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Review of Hydraulic Fracture Mapping Using Advanced Accelerometer-Based Receiver Systems

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Introduction

Hydraulic fracturing is an important tool for natural gas and oil exploitation, but its optimization has been impeded by an inability to observe how the fracture propagates and what its overall dimensions are. The few experiments in which fractures have been exposed through coring[1-3] or mineback[4,5] have shown that hydraulic fractures are complicated multi-stranded structures that may behave much differently than currently predicted by models. It is clear that model validation, fracture optimization, problem identification and solution, and field development have all been encumbered by the absence of any ground truth information on fracture behavior in field applications.

The solution to this problem is to develop techniques to image the hydraulic fracture *in situ* from either the surface, the treatment well, or offset wells. Several diagnostic techniques[6] have been available to assess individual elements of the fracture geometry, but most of these techniques have limitations on their usefulness. For example, tracers and temperature logs can only measure fracture height at the wellbore, well testing and production history matching provide a productive length which may or may not be different from the true fracture length, and tiltmeters can provide accurate information on azimuth and type of fracture (horizontal or vertical), but length and height can only be extracted from a non-unique inversion of the data. However, there is a method, the microseismic technique, which possesses the potential for imaging the entire hydraulic fracture and, more importantly, its growth history. This paper discusses application of advanced technology to the microseismic method in order to provide detailed accurate images of fractures and their growth processes.

Objectives

The objectives of this review are to

- outline the needs for accurate microseismic imaging of hydraulic fractures,

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- discuss the instrumentation requirements for reliable imaging,
- discuss the processing requirements for imaging, and
- prove the accuracy of the technique when using best-case technology.

Approach

Microseisms. Microseisms are small bursts of seismic energy generated by shear slippages along planes of weakness in the reservoir and surrounding layers. This mechanism is induced by changes in stress and pore pressure around the hydraulic fracture. Microseisms do not map out exactly where individual hydraulic fracture planes are located, but rather form an ellipsoid around the fracture, outlining the length, height, and azimuth of the fracture.[7] Because microseisms may occur several feet off to the side of a fracture, no information on fracture width is obtainable.

Microseismic mapping has been used since the 1970's for imaging geothermal[8,9] and massive-hydraulic fractures,[10,11] although it has been successful primarily in large field experiments where multiple wells or cemented-in seismic arrays were available.[8-14] Furthermore, microseismic processing and analysis techniques draw on the large body of experience gained from earthquake seismology.

Multi-Level Receiver Systems The typical natural gas and oil environment is considerably more difficult than the configurations employed in the elaborate field tests,[8-14] as there will seldom be more than one available offset well for seismic monitoring and wireline-retrievable receiver systems will need to be used. In such situations, it is essential to use multi-level triaxial seismic arrays with the best possible receiver, transducer, and telemetry technology. It is the advent of advanced multi-level receivers, with faster telemetry, enhanced computer processing and fast data-storage technology that have combined to make microseismic technology practical today.

Multi-level receivers are required because single receiver systems cannot accurately determine the elevation of a microseism in a layered formation. Head waves traveling through high velocity layers will commonly be the first arrival of the microseismic energy, resulting in a vertical particle-motion orientation (e.g., vertical hodogram) that is much steeper than the true microseismic inclination. Since a single receiver must rely on particle-motion information for the spherical orientation to the event, many microseisms will be misoriented using single receivers.

To accurately locate a microseism in a multi-receiver system, the distance equation to the source must be solved for three unknowns: origin time, origin elevation, and origin lateral distance. In theory, only three arrival times are required (e.g., two p waves and one s wave, three p waves, one p wave and two s waves), but, in practice, the most accurate microseismic locations are obtained when (1) two separate phases are used in the location algorithm (both p and s waves) and (2) more than three arrivals are detected so statistical information can be obtained. Thus the elevation and distance of the microseism can be measured without using inaccurate vertical particle-motion data. The only missing information is the horizontal azimuth, which can be accurately determined from particle motion data, even in a layered sequence. Furthermore, with a multi-level system there will be several horizontal azimuths measured -- one from each receiver -- so statistics on the measurement are possible.

Accelerometer Technology Accelerometers are the instrument of choice for microseismic monitoring because of several characteristics that are superior to geophones in the microseismic range. Studies performed using accelerometer arrays include Sarda et al,[15] Stewart et al,[16] Sleefe et al,[17] and Warpinski et al.[18,19] A discussion of their advantages and application follows.

