Modern 2D and 3D VSP: reservoir imaging from downhole

Brian Fuller and Marc Sterling, Sterling Seismic Services, and Larry Walter, Geospace Engineering Resources International (GERI), provide a guide to modern VSP and see further potential as the technology matures.

Check shot surveys and VSPs have been used for decades as a way to obtain a reliable time-depth tie for seismic reflections, constrain depth migration results, and generally improve seismic interpretations. Along the way seismologists also noted that seismic data recorded in the borehole generally contains higher frequency than surface seismic data. The empirically derived rule of thumb is that VSP data contain two times the frequency content of surface seismic data. It is commonly assumed that seismic frequency attenuation is smaller for borehole seismic data because the VSP raypath is shorter than for surface seismic raypaths and because the VSP seismic wavefield passes through the near-surface zone only once.

Figure 1 shows a direct comparison between a 3D surface seismic image and a 3D VSP image. Abutting slices from the respective 3D volumes both show discontinuous sand bodies where gas production is strongly influenced by faulting and stratigraphic variations. The 3D VSP image, however, contains about twice the frequency content of the surface seismic data and shows many more details of the reservoir.

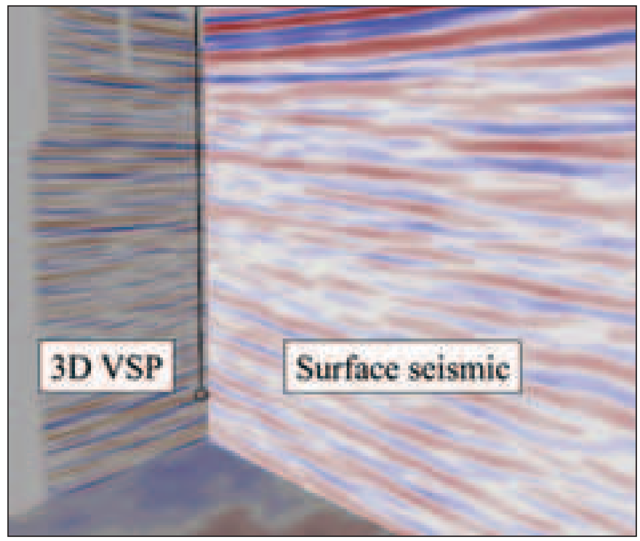

Figure 1 *Comparison of 3D VSP and surface seismic images. Two abutting slices from a 3D VSP image (left) and a 3D surface seismic survey (right) are shown. Discontinuous sands and shales are imaged by both datasets but the 3D VSP has twice the frequency content of the surface seismic data, thus small faults and stratigraphic changes that control production are more easily identified in the 3D VSP image.*

The higher frequency content available in VSP data provides an opportunity to use 2D and 3D VSP as a powerful reservoir development tool. The details of reservoir fault architecture and stratigraphy are simply easier to see with 120 Hz data than 60 Hz data. The purpose of this article is to provide the reader with an overview of modern 2D and 3D VSP methods and some factors driving the current rapid growth in use of the method.

Enabling technology

The availability of high capacity downhole data acquisition systems has been a key enabling technology for success in borehole seismic imaging projects, particularly for 3D VSP. We now know that in order to fully image a reservoir at a depth of 4000 m, for example, the vertical geophone coverage in the borehole should be at least 2000 m with a geophone interval of 15-20 m. We would prefer to have as much as 3000 m of vertical coverage in this case. As recently as the late 1990s the largest downhole seismic data recording systems had between five and 10 three-component geophones deployed on seven-conductor copper wireline. The cost of recording a survey with 2000 m of vertical receiver coverage with 5-10 geophones in the borehole would be prohibitive for most 2D VSP surveys and out of the question for full 3D VSP surveys.

A modern downhole data acquisition system should include several features to minimize the risk of survey failure and excessive cost. The features should include a minimum of 80-200 three-component geophone sondes, real-time transmission of data from geophones to the recording system at the surface, high temperature and pressure tolerance, efficient deployment and retrieval of the tool, high signal fidelity, uniform horizontal and vertical geophone response, low instrument noise levels, and high reliability.

