# Time domain 2D VSP and 3D VSP processing

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## Summary

Transformation of 2D VSP and 3D VSP data to surface seismic data simplifies the imaging process by allowing the use of well-established surface seismic data processing technology to determine the velocity field and statics solutions. The process has distinct advantages over the more commonly used prestack Kirchhoff depth migration for 2D VSP and 3D VSP processing.


## Introduction

Data acquisition geometry of 2D VSP and 3D VSP has seismic source points at the surface of the earth and seismic sensors deep in a borehole. The advantage of this geometry is that the frequency content of seismic data recorded in the borehole is often two or more times higher than surface seismic data recorded at the same location. The primary disadvantage of VSP data acquisition geometry, at least in terms of data processing, is that the source-receiver elevation difference results in asymmetry between the downgoing and upgoing reflected ray paths. The ray path asymmetry precludes use of the common midpoint reflection assumption that is heavily relied upon in surface seismology (Figure 1) thereby imposing greater requirements for correct imaging solutions. Albeit more difficult than surface seismic processing, pursuit of 2D VSP and 3D VSP processing solutions is worthwhile because higher frequency content in VSP data provides higher resolution of production-related geologic features such as faults and stratigraphic changes.

Early work in 2D VSP and 3D VSP seismic imaging was done by the commonly-known VSP-CDP transform (Wyatt and Wyatt, 1981), a reflection mapping algorithm that generally uses either a 1D velocity model or simple dipping velocity model. This method was a valid first step in VSP imaging but could not account for the complex velocity field of the earth so the images were limited. Prestack Kirchhoff Depth Migration, including multi-component methods, were later adapted for 2D and 3D VSP (Wang, 2004). Prestack Kirchhoff Depth Migration (PSDM), a depth-domain method, provides the advantage of being able to use arbitrarily complex velocity fields while honoring the VSP source-receiver geometry. Accurate PSDM results require accuracy of the migration velocity field including spatially variant velocities and anisotropic parameters. Determination of the correct velocity field parameters that lead to a structurally correct high-frequency image can be very difficult. A prestack depth migration velocity field that is less accurate than demanded by the highest frequency of the field data results in an image that in compromised in frequency content and in extreme cases can show incorrect structure.

The purpose of this paper is to discuss a new approach to 2D VSP and 3D VSP data processing that is carried out in the time domain. The method includes transformation of VSP field records so that the resulting data may be treated as though the geophones had been at the surface of the earth when the wavefield was recorded. Hence the many well-developed methods of surface seismic data processing can be directly applied to VSP data. For example NMO-based velocity analysis can be applied and true surface-consistent source and receiver statics can be computed. The method assumes nothing about the velocity field in order to achieve the data transform thus the many imaging problems imposed by Prestack Kirchhoff Depth Migration are removed.

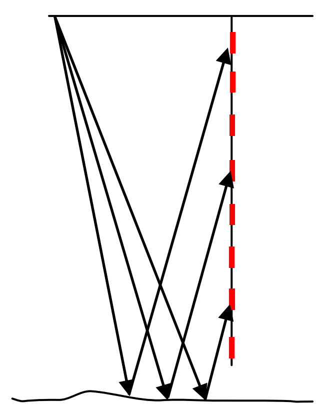

Figure 1. VSP Geometry. The source is generally at a different elevation from the receivers in VSP acquisition thus the common mid-point assumption of surface seismic data is invalidated. This sketch demonstrates that even though receivers (red dots) are all at the same offset from the source point the reflection locations vary with the receiver depth.

