A Brief Guide to Passive Seismic Monitoring

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Abstract

Passive seismic imaging is a quickly growing technology to map fracture growth during hydraulic fracture stimulations, map active fracture networks, monitor well failures and track injection of fluid and steam. In this paper a number of issues are presented which should be considered when applying some potential applications are described, along with potential pitfalls that a potential user should consider.

Introduction

In the last few years there has been an exponential growth in the application of passive seismic imaging. Passive seismic monitoring (see Maxwell et al., 2001, 2002, and references therein, for background information and a discussion of potential applications) typically targets either impulsive, energetic acoustic emissions within the reservoir, or in some cases, local natural earthquakes to image a reservoir or long duration signals associated with slow or creeping processes. Here the acoustic emission application will be discussed, and are associated with sudden, induced deformation in the reservoir. These acoustic emissions correspond with small magnitude microearthquakes, typically referred to as microseisms (although under certain conditions larger felt earthquakes can be induced). Microseismic events, related to either induced movements on pre-existing structures or the creation of new fractures, correspond to deformations as the rock mass reacts to stresses and strains associated with pressure changes in the reservoir. The microseismicity can be used to localize the fracturing, or to deduce geomechanical details of the deformation. Since the Rangely experiment in the late 60's, a number of passive seismic experiments have been pursued in the petroleum industry with varying degrees of success. Recently, a number of independent operators have successfully implemented passive seismic studies to address specific issues. The majority of these studies are under the umbrella of hydraulic fracturing, where the microseismicity is used to map directly the fracture growth during well stimulations. However, a number of other studies have been used to image deformations associated with primary production, secondary recovery or waste injection operations.

Microseismic imaging typically relies of downhole sensors, although near surface sensors can be used in some cases. Continuous seismic signals are analyzed for characteristics using "event/earthquake detection" logic, and the resulting classified signals are then stored and processed to compute parameters associated with the event. Most examples cosist of monitoring with a string of triaxial geophones in a single borehole. In these cases, p- and s-wave arrival times and signal polarization are used to determine hypocentral locations by forward modeling of a velocity structure. Dynamic images can then be produced based on the time history of the microseismic activity. Additional seismic source attributes, such as strength or magnitude, can also be determined. Seismograms can also be processed to deduce information about the travel path, such as anisotropy and velocity tomograms analagous to active seismic surveys.

Applications

During well stimulation by hydraulic fracturing, microseismicity can be used to image the orientation, height, length, complexity and temporal growth of the induced fractures (for example, see Maxwell et al., 2002). Monitoring microseismicity in real time further allows for intervention during the stimulation, to increase the effectiveness by providing the on-site engineer with an updated image of the fracture growth. The images can also be used to calibrate numerical simulations of the fracturing and predict the probable drainage area when the well is brought on line. This results in a better design tool for future wells and the option of optimizing the frac design.

Passive imaging can also be sucessfully used during various production operations in a reservoir. For example, passive imaging is currently used to track well failures (Boone et al., 1999) and steam injection (Maxwell et al., 2003) in Canadian heavy oil fields. Passive imaging can also be used to monitor gas or water floods (Maxwell, 2000). Passive imaging can also be used to image fault networks, and rock deformation associated with reservoir compaction.

Technical Considerations

Despite the monitoring objectives involved in a specific application of the technology, there are a number of general considerations to be made for a sucessful project. There are a wide variety of ways that a field or well can be instrumented, from temporary arrays deployed by wireline to permanently installed sensors. Ultimately, the sensor deployment will dictated by a trade-off between image optimization, practical considerations for deployment sites such as wellbore availability, availability as vendors bring new products onto the market, and project economics. Generally, the choice will require good vector fidelity, good coupling with the rock, high signal sensitivity and low noise pick-up and a wide frequency response with minimal distortion. Similarly, there are many ways of configuring an acquisition system, depending on the project objectives. Detailed discussion of the options is beyond the scope of this paper, and should be considered on a case-by-case basis. However, a fundamental issue common to all projects is consideration to data format and archiving which should be maintained to geophysical industry standards. In the case of data format, a universal industry standard for passive seismic data does not currently exist. SEG seismic file standards are an option, but have not been developed to specifically met the demands of passive data.

