Non-conventional Techniques for Focused Reservoir Imaging

William Chmela, READ Well Services, Houston, Texas, USA

Abstract

This presentation will focus on 3DVSP surveys and other non-conventional seismic techniques for focused reservoir imaging. These techniques can be used to improve resolution and to deliver more accurate reservoir models for production enhancement.

Introduction

New techniques and methods are being introduced by small innovative companies and have emerged in some areas as a primary imaging process. New technologies and data acquisition techniques have been developed that allow very large scale 3DVSP's to be acquired while using less than 10 percent of the rig time that similar surveys would have used just a few years ago. In tough imaging areas, this may be the only way to obtain improved images. In the past, the biggest factor limiting the use of 3DVSP technology was the cost involved with tying up a rig for days. By significantly reducing this cost, these high resolution surveys are increasing in frequency.

With many oil and gas fields moving into the declining stage of production, the industry is continuously looking for ways to improve the recovery of hydrocarbons from existing reservoirs. Historically in old fields, there is a wealth of high resolution data obtained at the borehole (well logs) and a much wider but low resolution view of the field from surface seismic measurements. The goal towards better understanding of the reservoir typically revolves around attempts to improve the resolution of the seismic image and/or to measure changes in the reservoir properties to uncover bypassed hydrocarbons.

3DVSP

In many hydrocarbon basins, the surface seismic image is obscured by anomalies between the seismic instruments and the reservoir. Some examples of these anomalies are shallow gas, weathered layers and undulating salt sheets. To obtain a better 3D image of the reservoir in these tough imaging cases, either the seismic sources or the seismic receivers can be moved beneath the anomaly. By moving the recording instrument closer to the horizon to be imaged, we see improvements in both vertical and horizontal resolution.

The technique of moving the receivers beneath these anomalies has been around for some time and is known as 3DVSP. Oil companies have been acquiring 3DVSPs since the late 1980's, but in most cases the technique has been too expensive to justify the effort. The early days of 3DVSP consisted of anchoring a small array (typically five levels) and shooting a number of seismic lines in a 3D grid. This small array would then be shifted in depth and the 3D grid retraced. Since borehole seismic processing requires a number of geophone depth levels to be acquired, this grid often had to be reshot a number of times into these small arrays. With the ability to now acquire up to 32 three-component levels on a standard seven-conductor wireline, the rig time associated with acquiring these surveys can be cut to about 20 percent of the time that was required in the early days.

Acquisition of 3DVSPs requires the downhole arrays anchored in the wellbore plus a mobile source at the surface to generate the seismic signal. In most cases this mobile source can be smaller than the sources used for surface seismic since the seismic travel path is reduced (the energy does not need to return to the surface). This allows the use of smaller highly tuned arrays for improved frequency content.

Significant advances to save time and money can also be found in the source deployment. By changing from the standard pattern of shooting (multiple straight lines in a grid) to shooting a spiral pattern around the well, the dead time associated with turning the seismic vessel around while moving from one line to the next is eliminated. This spiral shooting allows a survey to be completed in about three quarters of the time that it would have taken with the more traditional straight line shooting.

On a typical 3DVSP spiral shoot, the limiting factor determining survey time is the speed of the source vessel. To overcome this time limitation, the data can be acquired by flip-flop shooting with two or more sources. This type of multiple-source acquisition can be done by either deploying numerous sources from one boat or by using several dynamically positioned source boats steaming along intertwined Archimedes spiral paths. Flip-flop shooting between two boats enables each survey to be completed in one-half the time it would take using a single-source boat.

By combining the above mentioned techniques of long arrays, spiral shooting and multiple sources a 3DVSP can now be acquired in less than 10 percent of the time it would have taken using older technology and methods.

In some cases of severe shallow anomalies interfering with surface seismic, 3DVSP may be the only known way to produce images of sufficient quality for reservoir engineering models. (Figure 1)

There has been a large increase in the number of surveys acquired in the past two years in many basins around the world because the economics of acquiring 3DVSPs has been changing so rapidly. The increase in acquired data has allowed testing and refinement of processing techniques for extracting images from this data. It is now standard to do full multi-mode wavefield decomposition (separation of compressional and shear modes using multi-component algorithms) and 3D anisotropic depth migration. The vast amount of recently acquired data will help developers further refine these processing techniques.

