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In-Well Optical Sensing—State-of-the-Art Applications and Future Direction for Increasing Value in Production-Optimization Systems

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Abstract

For any production optimisation system to function effectively it must reliably receive quality data on demand. Over the past decade the reservoir monitoring industry has been addressing the issue of reliability including implimentation of a step-change technology – Passive Optical Sensing Systems.

Since the first installation of an in-well optical pressure gauge over 10 years ago, the industry has built a substantial track record with over 85 installations of P&T gauges and hundreds of DTS installations – acceptance is growing!

Initially Optical Sensing systems were expensive, complicated to install, and could only support limited applications. Today, they are on a par with electronic gauges with respect to performance, cost and installation simplicity. The state- of-the-art in optical sensing technology includes Bragg-grating based Pressure and Temperature sensors, permanent Distributed Temperature Sensing (DTS), Single- and Multiphase Flowmeters, and Seismic sensors.

This paper describes the operation of each of the sensing systems mentioned above, the data/information provided, together with details of application case histories. These range from simple single-gauge installations to complex wells with integrated pressure sensing, flow measurements and remotely activated zonal flow control – true Smart or Intelligent Wells.

The future direction includes even more complex intelligent completions and subsea deployments. Also high accuracy distributed array temperature sensing, optical distributed pressure sensing, sand detection, and distributed strain (e.g. for riser monitoring), are just a few of the new generation of sensing systems that are described in the paper.

As subsea continues to play an important role in our industry, the presentation (not included in this paper) will also include a synopsis from the SPE ATW "In-well Optical Sensing – Subsea Well Applications – Are We Ready?" held February 7th and 8th, 2006 in Galveston.

Introduction

To manage and optimize well production, operators need in-well monitoring systems that deliver high-performance measurements throughout the life of the well, and reliability without the need for routine maintenance or intervention. In the 1980's, the initial applications for optical sensing were focused on the military and areospace industries. The requirements that drove early development of optical sensing systems were not readily available in comparable electrical systems. These requirements included:

- **Small physical size,** allowing simple integration into small locations and embedding in composite structural systems.
- **Multiple sensing point and measurement types on a single fiber,** replacing multiple electrical sensors, instrument types and associated electrical wiring. This reduced system complexity and weight is critical in aerospace systems.
- **Silica with high temperature fiber coatings,** enabling the development of sensing systems for applications with operating temperatures in excess of 1,000°C.
- **High reliability,** maintained by having simple sensing elements at the measurement point and the sensor's instrument in a readily accessible location for servicing or repair.
- **Immunity to interference** from local radio or electrical transmission sources.
- **No spark hazard,** reducing the risk of fire.

Also optical communication systems significantly improve signal performance, data density and transmission distance.

These requirements also fit the needs of oil and gas in-well monitoring applications. Subsequently the first in-well optical Pressure and Temperature gauge was installed in a producing land well in the Netherlands in 1993. This initial system operated successfully for a period of more than 5 years. And so began the journey to broader acceptance of the technology in our industry. Through significant investment by service companies and operators in the development of sensor systems, a wider range of commercial optical sensing products and services has been brought to the oil and gas market.

1999 brought the first optical in-well seismic accelerometer application and the following year saw the first application of an optical in-well flowmeter, with a 3 phase meter application following in 2003. From the early beginnings in 1993 there are now applications with multi-zone Pressure and Temperatutre sensing, Flowmeters and Remotely Operated In-well Flow Control valves – true Intelligent or Smart Well applications facilitating production optimization at both the well and reservoir levels of operation.

The number of installations of optical sensing systems in our industry is growing rapidly and to-date there have been:

More than 100 Pressure and Temperature Gauge
Hundreds of Distributed Temperature Sensing
16 flowmeters (single and multiphase)
3 seismic arrays

optical sensing installations world-wide with over 1,000,000 feet of optical cable installed downhole, and more than 1,000,000 hours of cumulative operating time on these sensing systems – all illustrating how in-well optical monitoring systems have become key components of overall production optimization systems.

Optical Permanent Monitoring Systems

The ability to monitor and characterize a reservoir with a permanent monitoring system enables the operator's assets to be managed more effectively than with periodic well performance logging. Daily or weekly trends can be monitored enabling more efficient asset management through production optimization. Recognition of the value of this capability resulted in a rising number of electrical gauge systems being installed starting in the late 1980's and into the 90's.

