Fiber-Optic Sensing: Turning the Lights on Downhole

By packing a wide variety of sensors into a single fiber cable, simple package, multiple conventional monitoring systems can be replaced while reducing complexity and cost.

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Over the past five years, the oil and gas industry has seen a rapid increase in the deployment of fiber-optic sensing for downhole monitoring. Significant improvements in glass chemistry, interrogation technologies, and analysis applications have led the way to a robust downhole sensing solution. As many as 20 fibers can be packed into a ¼-in. tube (cable), which can be installed as a life-of-well monitoring system.

Each of the fibers can be turned into a fully distributed sensor for temperature (DTS), acoustics (DAS) and strain (DSS) measurements, or these can be used to interrogate multiple point sensors like pressure gauges and geophones. Fibers can also be used for downhole power transmission or data telemetry. Although conventional hardware has existed for decades to collect this same type of information, the question is: Why is the industry now seeing such excitement over fiber sensing?

One major benefit is that an operator can now monitor the entire well simultaneously. Things can be seen and heard in a wellbore that were impossible with point sensors or even wireline

Figure 1: This shows how fiber-optics cable is installed in an openhole completion. (Images courtesy of Halliburton)
tools. Another is that glass fiber by its nature is immune to electromagnetic radiation, can transmit data at high speeds, and can operate in extreme environments. All of these attributes equal a very attractive package that can bring benefit in most well monitoring scenarios.

Value of information from fiber optics
The value of information can be defined as the amount a decision-maker is willing to pay for information prior to making a critical decision. With the increased attention on unconventional reservoirs, the need for rapid subsurface learning has become increasingly important, with much of the decades of learning from conventional reservoirs not applicable. Unconventional reservoirs are being rapidly drilled and developed in both delineation and factory mode, with the windows of opportunity to make asset optimization decisions very short.

Operators are trying to optimize well spacing, stage spacing, and clusters per stage in addition to fluid chemistry, proppant selection, and many other variables. With such low recovery factors and high completion and stimulation costs, it is imperative that the optimal combination of variables be identified early in a project. No matter how many models are created to estimate what is going to happen, it is not until those models are calibrated with field data that they become truly valuable. With fiber monitoring being able to answer a multitude of questions without re-entering the wellbore, it is emerging as a very attractive option.

If operators look at how fiber-optic installations are being used in unconventional reservoirs today, they will see that the application is not limited to a single event or phase. In fact, most of the life cycle of a well is covered, from monitoring cement to monitoring completion to controlling stimulation to evaluating production and finally for identifying and monitoring restimulation candidates. The subsurface insight gathered by fiber optics during these different phases of a well is allowing operators to make quicker asset optimization decisions in shale plays.

Phases in the life of the well
Fiber-optics technology has an impact on each phase in a well’s life to see how the technology is currently being used.

Cementing phase: How long do we wait?
Once the fiber-optics cable is strapped and run behind production casing, it immediately becomes a source of valuable information. The DTS is used to evaluate the cement curing time so the operator knows when to pressure-test the well. The same analysis is used to identify the cement top.

Using a DAS, the operator is also able to track the downward movement of the wiper plug and verify that it has landed at the correct depth. Later, the cable can be used to look for cement integrity issues.

Completion phase: Is everything working correctly?
During completion, when balls are dropped to actuate sliding sleeves, an operator can acoustically track the balls as they travel down the well and verify that they are seated in the correct sleeve before running pumps up for the frac. If swellable packers are being used in the annulus, the fiber-optic sensor can verify the fluid top during the swelling period to verify that there is full coverage (Figure 1).

Similarly, in plug-and-perf completions an operator can see the depths at which the perforations are shot via the noise recorded on the DAS or the heat signature recorded on the fiber-optic temperature sensor. As pressure is applied to the completion equipment, information indicates the hardware is working as designed, and recommendations can be made to field personnel trying to verify hardware positions and fluid flow paths.

Real-time stimulation phase: Getting the best frac
As fracturing is started on a stage, operators can verify that plugs or packers are holding pressure and then identify which perforation clusters are taking fluid/proppant using temperature or acoustic sensing. The single most important use of fiber in stimulated wells is to track how many perforation clusters are taking fluid during the treatment (Figure 2).
In the field data that have been recently gathered, poor cluster efficiency has directly correlated to sparse fractures but long half-lengths. High cluster efficiency results in more uniform fracture spacing and half-lengths.

Once the operator knows where fluid is moving, it can actively use diverters to close off clusters that initially take fluid and force dormant clusters to initiate fractures. This method should create stimulation uniformity. With stimulation uniformity, stimulated reservoir volume (SRV) is optimized for each stage and the proper well spacing is set to eliminate stranded reserves. This type of optimization can make a marginal field into a solid producer.

In addition to untreated clusters creating increased (nonoptimum) frac spacing, this same phenomena could be created due to various other issues such as poor cement, poor stage isolation, or poor wellbore connectivity, to name a few. In field data that have been collected, as much as 10% of the treatment fluid for each stage can be seen passing by leaking plugs.

