As the exploration and exploitation focus turns to lower-quality reservoirs, operators that take advantage of state-of-the-art technology can not only maximize and sustain production, but can avoid expensive trial-and-error developments. Understanding reservoir characteristics, rock properties, and shale-specific production factors can make the difference between a cost-effective development and one that is riddled with production and completion headaches. Microseismic is one such technology that not only aids in enhancing production, but can provide crucial reservoir information not readily obtainable from any other source.

“Microseismic monitoring provides the only 3-D view of the reservoir’s drainage network,” said Dick Zinno, chief geophysicist for Weatherford International. “The ability to effectively manage your frac operation is vital to any operator, particularly in unconventional plays where efficiency is key to field development.”

For US operators, one of the first places the use of new technologies helped pioneer economic development of unconventional resources was the Barnett Shale. This has expanded to include many plays that are active across the US and Canada, with unconventional plays in both oil and gas in the international market not far behind. Understanding how a shale or unconventional reservoir fracs or breaks down is no longer a luxury, added industry consultant Nick Steinsberger – it is a necessity. Steinsberger was with Mitchell Energy in the early days of Barnett Shale exploration.

“In the Barnett, we [Mitchell Energy] had no clue what was happening to the rock until we ran those microseismic tools and monitored a frac,” he said. “Every time we ran the tools, they would burn up due to the high temperatures. Once we were finally able to run the tools successfully, we discovered that the frac had created a vast, highly complex network that utilized the closed or healed natural fracture network already there. This enabled us to understand what was going on, and then to create a development plan for the field.”

“That was about nine years ago,” Steinsberger said. “Today, microseismic is a tool that all savvy shale operators use to understand the reservoir, design their frac volumes, and to plan their development programs. Now, no one should complete a well in a new area without the use of microseismic. You can see how valuable this technology is by the fact that every large service company provides this service, and just 10 years ago, nobody had it.”

Hydraulic stimulations

Hydraulic stimulations are crucial to the economic development of these reservoirs. Microseismic mapping of these hydraulic stimulations can be achieved by a number of different configurations with differing technical requirements.

“We were the first company to successfully commercialize the large-scale use of microseismic in the oil field after years of development at several national laboratories,” said Kevin Fisher, general manager of Pinnacle, now a member of the Halliburton group of companies. The company performed its first commercial microseismic mapping project in 2001 in the Permian Basin. “Today, we perform more frac mapping than all of our competitors combined – nearly 20,000 mapping jobs since 2001.”

Microseismic provides the means to monitor frac propagation during hydraulic stimulation, allowing operators to react in real time to avoid geohazards such as karsts and faults, change perforation spacing, or adjust the number of intervals or sections that require fracturing. Pre-existing flaws and planes of weakness “slip” when activated...
by hydraulic fracturing, creating microseismic events which, when measured, help indicate key fracture properties including azimuth, height, length, affected reservoir volume, and complexity of the induced fractures. With real-time fracture mapping, operators can avoid nearby wet zones that would flood the well with water, faults that might communicate with gas or water zones, and fracturing into offset wells. The frac maps also are used to optimize well spacing, horizontal lateral length, and the number and size of frac stages needed to effectively stimulate the reservoir, as well as to help predict productivity based on the stimulated reservoir volume.

Geophones used to collect this data can be deployed in a number of ways:

- Inserted near the depth of the fracture in a nearby existing borehole (used most often);
- Inserted directly into the well being monitored;
- Placed on the surface near the well;
- Buried shallowly (at 1 to 300 ft, as opposed to formation depth); or
- Permanently installed for long-term usage.

Data from the array string is transmitted within seconds to a nearby monitoring van, or it can be beamed via satellite to a field office or a customer’s location.