Project Description

Frequency Considerations. In a hydraulic fracture, the generated microseisms are typically low-amplitude, high-frequency, short-duration signals that must be recorded faithfully by the receiver system. For fractures in consolidated sedimentary rocks, the dominant frequencies of the microseisms range from 200 - 2000 Hz, well above the optimum range of most conventional receiver systems which have their first resonances typically at a few hundred Hertz. Figure 1 shows an example of the spectrum of a typical microseism recorded in a sandstone formation at a distance of several hundred feet. The compressional wave (p wave) has the higher frequency content (1600-1800 Hz), while the shear wave (s wave) has the 1200 Hz frequency content of the lower amplitude peak. Accurate identification of the arrival times of the p and s waves is dependent on finding the frequency shifts seen here as well as shifts in particle motion.

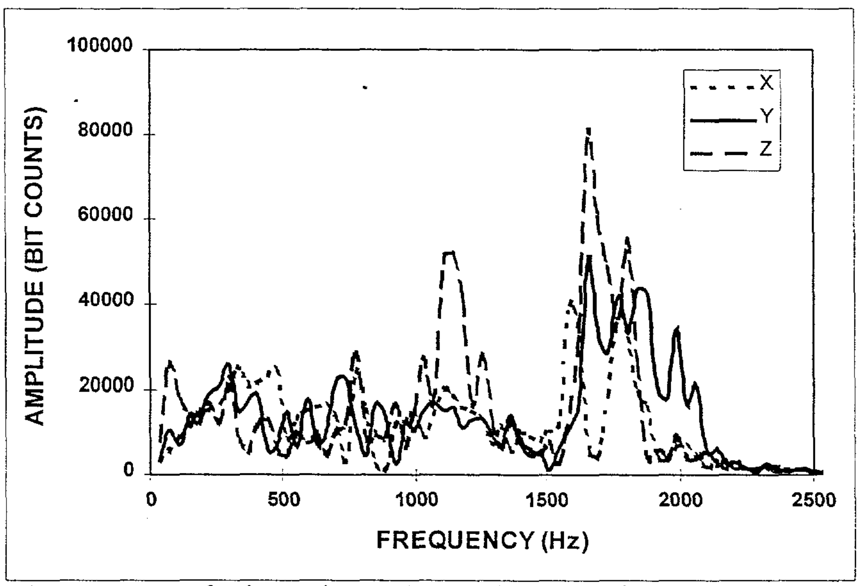

Figure 1. Example spectrum of microseisms observed on tri-axial receiver.

The first resonance of conventional receiver systems is usually due to the nature of the standard-swing wall-lock clamp arm, but additional resonances are often caused by cantilevered parts within the receiver.[20] The higher the first resonance, the more accurate will be the recording of the microseismic motion. The receiver used in this application[20] has been designed using modal analysis techniques to avoid having resonances below 2000 Hz, but to do so it must employ a different design of clamp arm. A right angle piston-drive arm has been found to be suitable for the design performance desired. However, this type of mechanism cannot be used in open holes and will not be suitable for some wellbore configurations, so there are advantages and drawbacks to most systems.

Sampling rates of the data acquisition systems need to be correspondingly fast to accurately capture the high frequency content. Since many of the microseisms have significant energy above 1500 Hz (see Figure 1), sampling rates of at least 1/8 millisecond are a minimum and faster sampling would be desirable. As always, appropriate anti-aliasing techniques must be employed. Based on frequency consideration alone, the higher frequency response of accelerometers makes them a better choice for this application than geophones.

Noise Characteristics. Since microseisms cannot be stacked like seismic surveys, the system electronic noise floor and data-transmission interference must be low enough to allow high signal-to-noise ratios for accurate microseismic location. Besides the higher frequency response, accelerometers have other advantages over geophones for such conditions, including better sensitivity at higher frequencies, and a lower noise floor at higher frequencies.[20,21] Figure 2 shows measured (data points) and theoretical (solid lines) noise characteristics of geophones and accelerometers. Geophones have a lower noise floor at approximately 50 Hz and therefore are applicable for low frequency applications such as surface seismic surveys and vertical seismic profiling. Accelerometers are better suited to high-frequency applications, which is why they are so common in military and high-tech applications. If the objective is to measure low amplitude microseisms at frequencies greater than a few-hundred Hertz, the accelerometer will always outperform the geophone.

