Simulating surface seismic records from VSP data: a 3D test

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Summary

It is possible to transform a walkaway Vertical Seismic Profile (VSP) to simulate a set of surface seismic shot records by convolving and summing together the appropriate sets of VSP records. This method is strictly formulated for a 2D medium, meaning that the surface sources and borehole geophones are all contained in a single vertical plane, and that the velocity model only varies in the same 2D plane. We test the limits of the method by examining what happens when we use data from both a 2D slice from a 3D model and the full 3D model.

Introduction

Throughout the past ten years, many advances have been made in seismic redatuming—where the level of the receivers is mathematically moved to the level of the shots, or vice versa (Bakulin and Calvert, 2006; Xiao, and Schuster, 2006). Schuster (2009) describes a variant of data-driven redatuming in which a VSP data set can be transformed into a surface seismic shot record by convolving and summing the appropriate pairs of VSP records together. This method requires that an appropriately dense coverage of borehole receivers.

Fuller et al. (2008) attempt a shortcut to this full solution. They replace the convolution by either (a) applying time shifts obtained from an interpolated map of time shifts estimated from first arrivals followed by summing or (b) a finite difference upward continuation process using an estimation of the subsurface velocity.

Whichever methodology is used to convert the VSP data into surface shot records, unexplored practical questions exist regarding the effects of limited source and receiver coverage, as well as the appropriateness of this method in geological settings that are not strictly 2D. In this paper, we explore these aspects.

Simulation Method

We start with a densely acquired walk-away VSP data set, as shown in Figure 1. We want to simulate a surface seismic shot located on the left side of well, with receivers located on the right side of the well. Each of these locations is the position of a shot for which VSP data has been acquired within the borehole. For convenience, we label the shots on the left and right sides of the borehole as S_L and S_R, respectively. Schuster (2009) provides an expression for converting the VSP data into a surface seismic shot record as follows:

$$G(B \mid A) \approx \int_{S_{well}} kG(x \mid A)G(x \mid B)dx \tag{1}$$

where B is the desired simulated surface shot location (shown as blue star in Figure 1), A is the simulated surface receiver on the right side of the well (shown as the other blue star), and G(B|A) is Green's function solving the 2D Helmholtz equation from the source at B to the receiver at A, which simulate the surface seismic data. Also, in Equation 1, k is a parameter, related to the medium velocity near the geophone, x is one of the receivers in the borehole, G(x|B) or G(x|A) is the Green's function from source at B or A to the receiver at x in the borehole, which are the VSP data we acquired. After the convolution of G(x|B) and G(x|A), we sum over all the receivers along the borehole to simulate the surface shot data from B to A.

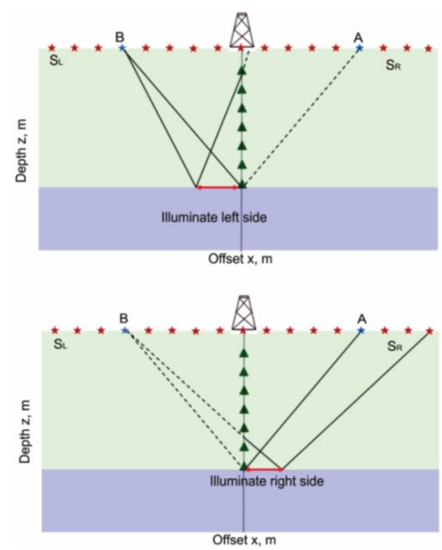

Figure 1. Diagram showing surface shots (red stars) and borehole geophones (green triangles). Top – Left Part contributions: the reflections in the VSP record from the virtual shot location (on left) are convolved with the first arrivals from the VSP shots on the right hand side. Bottom – Right Part contributions: the first arrivals from the virtual shot location are convolved with the reflections in the VSP record from the right hand side shots.