An additional advantage of acquiring multi-component data closer to the reservoir is it allows the direct recording of the reflected shear data that is missed with data acquisition using streamers on the surface. In areas of low or zero compressional wave reflectivity, there is often a large shear acoustic impedance reflectivity. In these cases, the shear wave image may be the only way to map the reservoir.

3DVSP produces additional data beyond the high resolution images. It allows for the study of azimuthal variations in velocity, reflectivity and multiple patterns. Also, since both the depth of the receivers and the downgoing wavelet are known, the shallow reflectors will be imaged at the correct depth and without contamination by multiples. The near offset image is a good reference for quality control of surface seismic processing.

Small Scale OBC

One significant disadvantage of 3DVSP is the coverage footprint. Production of a high resolution image is restricted to the area around the well, since the geophone placements are confined by the wellbore location. However, many of the techniques used in multi-component 3DVSP processing can be applied to multi-component Ocean Bottom Cable (OBC) processing. By deploying multi-component receivers on the sea floor, both P and S images can be produced .

By combining borehole seismic 3DVSP surveys with short OBC lines, the coverage of the 3DVSP can be extended. The parameters from the 3DVSP can also be used for processing the OBC. The 3DVSP raw data can be used to confirm the migration velocity model to be used in the OBC processing (including vertical P velocity, S velocity, attenuation, and anisotropy parameters.)

Integrated VSP and OBC is a economic way to do feasibility testing of OBC for reservoir imaging. If the small scale OBC survey shows promise for imaging and lithology determination, then the technique can later be extended to full 3D OBC surveys over the field. It is an inexpensive method of investigation.

The advantage of acquiring OBC data simultaneously with VSP is the economics. The seismic crew, seismic source vessel and recording unit have already been deployed offshore for the VSP. (Figure 2) In addition, there is often waiting time associated with the drilling rig when the 3DVSP crew is not productive. The extra cost for laying a couple of OBC lines and acquiring more data is small compared to mobilizing a complete OBC crew for a separate feasibility study.

Ocean Bottom Shear Source (OBSS)

As we focus on high resolution P and S images from OBC or 3DVSP, other new technologies have also been developed. An important application using multi-component data is to determine rock and fluid parameters from the P and S reflectivity. Before computing rock and fluid parameters, accurate P and S velocities must be known to correctly place these images in a common depth frame. In order to assist with this technique, READ developed a sea-floor shear-wave source. This source can be used to measure the vertical shear-wave velocity profile at the wellbore.

The sea-floor shear-wave source consists of "anchoring" the source to the sea floor and upon activation creating an impulsive shear wave. Since this source is anchored to the sea floor we are able to directly generate shear waves in the marine environment.

This shear-wave source can also be used for fracture studies. In a fractured (or azimuthally anisotropic) medium, the shear waves are often more instructive than the P waves since they are restricted to propagate polarized parallel to and perpendicular to the strike of fractures. This phenomenon, called shear-wave splitting or birefringence, makes it possible for this anisotropy to be investigated. Fracture orientation and indications of fracture density can then be obtained. In the past shear wave birefringence studies have been commonplace on land. This new source allows this technique to be used offshore.

4D and Permanent Seismic

The declining stage of production of many oil and gas fields leads to a discussion of 4D monitoring. 4D is the recording of 3D data more than once using the same survey geometry. Comparison of surveys over time is performed to detect subtle changes associated with production.

Much of the development work for 4D revolves around building tools to remove time-lapse differences between seismic data volumes, such as actual recording layout, coupling, noise, seasonal changes, statics, processing parameters and algorithms. Once these differences are accounted for, the hope is that any anomalous differences are due to changes in the reservoir associated with fluid movement.

It is important to try to eliminate as many of the differences in data sets at the acquisition stage. One way to eliminate differences in recording layout and coupling is to permanently install the geophones either in a 3DVSP configuration or on the ocean floor.

