, an LWD tool containing seismic sensors in the drillstring, and a high-speed mud-pulse telemetry system to transmit information to the surface.[6] Availability of real-time seismic waveforms allows operators to look thousands of feet ahead of the bit to safely guide the well to TD. Because drilling generates noise that could jeopardize seismic data quality, source activation and signal measurement must take place during quiet periods, when drilling has paused for other reasons, such as making drillpipe connections. A limitation of this method is that the seismic LWD receivers, being part of the drillstring, are not clamped to the borehole wall, although formation-receiver coupling generally improves with well deviation.

Several borehole seismic technologies are available for understanding fractures and fracture systems, both natural and hydraulically induced. The walkaround VSP is designed to characterize the direction and magnitude of anisotropy that arises from aligned natural fractures. In this survey, offset source locations span a large circular arc to probe the formation from a wide range of azimuths (above).[7]

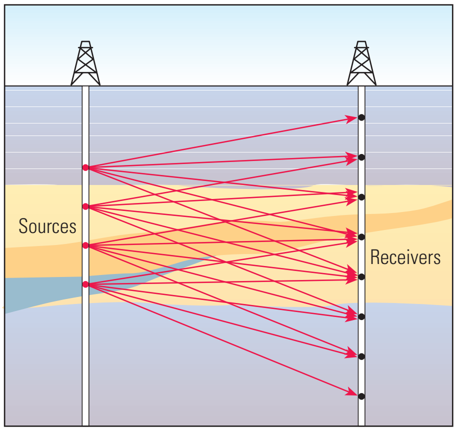
Hydraulically induced fractures can also be monitored using borehole seismic methods. While the fracture is being created in the treatment well, a multicomponent receiver array in a monitor well records the microseismic activity generated by the fracturing process (below). Locating hydraulically induced microseismic events requires an accurate velocity model.



^ Microseismic method of hydraulic fracture monitoring. Sensitive multicomponent sensors in a monitoring borehole record microseismic events, or acoustic emissions, caused by hydraulic fracturing. Data processing determines event location, and visualization allows engineers to monitor the progress of stimulation operations.

6. Breton et al, reference 4.
7. Horne S, Thompson C, Moran R, Walsh J, Hyde J and Liu E: "Planning, Acquiring and Processing a Walkaround VSP for Fracture Induced Anisotropy," presented at the 64th EAGE Conference and Exhibition, Florence, Italy, May 27–30, 2002.
8. The fluid injection under discussion here is for pressure support, not for hydraulic fracturing.
9. Hornby BE, Yu J, Sharp JA, Ray A, Quist Y and Regone C: "VSP: Beyond Time-to-Depth," *The Leading Edge* 25, no. 4 (April 2006): 446–448, 450–452.
10. Leaney WS and Hornby BE: "Subsalt Elastic Velocity Prediction with a Look-Ahead AVA Walkaway," paper OTC 17857, presented at the Offshore Technology Conference, Houston, May 1–4, 2006.

Crosswell VSP



^ Crosswell seismic surveys, with sources in one borehole and receivers in another. Because raypaths are at large angles to any formation interfaces, little energy is reflected; most energy recorded by the receivers comes from direct arrivals. These data reveal information about formation velocities in the interwell volume. The repeatable survey geometry makes crosswell seismic surveys useful for time-lapse monitoring of steam injection, for example.

Mapping the extent of the fracture with time helps monitor the progress of stimulation treatments and allows comparison between actual and planned fractures. Real-time information about fracture extent and orientation promises to help stimulation engineers optimize treatments by allowing them to modify pumping rates and volumes when observed fractures differ from plan. A drawback of the method is that nearly all applications have required deploying the receiver array in a monitoring well because it is believed that the treatment well is too noisy. The cost of drilling a monitoring well could be saved if the technology could be applied in treatment wells.

Another borehole seismic technology, called passive seismic monitoring, characterizes fractures by recording microseismic signals generated when fluid is produced from or injected into a naturally fractured reservoir. When fluid injection and production modify the stress state enough to cause seismic events, the resulting acoustic emissions can be recorded in nearby monitoring wells by arrays of multicomponent borehole receivers.[8] The technique is similar to monitoring hydraulic fractures, but the events are smaller in magnitude. The microseismic events can be plotted in space and time to identify the fractures that are responding to the change in stress state. Because the timing of microseismic events cannot be predicted, acquisition systems for passive seismic monitoring must be different from standard VSP acquisition systems. Recording systems need to be active for long periods of time, waiting to be triggered by acoustic emissions. In some cases, receiver arrays are installed permanently to record for extended periods.

Propagating seismic signals between wells creates yet another type of borehole seismic profile, known as a crosswell seismic survey (left). In these surveys, downhole seismic sources, such as downhole vibrators, are deployed at selected depths in one borehole, shooting to a receiver array in another borehole. Because the direction from source to receiver is subparallel to layer boundaries, most raypaths propagate without reflecting. Recorded data are processed to extract information about the velocities in the interwell region. Since crosswell data do not contain much information about reflectors, layer boundaries in the initial velocity model used to process the crosswell data typically come from sonic logs or standard VSPs. A limitation of the crosswell method is the maximum allowable distance between boreholes—a few thousand feet is typical—which varies with rock type, attenuation, and source strength and frequency content.

Many of the borehole seismic surveys mentioned above can be acquired at different stages in the life of a reservoir. Offset VSPs, walkaways, 3D VSPs and crosswell surveys can also be acquired in time-lapse fashion, before and after production. Time-lapse surveys can reveal changes in the position of fluid contacts, changes in fluid content, and other variations, such as pore pressure, stress and temperature. As with time-lapse surface seismic surveys, care must be taken to repeat acquisition conditions and processing as closely as possible so that differences between baseline and monitoring surveys may be interpreted as changes in reservoir properties.

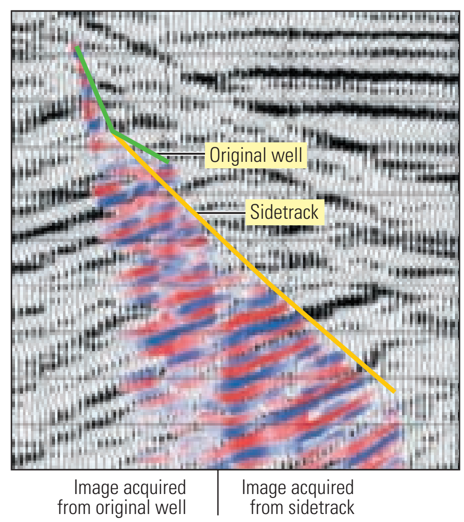
The VSP method has evolved from its humble beginnings as a time-depth tie for surface seismic data to encompass a wide range of solutions to exploration and production problems.[9] The remainder of this article is devoted to case studies that highlight the versatility of today's borehole seismic surveys, starting with VSPs acquired while drilling.

Reducing Uncertainty in Well Construction

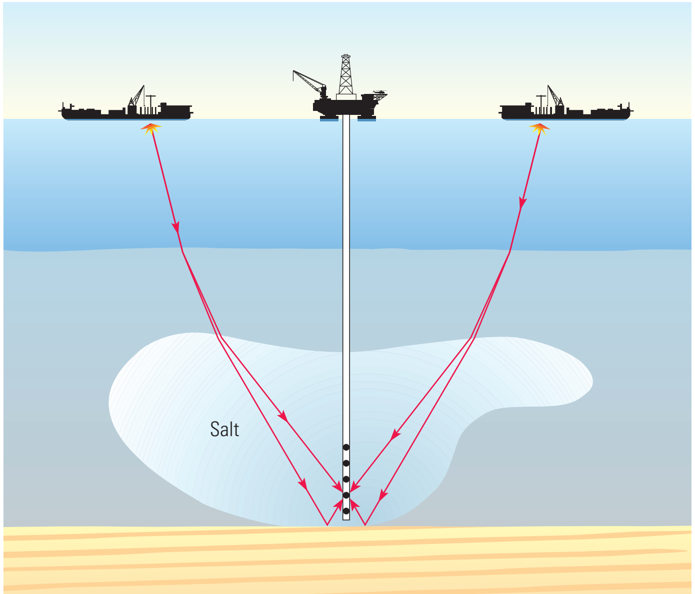
Borehole seismic surveys are best known for their ability to tie time-based seismic sections to depth-based information such as well logs and drilling depths. These correlations are possible because the depth of each borehole seismic sensor is known, and the time it takes for a seismic wave to arrive at the sensor is known. However, these correlations contain uncertainties when the well has yet to attain the depths that need to be correlated. In such situations, it is necessary to look ahead of the well's TD and predict formation properties ahead of the bit.

