Borehole deviation surveys are necessary for hydraulic fracture monitoring

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Summary

Not performing accurate borehole deviation surveys for hydraulic fracture monitoring (HFM) and neglecting the effects of the borehole trajectory results in significant errors in the calculated fracture azimuth and other parameters. For common HFM geometries, a 5° deviation uncertainty of monitoring or treatment wells can cause more than 40° uncertainty in inverted fracture azimuths. Furthermore, if the positions of injection point and receiver array are not known accurately and the velocity model is artificially adjusted to locate fracture on an assumed injection point, several milliseconds discrepancy between measured and modelled P-to-S-wave travel-times may appear at utmost receivers of the receiver array. This travel-time discrepancy may then be misinterpreted as VTI anisotropy. In the case of HFM, the uncertainty of the relative positions between the monitoring and treatment wells can have a cumulative, non-linear effect on inverted fracture parameters.

Introduction

Recently a large number of hydraulic fracture treatments have been monitored to determine fracture geometry (e.g., Rutledge and Philips, 2003; Berumen et al., 2004; Waltman et al, 2005). The fracture geometry is determined from microseismic events observed in a monitoring borehole. Usually only a single monitoring borehole is used due to signal attenuation and cost. Often, if the observation or the treatment well is nearly vertical, it is assumed to be perfectly vertical and no borehole deviation survey (i.e., the measurement of the borehole direction, which is then used to calculate the borehole trajectory) is done. Commonly, the orientations of the monitoring geophones are determined from back-azimuths of P waves generated by perforations located in the treatment well. Thus, the orientation of the monitoring array is determined relative to the position of the treatment well at depths corresponding to the perforations. The absolute orientation (in the geographical coordinates) of the monitoring array determines absolute positions of the observed microseismic event hypocenters and therefore, it determines the fracture geometry. Thus, any error in absolute orientation of the monitoring array is directly projected into error of the absolute fracture azimuth. We show that the effects on the absolute fracture azimuth may be considerable even for nearly vertical wells, if the well trajectory is not known accurately. Fracture geometry (mainly its azimuth and length) resulting from these HFM is then used for "infill drilling" where new wells are drilled into unfractured (and hopefully undrained) parts of the reservoir.

Furthermore, the borehole deviation affects not only the azimuth between the observation array and perforations, it also affects the distance between the treatment and monitoring wells in the corresponding depth. In the HFM, the starting isotropic velocity model is built from sonic logs and or vertical seismic profiling (VSP). Commonly, the velocity model is then adjusted to locate perforation shots to their assumed positions (based on the assumed perfect verticality or some other assumed deviation of the treatment and monitoring wells). The velocity model adjustment can be done in a number of ways but it usually involves fitting of P-to-S-wave travel-time, sometimes on some selected receiver(s) only. The difference in P-to-S-wave travel-time discrepancies which cannot be explained by the isotropic model adjustment are then fitted by adjusting a VTI (Vertically Transverse Isotropic) anisotropic velocity model. We show that the discrepancies can also be explained by an incorrect geometry between receivers and perforations.

Borehole deviation uncertainties

Drillers often quote accuracy of an average "vertical" borehole as 5° (e.g. Williamson, 2000) and they are probably right, a "vertical" well in a recent experiment deviated at the measured (treatment) depth of 1700 m (~5000 ft) by 8°. For this reason we shall consider the value of deviation uncertainty of "vertical" wells with no deviation survey to be 5°. To assess uncertainty in deviation survey measurements we compared two deviation surveys carried out for this well and found out that the average difference between the two independent measurements of the borehole deviation is 0.18°. We shall thus consider the value of deviation uncertainty of wells with known deviation survey to be 0.5°.

<u>Fracture Azimuth</u>

Let us first examine the effect of the unknown borehole deviation surveys on the fracture azimuth. For simplicity, we assume that the monitoring array is vertical. Figure 1 shows a map view of a hydraulic fracture monitoring: the blue point "Well 1" denotes the assumed position of a monitoring array and the other blue point "Well 2" denotes the assumed position of a perforation(s). H is the horizontal distance of these points. Without a loss of generality, we assume that both wells have the same average deviation uncertainty δ along the whole borehole, and that the perforation(s) and receivers are at measured depth h. Then the dashed circles in Figure 1 show uncertainty of the horizontal positions of the perforations and receivers. Two dashed lines show limits of relative back-azimuths of perforations with respect to the monitoring array. The uncertainty in the back-azimuths of perforations causes the uncertainty ΔΦ in fracture azimuth no matter what angle is between the fracture and the back-azimuth of the perforation.

