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Seismic Monitoring From Within the Stimulation Borehole of an Oil or Gas Reservoir

M. Albrecht *TBA Technology Inc., USA*

V. Mansurov *Kazakhmys Co., Kazakhstan*

Abstract

Seismic monitoring of reservoir stimulation through hydraulic fracturing has been used in the oil and gas industry as well as in stimulation of geothermal hot dry rock reservoirs for quite some time. Traditionally, this monitoring is performed from within special seismic monitoring boreholes that, due to practical and inversion restrictions, are not located in the immediate vicinity of the stimulated borehole. Monitoring boreholes are excluded from off shore drilling locations due to financial reasons. Financial reasons also restrict their use for many commercial reservoir stimulation operations. Monitoring boreholes are located in the far field of the stimulation well. As a result, high frequency information, as well as small near well events is not registered. Thus, very valuable high resolution information and in situ rock mechanical information is lost when using traditional monitoring boreholes. The advantages of focusing on data acquisition for seismic monitoring located in the stimulation borehole are large; high resolution information and classic seismological information can be obtained, and where applicable drilling costs for monitoring wells can be reduced.

1 Introduction

Seismic monitoring of hydraulic fracturing has been used in the oil and gas industry and in geothermal hot dry rock applications for quite some time. Traditionally, this monitoring is performed from within special seismic monitoring boreholes that, due to practical and inversion restrictions, are not located in the immediate vicinity of the stimulated well. Monitoring boreholes are excluded from off shore drilling locations due to financial reasons. Financial reasons also restrict their use for many commercial reservoir drilling operations. Monitoring boreholes are located in the far field of the borehole. As a result high frequency information, as well as small near borehole events, is not registered. Thus, very valuable high resolution information and in situ rock mechanical information is lost when using traditional monitoring boreholes. Focusing on the stimulation borehole itself as the only environment used to obtain rock mechanical and monitoring data, promises to be a challenging but possibly very rewarding endeavour.

2 Increase in situ rock mechanical information out of single stimulation boreholes

Many engineering disciplines deal with well-defined materials and conditions. In petroleum engineering, the situation is quite different (Roegiers, 1993). Rock mechanics must be expected to vary considerably from one reservoir to another, or even within the same reservoir from one geological unit to another.

Now that more difficult reservoirs are being developed and more sophisticated completions are being attempted, the role of sound rock mechanics principles has become fundamental in optimising every aspect from drilling to abandonment. Pore pressure, permeability and pumping rate (or fluid viscosity) are major contributors in questions like additive management in order to avoid a choking of the potential hydrocarbon production, bit selection and unexpected fluid losses that can jeopardise the stability of the borehole by removing its support, or even cause dangerous gas kicks. New methods that help determine in situ rock parameters are potentially valuable tools to improve drilling operations.

2.1 In situ pore pressure determination by seismic caused during stress measurements

A modified straddle packer equipped with seismic sensors has been placed into granite in the geothermal Urach 3 borehole at a depth of 3355 m. Figure 1 shows the packer pressure curve obtained during the placement of the packer, not during hydraulic fracturing.

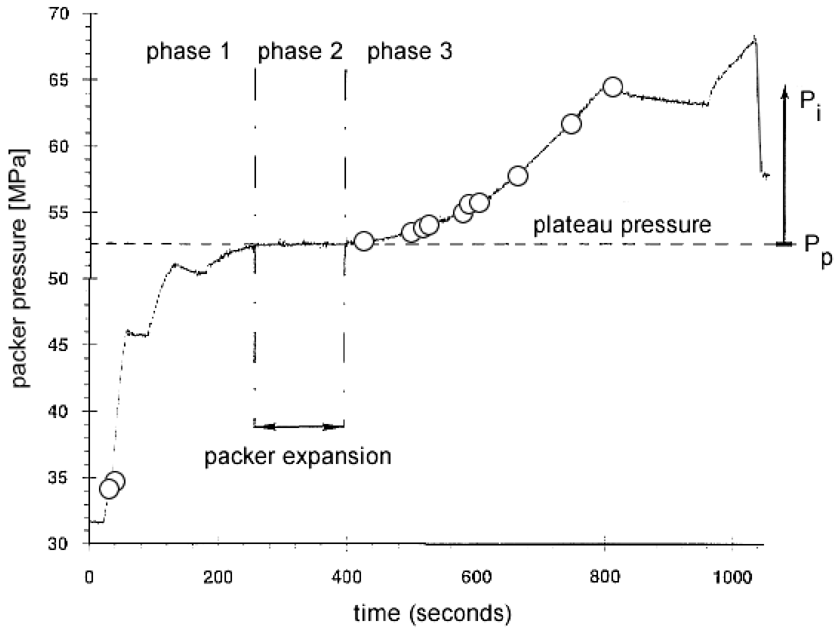


Figure 1 Packer pressure curve obtained during placement of the packer in the borehole Urach 3 in Bad Urach, Germany and the times (o) at which vibrations of the packer have been registered