Two types of borehole seismic surveys—seismic-while-drilling imaging and intermediate VSPs—can provide look-ahead information. In an example of the first, Devon Energy obtained a VSP image, in addition to time-depth and velocity information, while drilling a directional well in the Gulf of Mexico. Waveforms acquired during drillpipe connection and transmitted to surface during drilling operations were processed at a Schlumberger processing center and reported to Devon engineers at the rig site and in remote offices. An initial seismicVISION seismic-while-drilling image acquired 1,000 ft [305 m] above the target indicated that the well would not reach the target as planned (below). Devon team members in Houston decided to sidetrack the well and used additional seismicVISION data to guide the well to the intended TD.

Intermediate VSPs also deliver information beyond TD. BP ran such a "look-ahead" walkaway VSP in a deepwater well in the Gulf of Mexico.[10]



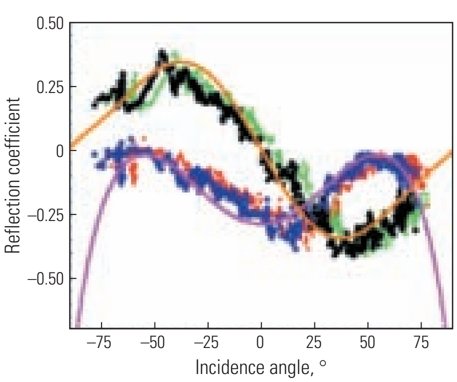
^ Imaging while drilling. Two seismic images acquired while drilling (red and blue) are superimposed on preexisting surface seismic data (black and white). The first seismic image (*left of vertical black line*), acquired in the original well (green) indicated to Devon interpreters that the well would not reach the target as planned. The well was sidetracked (yellow), and another seismic image acquired while drilling (*right of vertical black line*) indicated that the well would reach the target.



^ Acquisition of an amplitude variation with angle (AVA) walkaway VSP at the salt base. Processing assumes that the raypaths through the salt are equivalent for the direct ray and the ray that reflects off the base of the salt.

The well was to penetrate a salt structure to tap subsalt sediments. Drilling deepwater wells through salt is expensive and risky. The salt obscures seismic signals from underlying formations, making it difficult to image them properly, and also forms such a strong seal that pore pressure below salt can be abnormally high.

Estimates of pore pressure can be made from the ratio of seismic velocities derived from processing surface seismic data, but these velocities often have large uncertainties.[11] Borehole seismic surveys can help reduce the risk of drilling into subsalt sediments by obtaining more accurate seismic velocity ratios before the wellbore exits the salt.



^ Comparison of AVA data and modeled results. *P-p* (red) and *P-s* (green) reflected amplitudes can be corrected with a 6° shift in the angle of the interface, corresponding to the dip of the salt base (blue for corrected *P-p*, black for corrected *P-s*.) The best-fit model curves are shown in purple for *P-p* and orange for *P-s*. (Modified from Leaney and Hornby, reference 10.)

In the BP survey, a 12-level borehole seismic tool acquired walkaway data while clamped in the salt near the base salt interface (above). In this walkaway configuration, 800 surface shots were fired in a line extending approximately 25,000 ft [7,600 m] on both sides of the well. Compressional waves generated by the source reflect back as both *P*-waves, called *P-p* arrivals, and as *S*-waves, called *P-s* arrivals. With the tool clamped as close as possible to the base of salt, the seismic energy reflecting at varying angles near the base of the salt can be analyzed for amplitude variation with angle (AVA) of incidence. Analysis of AVA—analogous to well-known amplitude variation with offset (AVO)—reveals elastic properties of the materials at the reflecting interface.[12]

In this case, geophysicists expected to measure *P*- and *S*-wave velocities of the subsalt layers, along with quantified uncertainties, to be used in estimates of pore pressure and safe mud weight.[13] If results of the survey were to be useful for salt-exit drilling, time from last shot to mud-weight prediction had to be short, within two days.

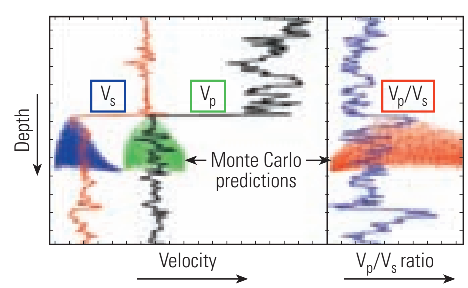
Amplitude variation with angle depends on the density and compressional and shear velocities of the material on either side of the reflecting interface. Measured AVA properties for *P-p* and *P-s* arrivals were compared with modeled values, and the inversion process iteratively modified the model to achieve a best fit with the data (below left). Inverting for subsalt compressional and shear velocities is possible because the density and velocities within the salt are known with a high degree of certainty. Noise in the data makes it difficult to invert for subsalt density, so an expected value is assumed.

The inversion predicted the ratio of *P*- and *S*-wave velocities with lower uncertainties than predrill estimates. A dipole sonic log recorded below and through the salt provided a post-drill measure of subsalt velocities, which were within the uncertainties predicted by the look-ahead walkaway VSP (below).

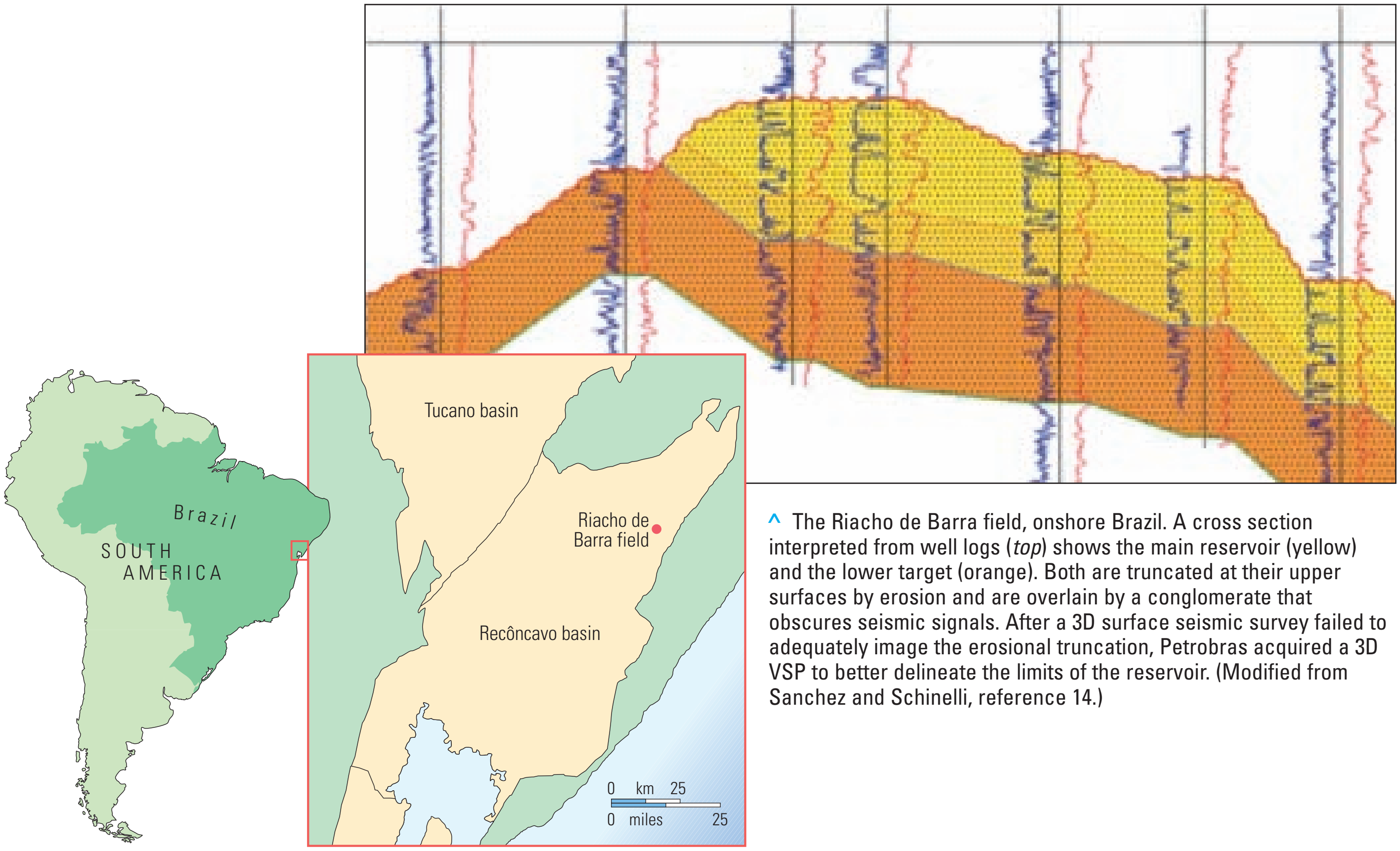
Double-Well 3D VSP

In the Riacho de Barra field, a mature asset in the Recôncavo basin of northeast Brazil, Petrobras sought to reduce risks in an infill-drilling campaign. Conventional 3D surface seismic data over the field had not satisfactorily resolved structural and stratigraphic traps: a high-velocity conglomerate formation in the overburden attenuated seismic signals and reduced bandwidth, deteriorating resolution and making it difficult for interpreters to define reservoir boundaries (next page, top).[14]