One pioneer company is Houston-based MicroSeismic Inc. (MSI). According to the company, its FracStar surface arrays and BuriedArray service – in which a near-surface array of permanently installed geophones are buried a few hundred feet below the ground and wirelessly linked together to monitor an area up to 500 sq miles – offer lower costs than traditional downhole monitoring and enables long-term reservoir management throughout a field’s producing life. To date, MSI has deployed more than 100 systems – 19 of which are in permanent installations – in shale plays across the US, including the Haynesville, Eagle Ford, Barnett, Woodford, Bakken, and Marcellus.

“MSI is the only provider that offers microseismic monitoring from the surface or near-surface in real time,” said MSI chief executive officer Peter Duncan. “Our arrays, consisting of hundreds or thousands of geophones, give us a much larger field view, allowing us to monitor entire laterals at once. This technique also allows us to conduct permanent, continuous monitoring at reasonable costs. Our competitors offer downhole monitoring with just a few sensors, which provides a very limited view near the monitoring well. We are getting the birds-eye view of the whole field.”

Duncan said clients choose MSI because the company offers a less risky and less expensive monitoring service that actually provides more information over the life of a field than traditional downhole microseismic monitoring, which requires a monitoring well within a few thousand feet. For the same cost as drilling a single monitoring well that will provide a limited view, a customer can get multiwell evaluations from a single permanently installed surface or near-surface array for a field-wide view. This gives a tremendous boost to long-term planning efforts and a more informed perspective on where to drill next.

“With our technology, we generate advanced microseismic attributes that map the entire fracture pattern so operators can see where their fracs are going and how the rock is actually breaking,” Duncan said. “This is incredibly powerful information to have and use as they move through each subsequent frac stage, adjusting pump pressure and proppant type to maximize production and recovery.”

Recording microseismic events to monitor rock fracturing in 3-D space and time during the stimulation process allows confirmation of the rock volume and formation geometry being stimulated. From this information, future well placement and completion designs can be optimized for cost-effective drainage of unconventional reservoirs.

“The key component to the use of microseismic is the ability to optimize not only the well you are dealing with at that moment, but an entire development program,” said Baker Hughes’ manager Steve Sadoskas. “You have to know what questions you are trying to answer in order to develop your strategy. Microseismic helps you determine if you are staying in the zone of interest, how many stages
are needed, ways to optimize future stimulation; and it can be used the same way in vertical wells or horizontal wells. By using microseismic, the answers become much clearer.

**A case in point**

Baker Hughes recently completed one of the largest microseismic hydraulic fracture monitoring surveys ever undertaken for Apache Canada in the Horn River Basin of northwest Canada. The project deployed Baker Hughes’ geophone strings simultaneously in two observation wells for more than 30 days. Microseismic events were recorded for hydraulic stimulations in 13 well bores adjacent to the observation wells. In all, more than 75 separate hydraulic stimulations were recorded.

The project used a variety of deployment geometries in both the horizontal and vertical sections of the observation wells to optimize hydraulic fracture imaging in the reservoir. Operations were conducted 24 hours a day, and VSFusion, a joint venture between Baker Hughes and CGGVeritas, provided real-time display of recorded microseismic events, both on the well site and in Apache's offices in Calgary and Houston. Apache used the real-time data to experiment with how different perforation patterns impacted fracture propagation and to make real-time changes in the fracture program as a result. At one point, the data showed an absence of growing microseismic activity, alerting Apache to switch from pumping proppant to flushing the well with water to avoid a potentially costly sanding-off of the fractures.

Baker Hughes’ IntelliFrac service offers the combined expertise of Baker Hughes and newly acquired BJ Services, enabling operators to monitor fracture dimensions during stimulation treatments and allowing real-time control of fracture operations. “Being able to look downhole and change the fracturing process on-the-fly is especially critical in areas with complex fracturing, such as shales,” said Baker Hughes’ vice president James McDougall. “By understanding hydraulic fracture propagation, operators can make better on-location treatment management decisions, and in turn, reduce well-completion and stimulation risk and uncertainty.”

“We have the ability to do all types of microseismic, and we do all of our own processing,” Sadoskas said. “Additionally, we have the ability to analyze advanced attributes. When you look at the total picture – from complex reservoir studies, frac models, acquisition, processing, optimizing production efficiency – Baker Hughes can do it all.”