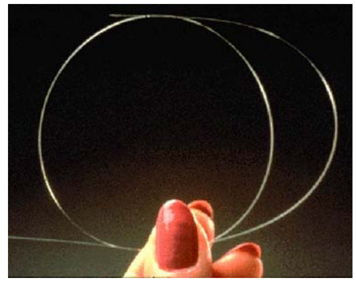
Although operators were realizing the value of permanent production monitoring and in-well flow control, some technology barriers still limited the application of permanent electrical-based sensing systems. Primary electrical sensing technology issues included limited operating temperature range and measurement performance, and poor reliability. Recognition of these limitations lead to the implimentation of a step-change technology – Passive Optical Sensing Systems. Not only does this optical technology address the shortfalls but it has expanded both performance and the types of measurements available. Today the following permanent optical in-well monitoring systems are commercially available:

- Pressure and Temperature
- Distributed Temperature Sensing (DTS)
- Single and Multiphase Flowmeters
- Seismic sensors.

providing a wide variety of data and information on well and reservoir performance.

Fiber Optic Cable

Fiber optics can be defined as a medium for carrying information from one point to another in the form of light. Unlike the copper form of transmission, fiber optics is electrically passive. A basic fiber optic system consists of a transmitting device, which generates the optical signal; a fiber optic cable, which carries the light; and a receiver, which detects the transmitted light signal.



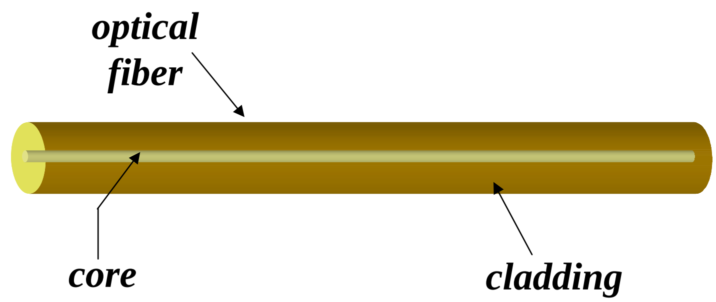


Fig. 1 Fiber optic cable.

There are two types of fibers used in the industry:

1) Single-Mode (SM) is used for high-bandwidth and long-length applications. This type allows for only one mode of light to travel within the fiber. Single-Mode fiber is used for flowmeters, pressure and temperature gauges and seismic sensors.
2) Multi-Mode (MM) is used for lower data rates and short-length applications. This type allows more than one mode of light. Multi-Mode fiber is used for Distributed Temperature Sensing (DTS) only.

The cable serves to protect the fiber against external factors such as tensile forces, lateral pressure, humidity, expansion, bending, etc. The two most-commonly-used-size downhole fiber optic cables are produced in 1/4" and 1/8" diameter sizes.

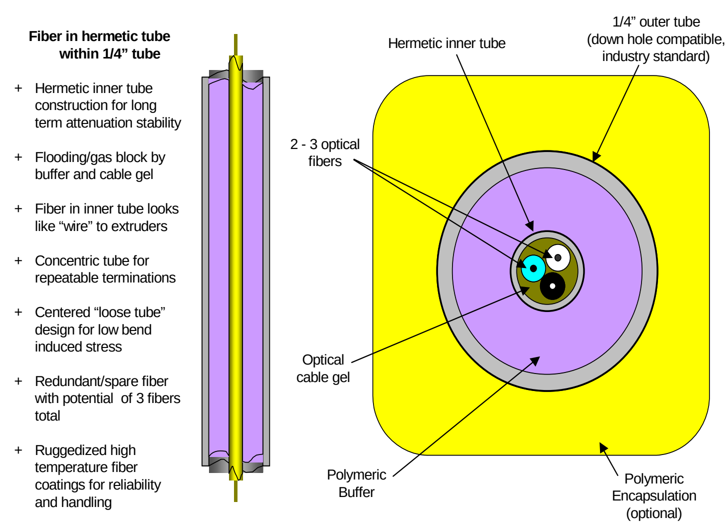


Fig. 2- The ¼" downhole fiber optic cable.

