While microseismic data have been used for decades for various applications including mineral mining, engineering, and gas and water storage, the use of microseismic monitoring for oil and gas production is a relatively new field that began in the early 2000s. The microseismic method has risen in priority as the industry has shifted its focus to unconventional hydrocarbon reservoirs.

One of the biggest challenges of microseismic monitoring is the perceived inconsistency in results from one service provider to another and from one program to another. Without a set of best practices or a standardized method for acquiring and processing the data, it is difficult to provide a consistent set of deliverables. For example, many service providers in the industry use purely automated processes that detect microseismic events without quality control (QC) to validate these beyond the mere use of a threshold magnitude as part of the data filtering during processing. A more accurate QC process has been developed with a carefully defined set of criteria for what is and what is not a microseismic event, using advanced processing algorithms, interpretation software, and the expertise of specialized geophysicists.

Microseismic accuracy
The accuracy of microseismic event interpretation depends on several factors such as the quality of the velocity model, the amount of noise, and the assumptions underlying the processing techniques. With many different techniques in use, E&P operators stress the need for service providers to quantify the accuracy and reliability of their results. By implementing a manual QC procedure, a trained operator ensures that each potential event is reviewed by a geophysicist before it is validated as an actual microseismic event.

To further enhance this process, extensive research is being conducted on synthetic data to estimate the sensitivity (the smallest event that can be imaged) and the uncertainty of several parameters, such as the position of the event, the type of focal mechanism (describing the geometry, slip direction, and mechanism), and the orientation of the frac so that error bars can be provided with the final results. These are all significant advances in the field that will have major implications for how data is used for more than simply reporting the time and position of an event.

Focal mechanisms, drilling program development
The provision of focal mechanism information also is a significant development for the field of microseismic. The location and magnitude of microseismic events give only limited insight into the processes controlling the creation and propagation of fracs. The focal mechanism provides a more complete representation of these events and can be calculated from the first compressional-wave motion. The most general description of a focal mechanism is through its moment tensor, which describes the frac as a set of equivalent forces. Focal mechanisms are usually displayed as “beach balls” representing the

There are several geometries that can be used for gathering surface microseismic data, each with variable degrees of noise quality. The grid geometry provides the most coverage and the greatest ability to filter out harmonic distortion caused by ground roll and surface conditions. (Images courtesy of CGGVeritas)

Emmanuel Auger, Francois Aubin, Vincent Rajic, & Allison Branan, CGGVeritas
strain at the event source as well as which sectors are in tension and which are compressed. These indicate the type of failure that has occurred by showing the slip direction, whether the fracture is shearing or tearing, and whether a change in volume has taken place (i.e., the opening or closing of fracs). Inversion for seismic moment tensors provides a means of characterizing microseismic events to gain an advanced understanding of the stress-strain field and the frac orientation and propagation.

Several service providers recognize the tremendous value this information can provide in terms of understanding the state of the local stress fields, which determines the orientation of induced fracs and whether they will open and stay open as well as predicting possible reactivation of existing tectonic faults. Interpreting this data enables adjustments to be made to geomechanical reservoir models and aids in designing drilling and completion strategies for optimal production to determine how many frac stages to incorporate, what pressure to use, and how much fluid and proppant injection will be required to stimulate the well.

Understanding the effects of hydraulic fracturing on the reservoir and the subsequent production allows engineers to modify their processes and customize the completion program between frac stages rather than using the statistical approach the industry has adopted in the past. The impact of this information could translate into improved production and reduced overheads as adjustments in the field during completion can be implemented immediately, potentially saving millions of dollars or bringing the well online faster. In addition, it enables the fracturing process to be halted if the fracs appear to be going out of the desired zone, therefore reducing any environmental risks.

Providing real-time focal mechanism analysis requires advanced processing technology and infield expertise to transform the data into a usable format for production optimization. Most service suppliers provide real-time information about the frac location and time; however, using proprietary software, CGGVeritas has the capacity to support real-time focal mechanism analysis as well.

**Integration of microseismic and conventional seismic data**

Passive microseismic data also is being recorded in conjunction with conventional active seismic data by permanent reservoir monitoring systems such as Seis-Movie. These systems provide long-term monitoring of changes in the reservoir, including the migration of fluids and frac movement and/or closure. These can be correlated with production to plan restimulation programs and the efficient and cost-effective management of field exploitation.

The true value of microseismic data lies in its integration with other reservoir data to provide a complete lithological and geomechanical model of the reservoir. This requires advanced reservoir characterization techniques and the combination of all available reservoir information, including well cores and logs, rock properties and attributes derived from petrophysical analysis, elastic and stochastic inversion of 3-D seismic, and geomechanical attributes derived from azimuthal anisotropy studies, as well as data from microseismic monitoring. Monitoring the fracturing process provides a technique for validating and refining the derived reservoir models. By using all the information in an integrated manner and combining geological, geophysical, geomechanical, and engineering expertise, it is possible to obtain a more complete reservoir model and optimize production while minimizing risk.