## Theory

Berryhill (1979) showed that a wavefield recorded at multiple locations can be continued to some other location if the travel time between each of the sampled locations and the new location is known. Figure 2 shows the concept as related to our VSP application in which a seismic signal, P(t), is computed at a point P at the surface of the earth. The input to the computation of P(t) is the summation (stack) of the seismic signals, $R_i(t)$, recorded at each of the downhole geophones. Prior to summation the measured seismic signal, $R_i(t)$, is delayed by the time $f_i$ that is equal to the travel time from the point P to the respective receivers. In other words the signal $R_i(t)$ is delayed by the first arrival time ($f_i$) between a seismic source at the point P and the $i^{th}$ geophone location, $R_i$. The seismic wavefield approximated at the new surface receiver, P(t), can be expressed as Equation 1:

$$P(t) = \sum_i R_i(t-f_i) \qquad (1)$$

2D VSP or 3D VSP data can be continued to new "pseudo receiver" locations at the surface of the earth by application of Equation 1. Time delays, $f_i$ , between borehole receivers and pseudo receivers at the surface of the earth are taken directly from observed first arrival times of the 2D or 3D VSP data. If a first arrival time is not available directly from a source located at a pseudo receiver location then the arrival time can be interpolated from other nearby source points.

Application of Equation 1 to 2D VSP or 3D VSP data transforms borehole seismic data to data that can be treated as surface seismic data. The well-developed methods of surface seismic data processing technology including NMO analysis and surface consistent statics can be applied to the transformed VSP data and a reflection image can be quickly and reliably produced.

**Data examples**

Figure 3 shows a comparison between 3D surface seismic data and 3D VSP data. 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 4 shows an extreme example of improved signal quality of 3D VSP data over surface seismic data. 3D VSP data recorded in West Texas in January, 2006 is shown next to surface seismic data recorded in late 2005 within 35 m of the 3D VSP well. The location is generally considered to be a difficult surface seismic data area. In spite of modern acquisition and processing methods the resulting surface seismic image was of low quality compared to the 3D VSP. In both the West Texas example and the example shown in Figure 3 the 3D VSP data has been instrumental in picking drilling locations to maximize production.

**Discussion**

The observed travel times ($f_i$) used in Equation 1 contain all velocity, statics and anisotropy information along the raypath from the surface to the downhole geophone. The information in the observed travel time allows accurate extrapolation of the wavefield to the surface of the earth without having to actually know the velocity, statics, and anisotropy parameters. Surface seismic processing techniques can be used on the transformed data however to separate velocity, anisotropy, and statics contributions to the wavefield appropriate for time-domain processing.

The transform of Equation 1 has allowed use of the common-midpoint assumption and reduced the imaging problem to picking correct stacking velocities, eta values for anisotropy, and solving for statics.

**Conclusions**

The method presented allows 2D VSP and 3D VSP data to be processed as surface seismic reflection data after the transform in Equation 1 has been applied. Processing the data as surface seismic data simplifies the determination of velocity and statics because well-developed processing technology from surface seismology can be applied.

**Acknowledgements**

We gratefully acknowledge Nancy House with EnCana Oil and Gas (USA), Denver, Colorado for the use of Figure 3 and Jay May with Concho Resources, Midland, Texas for the use of Figure 4.