To improve the seismic image, geophysicists examined the feasibility of conducting a 3D VSP in existing wells. The main goal of the survey was to resolve erosional truncations of the upper reservoir and delineate a deeper target that had



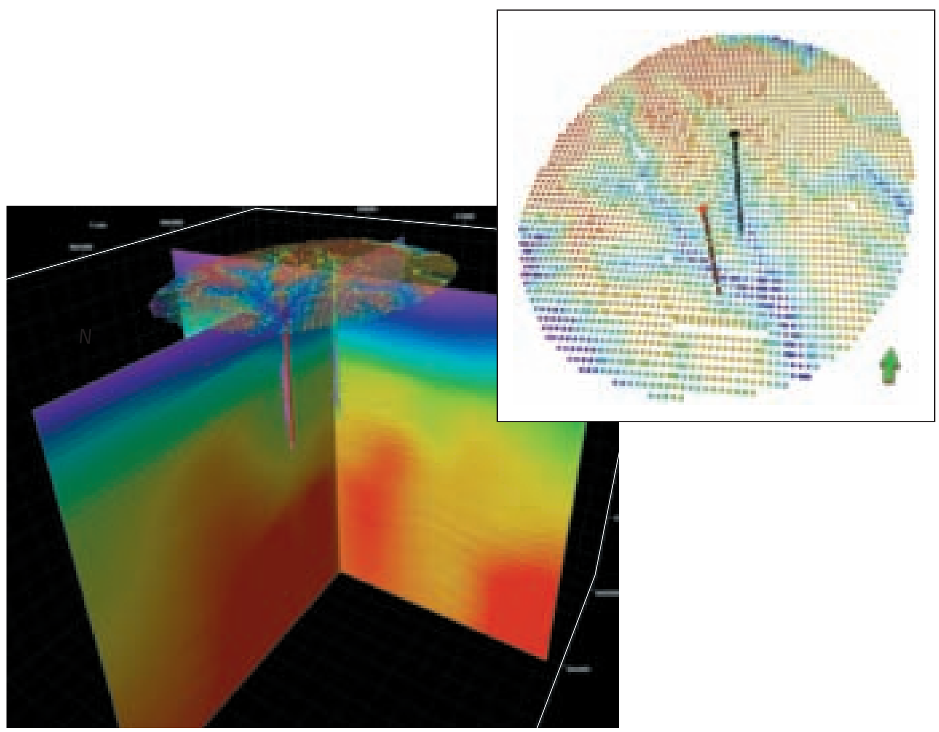
^ Comparing predictions of compressional (V_p) and shear (V_s) velocities and uncertainty ranges with measured values. The look-ahead walkaway VSP prediction of V_p and its uncertainty range (green) span the values later obtained by logging in the same well (black). Similarly, the predicted V_s and its uncertainty range (blue cloud) accurately estimated the subsequently logged shear velocities (red curve). Also shown is the predicted V_p/V_s ratio (red cloud) and the ratio of logging results (blue curve). (Modified from Leaney and Hornby, reference 10.)



^ The Riacho de Barra field, onshore Brazil. A cross section interpreted from well logs (*top*) shows the main reservoir (yellow) and the lower target (orange). Both are truncated at their upper surfaces by erosion and are overlain by a conglomerate that obscures seismic signals. After a 3D surface seismic survey failed to adequately image the erosional truncation, Petrobras acquired a 3D VSP to better delineate the limits of the reservoir. (Modified from Sanchez and Schinelli, reference 14.)

been poorly defined by surface seismic imaging. An initial velocity model was constructed from the 3D surface seismic data and calibrated by log data from more than 30 wells in the area. Ray-tracing through the model helped select the survey design that would maximize coverage at the targeted interfaces.

The 3D VSP design comprised 2,700 shot points over a 13-km^2 [5-mi^2] area, to be recorded from two neighboring wells simultaneously (right). To optimize acquisition logistics, a Petrobras seismic crew performed essential survey operations, such as location of shot points



^ Double-well 3D VSP acquisition design. More than 2,700 shot points were planned on lines over a 13-km^2 area. The area covered joins two circles centered on two wells (*right*). Shot locations are color-coded from low elevation (blue) to high elevation (red). A velocity model from existing 3D surface seismic data (*left*) was useful in planning the 3D VSP. In the velocity model, low velocities are blue and high velocities are red. (Modified from Sanchez and Schinelli, reference 14.)

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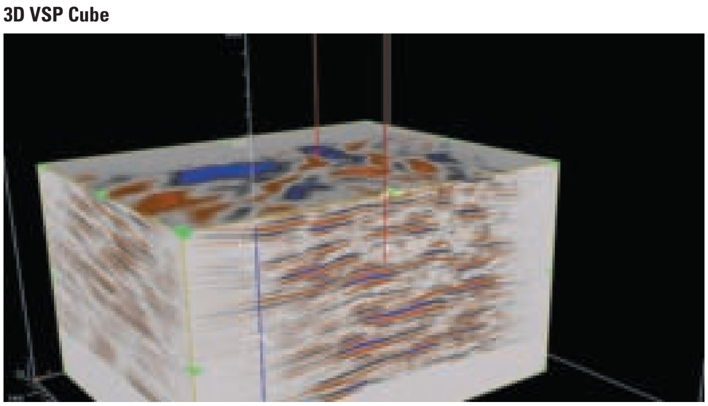
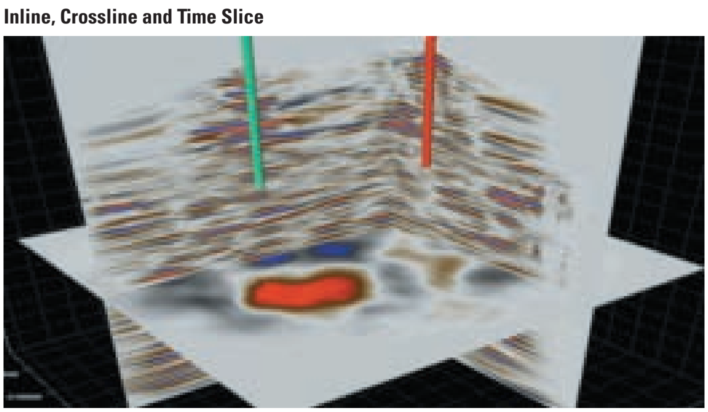
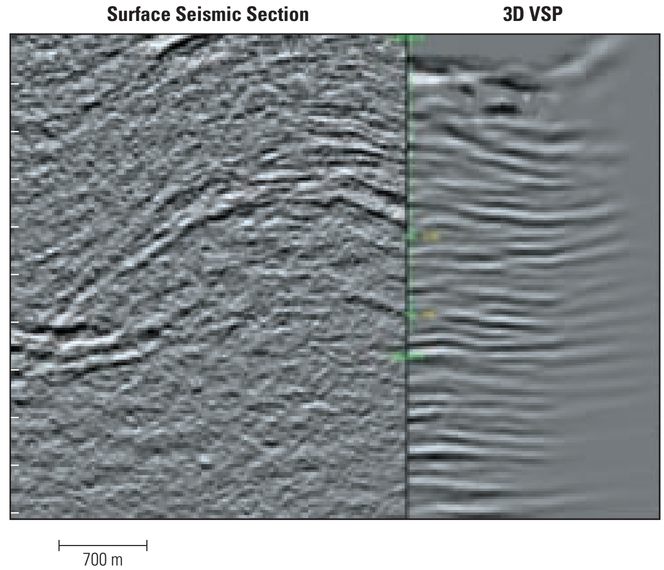






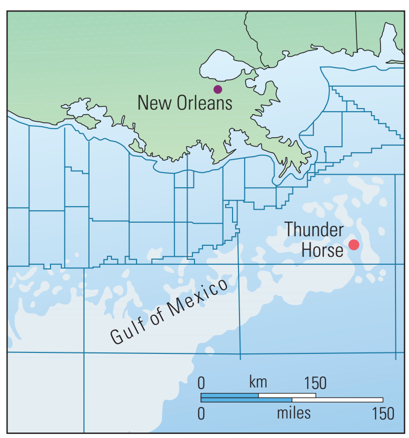
^ Petrobras 3D VSP results. The borehole survey produced high-resolution results that can be interpreted using software designed for 3D surface seismic data interpretation, including cube displays (*top left*), and inline, crossline and time-slice displays (*bottom left*). The resolution of the 3D VSP data was superior to that of the surface seismic data over the same area (*right*).