By using the evaluation scheme shown in Figure 2, we can develop correlations between pre-existing fissure planes found in televiewer measurements and polarisations of the experienced vibrations. Along with algorithms developed to compute the effective shear and normal stress and the shear direction it is now possible to determine the pore pressure within an extended Mohr diagram. Figure 3 shows curves for each fissure corresponding to the ratio of σ_T to σ_N which changes with the distance from the borehole. The beginning of the curves (marked with dots) corresponds to the effective tangential or normal stresses present on the borehole wall. The other end of the curve corresponds to the infinite distance from the borehole ($r \geq 10*R$ with R being the borehole radius), is referred to for analysis purposes as a special case in the conventional Mohr diagram. The pore pressure used for the curves in Figure 3 is 26 MPa, which fulfils the fracture condition. Thus, a pore pressure of 78% of the hydrostatic pressure has been determined for a depth of 3355 m.

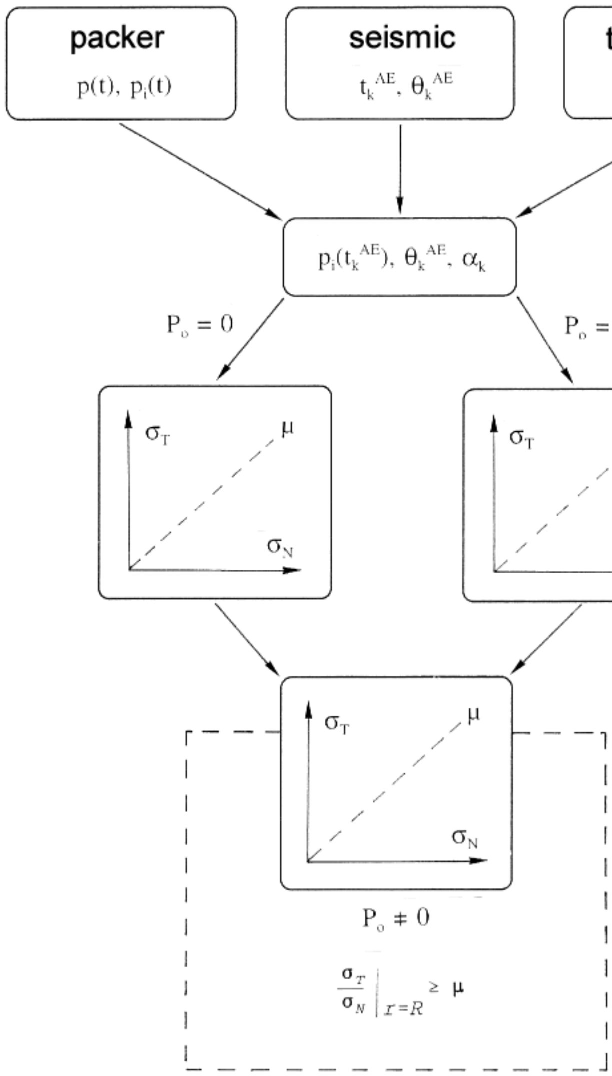
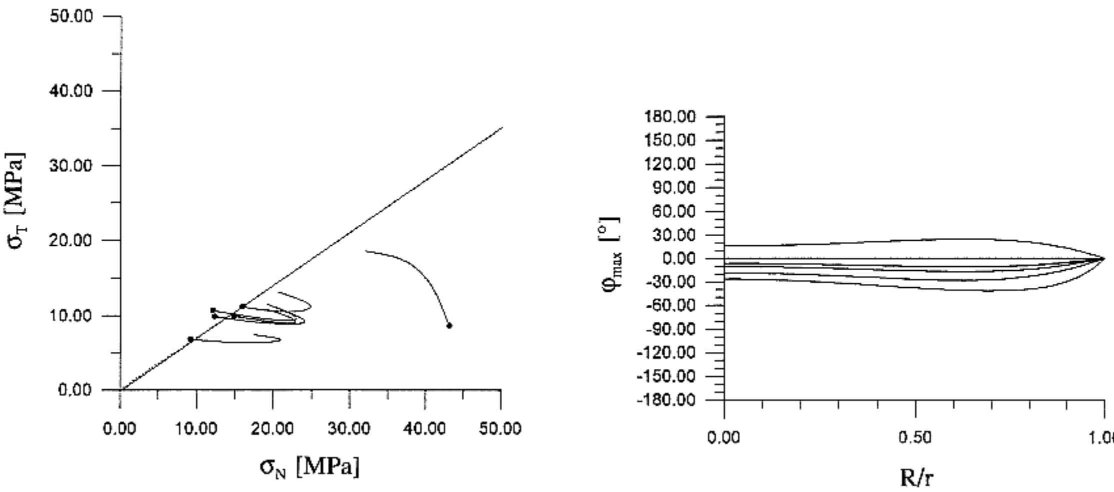