Recent advances have been made in building permanent downhole sensor packages with multiple levels. These sensor packages are both decoupled from the noise in the production tubing and well coupled to the formation.

Conducting 4D surveys using permanently deployed multi-component geophones on the seafloor or in the borehole has a significant advantage over repeated streamer surveys. Corrections for acquisition geometry and coupling in these permanent installations are small or non-existent.

Small scale OBC surveys can also be acquired at a lower cost by using a recording buoy rather than using an additional vessel for recording. In standard OBC recording, separate vessels are mobilized for the source and for the data recording. New technology has allowed the data to be recorded to a remote buoy while being monitored on the source vessel.

Changes seen over time with 4D seismic technology allows improved reservoir management decisions.

Fracture Monitoring

The improvement in downhole geophone technology has also led to new exciting possibilities for induced fracture detection. The ability to deploy long arrays with high sample rates, low noise floor, and 24 bit a/d also allows for the detection and location of extremely small high frequency arrivals.

Continuous monitoring of a seismic array in a well that is in the proximity of another well being hydraulically fractured allows the fracture to be mapped in real time.

The fracturing operation actually creates small micro-earthquakes as the rock fractures. Detection of both the compressional and shear seismic arrivals in a nearby wellbore allows mapping the height, length, and azimuth of the fractured zone. Knowledge of the true fracture geometry results in improved well placement for reservoir drainage.

Summary and Conclusions

This article focused on new technologies and methods that have the common goal of improving reservoir imaging to help build better reservoir models. The techniques discussed become a real possibility for widespread use as standard products. These techniques both improve the final images and improve the economics of acquisition.

Through extensive research and development projects and through constant technology watch, small innovative companies are able to quickly bring these advances to the market. The industry will benefit when large integrated oilfield service companies also offer these techniques. History has shown that future widespread use of these new technologies will lead to the emergence of new developments and small focused service companies will continue to be able to offer clients new and innovative products and services.

Acknowledgments

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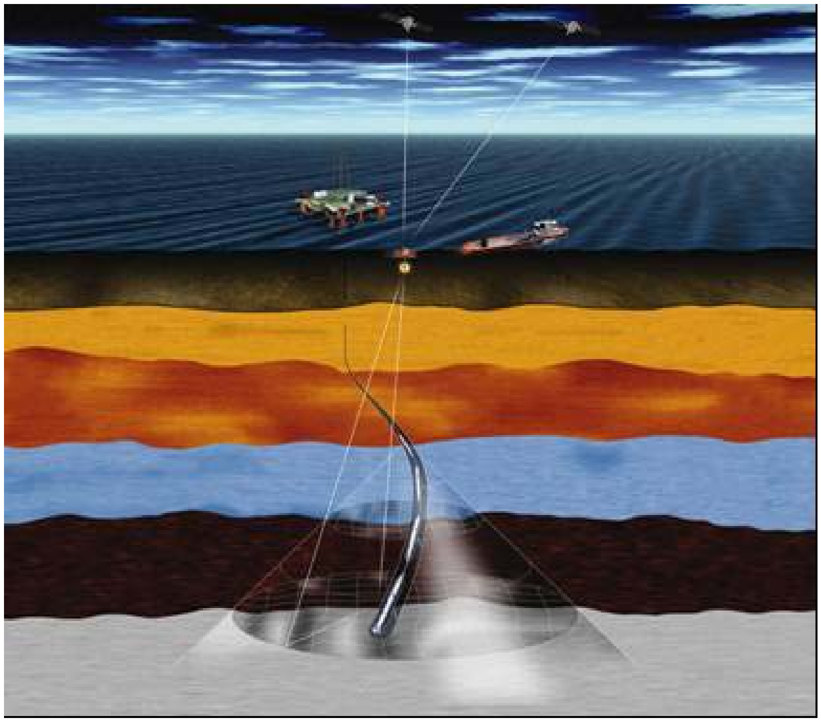

Figure 1 – 3DVSP surveys produce a high resolution image of the reservoir over a limited area. Combined with OBC, this area can be increased.

Figure 2 – VSP Source Vessel can be used for both the 3DVSP and the OBC reducing overall acquisition costs.