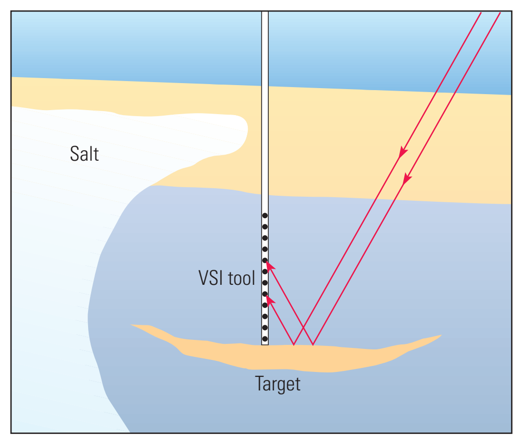
and drilling the 4-m [13-ft] shot holes for deployment of the dynamite sources. Rugged topography and a forested landscape added difficulty to the acquisition campaign. No rig was available at either well location, so a crane was mobilized to deploy the long receiver tools.

Because data recording requires good coupling between receiver and formation, the two wells were evaluated for cement bond quality. A well-intervention team performed cement squeezes in both wells to guarantee transmission of signals from the formation through the cement and casing to the accelerometer receivers in the well.

Before acquisition of the 3D VSPs, a 115-level conventional VSP was acquired in each well. The quality of recorded data helped optimize the depth location of the VSI arrays for the 3D acquisition, and the velocity information from each well was used to facilitate processing of the 3D VSP.

To reduce complexity of data processing, the 3D VSPs from each well were handled separately, and then merged before the final stage of migration. The imaging results show an increase in resolution over that of the 3D surface seismic data (above). Interpreters are currently working with the new 3D VSP data to define the limits of the reservoir.





^ Thunder Horse field in the Mississippi Canyon, Gulf of Mexico (*left*). BP ran several 3D VSPs in this area, which has numerous salt intrusions that reduce the effectiveness of surface seismic surveys. Three-dimensional VSPs can be designed so that many raypaths avoid propagation through the salt (*right*).

15. "Thunder Horse: No Ordinary Project," http://www.bp.com/genericarticle.do?categoryId=9004519&contentId=7009088 (accessed October 8, 2007).
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17. Ray A, Hornby B and Van Gestel J-P: "Largest 3D VSP in the Deep Water of the Gulf of Mexico to Provide Improved Imaging in the Thunder Horse South Field," *Expanded Abstracts*, 73rd SEG Annual International Meeting and Exposition, Dallas (October 26–31, 2003): 422–425.

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Gulf of Mexico 3D VSPs

An example of a marine VSP comes from the BP-operated Thunder Horse field in the south-central Mississippi Canyon, Gulf of Mexico. The field is in water depth of approximately 6,300 ft, [1,920 m], and is home to the largest moored semisubmersible rig in the world.[15]

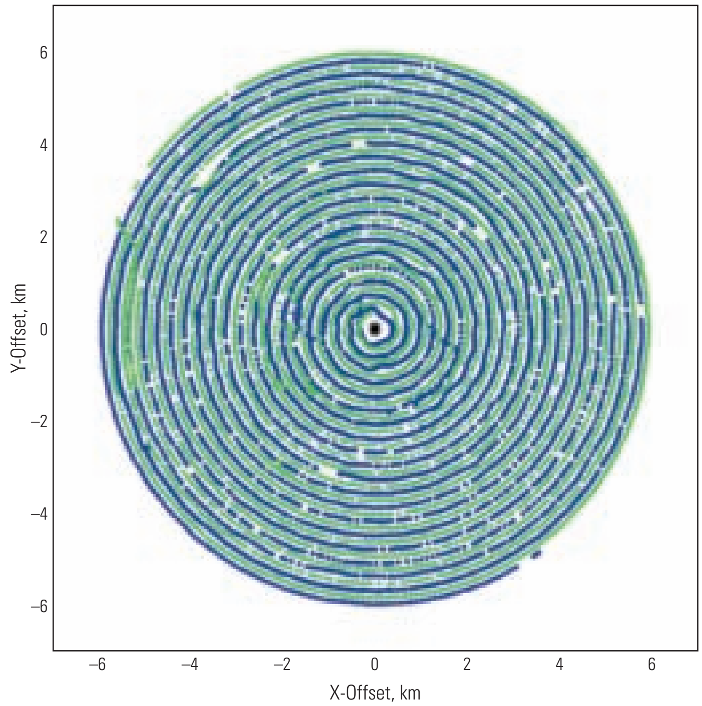
Seismic imaging in the area is extremely complicated because of the abundance of overlying salt bodies. Resolving structural complexity and stratigraphic detail is necessary for success, but difficult with 3D seismic data because the salt obscures major subsalt targets. Three-dimensional surface seismic data suffer from water-bottom and salt-sediment multiples, and from attenuation at the deeper reservoir levels.

Three-dimensional VSPs can be designed to reduce wave propagation through the salt (previous page, bottom). Avoiding raypaths through the salt eliminates some of the challenges inherent in conventional surface seismic surveys. And with VSPs, the reflected energy travels a shorter path, reducing attenuation and improving resolution. The true 3D geometry also produces data from a wide range of azimuths, a feature that improves illumination in surface seismic surveys.[16]

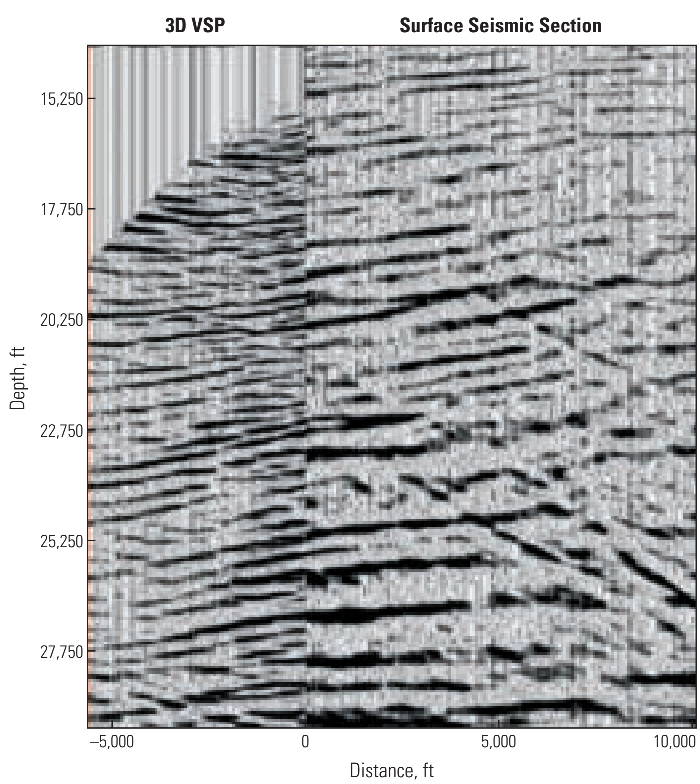
Day rates for deepwater drilling rigs are high, and 3D VSP acquisition can take several days to a few weeks, so the operation must be efficient. At the time of the first 3D VSP in Thunder Horse, a VSI tool with 12 three-component shuttles was available, the most that could be run. Standard pressures and temperatures were expected: 17,400 psi [120 MPa] and 275°F [135°C].[17]

The first 3D VSP was completed in February 2002 in the Mississippi Canyon 822-3 Well. The 12-shuttle VSI tool was positioned at three consecutive depths to produce an effective 36-level VSP. A spiral source pattern was selected for efficiency, and repeated for each receiver-array depth, firing approximately 30,000 shots, and generating more than one million traces (above right). The image was found to be much superior to the available surface seismic data, with markedly higher resolution, less noise and fewer artifacts (right).

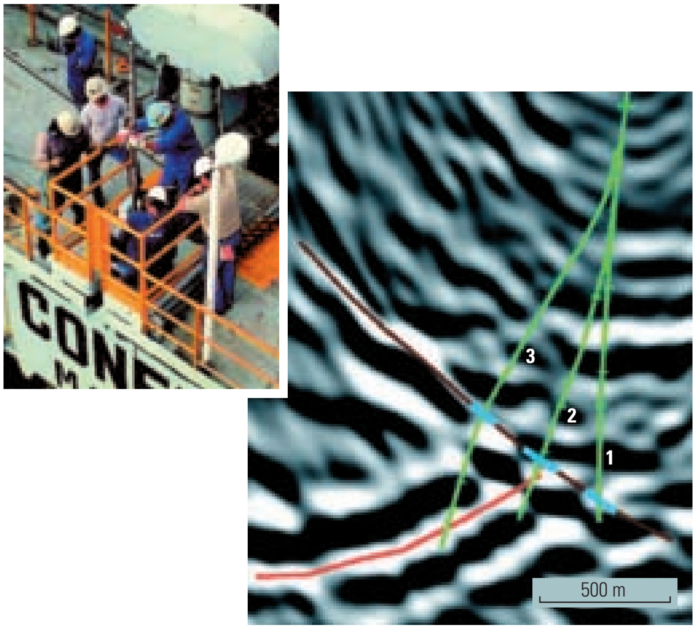
Using the multilevel VSI tool enabled efficient and cost-effective acquisition of 3D VSP data around targeted wells. High-resolution images from these VSPs can be used to guide placement of development wells, and images from multiple wells can be combined to give a more comprehensive image of the subsurface.