Figure 2 Evaluation scheme to determine the in situ pore pressure



(a) (b)

Figure 3 (a) Extended Mohr diagram for a pore pressure of 26 MPa; (b) Shear directions of the maximum shear stresses as a function of the relative borehole distance R/r

This means that a borehole tool engineered only to inflate (and retract), and equipped with seismic sensors, can acquire data needed to determine in situ pore pressure.

2.2 Determination of borehole parameters out of dispersion analyses of borehole wall displacements

A coupled borehole measuring system, containing a source and a receiver, can measure dispersive borehole waves that determine in situ borehole parameters (rock, borehole fluid and pore fluid properties) through a group velocity inversion process.

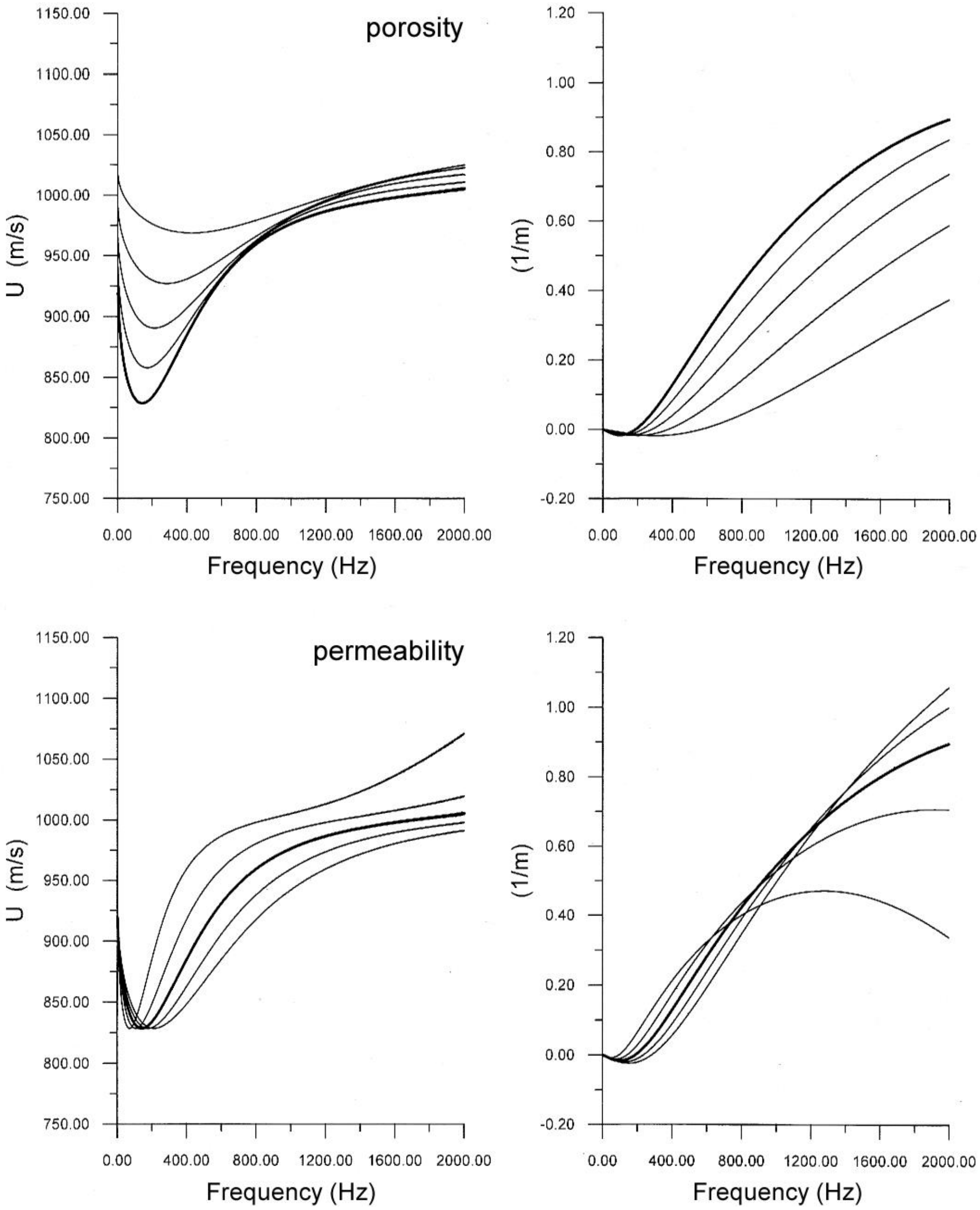


Figure 4 Group velocity and absorption coefficient as a function of porosity (0.10–0.30) and permeability (500–1500 x 10^{-15} m^2)

As presented by Albrecht and Mansurov (2004), group velocity and absorption coefficients can be calculated as a function of borehole radius, porosity, permeability, shear strength, viscosity, fluid bulk modulus, and fluid density. Figure 4 shows such results for porosity and permeability dependencies.

3 Increase high resolution reservoir information out of seismic registrations from within the stimulation borehole