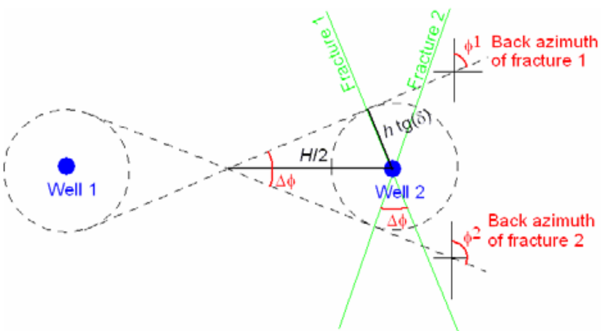

Figure 1: Map view of a vertical monitoring array (“Well 1”) and a perforation (“Well 2”). The dashed circles around “Well 1” and “Well 2” denote the limits of the horizontal uncertainty in positions of the array and the perforation, respectively. Two dashed lines tangent to these circles show back-azimuths of a perforation with respect to the monitoring array, and the two green lines “Fracture 1” and “Fracture 2” show two limiting orientations of the fracture being developed by the hydraulic fracturing.

The simple geometrical relationships shown in Figure 1 allow us to estimate the nonlinear dependency of the fracture azimuth uncertainty

$$\Delta\Phi = 2\arcsin\left(\frac{2h\tan\delta}{H}\right) \qquad (1)$$

Figure 2 shows fracture azimuth uncertainty for the two above-mentioned values of an average borehole deviation uncertainty and realistic values of h and H. Note, that the fracture azimuth uncertainty for the average deviation uncertainty of 5° is more than 40° for measured depths below 1000 m and the perforation-receiver separation of less than 500 m, i.e. a common scenario for HFM. Such uncertainty severely limits the use of the fracture geometry for the infill drilling. However, if the average uncertainty in the deviation survey is only 0.5° the fracture azimuth is well constrained for most of the measured depths and the perforation-receiver separations.

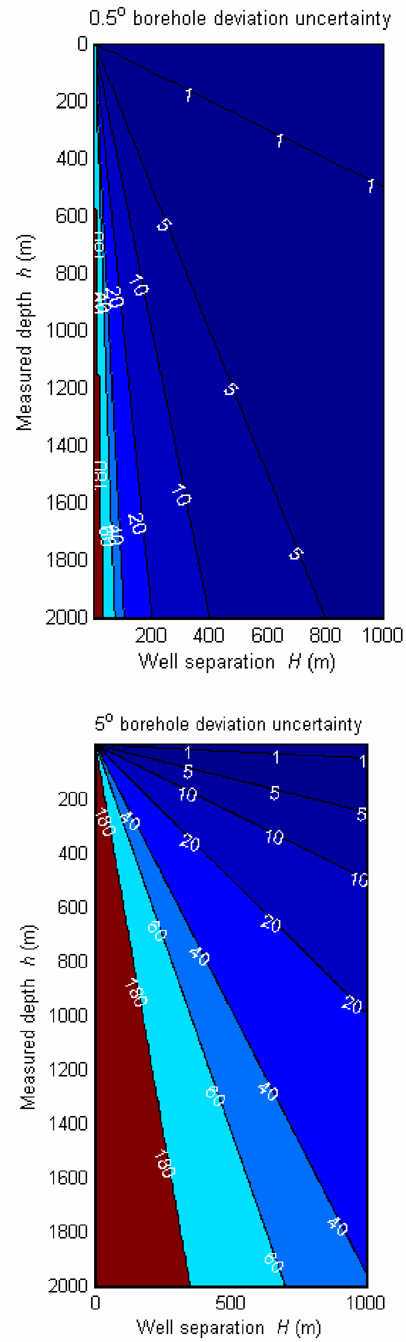

Figure 2: The fracture azimuth uncertainty in degrees for measured depths up to 1500 m (~4500 ft) and horizontal distances of injection to monitoring array up to 1000 m (~3000 ft). The top plot shows the fracture azimuth uncertainty for an average borehole deviation uncertainty of 0.5°, and the bottom plot for an average borehole deviation uncertainty of 5°.

Apparent anisotropy and uncertain locations

Let us consider two almost vertical wells inclined with an average deviation δ (dashed lines in Fig. 3), and let's examine travel-time errors caused by treating the wells as perfectly vertical (solid lines in Fig. 3). As explained in the introduction, it is common to adjust the starting velocity model, obtained from sonic logs and or VSP, in such a way that the adjusted model fits locations of perforations to the assumed positions of perforations. For simplicity, we adjust a true homogenous isotropic model (P and S-wave velocities, V_p and V_s) so that the new homogenous isotropic model (ηV_p and $\eta\ V_s$) has the same P-to-S-wave travel-time along the horizontal path from the assumed position of a perforation to an assumed position of a receiver in the same depth, i.e. from the red star "Perforation" to the red triangle "Rec 2" in Figure 3.

