haynesville HEAT

After temperature prevented downhole frac monitoring, Encana scores first success with near-surface arrays

By Pat Roche

In the fall of 2007 Encana Oil & Gas (USA) Inc. was planning to fracture stimulate wells in a play that has been ranked among the biggest natural gas discoveries in the history of the United States.

Encana, a unit of Calgary-based Encana Corporation, had high hopes for its blockbuster Haynesville shale gas play in northern Louisiana and wanted to get the best frac treatment possible in the ultra-tight rock.

To improve permeability, millions of tonnes of fracture fluids and sand would be pumped down wells at high pressure to liberate the gas. To optimize these treatments, Encana planned to use microseismic monitoring to ensure it was creating the fractures it wanted, where it wanted.

At the time, the established way of monitoring a frac was to lower geophones via wireline to reservoir depth in nearby observation wells. But the Haynesville turned out to be Encana's hottest play in more ways than one. When the wells were drilled, the temperature was found to be 370 F. To record a frac, a string of wireline receivers has to be downhole for several hours, and they can't survive for that long at that temperature.

Traditional seismologic frac monitoring from surface didn't work. So if downhole monitoring wasn't possible, the operator's only option had been to rely solely on computer simulations. But producers had discovered the rocks don't always break quite as simply as some of the early engineering models predicted.

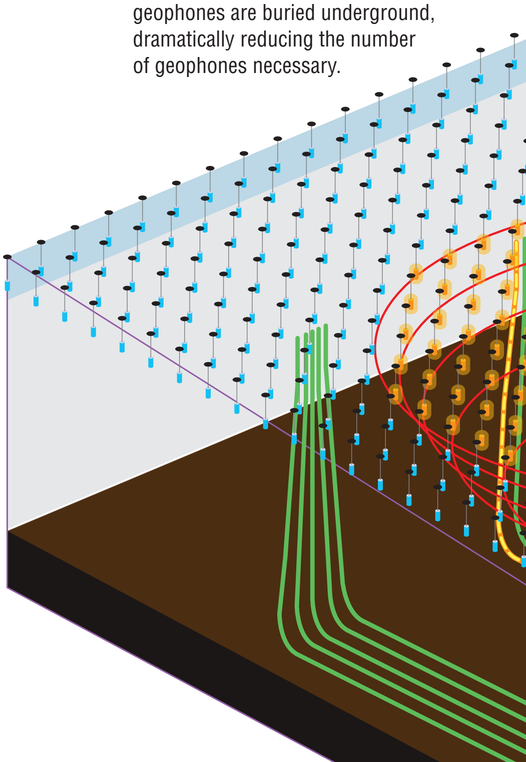
In this case, however, Encana had another option — though it had never been tried before.

Houston-based MicroSeismic, Inc. (MSI) had come up with a way of using microseismic to monitor frac treatments from the surface. While MSI's surface-based method was new, microseismic per se was not.

Microseismic monitoring is seismic data acquisition without an active source such as dynamite, air guns or Vibroseis. Instead, it uses small seismic events, or micro-earthquakes, within the Earth. Acoustic signals are emitted by compaction-induced fracturing that occurs as reservoirs are drained, for example, and, of course, by hydraulic fracture-stimulation treatments.

Microseismic technology for monitoring oilfields didn't exist commercially until the late 1990s. Since about 2005 it has really taken off, spurred by the boom in gas shales such as the Barnett and oil shales such as the Bakken. These ultra-tight rocks require massive hydraulic fracturing.

UNDER OBSERVATION
To cut the cost of laying 10,000 to 12,000 surface geophones for a single microseismic frac monitoring job, Microseismic developed a buried array technique whereby geophones are buried underground, dramatically reducing the number of geophones necessary.



Frac monitoring in the shales helped boost total revenue in the North American microseismic business to $150 million last year — about a 15-fold jump from early last decade, estimates Peter Duncan, MSI's CEO.

Traditionally, however, microseismic had a significant limitation compared to conventional reflection seismic. The weak signals are hard to monitor from the surface, so receivers were typically placed in monitor wells at reservoir depth.

But because the observation distance around each monitor well is only about 500 metres, multiple monitor wells would be needed for a full field development. This would be uneconomic. For this reason operators would just monitor two or three fracs at the start of a development, and hope the rest of the field would be the same — a risky assumption.

To make it economic for full field development, MSI came up with a way of monitoring frac treatments with geophones at or near the surface. It uses statistical processes called migration and "stacking," or averaging, to take advantage of a large array of geophones on the surface to overcome the signal-to-noise ratio to capture the very small microseismic signals.