The ability to determine the location, size, and orientation of man-made hydraulic fractures is necessary for the economical development of oil, gas and geothermal reservoirs (Fehler, 1982). In general, along with poor sensor coverage in the observation of induced seismicity during stimulation, only a very small fraction of the seismic information is used – the onset times. The onset times determined for compression and shear waves are used for a standard location of seismic hypocenters (Parker, 1989). The outcome can produce fissure planes and water conductivities. The total response of the reservoir, which is reflected in the complete seismogram, is ignored. This information can be used in three component migrations that can result in detailed reservoir images, even with a single three component sensor location. The reservoir images represent all first-order reflectors shown in the three component seismogram within the time window between the onset of the compression waves and the onset of the shear waves.

3.1 Theory of the three component migration

According to Figure 5 a compression wave is radiated from the hypocentre, reflected on the reflector and finally registered by the seismic sensor.

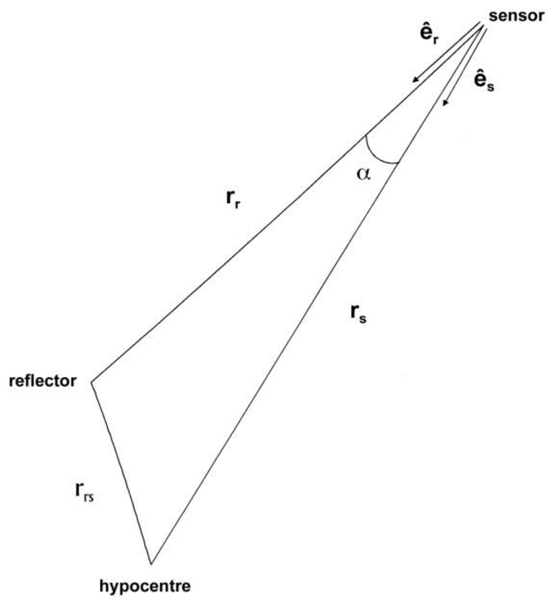


Figure 5 Radiation path geometry in three component migration

The distance of the centre r_s can be determined directly from the travel time difference for compression and shear waves (Equation (1)). The distance between the reflector and the centre r_{rs} and the seismic sensor and reflector r_r is determined following Equations (2), (3) and (4).