We expand Equation 1 into several pieces by separating the input VSP data into three portions—down-going direct first arrivals, up-going reflections, and down-going multiples. This allows us to focus on the interactions between the first arrivals and the up-going reflections. We call the Left Part the portion that convolves the up-going reflections from the left shot (G(x|B)), with the first arrivals from the right shot (G(x|A)). This is illustrated in the top part of Figure 1. We call the Right Part the portion that convolves the first arrivals of the left shot (G(x|B)) with the up-going reflections from the right shot (G(x|A)). This is illustrated in the bottom part of Figure 1. Equation 2 shows explicitly these two contributions.

$$G(B \mid A) \approx \int_{S_{well}} k * \Big[\overbrace{G(x \mid B)_{upreflections} G(x \mid A)_{firstarrivals}}^{\text{Left Part}} + \overbrace{G(x \mid B)_{firstarrivals} G(x \mid A)_{upreflections}}^{\text{Right Part}}\Big] dx \quad (2)$$

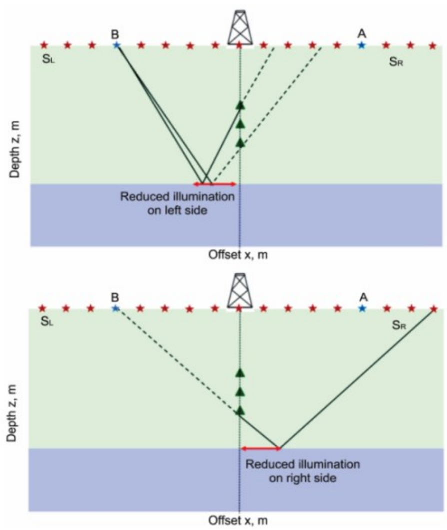

Figure 2. Schematic diagram showing the effects of reduced receiver coverage. Top – Left Part contributions do not illuminate as completely as with full coverage. Bottom – Right Part illumination can be severely compromised.

As is illustrated in the top part of Figure 1, the Left Part illuminates the portion of the subsurface to the left of the borehole (if the reflectors are horizontal). Similarly, the Right Part illuminates the portion of the subsurface to the right of the borehole, as shown in the bottom part of the figure. In our analysis we will ignore the contributions from the multiples because our chief concern is with the primary events.

It is possible compute the direct arrival at the surface location A, for the simulated shot at location B by convolving the first arrivals from the VSP shot at B (G(x|B)) with the first arrivals from the VSP shot at A (G(x|A)). However, if the shallowest receiver is not near the surface of the earth, then the event will not be at the correct time because the direct arrival travels along the surface.

Figure 2 illustrates the effect of limiting the borehole receiver coverage. The red lines in the figure indicate the full coverage illumination region (from Figure 1). We observe that reducing the depth of the deepest receiver causes a gap in the coverage near the well borehole. This is true for both the Left Part (top) and Right Part (bottom) contributions. The useful surface VSP shot locations are pulled in closer to the wellhead for the Left Part, but are pushed farther from the wellhead for the Right Part. The bottom of the figure shows the limiting case where only the right most surface shot is usable for the Right Part.

For the Left Part, increasing the depth of the shallowest receiver has the effect of moving the edge of the illuminated area closer to the borehole. It also moves the first useful shot on the right of the wellhead farther away. For the Right Part, the sensitivity to the shallowest receiver is not as great because this affects only the farthest to the right surface shot. Thus, reducing the depth range of the borehole receivers restricts the useful range of receivers in the simulated shot gather. Even if the walk-away VSP has complete surface shot coverage, the simulated surface shot record will have a limited number of receiver locations, which is directly related to the borehole receiver coverage. Figure 3 shows an example of a simple two layer model corresponding to Figures 1&2 with full and reduced coverage of borehole receivers.