Today there are multiple downhole sensor systems that are advertized to allow deployment of 400 or more 3C geophones. Figure 2 shows a 'slim-hole' VSP array tool manufactured by GeoSpace that may be deployed on a fibre optic wireline or instrumented all the way to the surface. The assembly shown weighs only 5 lb (~2 Kg)

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allowing hundreds of sondes to be deployed on a fibre augmented wireline without exceeding the weight capacity of conventional wireline designs. The bandwidth of fibre optic data transmission is orders of magnitude greater than seven-conductor copper wirelines providing real-time, continuous, high bandwidth recording from hundreds of multi-component sondes.

An efficiency goal of a modern survey, particularly for Vibroseis, is to keep the recording system running with just a few seconds between the end of recording for one source record and the beginning of recording for the next source effort. Fibre optic wirelines have the bandwidth to allow real-time recording so that no time is wasted waiting for data to be transmitted from downhole circuitry to the recording system. Classical copper wireline systems can force a wait time of up to 20 seconds after the end of a sweep to transmit data up the borehole, even for a small receiver array of only 24 receiver levels.

Multidimensional VSP data processing

Magnificent leaps forward in data acquisition capacity would be of minimal value without data processing technology that makes full use of the data. The geometry of 2D and 3D VSP data acquisition imposes data processing challenges by invalidating the common midpoint assumption enjoyed by the surface seismic method (Figure 3). In quite simplistic terms the common mid-point assumption of surface seismic data reduces the imaging problem to using the data to pick a normal-moveout (NMO) velocity that moves reflections to the zero-offset two-way time. The asymmetry of up- and down-going ray paths in VSP data acquisition geometry currently precludes a simple equation analogous to the NMO equation.

Early efforts to create 2D and 3D VSP reflection images were limited to reflection point mapping commonly referred to as the VSP-CDP transform. The VSP-CDP transform is often used with a 1D velocity field or simple dipping model.

