SUBSURFACE FRACTURE MAPPING WITH TILTMETERS

Frank Zamora and Tom Garvin
Halliburton Services
Duncan, Oklahoma

Tiltmeter technology, as a source of data acquisition for fracture mapping, has been largely neglected. The benefits of this technology, however, warrant a closer look at its capabilities.

This paper serves to re-introduce tiltmeters, illustrate how they work, explain their value, and explore how tiltmeter technology is pushing forward.

TILTMETER OPERATION

When a hydraulic fracture is created, the resulting earth dilation is reflected as a displacement on the Earth's surface that can be detected by sensitive instruments. These instruments are commonly known as inclinometers or tiltmeters.

Physical components

The principal component of a tiltmeter is a curved, glass container containing a small gas bubble in liquid that will conduct an electrical current (Figure 1). Electrodes on each side of the glass case generate an electrical current that passes through the liquid. The movement of the gas bubble alters the impedance between the electrodes, and the resistance is amplified and converted to a signal proportional to the tilt.

Tiltmeter signals are vectors, which means they have both magnitude and direction. A vector is resolved from X and Y channels (of an X-Y-Z spacial grid) generating a voltage proportional to tilt. The direction and magnitude of the vectors indicates the direction of the hydraulic fracture. Interpreting these signals provides parameters of the fracture including depth, shape, dimensions, and orientation.

Sensitivity and Resolution

These detection instruments must be extremely sensitive to detect an earth displacement associated with a normal hydraulic fracture. Such displacements are quite minute—in the order of a few nanoradians. A nanoradian is one-billionth of a radian or 5.73×10^{-10} degrees.

According to Lacy,[1] tiltmeters created to be sensitive to the small surface strains associated with hydraulic fracturing are also sensitive to the following environmental influences:

- Solar or lunar tides induced in the Earth's crust
- The thermoelastic surface strains associated with daily heating of the Earth
- Local effects such as the influence of wind on nearby trees
- Rain and subsequent changes in subsurface water
- Surface traffic such as cars, trucks, and cows

The "noise" signals created by these influences are accounted for during analysis.

Placement

Because of the instruments' sensitivity, the tiltmeters are emplaced several days before a fracture treatment to allow the instrument to reach stable conditions and to establish the normal site signals. These signals are filtered out as noise when the fracture signals are being read.

A typical tiltmeter installation involves drilling a 12-in. hole to 20 ft, cementing an 8-in. casing, lowering the tiltmeter, and filling the annulus between the tiltmeter and the 8-in. casing with sand to the level of the top of the tiltmeter (Figure 2). This installation helps to couple the instrument with the surrounding earth. Optionally, if the water table is below 20 ft, the casing may be left uncemented.

Instruments are deployed in an array to permit multiple "viewpoints" of the displacement field. Notice that an individual tiltmeter (Figure 3) will respond to displacement by indicating changes in horizontal acceleration and changes in the gradient of the displacement field as the dilation of a growing fracture continues to increase displacement.

If the tectonic characteristics of a field can be determined to be similar from well to well (i.e., a consistent fracture azimuth), other fracture parameters can be more accurately targeted by placing the tiltmeters in a grid pattern specific to the variable of interest. For example, a grid pattern formed with two parallel lines of tiltmeters spaced along the expected azimuth enhances determination of fracture length.

DATA ACQUISITION

Each tiltmeter is connected at the surface to a battery-powered data logger, which records the tiltmeter signals.

Analysis of tilt data for hydraulic fracture mapping has progressed to the point that an analysis of fracture azimuth can be given on-site. Complete analysis of estimated fracture geometry is usually a matter of days, not weeks or months as with most seismic monitoring methods. It is anticipated that in the near future a real-time display of tilt change records will be analyzed jointly with pressure response data. This dual real-time analysis will provide more accurate interpretations of fracture growth and provide an early warning of deviations from the anticipated fracture design.[2]

THEORETICAL MODELING

Resolving tiltmeter array vectors to reflect the "best fit" with a computed theoretical response provides information on the fracture depth, dip, strike, length, width, asymmetry, and the possibility of multiple fractures.