Reservoir temperatures that didn’t match the models used to formulate the fluid chemistry also have been observed. Inherently, it is assumed that formations are heterogeneous. But in Halliburton’s stimulation modeling, it is assumed that 100% of the completion hardware and fluid chemistry acts as designed. Fiber-optic sensing is now showing there is a lot more going on that doesn’t match the models than previously thought.

**Post-stimulation phase: Models have no value until calibrated**

Data from fiber optics is changing the definition of a calibrated model. In the past, microseismic data was used to calibrate the farfield frac growth of a model. The cluster efficiency data from fiber optics allows the estimation of the amount of fluid each cluster took during a stage. In certain basins the frac geometries and lengths drastically change with this ability to calibrate the frac model by modifying the near-wellbore fluid distribution across the clusters.

There are many other analysis steps that can be performed with fiber optics. For example, zonal isolation issues using DTS/DAS data can be used to evaluate leak through a plug, which allows an operator to back out that fluid volume from what is going into clusters in the frac model. All of these data further help in narrowing down recommendations around completion-optimization changes such as the number of clusters, holes per cluster, or cluster spacing.

A calibrated frac model has more accurate geometries and lengths, thus allowing operators to better evaluate well spacing (Figure 3).

Operators can also identify whether fluid from the current stage is interfering with any offset wells by looking at distributed temperature and pressure measurements in offset wells. That information can then be correlated with microseismic data to identify conductive highways that have been created between wells. All of this is very valuable for understanding well interference and critical for production history-matching.

**Production phase: Which stages in the well are producing?**

Using the same permanently deployed fiber-optic cable, an operator can monitor and analyze flowback and production from each stage without putting costly tools in the wellbore that would restrict flow and disturb readings. The ability to perform inexpensive production logging whenever desired allows operators to match production down to the cluster level.

Build-up tests across neighboring wells reveal stage-to-stage communication across wells. That is as opposed to not knowing the points of communication when build-up tests are performed just with surface pressure and comingled production data.

Production analysis is performed not only to build decline curves but also to understand stimulation effectiveness and be able to connect the dots between questions such as:

- What did our frac diagnostics show?
- What were the predicted flowback and production per stage from our frac diagnostics?
- What are the actual flowback and production per stage?

**Figure 3:** Differences between the original frac model and the calibrated frac model can be identified with fiber optics and microseismic data.
What is the production interference across wells and stages?

How are frac and reservoir models further calibrated?

Production analysis at the stage level highlights what areas of the well are candidates for re-frac operations. All this valuable information during the production phases drives optimization recommendations for future wells.

Planning for the next drilling pad

A well-calibrated frac model leads to a more realistic reservoir model. This allows analysis and modeling of the effective SRV as well as forecast production. A noncalibrated frac model fed into a reservoir model has major adverse impacts on figuring out well spacing and other variables in unconventional reservoirs.

A calibrated reservoir model allows performance of numerical reservoir simulation to history-match well performance and interaction of all wells (Figure 4). This improves the sensitivity study on well spacing, fracture lengths, conductivity, and fracture spacing along the wellbore, hence optimizing the evaluation of optimum completion and well-spacing strategy for the next pad.

What's next?

Development of fiber-optic sensing systems is not standing still. Step-changes in resolution and accuracy are occurring not only with the existing sensor types but also with new sensing techniques that are emerging that will make permanent installations even more valuable going forward. The application suite in this area is not yet mature. The more the industry digs into the raw data, the more value is being found.

Where the industry was happy with just a noise log from a DAS just a few years ago, it is now digging into the meaning of the frequency content of the data stream to tease out fluid density and other parameters.

The ability of the DAS to pick up and transmit data from other sensors is just now being investigated. Imagine being able to drop a sensor ball down a well that would take and acoustically transmit readings to a fiber line cemented behind casing. Fiber exposed to wellbore fluids can be used for spectroscopy or to identify the location and quantities of tracers in situ.

Recent tests have shown that a simple piece of glass fiber can pick up seismic energy and be used to create a vertical seismic profile (VSP) without the use of conventional geophones. The signal-to-noise ratio is poor at this time, but the sensor count is orders of magnitude larger than most conventional geophone arrays deployed downhole.

By packing such a wide variety of sensors into a single, simple package, the operator can replace multiple conventional systems while reducing monitoring complexity and cost. If operators want a horizontal production log, they can rent a data collection computer for a day rather than mobilizing a coiled tubing (CT) unit.

For a VSP, all that an operator needs is the vibe truck. For leak detection, rent or turn on another type of box. If the operator wants to upgrade its sensor to the latest technology, just change the hardware at the surface and leave the downhole sensor alone. All of the complex and expensive equipment is at the surface, while only glass and metal are downhole.

In some cases a completely new sensing technology can be added to the system by simply adding a new type of surface interrogator. Over the life of a well, this monitoring model has significant economic appeal. Although costs are coming down, even today most installations would pay for themselves if two or three horizontal logs were to be run during a well’s life. Permanent installations are just one option.

There are also requests for fiber-enabled wireline, slickline, and CT. Pumbable systems allow the fiber to be easily changed out as glass chemistry improves. In short, there are now many ways to “turn the lights on” downhole and make the earth transparent through fiber-optic sensing.