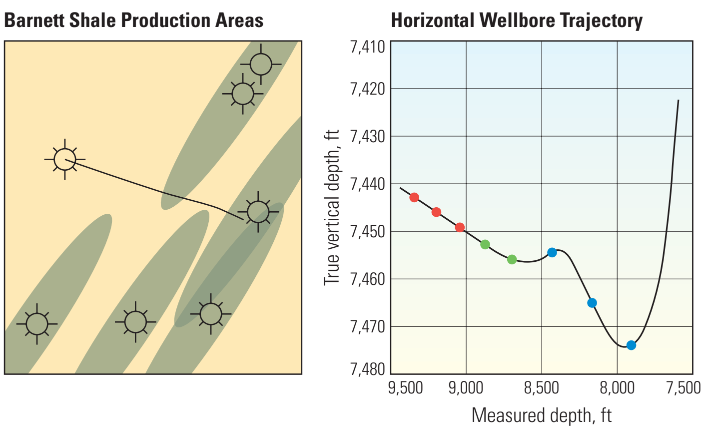
^ Spiral 3D VSP. A spiral shooting pattern included operation of a dual-source array and flip-flop shooting, with the source vessel first firing a source on the port side (blue dots), then a source on the starboard side (green dots). The spiral was repeated for each receiver-array depth. (Modified from Ray et al, reference 17.)



^ Comparison of 3D VSP results with a 3D surface seismic line. The 3D VSP data (*left*) show higher resolution everywhere compared with surface seismic data (*right*). (Modified from Ray et al, reference 17.)



^ Rigless 3D VSP in the Gulf of Mexico. While the rig was being used to drill one well, a 3D VSP was performed in another well by running a 20-level VSI tool through a false rotary on the aft end of the semisubmersible deck (*left*). In an image from the VSP data, a large-throw fault (purple) explains why some wells drilled into the structure did not hit the pay zone (red). Well 1 encountered the fault but failed to reach the reservoir. Well 2 intersected a small portion of the pay zone, and Well 3 hit the pay in the correct location. Fault location and dip information from dipmeter logs (blue) confirm the fault interpretation on the VSP image. (Modified with permission from Hornby et al, reference 18.)



^ Estimated stimulated fracture networks and a horizontal well in the Barnett Shale formation. Vertical wells (circles) penetrating the Barnett Shale produce from stimulated areas approximated by the shaded areas (*left*). The operator drilled a horizontal well (black line) to tap undrained areas. The wellbore trajectory (*right*) dipped low at the heel of the well then rose 30 ft [9 m] over the 2,000 ft [610 m] between heel and toe. The five perforation clusters in the toe section of the well (red and green) are the entry points for Stage 1 of the hydraulic fracture treatments. Blue dots are the entry points for Stage 2.

Marine 3D VSPs can even be run without a drilling rig. One example comes from the Green Canyon area of the Gulf of Mexico, where a complex salt body overhanging the Mad Dog field created a shadow zone that made it difficult to obtain a clear image from surface seismic data.[18] After casing was set at TD, a well in the field was temporarily abandoned, and the rig was moved to drill another well from the same deck. To acquire a 3D VSP in the first well, a wireline winch, capstan and acquisition unit were installed on the aft end of the semisubmersible's main deck. Through this opening, a 20-level VSI array with 100-ft [30-m] spacing between shuttles was run into 4,500 ft [1,370 m] of open water and then caught and guided into the subsea wellhead by a remotely operated vehicle (ROV). A video feed of the operation allowed the winch man and logging engineers to coordinate tool deployment with the ROV operator.

Once the receiver array was in place, data acquisition continued efficiently, with no nonproductive time. The source vessel, the WesternGeco *Snapper*, towed a three-gun array and shot two walkaway lines, and then shot the spiral survey geometry. The VSI system acquired the 32,000-shot 3D VSP in six days. BP realized substantial savings by not using rig time for the acquisition.

Results from the Mad Dog 3D VSP helped produce an improved image in an area where surface seismic data had been affected by overhanging salt (above left). Interpreters delineated a fault of approximately 1,640-ft [500-m] throw that had caused an early well to completely miss the pay interval. Of three wells drilled into the structure before the availability of the VSP, one hit the target in the right place, and logs from all the wells corroborated the fault location and dip interpreted from the borehole seismic data. BP determined that the cost of drilling two of the sidetracks could potentially have been saved if the 3D VSP had been acquired before drilling the first well.

Optimizing Hydraulic Fractures in Real Time

Borehole seismic tools have been used since the 1980s to detect seismic energy generated by hydraulic fracture treatments.[19] The goal is to use knowledge of the fracture geometry and spatial development to help improve fracture operations.[20]

The ability to make decisions that can optimize stimulation treatments relies on two main requirements: receiving accurate information about fracture propagation in time to change ongoing operations, and having the technology to effect the desired change.

To address the first requirement, Schlumberger has developed an innovative hydraulic fracture monitoring technique that provides stimulation engineers with real-time information pertaining to the geometry and development of hydraulically induced fracture networks. Real-time results allow operating companies to make timely decisions to alter the final geometry of fractures and reduce or prevent such undesirable situations as water production, overlap with previous treatments, fluid loss and uneconomic pumping.

The ability to change the outcome of a stimulation treatment depends on the problem at hand. If the fracture is developing out of its planned zone, a decision can be made to end the job. If the treatment is not reaching the desired intervals, pumped fluids can be adjusted to seal competing zones. Diversion technology can effectively bridge fracture systems and create additional complex fractures.

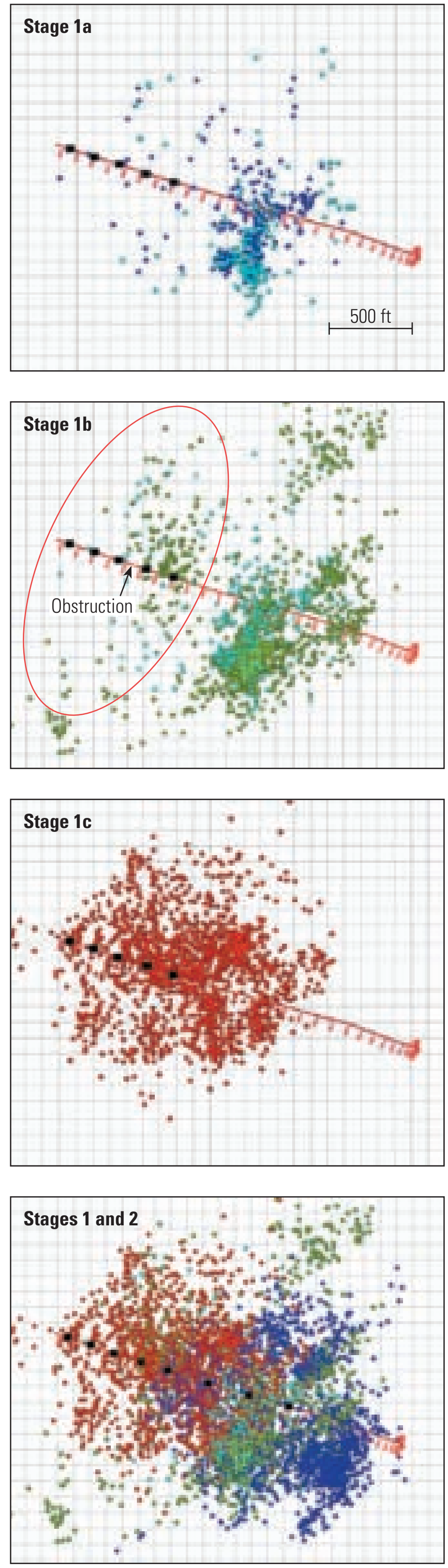
One operator used StimMAP hydraulic fracture stimulation diagnostics to track the progress of a multistage fracturing operation in a horizontal well in the Barnett Shale. This formation in the Fort Worth basin of north-central Texas is the most active gas play in the United States. The Barnett Shale formation is a naturally densely fractured, ultralow-permeability reservoir that requires a large hydraulic fracture surface to be effectively stimulated, and hence be economic.