The theoretical model currently used in making computations for best fit is the Davis Model.[3] This is an edge-dislocation model which assumes a dipping, rectangular-shaped fracture. The Palmer Model[4] is used along with the Davis model to compensate for fluid leakoff from the fracture. A perfect fracture "map" could be obtained from tilt signals if (1) the instruments were perfectly coupled to earth, (2) tilt signals were generated only by the hydraulic fracturing process, and (3) the Earth were truly homogenous and isotropic as is assumed in the theoretical computations.

Because conditions are not perfect, we use statistical analysis and minimum error functions to resolve physical measurements to the best estimate of the true fracture location and geometry. Since we are seeking information on at least eight variables, we need at least eight observation locations. The analysis is considerably improved if there are tiltmeters in at least 16 locations producing displacement data.

ANALYZING SIGNALS

As graphed in Figure 4, a tilt channel is analyzed as an offset to a prefracture trend. Signal amplitude is measured relative to the trend. Changes in injection rate will change the offset, and the total offset will be determined by the total volume of fluids pumped. Deeper wells require pumping greater volumes to generate signals with amplitudes great enough for tilt analysis.

Most coal gas well stimulations generate large tilt signals that can be measured in microradians. The larger signals result because pumped volumes are large, the injection rates are usually high, and the depths are relatively shallow. Figure 4, a tilt record from stimulation in the Mary Lee coal group of a well in Alabama, illustrates what an analyst might encounter when working in coal seam fracture mapping at depths near 1000 ft.

Note in Figure 4 the characteristic prefracture background trend (from A to B), the characteristic change in tilt related to the beginning of pumping (from C to D), the fracture closure characteristic (G to H), and the long-term background trend after shut-in (at H continuing to I). These characteristics are common to simple, vertical hydraulic fractures.

Azimuth and dip are determined with a high degree of certainty because these parameters are scaler (direction without magnitude). Other parameters desired to describe fracture location and geometry are vector quantities and are "certain" to the degree of agreement in theoretical compared to measured results.

The vector map in Figure 5 is from a recent hydraulic fracturing treatment in Michigan. The rectangular plane of this fracture has a -41.27° dip (0° being horizontal). The heading is 1.303° NE-SW from the wellbore.

COMPARISON OF OTHER TECHNOLOGIES

Several other measurement techniques will usually be used on a well in addition to tiltmeter data recording:

- Wellbore televiewers
- Radioactive tracer logs
- Anaxial strain recovery
- Wellbore sonic logs
- Minifrac analysis
- Fluid loss tests
- Downhole pressure transients
- Seismic measurements (geophones or accelerometers)

Many of the listed physical measurement techniques—with the exception of minifrac analysis, fluid loss tests, downhole pressure transients, and seismic measurements—are limited to wellbore or near-wellbore measurements. Near-wellbore observations (those which observe the area within several inches of the wellbore) have limited reliability because they represent a small sample size relative to the extent of most hydraulic fractures and because they could be distorted by testing procedures or (in the case of televiewers) the drilling process.

Choice of depth for near-wellbore measurements becomes critical when the objective is to characterize a fracture geometry of considerable height and unpredictable point of origination. Near-wellbore measurements will frequently indicate inconsistent results when compared among each other as well as with seismic examination or tiltmeter mapping.

Techniques that may not be limited by near-wellbore constraints may have other limitations. Transient pressure testing does not produce azimuth or dip descriptions and must rely on external experiments and/or mathematical models to constrain geometry.

Comparison of Tilt and Seismic Results

Seismic and tiltmeter results are generally consistent within 1° when reporting azimuth and dip of a near-vertical, biwing hydraulic fracture.[5] Seismic measurements are generally made "after the fact" because signals are recorded before and after the hydraulic fracture has been completed. Multiple fractures or horizontal orientations are difficult to discern from seismic investigations because data from all possible orientations are arriving at the sensors during the same time span.

One of the benefits of using tiltmeters for mapping fracture data is they work externally to the well. Tiltmeters, therefore, do not interfere with well operations and will not cause a shutdown of drilling and completion processes as is required when near-wellbore data is being obtained. Seismic methods often are designed for sensor placement and movement in the wellbore. Operations are disrupted during the period of seismic data acquisition whether the instruments are actually in the wellbore or external to the borehole.

Comparison of Tilt and Pressure Data

By combining both bottomhole treating pressure and rate with tiltmeter response records, an analysis can be obtained on the characteristics of the fracture.[2] For example, in the Mary Lee coal gas well referenced in Figure 4, correlations were made with pressure, rate, and tilt response records (Figure 6). The analysis of these correlations concluded that a primary fracture was created early in the job with a secondary fracture occurring two-thirds of the way into the treatment. (The secondary fracture may be seen at Point D in Figure 4 and at Point 4 in Figure 6.) Tilt and BHTP records showed changes of slope at the same points in time.

