Geophysical monitoring of heavy oil production

Everyone knows that reservoir monitoring in the heavy oil industry is a good thing. The challenge is how to cost-effectively monitor complex production processes in a way that helps to deliver knowledge about the subsurface that will enable efficiency improvements.

The best way to do this is to combine the right surface measurements with appropriate downhole information. An optimized combination of measurements can improve production efficiency by, for example, detecting unexpected intra-reservoir barriers to steam chamber growth, and detecting zones with low steam conformance. The challenge is to know which integrated package works best to meet the individual requirements of each reservoir.

Integrating surface and downhole measurements
Surface measurements include tilt-meter measurements to identify deformation; and reflection seismic surveys, which typically provide vertical resolution in the order of 4 m (13 ft). These surface measurements are calibrated with downhole seismic measurements that provide a higher level of vertical accuracy—typically about 1 m (3 ft)—although with limited spatial extent. Downhole measurements include vertical seismic profiles (VSPs), often using permanent sensors in well(s); “virtual source” seismic techniques; cross-well seismic; and electrical resistivity tomography (ERT), which can be effective at finding resistive bodies such as heavy oil reservoirs. Surface and downhole measurements are validated through repeat well logging and temperature measurements, such as provided by fiber-optic distributed temperature sensing (DTS) systems permanently installed in a well. DTS measurements are valuable for predicting the advance of a steam flood. The higher level measurements, such as the surface seismic, are improved by iterative inversion of the static reservoir model and dynamic reservoir simulation. The long-term objective is to be able to invert a range of different geophysical measurements to determine changes in a variety of properties, including temperature, saturation and stress. There is a wide range of potential surface and downhole measurements, so a key objective in the process is to determine a methodology to select a minimum package that will meet particular production requirements.

Monitoring using surface seismic
About 25% of the seismic activity in Alberta is related to reservoir monitoring and about 40% of the province’s heavy oil fields are being, or have been, monitored with surface seismic. This typically involves a “baseline” 3D survey being acquired before production, followed by another survey every 2 years. Differences in the amplitude, time and/or phase of the seismic signal from one survey to the next can indicate changes in fluid content, temperature and/or pressure. The technique is known as “4D” or “time-lapse” seismic.
A SAGD drilling pad typically produces from an area of about 1 km². Surface seismic surveys around such pads are normally about 10 km² (4 mi²) and take about 6 weeks to acquire. The targets are shallow—250-600 m (800-2,000 ft)—and the surveys are designed to provide the highest possible resolution. They are usually acquired with point receivers, typically at 12 m (40 ft) intervals, and a single vibrator source with 3 m (10 ft) moveup.

**Permanently installed surface monitoring systems**

In most seismic surveys, geophones are planted in the ground, vibrators move along roads or tracks to create the seismic source at many locations; then the equipment is removed for use elsewhere. In Alberta, seismic crews can usually only operate during the approximately 4 month period when the ground is frozen; the rest of the year, much of the land is “muskeg” waterlogged bog. To overcome this, and other, limitations, geophones—and occasionally seismic sources—have been permanently installed over some oilfields. Geophones can be buried close underground or placed in shallow boreholes. Small vibrator sources can also be installed in shallow boreholes. In some cases, re-useable drilled holes have been used for explosive sources.

Permanently installed systems make “on demand” seismic much easier, particularly when weather and ground conditions can prohibit equipment deployment. In addition, such systems avoid the logistical challenges of deploying vehicles and equipment around extensive surface facilities. A further benefit is that permanently installed sensors and/or sources provides better repeatability: reducing differences between surveys caused by variations in equipment positioning, and several other operational factors, that can mask the subtle changes in seismic signal related to changes in the subsurface.

In general, seismic imaging quality improves when equipment is closer to the target. To date, most seismic equipment is deployed at or near the surface. Installing permanent sensors very close to the pay zone would deliver higher quality; however, with thermal recovery systems, this will require them to be able to withstand temperatures of around 260 degC, which may become possible through fiber solutions.

**Learning from previous projects**

Every project the author has studied to date has provided a different set of measurements with different spatial extents and vertical resolution. A team at the Schlumberger Reservoir Technology Center (RTC) in Calgary is building on the experience of existing projects to develop a more structured approach to heavy oil reservoir monitoring projects. The ambition is to be able to define the most cost-effective solution to the needs of particular reservoir monitoring projects.

Several examples of heavy oilfield monitoring projects involving surface seismic methods, often integrated with other geophysical techniques, were presented by the author at an SPE/AIChE workshop, Houston, Feb 23, 2010:

- **Zhang et al (SPE, 2007)** show that amplitude differences between seismic surveys acquired for EnCana (now Cenovus Energy) at Christina Lake can differentiate between hot and cold zones. **Nakayama et al (TLE September, 2008)** present similar results from SAGD wells at JACOS’ Hangingstone field. The Hangingstone project also indicated that variations in Poisson’s ratio, calculated from measured seismic P-wave and S-wave velocities, correlate well with changes induced by steam injection, and can differentiate between areas of steam, hot oil and cold oil. **(Kato et al, TLE September 2008).**
Hedlin et al (SEG Expanded Abstracts, 2009) show that in CHOPS applications, amplitude versus offset (AVO) anomalies can differentiate between producing areas and unproduced areas of the reservoir. This information has been used to plan infilling drilling.

Forgues et al (SEG Expanded Abstracts, 2006) present details from a Conoco-Phillips project at Surmont. Here, permanently installed sources (low power vibrators), and vertical and horizontal geophones have been buried close beneath the surface. Measurements have been made on a monthly basis. Variations in transit time through the reservoir between surveys can indicate the progress of the steam flood. Byerley et al (SEG Expanded Abstracts, 2009) present the results of 4D seismic surveys acquired at Surmont over six month intervals. These identified several SAGD well pairs which were underperforming due to poorly developed steam chamber conformance. Using the 4D observations, an optimized well operating strategy was implemented to improve conformance and recovery from these well pairs by more effectively managing heel/toe injection and production splits.

Zhang et al (SPE, 2007) also indicate that in EnCana's Christina Lake project, crosswell seismic—in which sources are deployed close to the target in one well while receivers are placed in an adjacent well—can provide much better resolution than surface seismic.

Bakulin et al (TLE 2007) present a “virtual source” acquisition geometry in which receivers are deployed in a specially drilled shallow horizontal well above the reservoir. Placing receivers within the subsurface removed near-surface effects and provided higher-resolution than surface seismic, but lower resolution compared to crosswell seismic.

McGillivray (SEG, 2004) presents an example of integrated reservoir surveillance from Shell's Peace River field. This project deployed permanent geophones in a specially constructed deviated well above the reservoir. Permanent (reusable) shot holes were built at the surface. The downhole sensors measure not only the reflection seismic data during the various 4D surveys, but also continuously record microseismic events related to movements in the reservoir caused by changes in pressure and temperature. Tilt meters have been used at Peace River since 2002.

Maron et al (EAGE 2005) describe how the tilt meter measurements have been combined with the surface 4D seismic and microseismic measurements in the integrated reservoir surveillance program.

References
Zhang, Weimin, Sung Youn, Quang Doan: “Understanding Reservoir Architectures and Steam-Chamber Growth at Christina Lake, Alberta, by Using 4D Seismic and Crosswell Seismic Imaging”, October 2007 SPE Reservoir Evaluation & Engineering, pp. 446-452