Bragg Gratings

Bragg Gratings (BGs) or gratings are wavelength dependent mirrors that can be inscribed into the glass core of an optical waveguide. BGs are created by exposing the core of the waveguide to high power UV laser beams and thereby inscribing a shift in the refractive index in the glass core. The inscribed refractive index is tailored in such a way that it has a grating that corresponds to a certain wavelength of light. A broadband light source is used to illuminate the fiber and sensor (where the input spectrum of the light has a bell-shaped curve). As the broadband light beam passes through the gratings, a portion of the beam continues to travel (transmitted component) whereas a portion is reflected back. The reflection occurs only at the wavelength of the gratings.

BGs are used in the flowmeter, P/T sensor, and the seismic sensors, however, the application of the BGs in these sensors are significantly different. The P/T sensor relies on a change in length of the BG, and its corresponding shift in reflected wavelength to determine the temperature and pressure. The flowmeter and seismic sensors employ a method called an interferometric sensing where the BG's operate as mirrors and the length of the fiber between the BG's acts as the sensor. The interferometric sensing system uses a laser (rather than a broadband light source for the P/T sensor) pulsed in a series of accurately timed blocks. By demodulation of the reflected signal, the dynamic pressures of the fluid can be determined from the change in length of the sensor.

Pressure and Temperature

Concurrent with the introduction of optical communication systems in the late 1980's, techniques were being explored that would enable light to be manipulated to provide physical and chemical measurements. Strain and temperature measurement systems for structural health monitoring of aerospace and naval systems were one catalyst in the development of optical sensing technologies. The early to mid 1980s saw the development of foundational sensing technologies, based on interferometers and later, Bragg gratings, which is the technology used in the overwhelming majority of in-well optical Pressure and Temperature sensing system installations.

With the success of the first land well installation in 1993, which utilized the Optoplan FOWM (Fibre Optical Well Monitoring) system, a field trial for the first platform-based FOWM system was conducted in 1994 at the Gyda field operated by BP in the Norwegian sector of the North Sea with an operating temperature of greater than 150 degrees Celsius. The first subsea optical permanent monitoring system was installed in 1996 in the Guillemot field. This system consisted of a subsea optical instrument incorporated in a subsea instrumentation pod and an optical wet-mate for a vertical subsea tree. Three subsea monitoring wells at Shell's Heron field and one subsea well at Shell's Egret field followed in 1998-99. These four installations leveraged the optical pressure gauge's long-range (>20km) capability and placed the sensing instrument on the surface. The sensor was monitored from the surface instrument through an optical cable that was integrated in the umbilical and through a vertical wet-mate connector to the pressure gauge located in the well. This configuration reduced the complexity of the subsea monitoring system by replacing the subsea instrumentation pod with an instrument that was readily available at the surface. These installations were successful in demonstrating both the optical system hardware, including optical cable, instrumentation, and connectors, and the processes required to install optical systems in North Sea environments. Three additional FOWM systems were installed in high-temperature platform wells in 1998 and 1999. The early pressure transducer (P/T) technology used in OptoPlan's FOWM system was based on optical exitiation and interrogation of a micro-machined resonator that incorporated extremely complex mechanical packaging. The mechanical packaging structure slightly changed over time due to the soldering material being exposed to the reservoir pressure and temperature, causing the reflected signal from the resonating element to deteriorate.

Based on these early experiences, development of an advanced sensing technology platform based on BG's was initiated. The BG technology allowed the sensor to be incorporated directly into the optical pathway, simplifying the sensor to a single monolithic glass structure. The stable glass was separated from the unstable mechanical transducer sensor designs to overcome the issues with sensor deterioration observed in the early FOWM systems. Multiple BG's representing different sensors could also be linked on a single fiber using a technique called Wavelength Division Multiplexing (WDM).

The first field trials for systems with this new BG-based sensor were conducted successfully in 1999, demonstrating that the sensing element issues experienced with the FOWM sensor element had been overcome.