SUMMARY

Tiltmeters are sensitive to the deformation of the Earth's surface as caused by a hydraulic fracture of a subsurface formation. The movement of the tiltmeter during the fracture treatment is recorded as a vector with both magnitude and direction. Once downloaded from a data logger, the signals are analyzed to determine the geometry of the fracture.

Past studies have shown great consistency between results obtained with tiltmeters and results obtained with seismic and pressure records.

Two advantages of tiltmeters are (1) passivity and (2) early signal processing.

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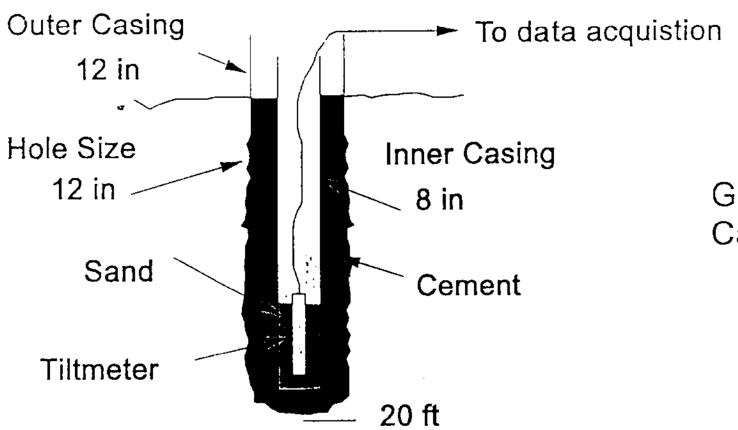