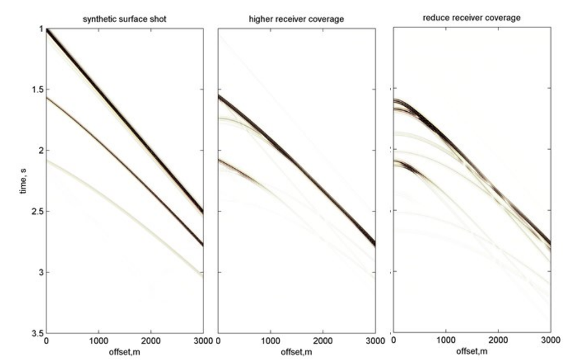

Figure 3. Two layer model simulation. The model was created as in Figures 1&2 with reflector depths at 1200 m and 1900 m. The shots are on the surface from x = -3000 m to 3000 m. Left – Actual surface shot record modeled for the shot at x = -2000 m. Middle – simulated surface shot with "full" borehole receiver coverage from z = 10 to 1170 m. Right – simulated shot with reduced borehole receiver coverage from z = 390 to 790m. The receivers are spaced at 10 m for both cases.

As Schuster (2009) points out, the simple convolution process to simulate the shot record creates some artifacts in the output traces. Some of these are caused by edge effects in the stacking process. Tapering can be applied to reduce these effects. However, it is not a straight forward matter to determine the time and offset varying ranges to apply such tapering. So, for simplicity, in this paper, we have not attempted to reduce the artifacts. This part will be shown on the presentation.

Synthetic Example

Figure 3 shows the 3D model we used to explore aspects of simulating surface seismic records from a walk-away VSP. The model dimensions are 10 km in both x and y, and 8 km in depth (z direction). The surface shot line is located at x = 5000 m. We chose the location of the simulated shot to be the large black star at y = 2000 m. The 100 red dots on the right side of the well are the shots corresponding to the desired simulated receivers at y = 5000 to 9950 m with a spacing of 50 m. For VSP acquisition, there are 200 receivers in the borehole from a depth of 1 to 3981 m with spacing of 20 m. The source is a Ricker wavelet with a 33 Hz center frequency.

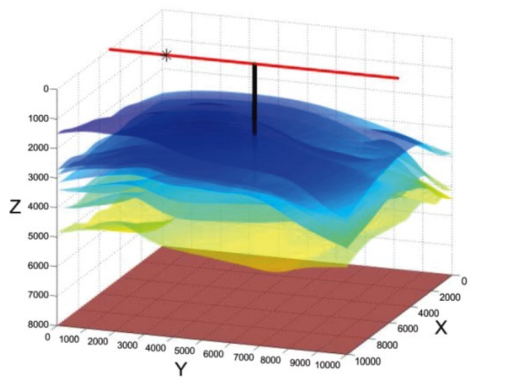

Figure 3. 3D model containing eight layers. The shot line is shown by the red markers. The large star shows the location of the simulated surface shot. The vertical, small black markers show the borehole geophones.

We first create a 2D model by selecting a vertical slice through the 3D model through the shot line. A synthetic shot record was created with the source located at y = 2000 m (the black star in Figure 3) and receivers on the right side of the well. It is shown on the left side of Figure 4. A corresponding shot record was created using the full 3D model, which is shown on the left side of Figure 5. In many aspects, these records are similar. However, on close inspection, significant time shifts occur between the events on these records. In addition, significant out of plane events are evident on the 3D result.

For these two modeled data sets, we followed these steps:

1. We chose the location for the source of the simulated "shot" to be on the left side at y = 2000 m, corresponding to one of the VSP shot locations.
2. We chose a location to simulate a "receiver" for that shot, on the right side of the borehole at one of the VSP shot locations from y = 5000 to 9950 m.
3. In each VSP record, we create two data sets—one with only first arrivals and the other with only up-going reflections.
4. We compute the Left Part contribution by convolving and summing the up-going reflections from the "shot" side with the first arrivals from the "receiver" side.
5. We compute the Right Part contribution by convolving and summing the first arrivals from the "shot" side with the up-going reflections on the "receiver" side.