$$\Delta t = t_S - t_P = r_S\left(\frac{1}{v_S} - \frac{1}{v_P}\right) = \frac{r_S}{v_{eff}} \tag{1}$$

$$r_{rs}^{\,2} = r_r^{\,2} + r_s^{\,2} - 2 r_r r_s \cos\alpha \tag{2}$$

$$t_r = \frac{r_{rs}}{v_P} + \frac{r_r}{v_P} = \frac{1}{v_P}\left(r_{rs} + r_r\right) = \left(t - t_o\right)\Big|_{t\in[t_P;t_S]} \tag{3}$$

$$\begin{pmatrix} x_r \\ y_r \\ z_r \end{pmatrix} = r_r \begin{pmatrix} \sin\nu_r \cos\varphi_r \\ \sin\nu_r \sin\varphi_r \\ \cos\nu_r \end{pmatrix} = r_r \breve{e}_r \tag{4}$$

From Equations (2) and (3) the distance between the seismic sensor and the reflector r_r is obtained according to Equation (5).

$$r_r = \frac{(v_P t_r)^2 - r_s^{\,2}}{2(v_P t_r - r_s \cos\alpha)} \tag{5}$$

Equation (4) computes the exact position of the reflector in Cartesian coordinates $(x_r, y_r, z_r)^T$. For this purpose the beam angle α between the wave coming from the reflector and the direct wave from the hypocentre to the sensor is to be determined, as is the amplitude ν_r of the wave directed towards the reflector and its azimuth angle φ_r. Those angles can be determined based on Montalbetti and Kanasewich (1970), considering correlations and polarisations within a correlation window τ of the three component registrations.

3.2 Migration of data registered in a reservoir

Figure 6 shows a three component registration obtained in the Kakkonda geothermal field that is located in Iwate Prefecture, Japan (Soma and Niitsuma, 1994). A 50 MWe geothermal electric power plant is located in the field and production well buildup tests have been carried out with closed wellhead valves. During those tests a downhole triaxial sensor was located at a depth of 45 m in an observation well.

The hypocenter of the event has been determined with a triaxial hodogram method where the P-wave arrival direction and the P-S arrival time delay are measured from a three component signal. The hypocenter is at a depth of about 1000 m.

Figure 7 shows the migration result for this single seismic registration. The frac-system can be seen from the side and from above.

The migration including the average seismic velocities can be calibrated using existing, traditional borehole surveys. Because the migration result depends highly on the accuracy of the event location, improving the event location via “Doublet” location as described by Moriya et al. (1994) will improve the migration. Also, stacking the migration results of multiple events will increase the resolution of the reservoir image, filtering out statistical noise and inaccuracies in the process.

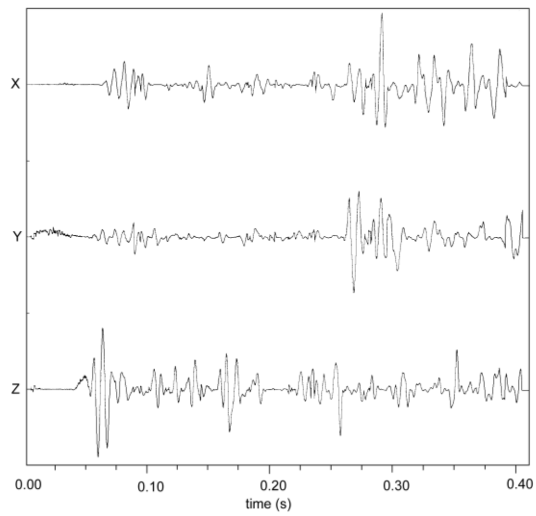


Figure 6 Normalised three component registration obtained during well build-up tests in the Kakkonda geothermal field