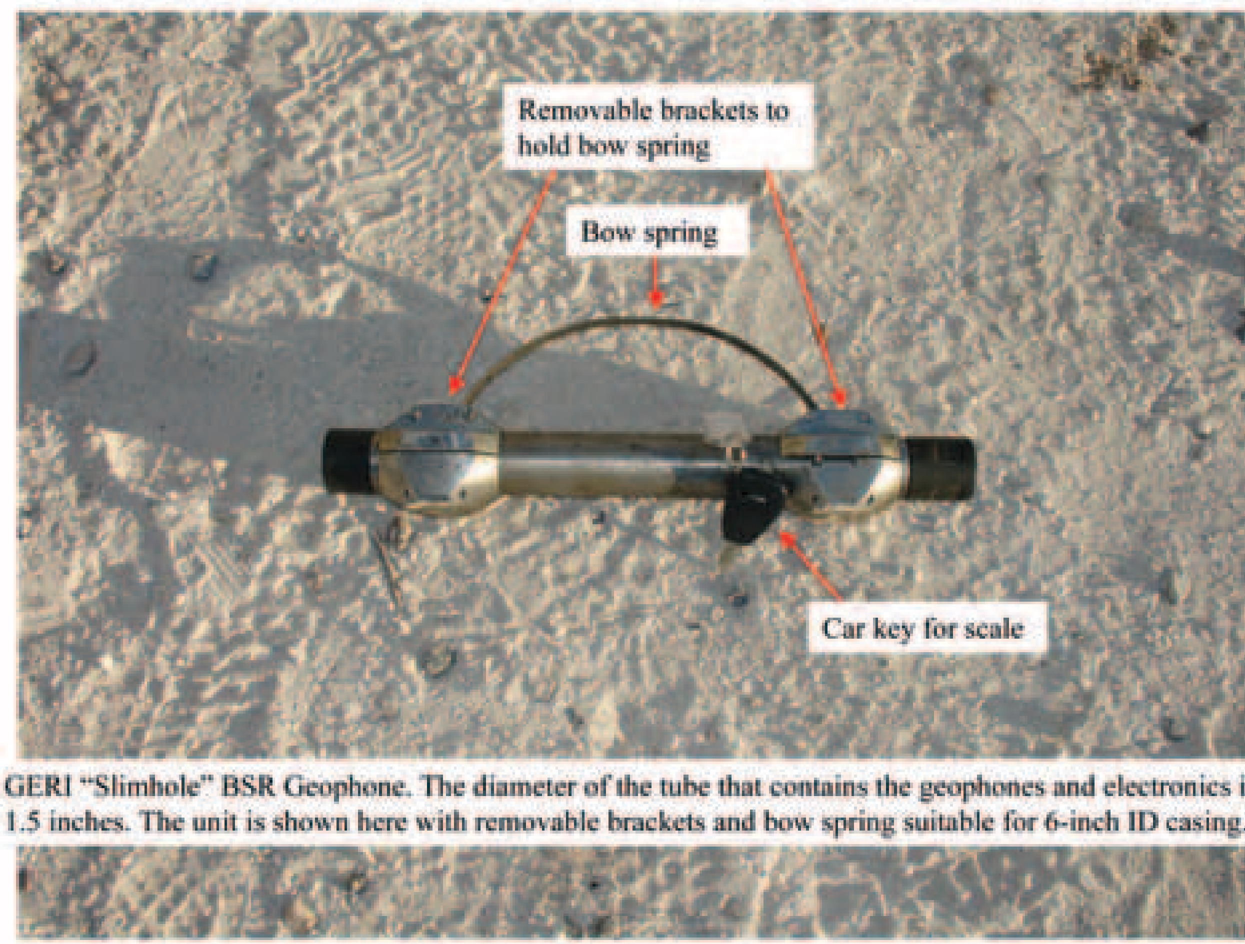

Figure 2 *Slimhole borehole sonde. The three-component geophone sonde is shown with a clamping device attached. The weight of the device shown is about 2 Kg and as many as 480 of these sondes can be deployed on a fibre augmented wireline. There is effectively no time delay between the geophones and the recording system with the maximum number of sondes on the wireline.*

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Later applications of Kirchhoff and finite difference prestack depth migration provided greater flexibility to use complex velocity fields but require detailed knowledge of spatially-variant velocity, spatially-variant anisotropy, and near-surface velocities for statics. Generally this detailed information is not available and is difficult to derive from the data.

Further evolution of processing technology has led to processing 2D and 3D VSPs in the time domain. The method avoids the more onerous requirements imposed by the depth migration method in that velocities and anisotropic parameters can be picked from the data and true surface-consistent statics can be computed. The images in this article are processed using a modern time-domain method. Figure 4 shows an example of 3D data recorded in West Texas in January, 2006. The survey objective was to guide step-out drilling near the wildcat well in which a 3D VSP dataset was recorded. Figure 5 shows a side-by-side comparison of the 3D VSP image and a 2D surface seismic line that passes within 35 m of the 3D VSP well. The 2D dataset was recorded in this difficult data area in late 2005. In spite of modern acquisition and processing methods, the resulting image was of low quality compared to the 3D VSP. In both the West Texas example and the example shown in Figure 1, the 3D VSP data has been instrumental in picking drilling locations to maximize production in the area.

Regardless of the data processing method used for imaging, processing of 2D and 3D VSP data should always include at least the following similarities to surface seismic processing: trace editing, summing of multiple shots, geometry assignment, datum elevation corrections, gain, surface-consistent deconvolution, and rigorous handling of near-surface statics. Virtually all modern VSP data is recorded with three-component geophones so the data processing flow must be able to take advantage of the signal enhancement opportunities presented by 3C geophones via time-variant rotation or 3C migration algorithms.