The optical pressure gauge was designed to have a level of measurement performance comparable with current electrical quartz-based pressure gauges, however with significantly improved measurement stability and reliability. The simple, monolithic structure of the optical pressure element (**Fig. 3**) meets the stability requirement by amongst other things, eliminating any dissimilar materials or bondlines in the pressure measurement structure. Testing to validate the sensor's stability at 150°C at 5,000 psi began in June 1999. Today, with over six years of testing, the pressure gauge has demonstrated no detectable drift. This compares to a standard specification of +/–2 psi per year for typical quartz gauges. The optical sensor's proven stability has provided reservoir engineers with the means to monitor reservoirs throughout their operational life, using a pressure gauge that maintains its accuracy without needing to correct for drift. In addition, the gauge also supports long-term reliability. Electrical gauge reliability is adversely impacted by a high component count for the sensing and transmitter elements. Conversely with the optical gauge integration of a single piece pressure and temperature transducer with a simple transducer pressure housing delivers the smallest component count solution and highest reliability capability. Extensive Highly Accelerated Life Testing (HALT) demonstrates a projected lifetime of the sensing fiber-optic pressure gauge of more than 20 years.

One of the commercially available optical Pressure and Temperature gauges has a pressure rating of 20,000 psi and a temperature rating of 175 ºC. The pressure accuracy and resolution are 0.01% Full Scale (±2 psi) and usually less than 0.03 psi, respectively. The temperature accuracy and resolution are ±0.1 ºC and less than 0.02 ºC, respectively.

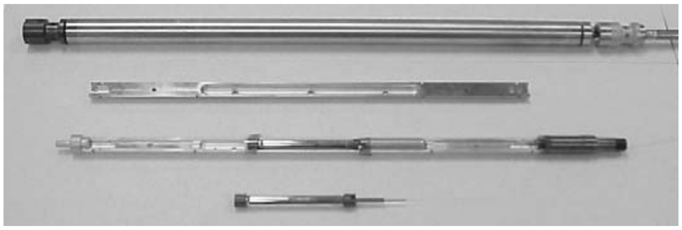


Figure 3 Optical pressure gauge assembly (optical pressure transducer highlighted)

The first production well to use the Bragg grating-based optical pressure gauge was installed in deepwater in the Gulf of Mexico in April 2000, and it continues to operate reliably today.

Multi-zone pressure and temperature monitoring was introduced in November 2003 with a three-zone pressure-monitoring system in Nigeria. This system provides zonal reservoir monitoring in support of a zonal flow control system. The number of optical pressure gauges that can be supported by a single cable in a well continues to increase, with current products supporting up to nine gauges in a well.

Distributed Temperature Sensing (DTS)

Distributed physical measurement techniques were developed from technologies used to characterize the optical transmission performance of communication systems. These distributed measurement systems use time-of-flight monitoring techniques, whereby measurements along a fiber are derived from the timing and characterization of return signals from pulses of light transmitted through the optical fiber. Initial applications were developed for the industrial sensing market, including detection and localization of temperature measurements for chemical plant pipeline monitoring and fire detection.

DTS monitoring was the first commercially successful optical monitoring service offered in the oil and gas market. Companies such as Sensor Highway (subsequently Sensa and now part of Schlumberger) and Pruett Industries (now part of Halliburton) provided the means to install an optical fiber into standard hydraulic control lines located along the completion string to provide temperature logging of wells. This simple technique of installing optical fibers in the well opened the market for temperature logging of wells with optical DTS instruments. Operators could temperature-log a well without stopping production. In 2001, Weatherford's permanent downhole optical cables were enabled with DTS capability, providing a common cable to support optical P/T, flow and seismic measurements and temperature-logging capabilities. Previous DTS systems were offered as a stand-alone optical measurement, with pressure measurements supported by electrical gauge systems. This typically required two hydraulic control lines and an electrical control line for the pressure gauge. The ability to support multiple optical systems on a single cable means that the addition of DTS capability to an optical monitoring system requires no additional downhole equipment. Compared with multi-line systems, this common optical cable system saves both operational time and product cost. In addition, with the multi-mode DTS fiber designed into the cable, issues that could potentially distort DTS measurements (such as uncontrolled strain levels in fiber pumped into hydraulic control lines) have been designed out of the system.

Some uses of DTS data are:

- Thermal profiling of well
- Production and injection profiling
- Identification of well problems
- Monitoring water, gas, steam breakthrough
- Gas lift optimization
- ESP monitoring

DTS Installation Case History

Fiber optic Distributed Temperature Sensing (DTS) is being used for a variety of well monitoring applications around the world. One operator in the Middle East has installed a DTS system in an open hole, dual lateral water injection well to determine and monitor injectivity distributions. The system was installed below the production packer across the 6000 ft horizontal section of the main bore on a 3½" stinger tailpipe to a total depth of over 12,800 ft. The DTS cable also traverses the junction of a second open hole branch of the well.