The horizontal infill well was drilled in the direction of minimum principal stress to facilitate creation of transverse hydraulic fractures. The estimated stimulated fracture networks of several nearby hydraulically fractured vertical wells intersected the heel section of the well (previous page, bottom). These regions of low stress caused by previous stimulation treatments will tend to attract propagating fractures, making it potentially difficult to stimulate the toe of the well.

The treatment was designed to comprise two stages, with the first stage targeting five perforation clusters nearest the toe of the well. From the microseismic events localized in Stage 1a, it is clear that the fracture developed away from the higher stress interval near the toe, and extended toward the lower stress interval in the heel, leaving the toe section understimulated (right). A diversion stage was pumped to try to divert the next treatment to the far perforations. Monitoring the seismic activity during Stage 1b indicated that again the toe section of the well was not fracturing, and again, stages of diversion fluid were pumped to try to divert fluid from the competing zones.

Inspection of the microseismicity map revealed that seismic events were occurring near the first two perforation clusters, but not beyond. Coiled tubing was run to see if some type of obstruction was preventing a fracture from initiating between the second and third perforation clusters. Engineers determined that a sand plug was prohibiting stimulation in that section of the well.

After the sand plug was removed, Stage 1c successfully stimulated the toe section. Immediately, microseismic events were detected in the previously unstimulated sections of the toe. With additional diversion stages pumped whenever the real-time microseismicity ceased to grow, the operator was able to stimulate the 900-ft [274-m] toe section of the lateral without using numerous time-consuming bridge plugs and perforating steps. A subsequent stage treated the heel of the well, which was also mapped by microseismic activity.



> Microseismic events mapped during progression of hydraulic fracture treatments. Stage 1a (*top*) stimulated the region near the heel of the well, but left the toe mostly unfractured. Diversion fluid was introduced to divert the next treatment to the perforation clusters at the toe. Stage 1b (*second*) also failed to stimulate the toe, and indicated an obstruction in the well between the second and third perforation clusters. Following removal of a sand plug, Stage 1c (*third*) successfully stimulated the remaining 900-ft toe section. When all stages are plotted together (*bottom*), it can be seen that Stage 2 stimulated the heel section of the well (dark blue dots).

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20. Fisher MK, Heinze JR, Harris CD Davidson BM, Wright CA and Dunn KP: "Optimizing Horizontal Completion Techniques in the Barnett Shale Using Microseismic Fracture Mapping," paper SPE 90051, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.

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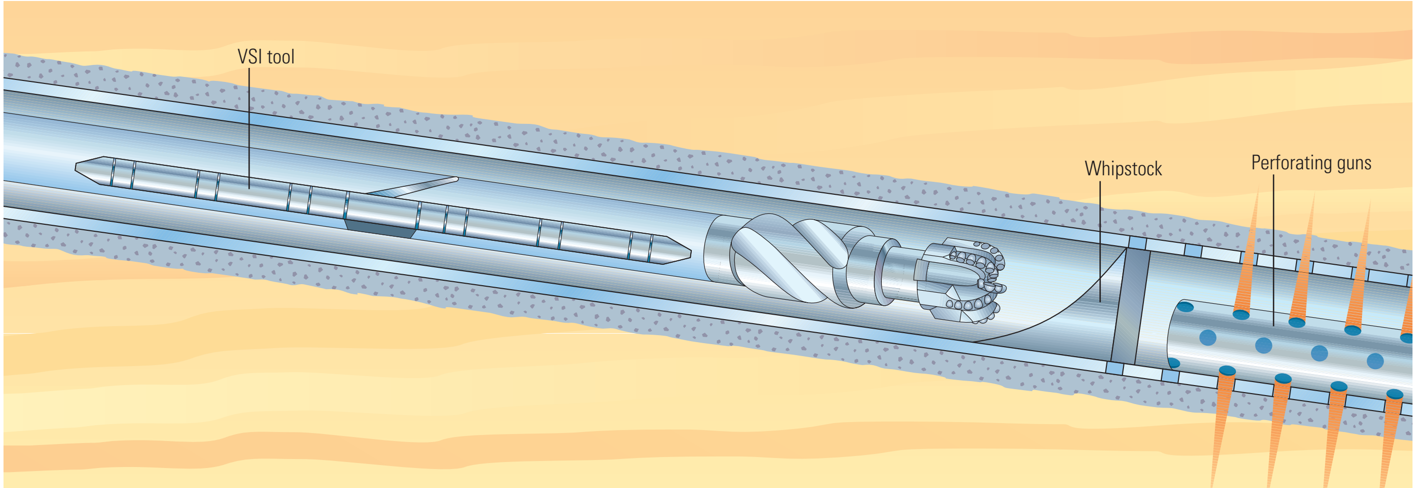


^ Monitoring TCP operations with a borehole seismic receiver. Perforating guns were conveyed by coiled tubing, left on the bottom of the hole and set to fire with a long delay. After a whipstock was set, a VSI tool was deployed through drillpipe and anchored 100 ft above the whipstock. Detonation of the guns created seismic signals recorded by the sensors.

Monitoring Perforating Operations

Shell Exploration & Production was constructing production wells in the Cormorant field, UK North Sea. The wells were to be perforated with tubing-conveyed perforating (TCP) guns. Shell had considered several methods of verifying TCP operations, and decided to try monitoring the shots with a borehole seismic tool. In wireline-conveyed perforating, changes in cable tension can indicate that the guns have fired, and this can be confirmed when the guns are retrieved and inspected on the surface. In tubing-conveyed perforation, the guns may be left in the well and never returned to the surface. Without positive indications that the guns have fired, the only proof of the operation's success is pulling the tubing and retrieving the guns, at great expense to the operator.

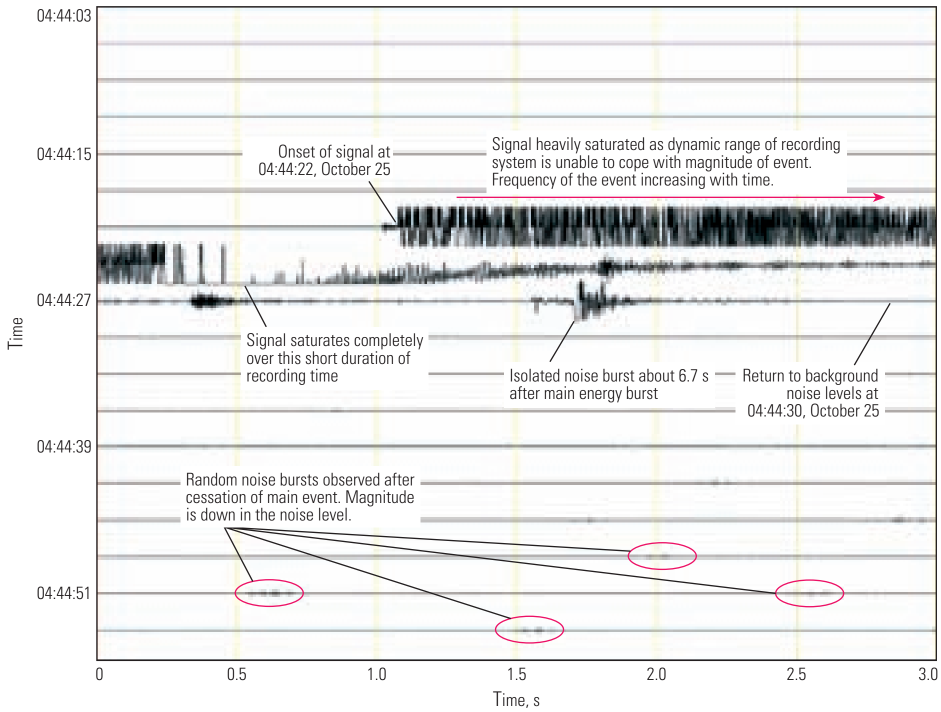
Although the VSI tool is designed to record borehole seismic surveys, the receivers are also able to detect signals generated by disturbances in the vicinity of the borehole. The tool would undoubtedly be able to detect signals from a source as powerful as the shaped charges used for perforating if it were run in the same well. Unlike other borehole seismic tools, the VSI tool can be used to acquire records of any time duration. In typical deployment for logging borehole seismic surveys, the recording length is set to approximately 5,000 ms and starts at the activation of the controlled seismic source. However, for monitoring perforation shots, the recording system was set to begin recording once the tool had been anchored in position, and to continue recording until switched off by the seismic field engineer.