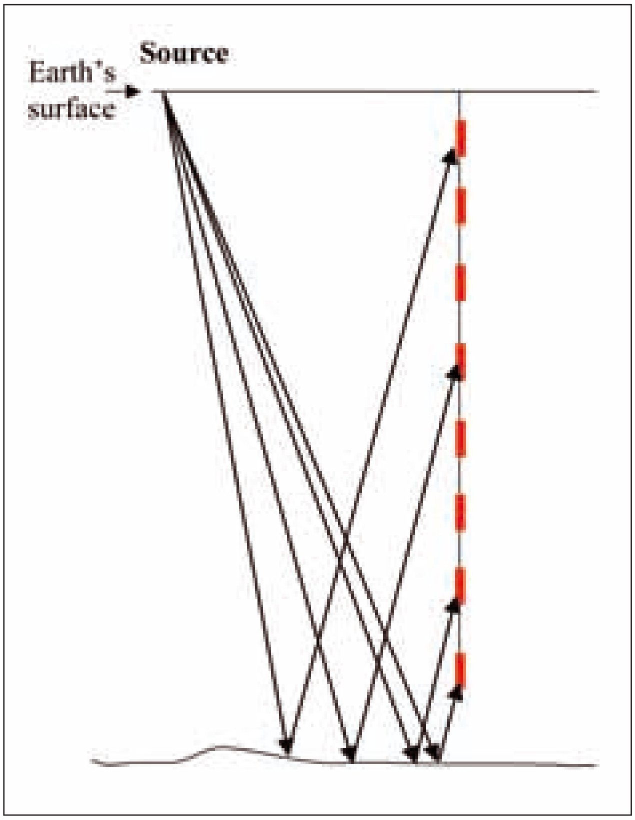

Figure 3 *Offset VSP geometry. The asymmetric downgoing and upgoing ray paths of VSP geometry result in the reflection points being a function of the source and receiver positions and the velocity field rather than the common mid-point assumption of surface seismic data. The asymmetry imposes greater complexity in reflection velocity analysis than is encountered in surface seismic data processing. The higher frequency of VSP data imposes an additional requirement on velocity field accuracy.*

Field operations

Source density

Figure 6 shows the source-point layout for a large 3D VSP recorded in 2005. There are 1114 source points around the well location at the centre of the source coverage. High source density near the well is desirable because source points near the wellbore provide a smaller area of specular reflections than source points far from the wellbore. The reduced density and circular pattern of sources at larger offsets provides uniform reflection coverage while minimizing the field effort and environmental impact of the source.

Receiver movement

As discussed above it is important to record data along a large vertical aperture in the borehole to adequately image the reservoir volume. For shallow reservoirs at 2400 m or less a single high capacity sonde string of 80 to 100 geophones, with 15 m sonde spacing, can provide 1200-1500 m of vertical receiver aperture for each shot point. The sources would need to occupy the point just one time. With deeper targets it would be typical to record up to 3000 m of vertical coverage in which case the receiver array would need to be moved to a new position and the source points would need to be re-occupied. The source needs to visit each source point for each new placement of the receiver array. The goal of moving the geophone string and visiting the sources multiple times is to simulate, having had a continuous string of geophones in the borehole that was 3000 m long. Multiple source point visits demand that the source signature is repeatable; this in turn demands that a vibroseis source goes back to exactly the same position on each visit. Explosives should be placed

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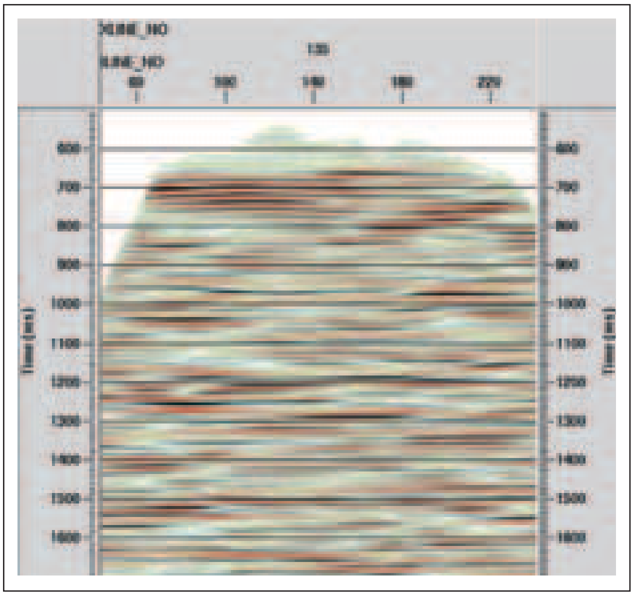

Figure 4 *West Texas 3D VSP image. This image is from a 3D VSP in West Texas. The dataset was recorded in January 2006 and is being used to pick step out drill locations from the 3D VSP well.*

as near as possible to the same ground conditions for each visit to the source point.