**References**

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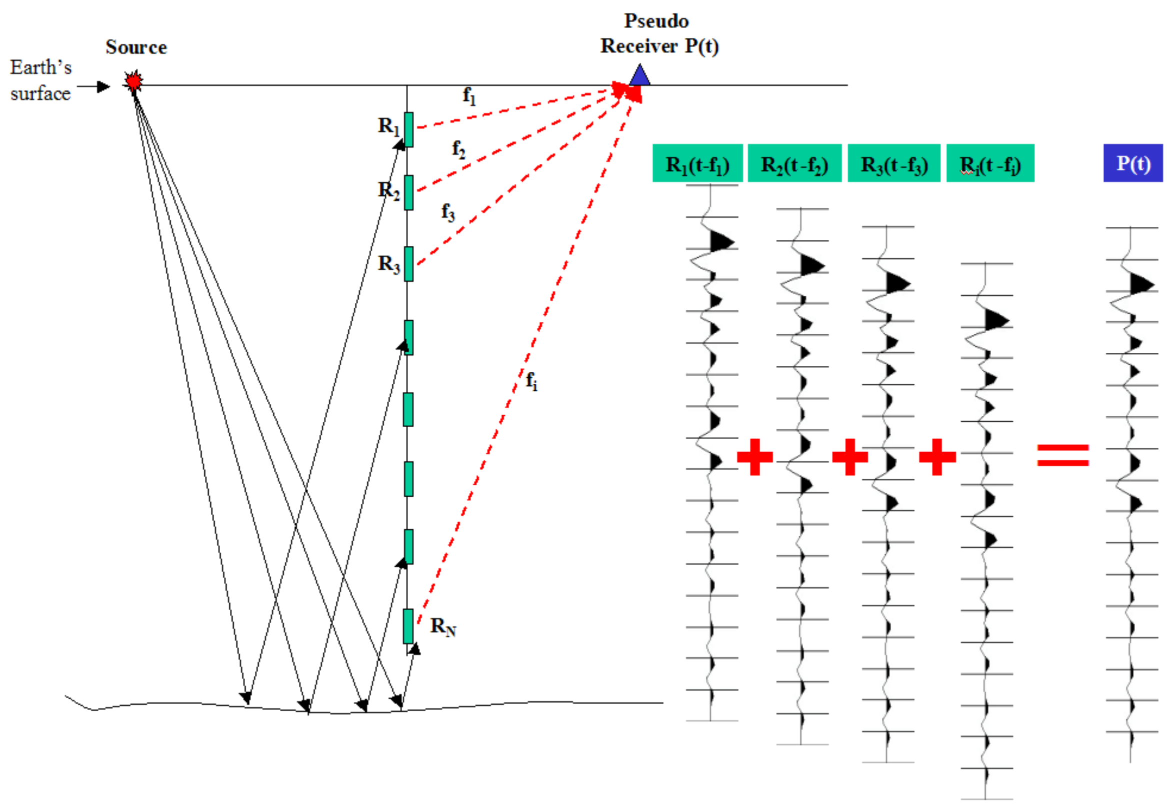


Figure 2. Diagram describing how a pseudo-receiver trace P(t) is constructed by using the recorded signals at each recevier location ($R_i$) and the associated first arrival times ($f_i$) to the surface location. The first arrival times are measured directly if another surface source is taken at this location. If no surface source exists at this location travel times are estimated from nearby sources via interpolation. Each recorded trace ($R_i(t)$) is delayed in time by the appropriate travel time ($f_i$) and then summed with all other receiver signals to approximate the signal that would have been recorded at this surface location (P).

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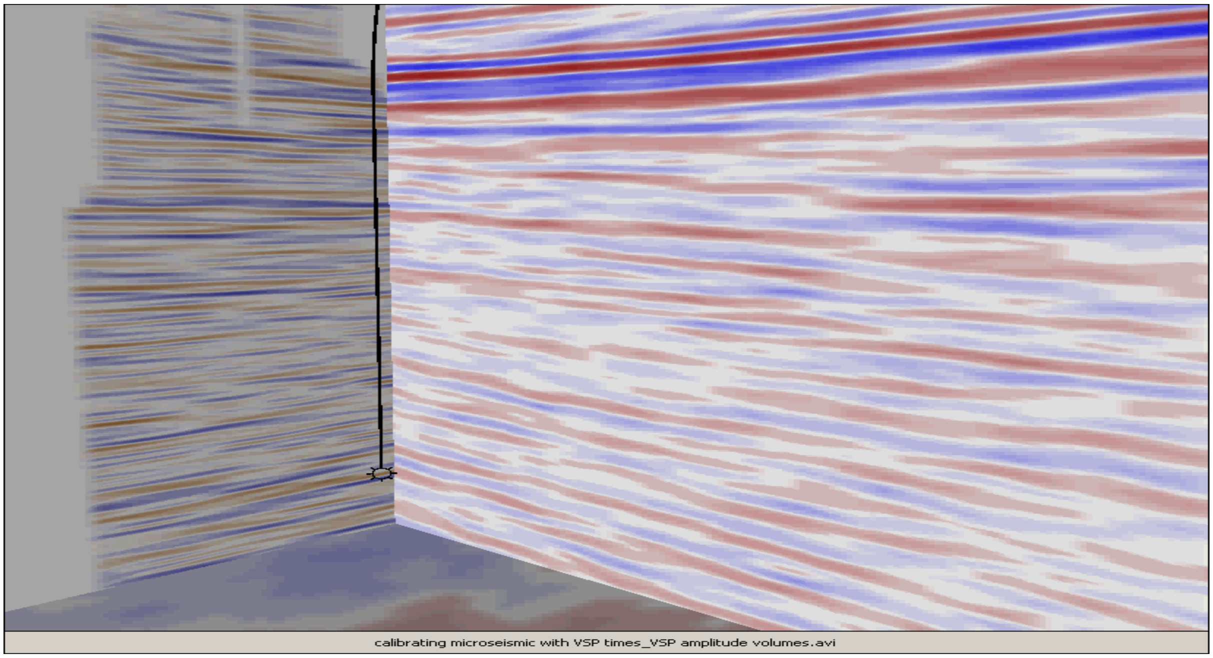