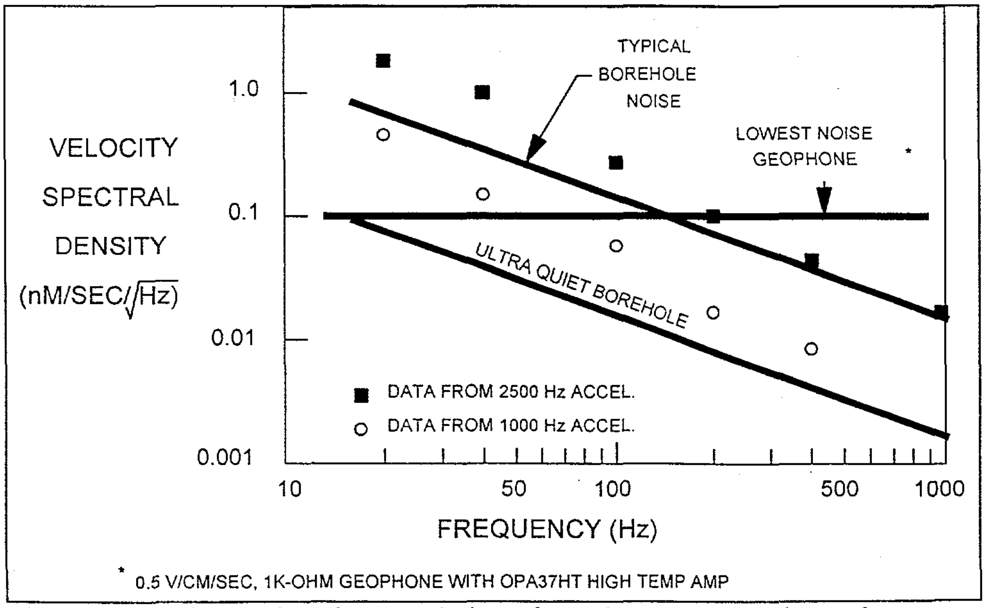

Figure 2. Typical noise characteristics of accelerometers and geophones.

Mechanical Gain. Other features of accelerometers, particularly their mechanical gain at the resonance frequency, can be tailored to help detect signal arrivals. The accelerometers used in this application have a 40 dB mechanical gain at 2200 Hz. If there is any energy at 2200 Hz from the impinging microseism, the mechanical gain helps to bring the signal rapidly out of the noise (fast rise time) and aids in accurately defining the p-wave arrival time. This resonance feature is particularly helpful when signal strength is low and there is difficulty in obtaining sufficient signal-to-noise ratios. Figure 3 shows a typical microseism, recorded from an event about 700 ft from the receivers, in which the p wave rapidly breaks out of the noise.

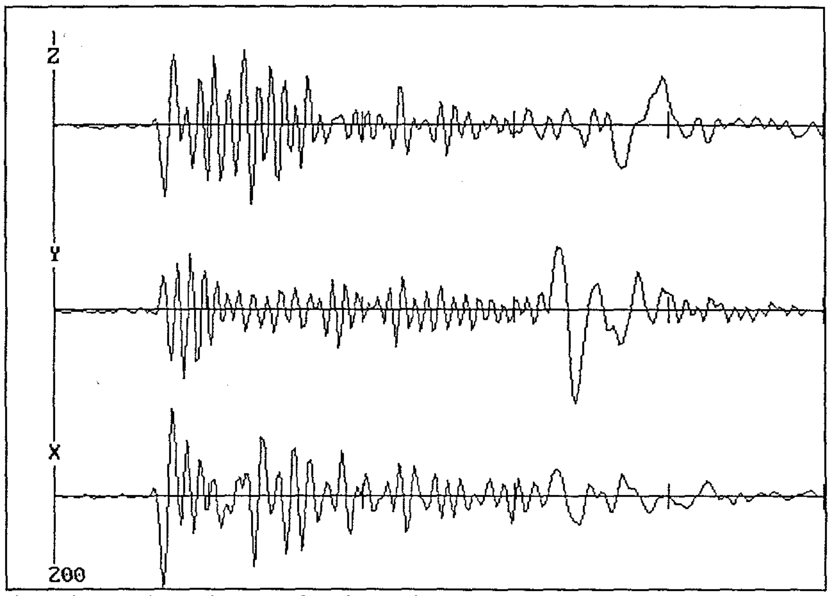

Figure 3. Example microseism detected using tri-axial accelerometers.