The DTS system has been used to conduct special "warmback" tests of the well to determine the injection profile. During a warmback test, water injection is halted, and the DTS system is used to monitor the thermal profile of the well as a function of time after shut-in. By analyzing the rate of "warmback" of the well toward the original geothermal temperature profile, the injectivity of different portions of the well can be determined - sections of the well with higher injectivities will warm back slower that sections with low injectivities. In the case of this operator, an analysis of the warmback DTS data taken after one month of injection clearly showed that most of the water was being injected into a high permeability zone just below the casing shoe at the heel of the well. Very little water was being injected into the second lateral or the toe of the main bore. This allowed well stimulation treatments to be designed and performed. Analysis of DTS data from subsequent warmback tests indicated that injectivities along the length of the well were becoming more balanced.

Single And Multi-Phase Flowmeters

Single and multi-phase optical in-well flowmeters address the same value proposition as electrical flowmeter systems—providing real-time zonal flow and phase fraction measurements near the producing region. In addition, optical flowmeters share the benefits of optical pressure gauges, including the long-term measurement stability and high reliability provided by a passive optical sensor. Furthermore the in-well flowmeter is based on sonar technology and as such does not require any sensors or sensor windows in the flow stream. The flowmeter is completely non-intrusive (see **Fig. 4A**) and offers full through-bore access and also no permanent pressure drop along its length. It measures the momentum averaged flow velocity (volumetric flow rate) and the acoustic velocity in the flowing mixture. The speed of sound is directly correlated to volume fractions of oil, water and gas. The flow velocity and speed of sound are deduced from measurements of dynamic pressures in the flow stream. These pressures are processed using array-processing algorithms similar to those used in Sonar applications.

The flowmeter is ideal for multi-phase flow and can measure liquid and/or gas flow with no changes in hardware.

Applications for downhole flow data are numerous:

Reduce surface well tests and facilities: The ability to measure flow rates downhole may eliminate the need for a surface test separator, thereby significantly reducing the facilities requirements on the platforms. It also eliminates safety issues associated with conducting periodic well tests. Furthermore, real-time flow data from the well will immediately identify production anomalies.

Zonal production allocation: In multi-zone completions, data from downhole flowmeters is used to allocate production to or from individual zones. This is achieved with a flowmeter placed above each producing zone and/or with flowmeters between each zone. Real-time determination of zonal rates is found by difference of flow rates measured between zones.

Commingled production: Regulatory agencies may require production data from individual zones in a field. Therefore, downhole flow data allows for commingled production from multiple zones.

Early identification of productivity decline or production anomalies*:* Changes in well productivity due to gas/water breakthrough or downhole scale formation can be identified on an individual well basis and remedial action can be planned in a timely manner.

Well ramp-up: Real-time downhole flow and pressure data allow completion and production engineers to better visualize and control well clean-up, reduce uncertainty in drawdown, and reduce the duration of the ramp-up period, thereby bringing the well on-line quicker and potentially at a higher rate.

Direct determination of productivity index: Real-time downhole flow rate and pressure data allows determination of a well's productivity index at any time without need for intervention.

Figs. 4 A & B - Optical flowmeter.

The Optical Flowmeter can be configured as a single-phase or as a multiphase flowmeter. The single-phase flowmeter is equipped with sensors that directly measure the flow velocity. The multiphase flowmeter is equipped with sensors for flow velocity and sensors that measure the acoustic velocity in the flowing mixture. The acoustic velocity is an excellent indicator of volumetric fractions of oil, water, and gas in the flowing mixture. The measurement section of the flowmeter consists of multiple sensors distributed along the length of the pipe.

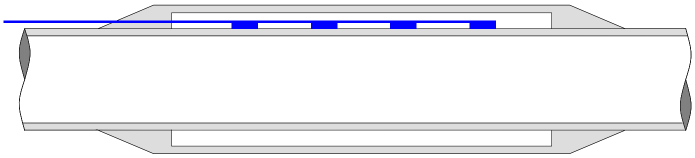


Fig. 5 - Flowmeter sensor array on a single optical fiber.