Figure 3. Comparison of 3D VSP and surface seismic data. Abutting slices from a 3D VSP image on the left and a 3D surface seismic image on the right shows the higher frequency and resolution of the 3D VSP data. Fine stratigraphic and faulting features are more visible on the 3D VSP image.

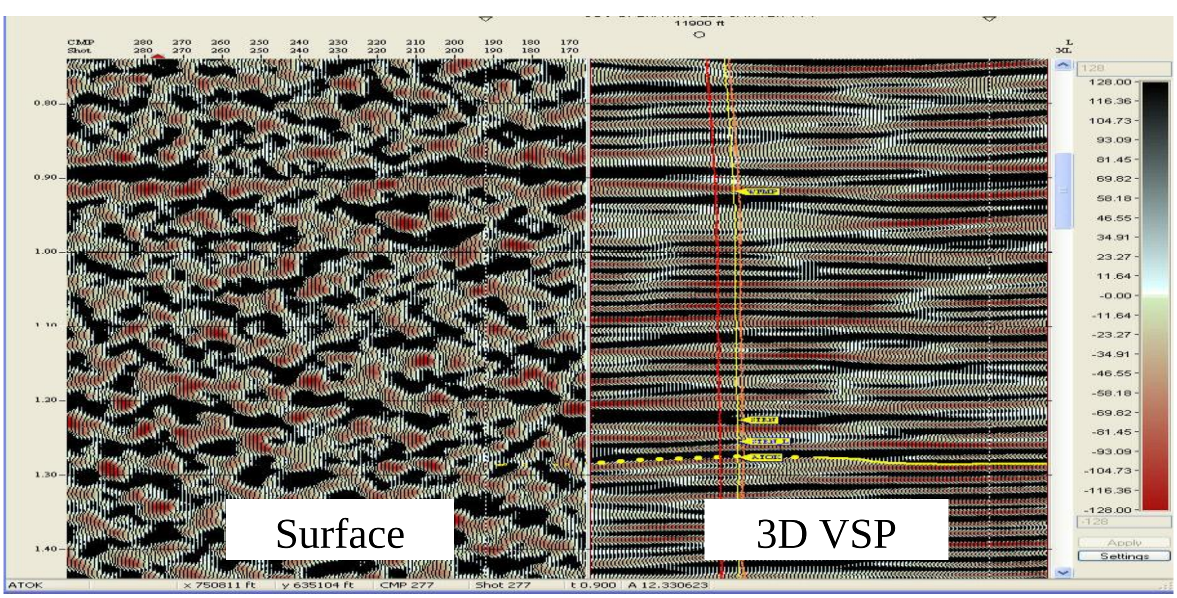


Figure 4. Comparison of 3D VSP and surface seismic data. Surface seismic data recorded in West Texas (left) is compared with 3D VSP data (right) recorded at the same location. The surface seismic data was recorded in late 2005 with modern equipment and the data was processed using modern methods. The 3D VSP data was recorded in January, 2006. The location of these surveys is considered to be a difficult data acquisition area but the 3D VSP result was obviously less hampered by the local conditions.