Downhole Digitization Since microseisms are low amplitude signals when detected, the best results are obtained when the signals are not further distorted by noise added during transmission. Analog data will generally suffer reduced signal-to-noise characteristics due to noise pickup in the wireline, in surface cable runs and instrumentation, and due to downhole power. Analog data are further constrained by a limited transmission dynamic range.

Downhole digitization overcomes many of these problems by immediately converting the signals to digital information. The downside of adding downhole digitization is the added complexity of the receiver system. Downhole digitization also allows for downhole digital filtering, data compression, and error checking.

Telemetry. When multi-level receiver systems are employed (as they must be for accurate locations), data telemetry rates are faster than that typical of conventional logging tools, and telemetry systems must accommodate higher data rates than currently available with 7-conducter wirelines. Continuous recording of 5-level tri-axial-receiver digital data at 1/8 millisecond sampling with 16 bit resolution and error checking would require about 3Megabits/second data rates. Faster sampling, more receivers, or higher bit resolution will increase this rate proportionately. Digital transmission over fiber-optic wirelines has been found to be a solution for this type of monitoring, but other technology (e.g., special multi-conductor wirelines) can also be employed. Fiber-optic wirelines have an additional advantage of lower noise interference during the transmission compared to standard copper technology.

Signal Processing. The final element in developing a workable microseismic technology is automatic processing of the microseismic events. Automatic processing requires accurate location of the p-wave and s-wave arrivals, both of which are facilitated through the use of accelerometers. P-waves will often have faster rise times on optimally designed accelerometer systems since the mechanical gain of the accelerometer resonance enhances the initial p-wave arrival and the relatively high frequency of microseismic p-waves can be adequately recorded with an accelerometer. The better frequency response of the accelerometer can then also be used to help discriminate between the p-wave coda and the subsequent s wave, which typically arrives with a different characteristic frequency. For both phases, accurate processing is difficult if the receiver system has low-frequency resonances which distort the impinging signal.

The key to automatic processing is distinguishing between analyzable microseisms and other signals. Such a differentiation is most easily achieved on the p wave, as the s wave may not be present depending upon where the receiver is located relative to the source radiation pattern. On multi-level systems, effective algorithms can be written to "comb through" both time and space to assure that a meaningful microseism is detected. S-wave detection can then make use of the three characteristics that often differentiate the s wave from the p wave:

- lower frequency,
- amplitude shift, and
- orthogonal particle motion shift.

While amplitude changes can be seen on nearly any receiver system, resonances can often obscure both the frequency change and the change in polarization (thus, the importance of employing high-quality receivers).

Microseismic Location. Microseisms can be located using the technique discussed in the section on Multi-Level Receiver Systems. A base level of processing would require the assignment of average p-wave and s-wave velocities and a regression on the various arrival times. Such an analysis is very effective when the velocity structure is relatively uniform or there are many receiver stations spread out over a large aperture.

For sparse receiver arrays in layered environments, a second level of processing would include the detailed velocity structure. Two common methods of solution of such problems include ray-tracing techniques and arrival-time techniques. In this application, the Vidale-Nelson algorithm[22] using an arrival-time approach has been found to be ideal for accurately locating microseisms in layered media.

Results

Validation. Validation of the microseismic method has been achieved through experiments conducted in sedimentary Mesaverde rocks at the DOE/GRI Multi-Site (M-Site) project in western Colorado.[14] This site, which functioned as a hydraulic-fracture diagnostic laboratory from 1992 through 1996, consisted of a treatment well surrounded by an instrumented monitor well and a second observation well for wireline receiver arrays. Figures 4 and 5 show plan and side views of the site layout. In Figure 5, the monitor well is shown to consist of 30 tri-axial receiver stations and 6 bi-axial tiltmeter stations, all cemented in place across from two sandstone intervals which were hydraulically fractured. The observation well, MWX-3, is a cased 7-in wellbore in which wireline-run multi-level accelerometer arrays are fielded. From these two wells, hydraulic fractures in MWX-2, the treatment well, are monitored. Additionally, two deviated lateral wells, IW-1B and IW-1C, are shown.