The sensors from both arrays are multiplexed along a single, continuous optical fiber and are interrogated from surface installed instrumentation. This information is then processed, utilizing techniques developed for the sonar array processing industry and other applications, to extract the speed of sound and the flow velocity. A schematic of the cross sectional view of the meter is shown in **Figure 5**. Note that the sensors are not coupled to the outside sleeve thus ensuring that the flowmeter is unaffected by annular flow.

An optical P/T gauge is usually integrated with the flow instrumentation as shown in **Figure 6**. The combined gauge makes measurements of pressure, temperature, bulk velocity and speed of sound.

In a 2-phase configuration, the flowmeter is deployed with at least one P/T gauge. In a 3-phase configuration, the flowmeter is deployed with two P/T gauges separated vertically in the well (or a single ΔP gauge where there is insufficient vertical separation). The vertically separated gauges measure the absolute pressure at each location. The pressure difference between the gauges is corrected for frictional pressure loss using the flow rate from the flowmeter such that an accurate hydrostatic head and mixture density can be found.

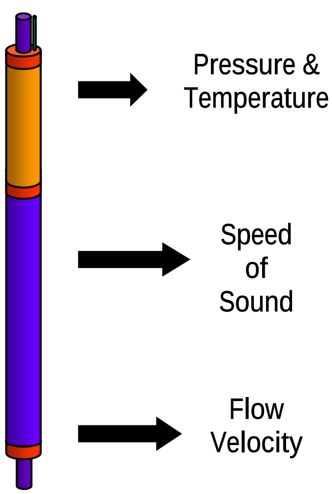


Fig. 6 -Flowmeter with integrated P/T sensor.

For intelligent completions, the downhole flow sub can be designed with multiple slots for hydraulic or fiber optic cable bypass.

The only commercially available alternative to the optical meter is the Venturi based flowmeter using dual quartz pressure gauges. Although Venturi flowmeters are widely used and well understood, they have significant limitations.

Flowmeter Performance

Excellent accuracy and repeatability has been demonstrated in lab and field tests. Single-phase accuracy is typically better than ±1% (95% CI) and has been calibrated to within ±0.25%. In multiphase flows, lab tests have demonstrated flow velocity accuracy less than ±5% over the full range of oil, water, and gas volume fractions (95% CI).

Flowmeter in Multiphase Flow

The optical flowmeter is, by itself, a 2-phase flowmeter suitable for liquid/liquid or liquid/gas flows. In two-phase flows, the speed of sound is determined and is correlated to the volume fractions of oil and water or liquid and gas. The total flow rate is calculated from the measured momentum averaged flow velocity. The component flow rates are calculated by the volume fractions and total flow rates by applying a proprietary multiphase flow model.

Flowmeter Instrument

The flowmeter surface instrumentation is integrated into a standard rack designed for an air-conditioned control room. Furthermore, the flowmeter instrumentation is integrated with optional pressure and temperature instrumentation, optional DTS instrumentation, network accessible storage and other auxiliary equipment. The entire system is controlled by Weatherford's Reservoir Monitoring System (RMS) software.

The flowmeter is designed to provide real-time continuous measurements of injection or production flow rates. Real-time rates are transmitted to SCADA/DCS system and the instrumentation system supports most common communications hardware and protocols. The system also has local storage of raw data and measured results and is accessible through a "thin-client". The thin client is a web browser based system (requires no special software) and allows for password protected data access to real-time and historical data on the users intranet.

Flow Meter Installation Case History A

An optical flowmeter was installed offshore Trinidad in March 2002. The flowmeter is continually providing real-time high quality measurements of downhole pressure, temperature, and oil, water, and gas flow rates. The 3½" meter has an ID of 2.922" and an OD of 5.5" and was installed at a measured depth of 12,114 ft and a deviation of 71°. The installation went as planned, with no unscheduled rig time required. Data connectivity is also available via the client's wide area network linked to an external network accessible storage server located in the flow meter instrumentation unit. All flow and diagnostics data is stored on this server and allows for password-protected access from the users desktop anywhere on the client's wide area network. The network connection also allows technicians to perform remote system diagnostics and to access and change certain data acquisition parameters remotely from any client office.