With any passive imaging project, the largest technical risk is related to the ***sensitivity*** of the array. In order for acoustic signals to be classified as originating from a microseismic source, sufficient signal strength must be recorded with the seismic sensor relative to background noise. Obviously, digital signal processing techniques can be used to enhance the signal relative to the noise found in raw data records. Signal classification can be complicated in certain situations by the presence of impulsive acoustic noise associated with oilfield operations (pumps or surface noise) or borehole noise (tube waves). Typically the acoustic noise can be classified based on either signal attributes or apparent moveout across the seismic array. However, background seismic noise related to acoustic noise and/or electronic noise in the recording system will typically vary site to site. The amplitude of the microseismic signals recorded at a sensor will be related to the source strength or magnitude of the particular event and transmission losses. During hydraulic fracturing, for example, source moment magnitudes in the range –3 to –1 are typically recorded for the strongest events. The smallest events that will be recorded depend on the background noise and transmission loss, which limit the number of events that will be recorded. If the seismic sensors are at a relatively large distance from the source, significant signal strength may only be recorded for the relatively few, large magnitude events. For a particular array, the influence of expected noise and attenuation conditions can be examined prior to the start of monitoring, but the principal activity rate and range of magnitudes can only be measured *in situ*.

Another key issue is the ***resolution*** of the data. Hypocentral location uncertainty of the events is a key parameter for the seismic image quality. Random location uncertainty arise from uncertainties in arrival time and hodogram data. Systematic sources of error generally arise from velocity model uncertainties or simplifications, and fundamental geometrical uncertainties. Even with very detailed velocity models, uncertainties will always exist that can lead to location uncertainties. These systematic and random data errors can be quantified and need to be considered when interpreting the image. For example, if an interpreter is assessing the correlation between microseimic activity and a specific,thin lithological unit, random errors could result in a “blurring” above and below the unit if depth errors are larger than the unit. Furthermore, systematic errors may lead to the microseismic activity appearing at the wrong depth. The other potential component of systematic errors is from geometrical uncertainties. For example, the actual location of sensors in a borehole will be limited by the accuracy that the borehole geometry is known. Furthermore, if operations in an offseting well are being monitored, the relative geometrical or surveying errors can lead to systematic offsets. Typically this is more difficult to quanitify, due to a tendancy for drilling and surveying accuracies to be overly optimistic.

Considering the fundamental sensitivity and resolution of a passive image, a geophysical interpretation of the spatial and temporal elements of an image can be made. In many instances, this is based on basic hypocentral parameters of time and location. The key interpretational aspect comes by integrating with other geophysical and operational data. For example, integration of hydraulic fracture passive data with pumping data allow reservoir engineers to diagnose stimulation performance and redesign future jobs. This particular application is relatively mature and the “value loop” of the data is well established.

In the case of permanent reservoir imaging, the interpretational path may not be as straight forward. Passive imaging may be one of many geophysical data sets, each providing a different element of the reservoir dynamics. For example, integration of passive data and 4D seismic data at Peace River provided insight into different aspects of steam flow (McGillvary, 2004). Similarly, integration of tilt meter data (Wright, 1999) can be used to compliment localized seismic deformation with reservoir strains, analogous to volcanic monitoring. Ultimately, integration into a common earth model with a reservoir simulator may be needed. In terms of passive data, the link between a reservoir simulator and passive data will require a geomechanical model of strains. This remains one of the big challenges with the application of the techonology, which must be addressed before the reservoir engineer can make operational decisions in a general sense. Nevertheless in specific cases, operational decisions can be made directly from the passive data (e.g. monitoring casing failures, Boone et al, 1999).

Conclusions

In summary, before proceeding with a passive monitoring project there are a number factors to consider. Beyond the specific logistics of how to deploy sensors and configure a recording system, the sensitivity and resolution of the monitoring can be investigated. However, the largest technical risk will likely be the number of microseisms that will be recorded. Furthermore, how the data will be used and what decisions can be made needs to be considered. However, the “surprize” factor in any monitoring project may result in changes, as the nature and impact of the actual data set becomes apparent.

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