The wells were to be multilaterals with a main bore and one lateral bore. Typically, after the main bore was drilled and cased, more than 3,000 ft [910 m] of TCP guns were run to the reservoir interval and left in place, to be detonated by a trigger-delay system. A whipstock—for exiting the casing to drill the lateral bore—was then set in the main wellbore above the interval to be perforated. A VSI shuttle was anchored 100 ft [33 m] above the whipstock to monitor the detonation of the perforating guns (above). After the firing of the guns and drilling, completing, perforating and cleaning up the lateral bore, the whipstock was perforated to allow the reservoir penetrated by the main bore to flow.

The VSI tool detected the sharp onset of signal from the perforation shots (next page, top). The tool was close to the whipstock, and the large magnitude of the signal saturated the dynamic range of the recording system. Although the amplitude cannot be read from the recording, an increase in frequency of the signal can be detected for several seconds after the onset. Signal level returned to the level of background noise approximately 8 seconds after signal onset. The seismic signals confirmed the successful firing of perforation guns.

The primary purpose fulfilled, Shell engineers examined the seismic data for additional information. The guns had fired, and the empty guns had filled with fluid. The return of the seismic signal level to background noise levels indicated that fluids were no longer moving in this portion of the borehole. The total duration of signal on the seismic record was interpreted to represent the time it took the empty gun volume to fill, and could be related to the inflow performance of the well. Given that the borehole below the whipstock is a closed system, and knowing the volume of the perforating guns, effectively a chamber at atmospheric pressure, Shell engineers included the time required to fill the guns in a calculation to obtain a rough estimate of absolute open-flow potential. With this additional information from the seismic monitoring of perforation shots, Shell engineers gained understanding of reservoir behavior.

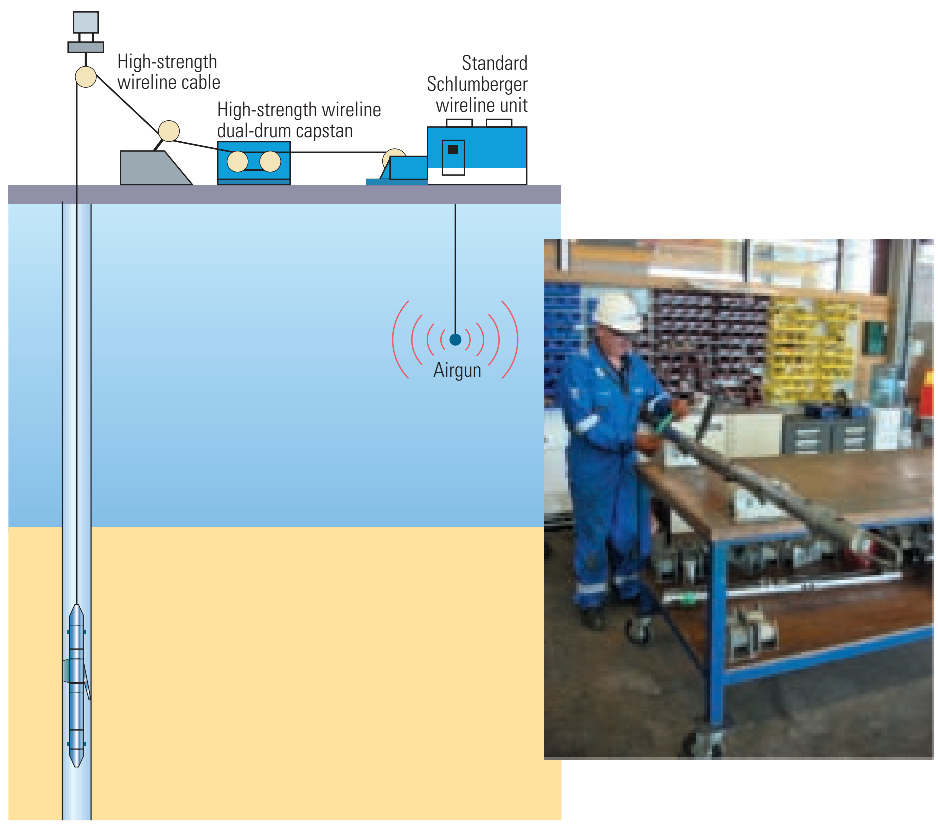
> Seismic recording of perforation shots and other events. This display is a continuous record, starting at the top, with the second line a continuation of the first, and so on. For each line, the vertical axis is signal amplitude. The signal from the perforation shots appears with a sharp onset at 04:44:22. The signal saturates the dynamic range of the recording system for several seconds. The recording returns to background noise levels at 04:44:30, but some isolated noise bursts occur earlier and later.



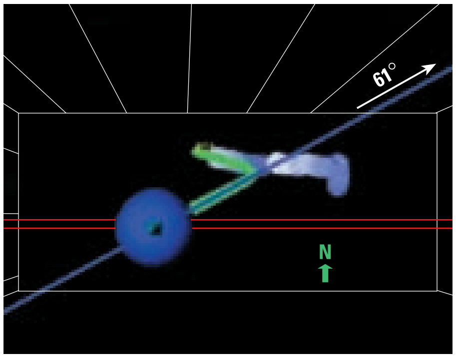
High-Pressure, High-Temperature Surveys

While the VSI tool can log borehole seismic surveys in most wells, high-pressure, high-temperature (HPHT) wells have special requirements. The seismic acquisition tool developed for the SlimXtreme slimhole high-pressure, high-temperature well logging platform combines high-performance packaging with analog recording, minimizing the use of fragile electronics (right). This 3⅜-in. tool, like the other tools in the Xtreme family, was engineered to operate in conditions up to 30,000 psi [207 MPa] and 500°F [260°C]. The short, lightweight sonde was designed with a single three-component set of receivers to handle checkshot surveys, but is now also being used to acquire full VSP images in HPHT wells.

ConocoPhillips (U.K.) Limited had several reasons for running the slim analog seismic tool in a challenging HPHT well drilled in the central North Sea. The first was to generate an accurate time-depth correlation between well data and the time-based 3D marine seismic data over the target. While the reflection at the base of the chalk was clearly interpretable in seismic sections, the deeper reflection at the top of the reservoir was not as easy to pick. Correlation between VSP, well log and surface seismic data would increase confidence in interpreting the shape and extent of the reservoir.



^ Borehole seismic acquisition tool for extreme conditions. The SlimXtreme slimhole high-pressure, high-temperature logging platform operates in conditions up to 30,000 psi and 500°F. Operating companies have used the tool in conditions up to 238°C [460°F].



^ Trajectory of the ConocoPhillips North Sea HPHT well. In this plan view, the source position is a blue sphere, the receivers in the borehole are green dots, and the reflection points on the target are in shades of blue and white. The upper portion of the well follows an azimuth of N61E, then veers to the northwest with depth. The source-receiver geometry and traveltimes were projected onto a vertical section along N61E to define a single azimuth with which to migrate the data.

ConocoPhillips also wanted to acquire a depth-based VSP image of the reservoir interval and layers below the well TD. In the surface seismic data, the dipping reservoir layers are partially disrupted by noise from multiples, which appear as horizontal reflections that interfere with the signals from the reservoir. Because a VSP records both downgoing and upgoing waves and features multicomponent processing, a VSP image may contain fewer multiples and give a more accurate picture of the reservoir structure. And by extending the image below the well, it would be possible to correlate horizons beneath the reservoir with reflections seen on surface seismic data.

The third reason for acquiring VSP data was to obtain better estimates of formation velocities for improved reprocessing of the 3D marine seismic data. Reducing uncertainties in the velocities of the chalk and underlying formations would produce more accurate 3D images, potentially leading to reduced risk in future drilling in the area.

The slim analog seismic tool was the only option for acquiring a VSP in the expected pressure and temperature conditions. With TD below 15,000 ft [4,600 m], temperatures could be as high as 380°F [193°C]. The well trajectory was deviated above the chalk, and then sidetracked out of the plane of deviation as depth increased.

In spite of the extreme conditions, logging proceeded smoothly. The tool acquired data at receiver stations every 50 ft [15 m] spanning a depth interval from the reservoir up through the chalk, and also at more widely spaced intervals higher in the section. At the deepest of the 73 stations, temperature reached 380°F. The seismic source comprised three 150-in.^{3} airguns and was deployed at the rig in a zero-offset survey configuration.