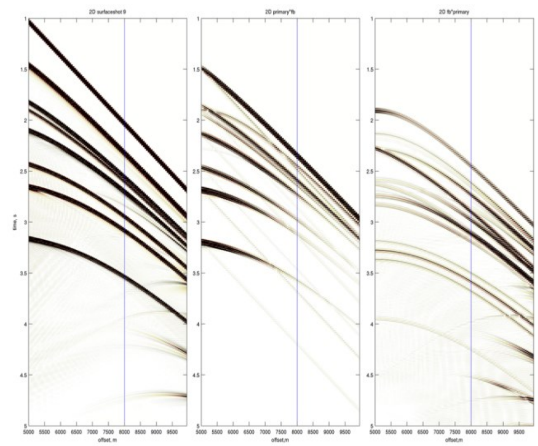

Figure 4. 2D model simulation results. Left – Actual surface shot acquired with a 2D model. Middle – simulated surface shot from the Left Part. Right – simulated shot from Right Part.

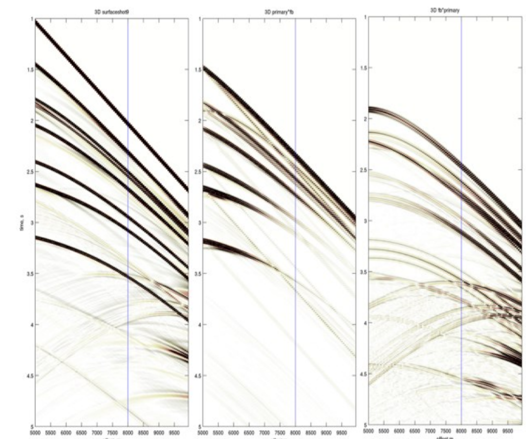

Figure 5. 3D model simulation results. Left – Actual surface shot acquired with a 3D model. Middle – simulated surface shot from the Left Part. Right – simulated shot from Right Part.

The middle panels of Figures 4 and 5 show the Left Part results for the 2D and 3D models, respectively. The right panels in Figures 4 and 5 show the corresponding results for the Right Part. We have not modeled the direct arrival on either of these simulated results. The simulated shot is located on the left side of the well at an offset of 3000 m from the wellhead. On each panel, we draw a vertical, blue line at 8000 m, which indicates the corresponding 3000 m offset on the right side of the wellhead. As can be seen in Figure 1, simulated traces to the right of the wellhead and less than this distance will have common midpoints on the left side of the borehole. For horizontal 2D layers, this is the range for which the Left Part will be valid. So, in the middle panels of Figures 4 and 5, traces to right of this line will likely be invalid. Alternately, traces to the left of the blue line in the right panel will likely be invalid. However, because the layer geometry in these two models is not horizontal, these are only guidelines with respect to the range of valid simulated traces.

Examining the 2D results in Figure 4, we see that the traces before the blue line in the middle panel are a fairly good approximation to the corresponding traces in actual shot record. (Note again we have not simulated the direct arrival.) We do see fading of the reflections as we approach the blue line, and some artifacts exist that could have been reduced using some weights during stacking. Examining the traces after the blue line in the right panel, we observe that they are a fairly good approximation, but certainly contain artifacts not found in the actual shot record.

Turning to the 3D results in Figure 5, we make some similar observations as for the 2D case. The traces before the blue line in the middle panel are a fairly good approximation to the corresponding traces in the actual shot record, but fade with increasing offset. Examining the traces after the blue line in the right panel, we see a fairly good correspondence to the events with the actual shot record. However, there are significant amplitude changes. In addition, time shifts occur between the simulated traces and the actual shot record, which is not surprising given the complexity of the 3D model.

Conclusions

We investigated a method to transform a walk-away VSP to simulate a set of surface seismic shot records. It convolves and sums together the appropriate sets of VSP records to create this simulation. For acquisition in areas with strictly 2D geology, this method is well-defined and behaves accordingly. However, an understanding of the receiver and shot coverage is necessary to stack together the convolved pieces of the solution to reduce artifacts and provide reliable results. For areas with 3D geology, the problem is more difficult. The method can certainly be applied to the data and a result obtained; but, it is more difficult to understand which events can be trusted. The simulated shot record using VSP records for the 3D model provided records qualitatively similar to actual shot records. However, using this simplified method does not allow obtaining the exact answer because of its theoretical limitations.

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