The large surface arrays are cheaper than downhole recording because they eliminate the need to drill monitor wells, and the equipment costs less because it's readily available and used by conventional seismic companies.

Describing MSI's surface arrays, Duncan says the best analogy is a dish microphone. A dish microphone captures multiple weak voice signals — beams of sound — and stacks, or averages, them. This stacking process — which is called beam steering — produces a signal strong enough to capture by concentrating the weaker signals at the centre of the dish.

"And that's exactly what we do in seismic when we lay out geophones over the surface of the Earth — we're effectively building a big dish microphone," Duncan explains. "And we steer that microphone towards a target in the computer by applying different delay times to the different geophones.

"The dish is a particular shape in order to create a delay and then reflect the signal back to that central microphone. We create those same delays mathematically in the computer. That's what migration and stacking are all about."

> **"We could put in a buried array for about the same cost as the layout and pickup of one implementation of a surface array. And now we've got an asset that can be used for the life of the field."**

Going deeper

MSI's original approach was to lay out groups of geophones on the surface in a pattern it calls a FracStar.

The layout looks like the spokes of a wheel centred on the well being fraced. And the radius of this wheel would be about equal to the depth of the frac. So if the reservoir being fraced was 3,000 metres down, the "dish microphone" array was 6,000 metres across and had 10,000 to 12,000 geophones.

MSI had spent the previous couple of years perfecting the technique and trying to convince industry it worked. Since the reservoir temperature ruled out downhole recording in the Haynesville, Encana decided to test MSI's new surface-based FracStar method.

One of the ways MSI overcame the poor signal-to-noise ratio that normally precludes surface microseismic recording was by using many geophones. But laying out and picking up thousands of geophones was an expensive way to monitor one frac treatment.

In the case of Encana's Haynesville deployment, the area was heavily wooded, so the project involved a significant amount of line cutting and associated expenses. In all, it cost Encana about $800,000 (U.S.) to monitor that one well.

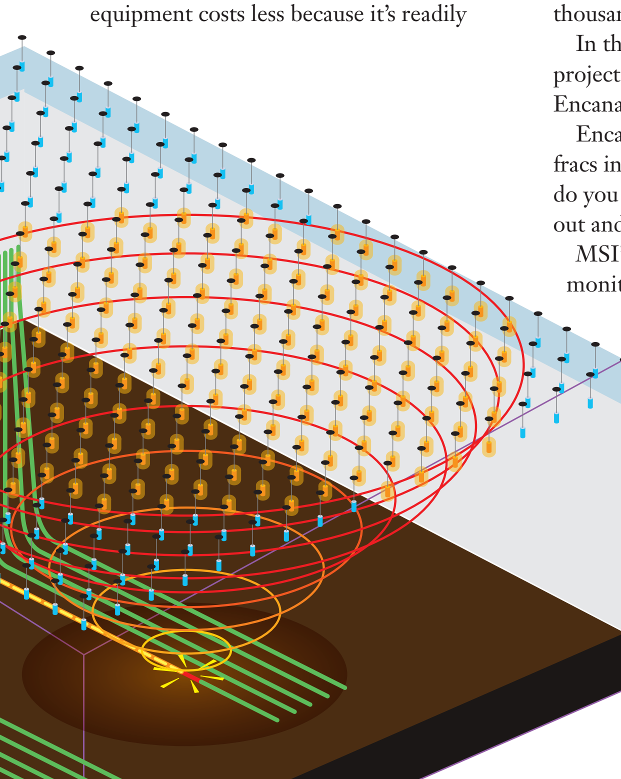
Encana, one of MSI's major clients, liked the results and wanted to monitor many more fracs in the same field — but not at $800,000 per observation. So the question became: How do you monitor the fracing of multiple wells in a field over several years without having to lay out and pick up 10,000 or 12,000 geophones each time?

MSI's initial Haynesville deployment for Encana proved surface-based microseismic monitoring is possible. The reason so many geophones were used is the surface is noisy. MSI overcame the noise by having thousands of observation points and then stacking the data.

Since most of the unwanted noise is in the Earth's top tens of metres, Duncan and his colleagues reasoned that far fewer geophones would be needed at a depth of 100 metres. Thus was born the idea of the buried array. To reduce the number of geophones, MSI simply buried the arrays 100 metres beneath the surface.

This dramatically reduced the number of required geophones.

For example, using a FracStar, or "dish microphone" array, on the surface over a 40-square-kilometre area would require 1,000 groups of 12 geophones each — which is 12,000 geophones. Duncan says the same area could be monitored by 100 groups of geophones buried 100 metres below the surface. And since the groups of geophones used in buried arrays are typically three to six phones, not 12, the total



SOUNDPROOFING
By burying geophones 100 metres deep rather than placing them at surface, Microseismic was able to eliminate most of the surface noise reaching the instruments.

would be much smaller.