Figure 1 - Typical tiltmeter installation

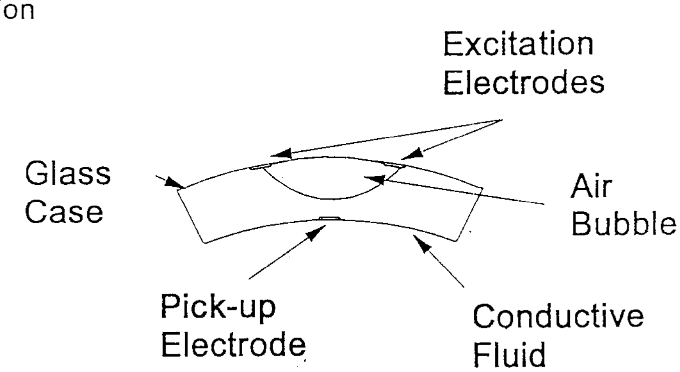


Figure 2 - Schematic of tilt sensor

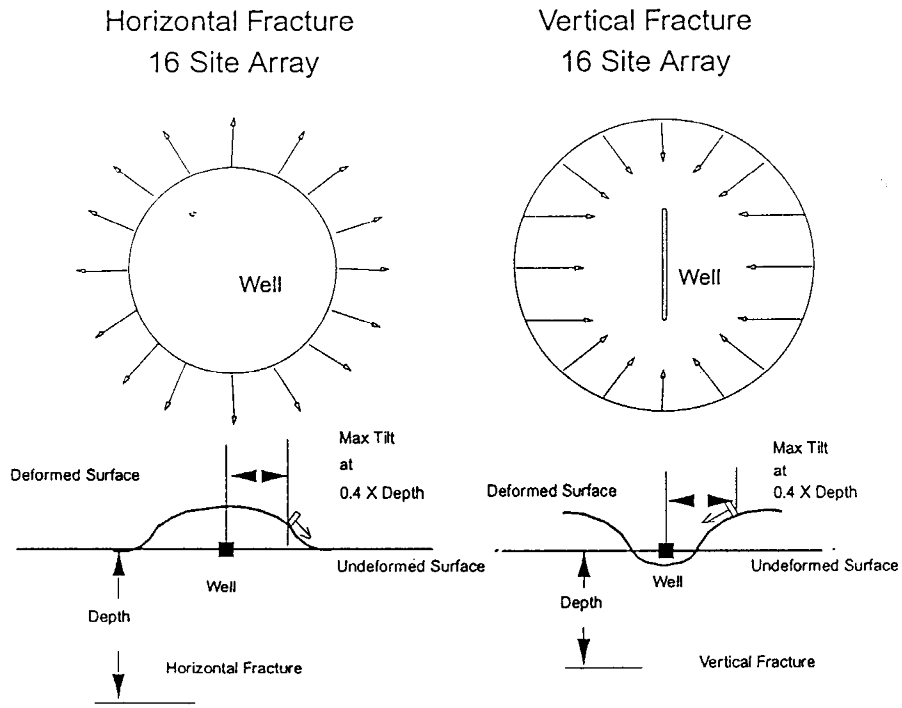


Figure 3 - Theoretical tilt vectors

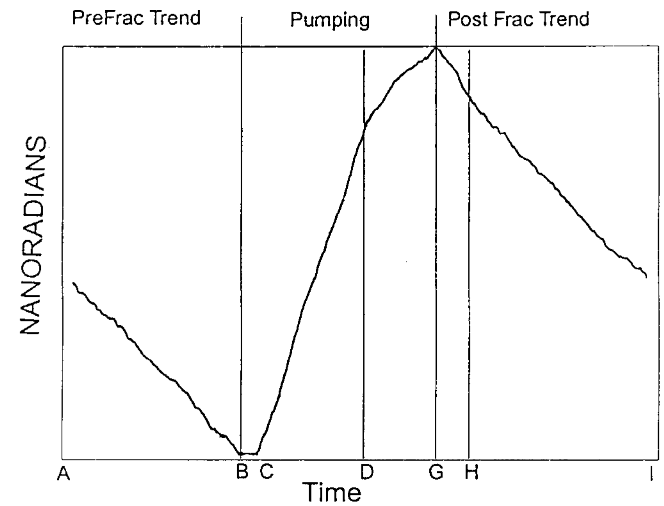


Figure 4 - Tiltmeter channel

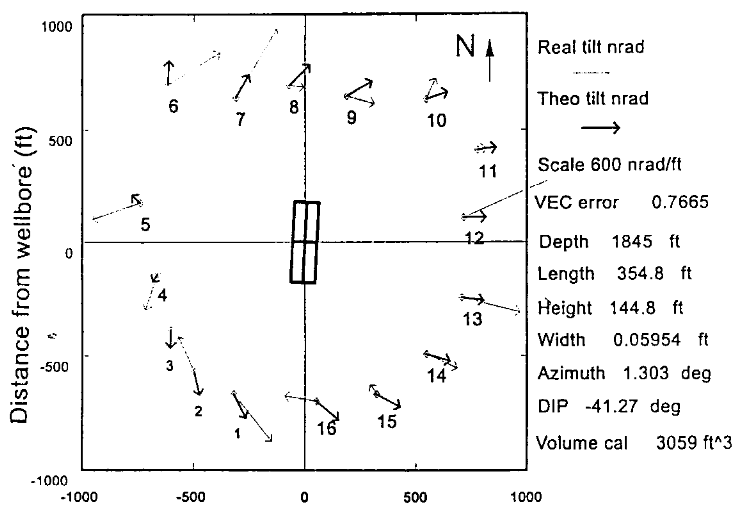
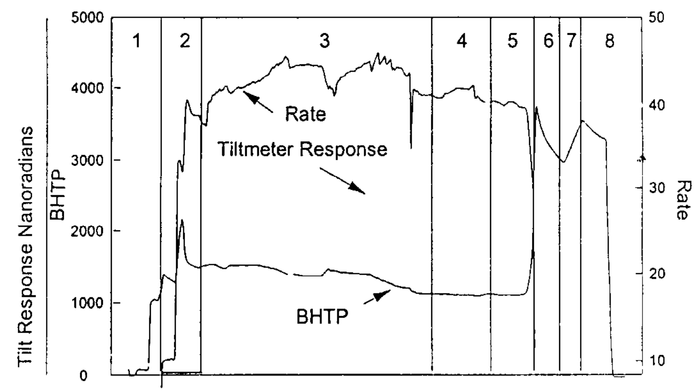


Figure 5



1. Pre-Frac Trend
2. Start Pumping
3. Open Primary Fracture
4. Open Secondary Fracture
5. Sand Out
6. Shut In
7. Try to Reestablish Rate
8. Post Frac Trend

Figure 6