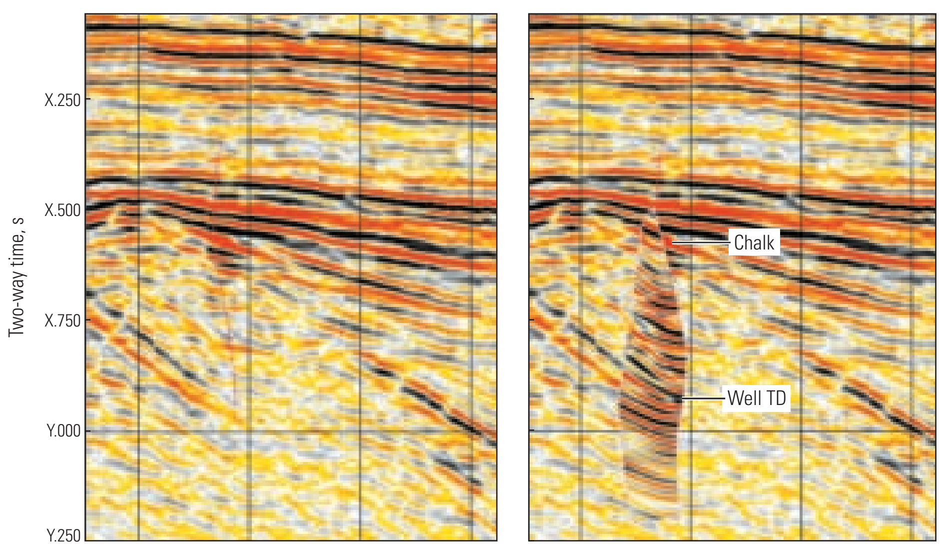
Processing the three-component data to determine where the reflections originated included standard steps as well as a special correction for the 3D nature of the borehole trajectory. This would allow the VSP data to be migrated using a 2D algorithm. The 3D trajectory of the borehole was projected onto a vertical plane aligned with the shallow portion of the well (left). Reflection times, locations and amplitudes were calculated assuming the VSP signals were confined to this plane, but in reality, some reflections occurred out of the plane. To take account of this, raypaths and traveltimes for each trace were calculated using the 3D velocity model derived from initial surface seismic processing, and compared with raypaths and traveltimes calculated from a 2D model extracted from the 3D volume in the dominant vertical section chosen for processing. The difference between the two sets of computed traveltime residuals was added as a static correction to each trace prior to migration.

The differences in the velocity models also indicated that the VSP detected higher velocities in the chalk layer and lower velocities below the chalk than were seen in the surface seismic velocity model. These differences translate into mis-ties observed between the VSP image and the surface seismic image below the chalk interval (below).

The depths of reflectors in the VSP image also matched those of a synthetic trace generated from sonic and density well logs, confirming the accurate depths of the VSP image in spite of the conflict between the 3D nature of the acquisition objective and the 2D approach to solve it (next page, top left). ConocoPhillips (U.K.) Limited is using velocities obtained from the borehole seismic survey to aid the reprocessing of existing surface seismic data, and plans to use the slim analog seismic tool in future HPHT wells.

Waves of the Future

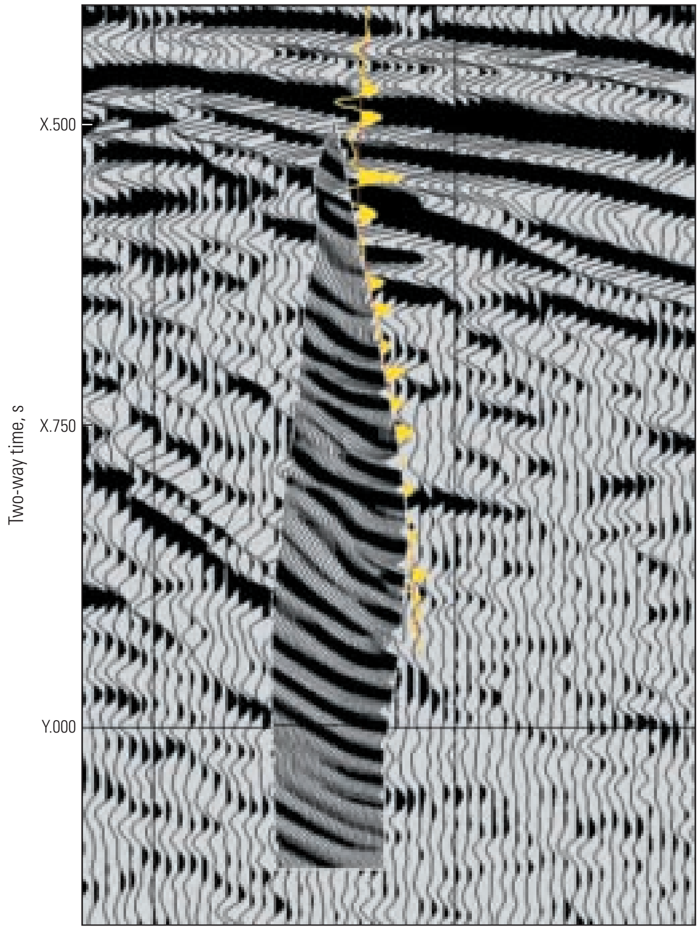
Borehole seismic surveys have advanced far beyond their origins as methods for converting time to depth for well-to-seismic correlations, although they are still used primarily for time-depth ties. As seen in this article, VSPs can satisfy a wide variety of needs, providing 3D images of the subsurface, contributing to optimized hydraulic fractures, verifying perforating operations and obtaining high-quality data in HPHT conditions.



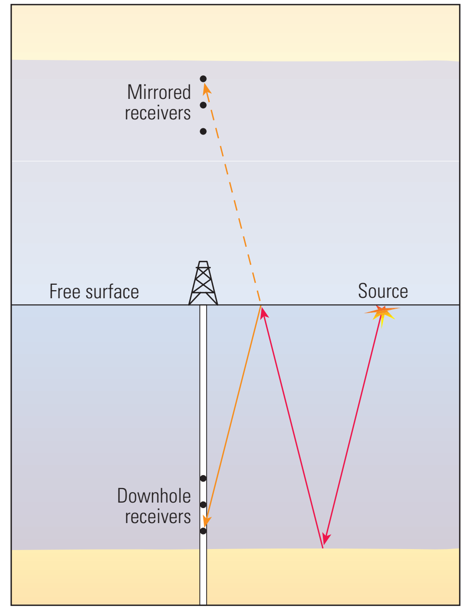
^ Comparison of VSP results with surface seismic data. The surface seismic image produced using chalk velocities that are too low (*left*) fails to tie with the VSP (*right*). (The VSP is a small region with higher amplitudes and higher resolution than the surface seismic image, and narrows upward.) The mismatch can be seen at several intervals.

21. Hornby et al, reference 9.

22. Djikpesse H, Haldorsen J, Miller D and Dong S: "Mirror Imaging: A Simple and Fast Alternative to Interferometric Migration of Free-Surface Multiples with Vertical Seismic Profiling," submitted to *Geophysics*, 2007.



^ Matching reflector depths in a VSP image and a log-derived synthetic trace. One test of properly depth-correlated seismic data is matching with a synthetic trace generated from sonic and density well logs. In this case, the synthetic trace is plotted in yellow for visibility, and only positive amplitudes are plotted, so as not to obscure the seismic data. Throughout most of the well, the positive amplitudes in the synthetic trace correlate with those in the VSP, giving confidence in the projection assumptions made during processing. The VSP image extends beyond the bottom of the well.



^ Mirror imaging, an example of interferometry. The free surface and the area above it are replaced by a mirror image of a medium with the same elastic properties as the medium containing the borehole and receivers. Receivers in the new material are the mirror image of the original receivers. Whereas the original borehole seismic experiment had a zone of illumination restricted to below the receivers, the mirrored experiment has a zone of illumination that extends to the former free surface.

The future of VSPs will undoubtedly take many directions. Hardware innovations will include new downhole tools to withstand demanding conditions and new sources to enable even more efficient acquisition. Permanent installation, allowing long-term reservoir monitoring, has been tested by some operators.[21] Permanently installed tools could be used to conduct time-lapse surveys or to detect seismicity induced by production or injection, even when deployed in the producing or injection wells.

Other advances will come in processing to produce better images from acquired data. Most processing for creating images from VSP data has borrowed from surface seismic methods. But borehole seismic surveys, with their particular geometries, offer opportunities that have not been fully explored.

One promising area is called interferometry, which is the interference of two or more waves to produce an output wave that is different from the input waves. Researchers are investigating ways to use interferometry to transform signals previously considered as noise into valuable information. For instance, in typical VSP data imaging workflows, only primary reflections are migrated. Free-surface multiple reflections are usually regarded as noise and thus eliminated before migrating the recorded data. While benefiting from reduced attenuation and improved velocity control with respect to migrated surface seismic data, the resulting migrated VSP images are restricted to a relatively narrow zone of illumination lying below the borehole receivers. However, free-surface-related multiples contain valuable information about shallower subsurface structures, and if properly migrated, they can provide wider illumination, and better vertical resolution of the subsurface properties than when imaging using primaries alone (above).[22]

The early goal of VSPs was to reduce risk by enabling accurate time-to-depth correlation between surface seismic data and well logs. Current and future capabilities of borehole seismic surveys still include risk reduction, but also extend to improving recovery. –LS