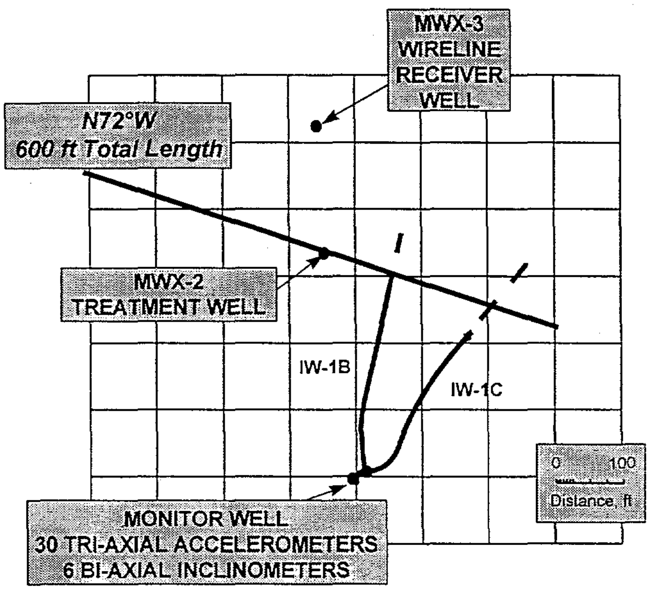

Figure 4. Plan view of M-Site layout.

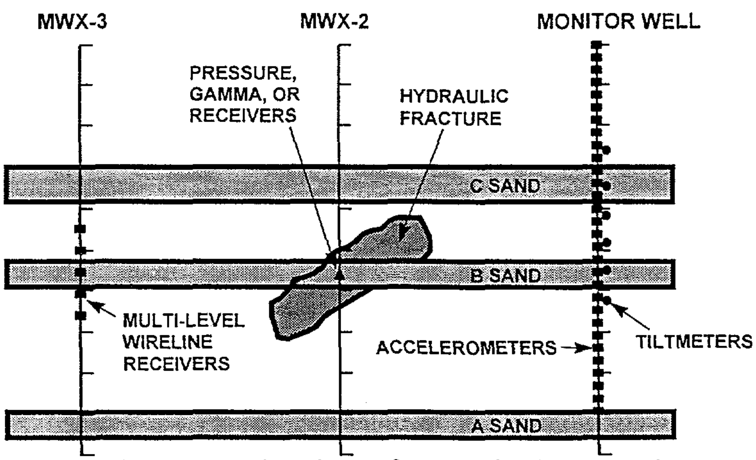

Figure 5. Side view of M-Site layout showing a fracture in the B sandstone.

The question of validation of the microseismic data consists of two parts:

- How accurate can the microseisms be located, and
- How does the seismic fracture geometry relate to the "mechanical" fracture geometry.

The first question is a purely technical issue dealing with the receivers, the transducers, noise, processing, the array aperture, the number of receivers, and several other factors. There is no limit on the accuracy of the microseismic locations given sufficient resources.

The second question is more important, as it implies that there is an interpretation issue. Mechanical models suggest that the microseismic envelope will be slightly larger than the fracture, but mechanical models seldom contain the complexity associated with actual reservoirs. A final resolution of this question is best performed in actual field experiments in well-instrumented sites. At M-Site, the inclinometers, which measure the deformation of the rock and thus are a direct response of the mechanical size and shape of the fracture, were used to validate the fracture heights obtained from microseisms. The difference between microseismic and inclinometer heights for the B sandstone injections was found to vary between 3 and 13 feet over heights of 50-135 ft, an excellent comparison in this highly layered environment.

Microseismic azimuths were compared with the locations of the hydraulic fractures in the intersection wells. For well IW-1B, the measured azimuth of N72°W is in good agreement with the microseismic azimuth of N74°W. Data from well IW-1C data are not fully analyzed yet.

Fracture lengths were compared on one experiment in the C sandstone where a fracture treatment intersected the IW-1C lateral well, which was drilled previous to any fracturing in the C sandstone. At the moment of fracture intersection with the lateral well (after 130 bbl of linear gel were injected at 20 bpm), the length is precisely known and can be compared with the microseismic data. Figure 6 shows a plan view of the microseismic geometry relative to the lateral well at the moment of intersection. Microseisms were found to clearly extend out to the intersection well location with a discrepancy of less than 10 ft. At least in this one location, which is typical of most tight sandstone reservoirs, the microseismic method has been shown to be highly accurate for characterizing the geometry of an induced hydraulic fracture.