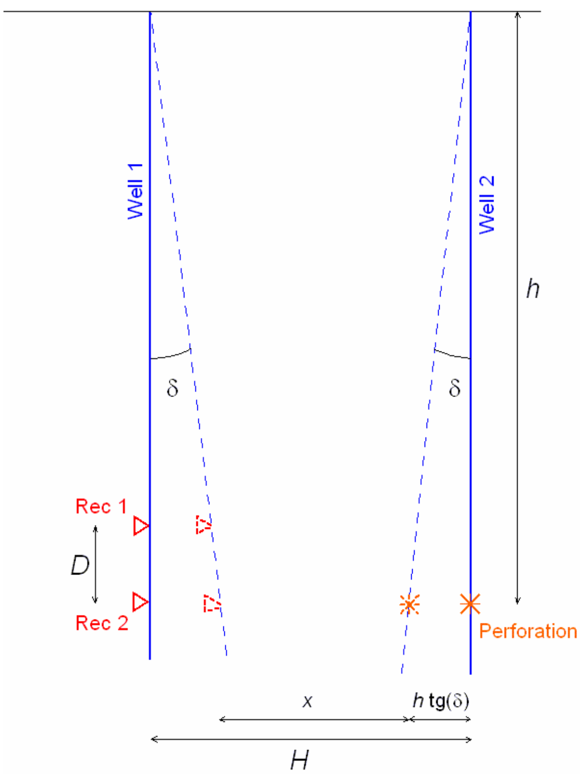

Figure 3: Side view of the two vertical wells.

Assuming the receiver array and the perforation in expected positions (shown by solid lines in Fig. 3) rather than in the true positions (dashed lines), we must adjust both P and S-wave velocities by a factor of η=x/H, where x is the true distance and H is the assumed distance between the perforation and the receiver "Rec 2". However, such velocity adjustment will create a travel-time difference ΔT_{PS} between the true (observed) and "adjusted" synthetic P-to-S-wave travel-time difference at the top of the observation array – red triangle "Rec 1"

$$\Delta T_{PS} = T_{PS}^{True}\left(1 - \frac{x}{H}\sqrt{\frac{D^2 + H^2}{D^2 + x^2}}\right) \qquad (2)$$

Here, T_{PS}^{True} is the P-to-S-wave travel-time from the true position of the perforation to the true position of the receiver. The travel-time discrepancy ΔT_{PS} in equation (2) does not correspond to any type of anisotropy and therefore the position errors can't be corrected for by a homogeneous anisotropic media.

Figure 4 shows ΔT_{PS} travel-time difference for realistic velocities and for the values of H, h and δ typical for HFM (for $x = H - 2h\sin\delta$). Note, that the travel-time errors reach several milliseconds, well above sampling used for most of the HFM observations. Also note that the travel-time discrepancy strongly depends on perforation-receiver distance and so the microearthquakes far from the perforation will have different error than those close to the injection points. Such travel-time discrepancies will create location artifacts and increase travel-time residuals.

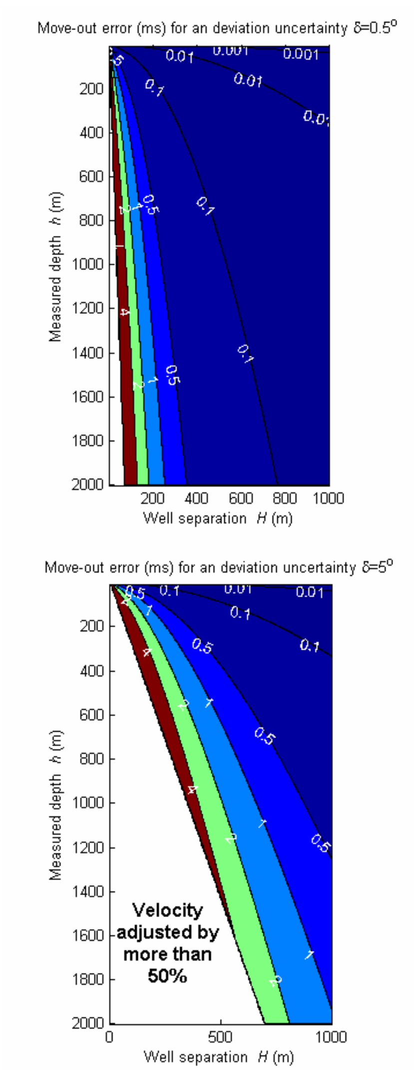

Figure 4: ΔT_{PS} (in milliseconds) of equation (2) evaluated for a homogeneous model with V_p=4400 m/s, V_s=2600 m/s, and D=100 m. The top plot shows travel-time difference for an average borehole deviation uncertainty of 0.5°, and the bottom plot for an average borehole deviation uncertainty of 5°.

Conclusions

Figures 2 and 4 show that the hydraulic fracture monitoring is severely limited with the 5° average borehole deviation uncertainty of treatment or monitoring well. Such uncertainty may result from an assumption, that both observation and treatment wells are vertical and no deviation survey is necessary. The top plots in Figures 2 and 4 show that the 0.5° average well deviation uncertainty enables to obtain a reasonably accurate results from HFM jobs. The 0.5° average deviation uncertainty can be achieved for wells with measured deviation surveys (from well-head to treatment depth). Deviation surveys are an important factor in determining the quality of the information that can be obtained from HFM results. Importance of the deviation surveys accuracy increases with the depth of a treatment, length of observation array and decreases with the (monitoring to treatment) well spacing.

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EDITED REFERENCES

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