In operation the flowmeter determined that the free GVF downhole increased from 0% to 60% in the first month of production, possibly indicating gas coning. The downhole GVF at the current time is in excess of 99% and the test separator GVF is in excess of 98% (at approximately 1000 psi). Total mass flow rate measured by the flowmeter agrees with well test results to within ±5% for nearly all data points over a 15 month period. The gas rate is well within ±10% for all well tests from mid April 2002 to June 2003.

Flow Meter Installation Case History B

A 4-zone intelligent Water Alternating Gas (WAG) injector was installed in a platform well in the Norwegian sector of the North Sea, in May 2004. The completion includes three Weatherford optical single-phase flowmeters with integrated P/T gauges, one 4½" and two 3½". Furthermore, the completion includes one on/off and three variable downhole valves for controlling injection rates into each of the four zones. The completion was run in 9 $^5/_8$" casing and a 7" liner with the three downhole flowmeters set at 2561, 3138, and 3340 meters. The total injection rate for the well has reached up to 40,000 bbl/d.

The combination of downhole valves and flowmeters allow full control and monitoring of zonal injection rates and has proven to be a valuable tool in managing reservoir pressures and optimizing production for the client. After more than one year of operation during water injection, all the valves and the optical monitoring equipment are functioning satisfactorily. It is estimated that up to half of the well's value creation during its expected lifetime is due to the downhole instrumentation and control system.

The main objective of this particular intelligent completion was to be able to selectively direct both water and gas injection into zones where it is most needed and monitor the rates into each zone at any given time. An important feature was the ability to choke back injection into zones that draw undesirable amounts of water and to be able to close zones where gas injection is not beneficial. Finally, remote control (onshore) and monitoring of sleeves and sensors were considered very useful and cost-effective functionalities. An essential part of this last matter is that the flow and P/T data are easily accessible for the production engineers to monitor the equipment. A major challenge was to identify equipment that could withstand a reservoir temperature of 125°C and temperature swings down to 15-30°C during water injection. It was also a design challenge to establish flowmeters that could measure a wide range of water and gas rates with no changes in hardware.

Measurements at various choke positions have demonstrated excellent agreement between surface injection rates and downhole measured rates.

To achieve the same degree of reservoir management without the installed equipment in this well, at least one additional well (to a typical cost of at least $10 million) would be required together with a frequent and costly wireline-logging program.

Seismic Sensors

The optical seismic system is specifically designed for permanent, reliable, and repeatable active borehole seismic imaging and continuous passive monitoring, including microseismic monitoring. In addition the system was designed such that it requires no additional intervention within the candidate well after the completion. This system has undergone significant environmental qualification and field testing, and is now undergoing further deployments worldwide. The optical seismic sensors are readily installed on production tubing or casing and offer high reliability by containing no downhole electronics.

Permanent in-well seismic sensing allows for a wide range of reservoir imaging and monitoring applications. Traditional borehole seismic logging surveys have been utilized for many years for imaging around wellbores, principally as an exploration tool. The ability to permanently install seismic detectors downhole greatly expands the utility of in-well seismic sensing, particularly in the production phase. Recent advances in 3D data acquisition, processing and image visualization allow geoscientists to "see" the reservoir and to be virtually immersed into the subsurface, tracking wellbores directly into producing targets. Repeat, or time-lapse (4D), seismic allows for the dynamic monitoring of the producing reservoir.

To date, 4D seismic imaging predominately involves repeat surface-based seismic surveys. Information on fluid movement, sweep efficiency and bypassed hydrocarbons in a producing field is just some of the value gained from 4D seismic. While extremely useful, 4D surface seismic surveys can suffer from poor repeatability due to changing environmental or data acquisition parameters. Periodically, a temporarily deployed seismic logging sensor array is used in conjunction with the surface survey for enhanced imaging and calibration. Though well access for the logging device is difficult, the borehole information can greatly enhance the surface data.

With permanent in-well seismic sensors installed in wellbores, not only can 4D surface seismic data be readily calibrated to the well production data, but used independently, in-well seismic sensors are a cost effective means for ascertaining information away from the wellbore on an ongoing basis. For example, 4D Vertical Seismic Profiles provide high resolution imaging of the reservoir up to several thousand feet from the wellbore. To help image the reservoir at a scale that better represents the real complexities of the producing formations, very high resolution crosswell seismic surveys can potentially be more efficiently planned with permanent sensors, as opposed to having to deploy multiple logging tools in adjacent producing wells.