Survey design

VSP survey design can be done first in the office, but eventually a scout will need to visit the ground locations to determine access issues that cannot be seen from a map. Much of the scouting work can be minimized by picking the source points in a modern GIS (Geographic Information System) software package using recent high-resolution satellite or LIDAR images. The survey planner can avoid putting source locations near production facilities, terrain features, or other sensitive structures. Once the field crew actually visits the source points, the locations can be recorded with an accurate GPS system. Modern Vibroseis crews should avoid using stakes in the ground and flags for navigation. Instead the operators should have a GPS navigation system to show where each source point is and the path from the current source point to the next point.

GPS records

GPS systems on vibrators have an important function beyond convenience of the vibrator operator. Human error has a way of finding a way into all large projects, the most common of which is when the observer writes down the wrong source location for the vibrator. This type of error is usually discovered after the crew has left the field and sometimes the errors cannot be repaired in processing. Modern GPS equipment removes this error-prone part of observer's notes in 2D and 3D VSPs. All that is necessary is that each vibrator records its location and GPS time when it receives the electronic tone to start the sweep. The start time of the recording system also puts the GPS time in the trace headers. Coordination of the GPS time stamps provides accurate and automatic source geometry.

Number of sources

Generally only a single Vibroseis truck is needed for each VSP source point rather than an array of multiple vibrators. We have also found that even smaller vibrators (40,000 lb to 50,000 lb) are adequate for 2D VSP and 3D VSP projects. Smaller and fewer vibrators minimize the environmental footprint of the seismic source which can be important in some locations. It is not uncommon to push the vibrator sweep up to 160 Hz or higher for 2D and 3D VSP surveys. At higher frequencies the vibrator mechanical systems and electronics must be in excellent working order to obtain the necessary repeatability at source points.

Vibrator usage

An efficient way to use three or four vibrators in 3D VSP data acquisition is to record data from one vibrator point, while the rest of the vibrators move up to their next source points (remember, one vibrator per VP). In a properly planned survey there will always be a vibrator ready to start its sweep as soon as the last record of the currently sweeping vibrator has completed recording. When one recording has finished the next available vibrator can start sweeping, usually within 2-3 seconds. This brings focus back to the real-time capability of the downhole recording system. There should be virtually no delay in transmitting data from the geophones to the recording system so that the vibrator sweeps can be started within seconds of the end of the previous record. The number of sweeps typically varies from two to 10 depending on noise conditions in the borehole and the horizontal offset of the vibrator.

Value versus cost

As with surface seismic surveys, planning and experience greatly facilitate efficient field operations and minimize mistakes. Modern borehole systems provide a new balance in the equation of survey value versus cost and risk. The accommodation of environmental and cost limits on source efforts can be balanced with the availability of hundreds of levels of multi-component receivers and significant reduction in time occupying a producing wellbore. Technology has provided the ability to choose the appropriate balance for each case.

Near term advances

There are still significant foreseeable advances to be made in 2D and 3D VSP data acquisition and data processing.

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Downhole tools can be packaged for deployment in a wider variety of wells and at a lower cost per receiver tool. Innovative developments will place digital sensor modules inside coiled tubing allowing efficient deployment in pressurized wells, deviated boreholes, and in the potential hazards of uncased boreholes.

More efficient use can be made of Vibroseis sources by simultaneous recording of the signal from individual vibrators at different source locations. The individual source records are then later separated through signal processing. The HFVS method developed by Mobil has been successfully used to record 3D VSP data from four simultaneous vibrators. This method increased survey efficiency by a factor of over three in some cases when compared to recording sweeps from individual vibrators at their respective source points. The idea of simultaneous vibrators can perhaps be taken further by using a combination of GPS recorders and recording systems that can operate continuously and in real-time. Using these advanced operating modes the need for a start tone from the recording system, and to a large extent the need for detailed observers' notes, can be eliminated.

Advances in data processing will take advantage of the converted S-wave field that is almost always present in 2D and 3D VSP data. Interestingly there is also commonly a direct S-wave from conventional Vibroseis sources that can be processed as a direct S-S reflection image. The ability to use both the P-wave and the S-wave images greatly enhances the value of 3D VSP surveys.