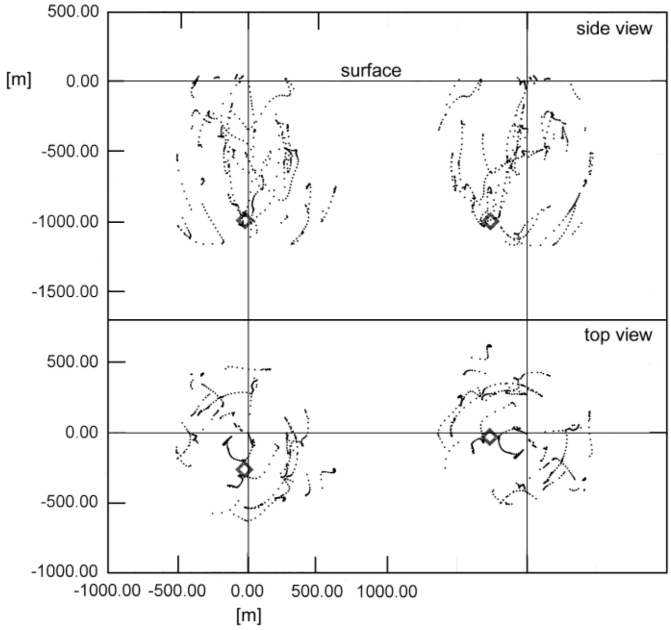


Figure 7 Migration result from the single seismic event shown in Figure 6, measured in the Kakkonda geothermal field, Japan

4 Near field seismic registrations within a single stimulation borehole

Shear fractures are caused by hydraulic fracturing create waves that are carried in the borehole. When measured by a probe within the borehole, these waves show a dispersive behaviour. A standardised dispersion analysis allows determining the dip of the related shear fracture. The proposed inversion of the fracture dip allows coming one step closer to a high resolution image of the stimulated reservoir in order to optimise reservoir exploitation as well as reservoir stimulation.

The integration of all elementary waves as described by Albrecht and Mansurov (2004), which are radiated by a shear fracture according to Figure 8, results in a seismogram as recorded by a borehole probe during hydraulic fracturing.

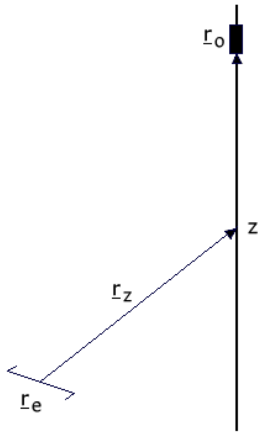


Figure 8 Generation of an elementary wave by a shear fracture, carried in the borehole

Figure 9 shows the synthetic registration of the z component generated by the direct wave (Figure 9(a)), the wave carried in the borehole (Figure 9(b)) and the superposition of both wave types (Figure 9(c)).

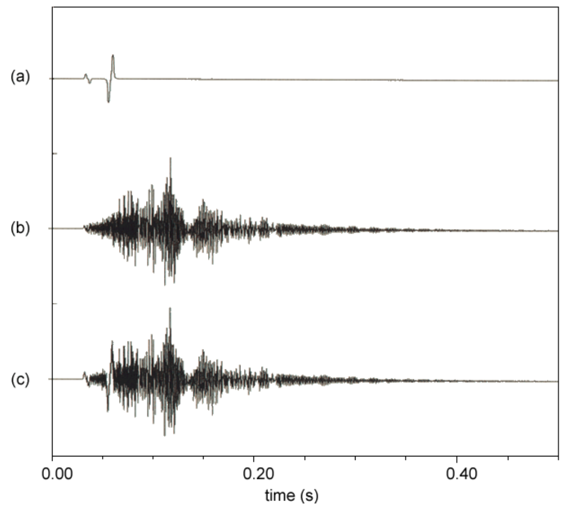


Figure 9 Synthetic wave types in the z component as a result of the geometry specified in Figure 8: (a) direct waves; (b) waves carried in the borehole; (c) superposition of (a) and (b)

The depth dependent amplitude of elementary waves is determined by the radiation characteristic of a fracture due to its spatial orientation. Between Figures 10(a) and 10(b) a comparison is made between the registration for a dip of 10° and a registration for a dip of 15° at the same strike of 270°. The presentation of the standardised dispersion analysis calculated following Dziewonski et al. (1969) shows a clear change of the amplitude in individual frequency ranges. Thus, the analysis of the standardised spectral amplitudes allows the determination of the dip.