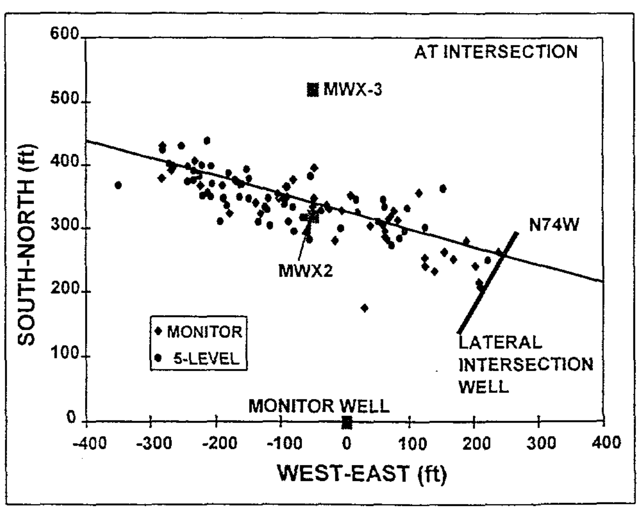

Figure 6. Microseismic data at the time of intersection of lateral well.

Imaging Fractures These M-Site experiments provided much information about the growth patterns of fractures, unexpected trends in height growth, and the response to different fluid types. Unfortunately, these types of results cannot easily be shown in static picture format. Figure 6 has already shown the plan view of a fracture in the C sandstone. Figure 7 shows the side view of a 200 bbl injection of KCl water at 10 bpm into the B sandstone. In this case, the fracture was well contained within the sandstone and shows considerable asymmetry in length growth. Asymmetry in both length and height growth are common in all of the tests conducted at M-Site (4 A-sandstone injections, 7 B-sandstone injections and 6 C-sandstone injections).

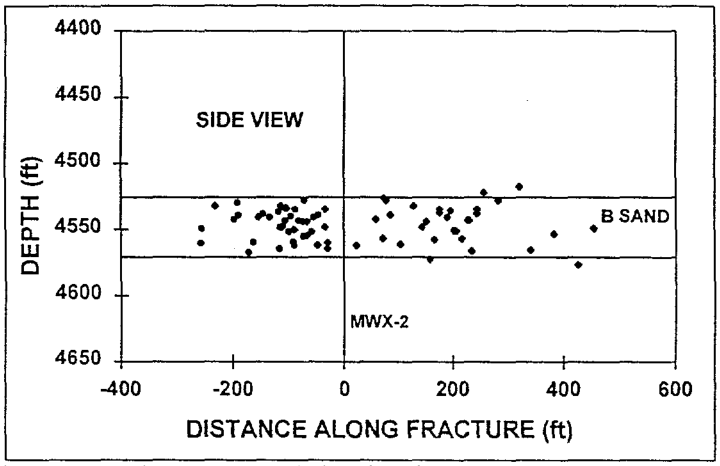

Figure 7. Example side view of KCl water injection in the B sandstone.

Application

The application of this technology is directed towards hydraulic fracturing, but it also has potential application in gas storage, waste injection, and reservoir characterization and management. Having the capability to image the growth of a hydraulic fracture provides direct benefits of:

- validating and improving fracture design models,
- optimizing multi-zone fracturing, re-fracturing, and fracturing in problem reservoirs
- optimizing well layouts and infill drilling programs, and
- eventually providing the capability for real-time control of the fracturing process.

The basic plan is to have wireline service company available who would

1. run wireline receivers into an offset well,
2. clamp the receivers in place,
3. orient the receivers,
4. take background data of the reservoir activity,
5. monitor the hydraulic fracture and post-fracture activity,
6. provide real-time or near-real-time data on site, and
7. provide detailed post-processing, if necessary.

The service is cost-effective and accurate if high quality microseisms are obtained which can be analyzed on site.

Future Activities

Future activities focus on joint tests with industry to exercise and optimize the technology in realistic field environments. Such testing allows factors such as reservoir type, depth, well conditions, temperature, surface conditions, reservoir production environment, and others to be tested and included in optimization of the diagnostic system. It is hoped that several tests in widespread locations can be conducted in the next year.

Acknowledgments

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