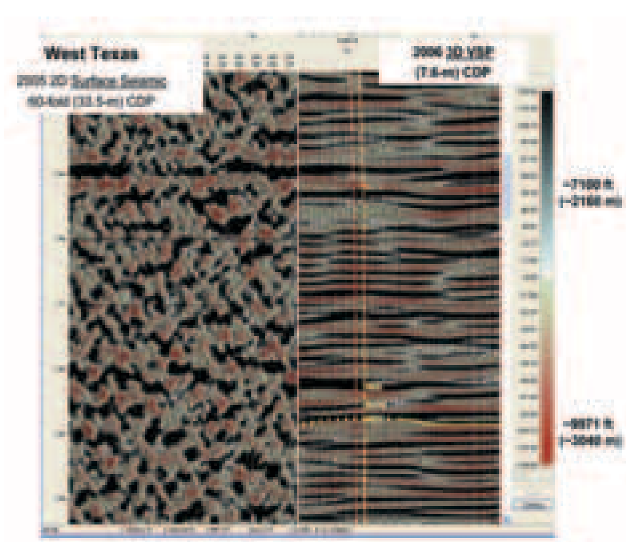

Figure 5 *Surface seismic and 3D VSP comparison. A recently-recorded 2D seismic image (left) near the 3D VSP well is shown for comparison of data quality with the 3D VSP data (right). This area in West Texas is a difficult data area for surface seismic data but apparently much less so for the 3D VSP technique.*

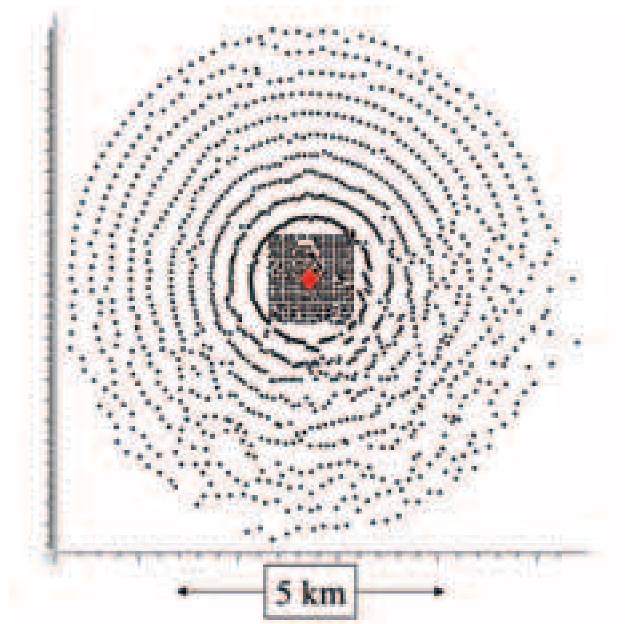

Figure 6 *3D VSP source point map. A source point map for a recent 3D VSP shows dense source spacing near the receiver well at the centre of the survey. The roughly circular source pattern at larger offsets provides uniform reflection coverage. The target depth range for this survey was as much as 5000 m.*

Proposed terminology for borehole receiver surveys

The three-letter acronym VSP stands for Vertical Seismic Profile. The classical name VSP is appropriate for the true zero-offset VSP in which the source and receivers occupy nearly the same XY location and the objective is to obtain a normal-incidence reflection profile. In 2D and 3D VSP surveys the wavefield is quite deliberately recorded at non-vertical incidence in order to obtain reflection information away from the wellbore. We suggest that the names used to reference technology should describe the technology and that names should keep pace as the technology changes. We propose the term Borehole Receiver Survey (BRS) as a general term to describe seismic surveys with receivers in the borehole. For example the terms 2D BRS, 3D BRS, or time-lapse 3D BRS would accurately describe common applications of multi-dimensional borehole seismology. The term VSP would be a special 1D case of a Borehole Receiver Survey. Acceptance of this descriptive terminology would provide a more immediate understanding of the method, the means by which they are accomplished, and the value of the information they provide.

Acknowledgments

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