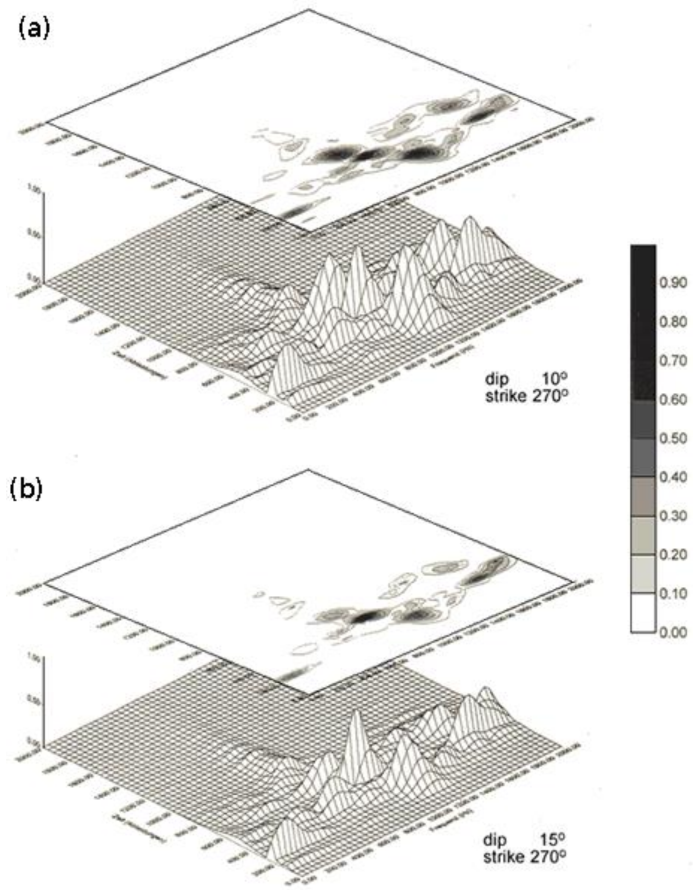


Figure 10 Dispersion analyses of a synthetic borehole wave (dips of 10 and 15° for a strike of 270°)

Variation of the fracture's strike is not visible in the standardised spectral amplitudes (see Figures 11(a) and 11(b)). There are no evident differences. It can therefore be concluded, that a standardised dispersion analysis of waves carried in the borehole allows determining the dip, but not the strike of a fracture surface.

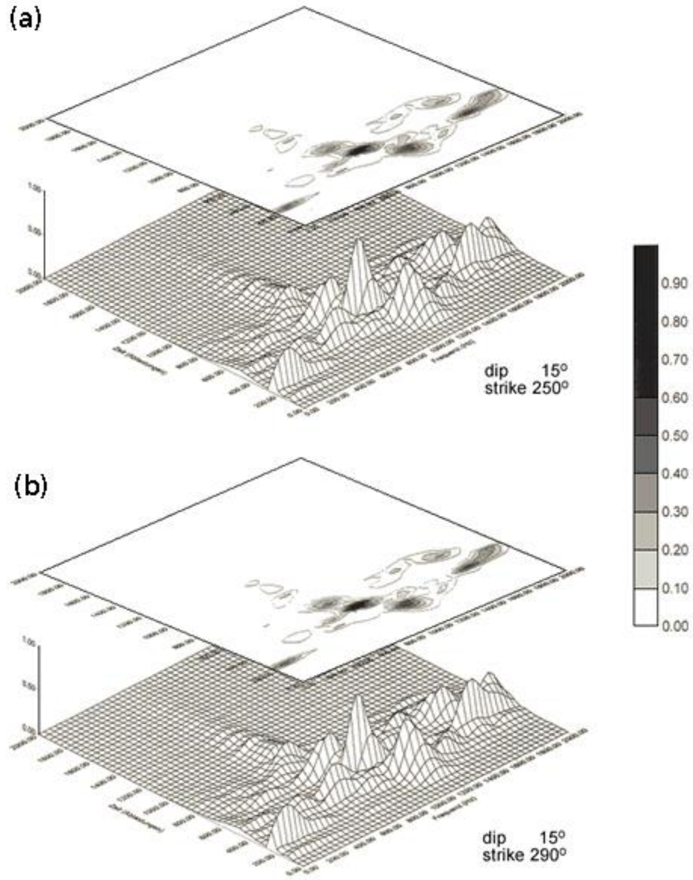


Figure 11 Dispersion analyses of a synthetic borehole wave (dip of 15° for a strike of 250 and 290°)

5 Conclusions

Some of the proposed methods described here have been tested and proved useful in field evaluations using seismic data obtained during hydraulic fracturing in geothermal reservoirs at depths ranging from 3355 to 1000 m. New approaches suggest new or modified data acquisition methods from within only one borehole, the stimulation borehole itself. The advantages of focusing on data acquisition out of the stimulation borehole are large; high resolution seismic and rock mechanical information can be obtained, classic seismological information remains obtainable and, where applicable, drilling costs for monitoring wells can be reduced.

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