Weatherford offers a slightly different approach to microseismic monitoring, deploying the tools in the treatment well rather than in an offset well. The company’s SeismicSpear system can be moved and oriented during the survey to monitor the near-field signal from close up, revealing high levels of detail, and following the microseismic activity for excellent control of frac height. For one client operating in a tight-gas reservoir in the Piceance Basin shale, Weatherford’s microseismic service provided understanding of the frac height, azimuth, and containment, and “proved invaluable for the hydraulic stimulations programs across the entire field and
Wellbore Information

reducing the number of wells that had to be drilled,” Weatherford’s Zinno said.

“Our microseismic surveys form the key technology for the economic development of an unconventional reservoir,” he added. “With microseismic surveys, operators can reduce the time and costs of fracturing operations, which can lead to higher production rates, lower decline rates in hydrocarbons, and less water incursion.”

Once the microseismic dataset has been gathered and processed, operators can use the data to optimize field development plans. Sadoskas said the speed and accuracy of the process data is key to successful microseismic operation. “Some companies use discreet picking of compressional (P waves) and shear waves; some use migration techniques. Both methods have advantages. One of our [Baker Hughes’] differentiators is the ability to do both methods. By combining frac modeling, including microseismic mapping, production analysis, advanced attributes such as focal mechanism, and geomechanical studies, operators can move toward total integrated answers in a geomechanical model. This helps clients optimize reservoir exploitation as they develop their acreage.”

Interpreting the data

Microseismic mapping provides the data to calibrate hydraulic fracturing with the goal of keeping a close eye on the path of fluids and to keep the fracture activity in specific zones. Customers also can get a better handle on well spacing and field development once a clearer understanding of the reservoir is obtained. Schlumberger uses a computerized process to interpret mapping data, a feature not offered by others.

The Schlumberger microseismic processing system addresses the full range of issues that contribute to uncertainty, repeatability, and turnaround time. To provide the highest level of value from microseismic services, the methods for addressing these issues include station distribution bias, well path uncertainty, velocity model uncertainty, time pick uncertainty, hologram uncertainty, and inversion bias.

Later this year Schlumberger plans to introduce the first complex fracture simulator that uses the characterization of the reservoir natural fracture network to simulate the complex growth of hydraulic fractures in unconventional reservoirs. This new modeling software is fully integrated in the Petrel* seismic-to-simulation software reservoir modeling environment. The integration of microseismic data and true complex fracture simulation will provide the most significant industry step change in the understanding of hydraulic fracture growth and resulting conductivity based on a calibrated model for unconventional reservoirs.

“The detection and location of microseismic events using an automatic process is an important first step in providing a sensitive and accurate microseismic picture,” said Rick Klem, marketing and sales support manager, hydraulic fracture monitoring, Schlumberger. “However, the true value of microseismic data is realized through two main interpretation aspects: first, to enable informed fracture-control decisions to be made in real time during fracturing treatments, and second, to enable improved completions on future wells. The interpretation required to achieve this depends on full integration of the microseismic data with all the other reservoir data (such as logs, seismic, etc.) performed by people with a strong background in both hydraulic fracturing and reservoir characterization.”

The Schlumberger StimMAP* LIVE real-time microseismic fracture monitoring service provides fracture monitoring within 30 seconds of microseismic activity. Based on proprietary coalescence microseismic mapping (CMM) that allows processing more events per minute than would be possible with hand-picking, there is close agreement for the fracture geometry on the same dataset. The CMM technique provides more events because multiple arrivals can be handled in a single time window, according to the company.

Microseismic hydraulic fracture monitoring is a complicated process that requires a full software suite to provide modeling, survey design, microseismic detection and location, uncertainty analysis, data integration, and visualization for interpretation. It also requires a fully automated processing and data transmission process to form the basis of true real-time decisions that positively affect hydraulic fracture placement. Visualization and interpretation using Petrel* seismic-to-simulation software provide analysis within the geological model, integrated with seismic and petrophysical data.