The trick was to reduce the cost of monitoring each frac by permanently installing the buried array so it could be used for several years for an entire field, not just one well.

You trade the cost of laying out and picking up a temporary array of 1,000 geophone groups for the cost of cementing in 100 geophones groups at 100 metres depth. And whereas the former has to be done for every well fraced, the latter only has to be done once for an entire field.

"We could put in a buried array for about the same cost as the layout and pickup of one implementation of a surface array," Duncan says. "And now we've got an asset that can be used for the life of the field."

Costs and benefits

Given the economies of scale and the success of the FracStar surface array, Encana decided to install what may have been the world's first buried array — also in the Haynesville play northern Louisiana.

It also helped that Pete Smith, a geophysicist in the Denver-based new ventures group that discovered the Haynesville for Encana, had already done some experiments with buried arrays. About five years earlier, in the Piceance Basin in western Colorado, Smith had drilled seven 100-foot deep holes in which he installed geophones.

In that early experiment Smith was able to able to see seismically some of the energy from perforation shots 8,000 feet below. But that array was too sparse to produce useful information with the processing capabilities that existed at the time.

The algorithm, or data processing technique, MSI demonstrated in the FracStar surface array proved that processing capability was no longer a constraint. So Encana installed the first permanent buried array — which covers about 25 square miles of the field — and monitored the first frac treatment with it in the fall of 2008. The multi-stage frac was done in a 4,000-foot-long lateral at a depth of about 11,500 feet.

It cost Encana about $600,000 (U.S.) to install this permanent buried array, Smith says — three-quarters of the cost of the temporary surface array that monitored the fracing of only one well.

He adds it costs about $10,000 per frac stage to process the data with MSI. Smith notes this is a small fraction of the cost of deploying geophones at reservoir depth. MSI guarantees the geophones for 10 years.

While the $600,000 was a onetime cost because the geophones are permanently installed, Smith estimates it initially also cost about $7,000 a day to lay out the recording boxes on the surface and pick them up. (Duncan notes it's no longer necessary to retrieve the boxes every day to collect the data — that's now done via Bluetooth or Wi-Fi connection.)

"In retrospect, I think it was a spectacular success," Smith says. Encana is currently installing its fourth permanent buried arrays in the Haynesville.

So what was learned?

Encana's Smith says that first buried array provided a good X, Y, or lateral, image of where the frac was going. As expected, it showed the frac stage pumped in the toe of the horizontal well, which are harder to pump, doesn't yield as much seismic activity as the stages pumped closer to the heel.

But the learnings went beyond the predictable.

The first four stages of this eight-stage frac were pumped with a slickwater and the rest with a linear gel. Processing of the data shows the slickwater was travelling further from the wellbore than the linear gel.

"That was an interesting finding for us," Smith says. Most of the high-amplitude events occurred later in the pumping of the frac and correlated with proppant injection.

However, the key finding was that more high-amplitude events occurred during the pumping of the linear gel stages than during the slickwater fracs. This convinced Encana to use the linear gel more often and today the linear gel has become the standard frac used in the Haynesville, Smith says.

"There were a greater number of large-amplitude events that covered a larger area during the linear gel stages," he notes. "And so our interpretation of that was that we were propping a larger effective area during the frac." It's hard to isolate the precise impact on production because the length of the laterals and the number of frac stages per well also increased. But Smith says the linear gel, and hence the use of the surface microseismic, is part of the Haynesville story as well.

Last winter, meanwhile, MSI installed its biggest array in the Bakken for Whiting Petroleum Corporation's Sanish field development. The buried array covers 152 square miles in Mountrail County, North Dakota.

"We're monitoring eight to 10 wells a month for Whiting," Duncan says. "And they'll use it for the life of their field."

MSI currently has — either in the ground or in the process of being put in the ground — 17 buried arrays covering about 550 square miles, Duncan says. Those are in the Marcellus, the Haynesville, the Barnett, the Bakken and the Permian basin of west Texas.

No buried array has yet been installed in Canada. However, Duncan says MSI installed small noise test arrays (which are done ahead of doing a buried array design) in the Horn River basin of northern British Columbia.

"We've been doing a lot of work as well on the Saskatchewan side of the Bakken play in the Williston Basin," he adds. "And we've done a number of our FracStars — the [temporary] surface arrays — down there."

While unsure whether the first permanent installation in Canada will be in the Horn River or the Bakken, he is confident the timing isn't far off. "We will have a buried array in Canada this year," he says. •