Halliburton not only offers microseismic mapping, but through Pinnacle (acquired by Halliburton two years ago), the company can provide the additional related service of tiltmeter mapping – the only company providing this technology in the oil and gas industry. Tiltmeters are commonly used in civil engineering and construction projects (bridges and buildings) and to map volcanic activity. By increasing the sensitivity of the meter to the nano-radian – one part in a billion – Pinnacle was able to adapt this technology to measure the subtle rock deformation patterns during fracturing.

“We place a larger number of tiltmeters around a well – usually about 50 – which will detect micro-deformations during the frac process,” Fisher said. “Combined with microseismic, we can create a more complete picture of what is happening in the reservoir than just with microseismic alone. We don’t just produce dots on a map – this is where we excel.”

Pinnacle maps more than 5,000 fracs each year, and has been deploying the tiltmeter since 1992. The devices are placed in holes approximately 30 ft deep, roughly one to two miles from the well bore. According to Fisher, the company is working on further innovations, including a tool that combines microseismic and tiltmeter into one device.

“We are able to create a real-time look at the complexity of the fracture and help the client decide how to avoid or mitigate any geo-hazards encountered and how to optimize the well as the completion is in progress,” he said. “We are also different than our competitors in that we utilize novel technologies, such as a fiber-optic telemetry system, that transmits data 20 times faster than conventional wireline. This allows an unequalled capability of both running more tools and sampling at a higher frequency than any of the major wireline companies. We’ve pioneered add-on services
such as providing real-time results, perforation timing for velocity model optimization, expanded and stacked arrays for difficult reservoirs, source parameter analyses to glean more information from the microseismic spectral data, and using frac mapping results to calibrate fracture models.”

**Weighing the costs**

The microseismic sector, for all of its advances, still faces challenges. Finding existing monitoring wells, if a client chooses that route, sometimes can be difficult. And if a monitoring site is not readily available, a borehole might need to be drilled, which costs money and takes time. Some operators hesitate to acquire microseismic data, wondering if the results obtained will be worth the cost. For reluctant participants, Halliburton offers a fracture design and consulting service that can help clients decide if further data acquisition and frac mapping are needed.

“It can be a challenge,” Fisher said, “but you don’t want to wait until your 100th well to say, ‘Hey, maybe I should have looked at the reservoir more closely back at the beginning of this program.’ You want your decisions to be based on real engineering data, not gut feelings, and the time to obtain that data is early on in a program.”

Microseismic monitoring also plays a role in the selection of chemicals, liquids, and proppants used in fracturing, as well as the effectiveness of acidizing and other chemical treatments. Zinno said Weatherford has mapped different fracturing patterns as a result of changes in slurry composition. “To a large extent, the mapping of created fracture patterns allows the stimulation design engineer to select the appropriate slurry for maximum effectiveness within a given pattern. For instance, in the early years of Barnett Shale development, it was discovered that the fracture networks were much more complex than previously thought. As a result, finer grain proppants were deemed more appropriate, and gels to carry the proppant were not necessary,” he said. “The viscosity of a slurry can alter the induced seismic emissions that we record. However, these emissions are not changed by the chemical make up of the slurry.”

Economics will, no doubt, continue to dictate that unconventional oil and gas plays remain in the forefront of US E&P. According to the US Department of Energy, production of unconventional gas in the US represented approximately 40% of the nation’s total gas output in 2004, but could grow to 50% by 2030 with the advent of advanced technologies. Microseismic, tiltmeter mapping, and other related and innovative services will remain valuable assets in the quest to find and produce more hydrocarbons.

“If you attended an SPE [Society of Petroleum Engineers] or SEG [Society of Exploration Geophysicists] conference eight years ago,” Sadoskas said, “you’d be lucky to find five people talking about microseismic. Now, you’re lucky to find a seat.”

*Mark of Schlumberger*