In-well seismic sensors also help monitor production away from the wellbore through, for example, the monitoring of microseismic activity related to remote fluid movement or formation compaction. Permanent seismic sensors can also monitor other production activities, such as nearby drilling. The range of permanent in-well seismic applications will grow as more wells are instrumented. In combination with pressure, temperature, flow and phase fraction monitoring, and downhole flow control, in-well seismic sensing will help reservoir and production engineers dynamically manage and enhance reservoir production.

The optical seismic sensors use a technique known as interferometry. As shown in **Figure 7**, two semi-reflective wavelength-selective mirrors known as fiber Bragg gratings (BG) are written into the fiber core on each side of a length of sensing fiber. Light is directed into the fiber from a source located in the surface instrumentation. When the light reaches the first BG, a fraction of it is reflected while most of the light is transmitted and propagates through the sensor fiber to the second BG. The process is repeated, with some light reflecting back to the first BG and most of the remaining light transmitting through the second BG. Light in the form of the reflected wavelengths ultimately reaches and is detected at the surface instrumentation. When the sensing fiber is strained, the optical phase difference between the reflected light from the first BG and the second BG generates an interference signal that represents the amount of strain. Depending on the length of fiber, interferometric sensors are capable of detecting much smaller strain changes than Bragg grating sensors and so are more suitable for measuring small earth strains.

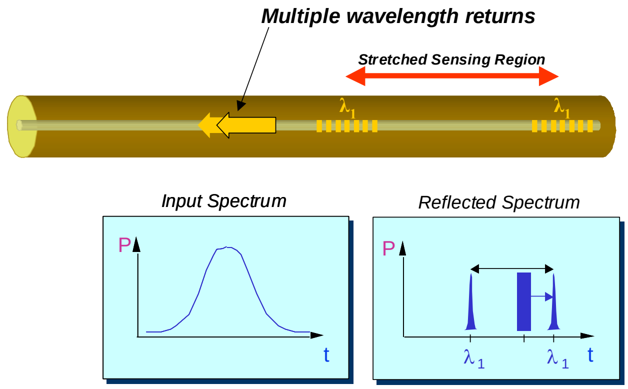


Figure 7 Bragg Gratings in Interferometer Sensor Configuration

The fiber interferometers are configured around a proof mass to form high fidelity, miniature accelerometers. Because the annulus space surrounding the production tubing and casing is limited for permanent tubing-conveyed installations in an oil/gas well, a slim line 3C accelerometer tubular package has been designed and deployed in multiple applications. In order to optimize sensor vector fidelity, scale factor, sensor bandwidth and also shock resistance within the packaging constraints, two different accelerometers were designed with matched performance in order to accurately measure particle acceleration in three directions with high uniformity, independent of mounting direction. One sensor was designed to measure acceleration along the longitudinal (z-axis) direction, and another sensor was developed to measure particle acceleration in the x and y (radial) directions. One longitudinal and two radial accelerometers, orthogonally configured, are used to obtain 3C measurements along a single tube. The instrumentation package is a fiber optic based seismic sensor system based on optical interferometric and WDM principles. **Figure 8** shows a schematic of a 16-channel instrumentation system (eight laser wavelengths and two fibers) and a compatible 8-channel optical sensor array network. The intrinsic performance of the above system is very good, with total harmonic distortion (THD) and channel cross-feed along a single fiber sensor line are significantly less than 0.1 % (-60 dB) and 1 % (-40 dB) respectively. The system can be expanded to 24-channels using three fibers.

Figure 8 Seismic Instrumentation Package

The deployment process (**Figure 9**) for the in-well sensor package allows a multi-station array to be integrated into the tubing with precise spacing and results in no significant increased risk to the completion and minimal disruption to the tubing running services. The packaged 3C optical sensors are installed in ruggedized, protective carriers. These carriers also contain an active coupling mechanism that maintains the sensor module safely retracted during run-in-hole operations. The sensor module is then released at the desired depth through active or passive methods.

The 3C stations are linked by a ruggedized optical downhole cable at the factory to fit the desired completion. The carriers are then loaded onto a Deployment Drum that allows transportation of the array. The drum is then fixed onto an Array Spooling Unit in the field location prior to installation. The spooling unit is positioned on the rig floor
during array installation only and can be removed during other operations.

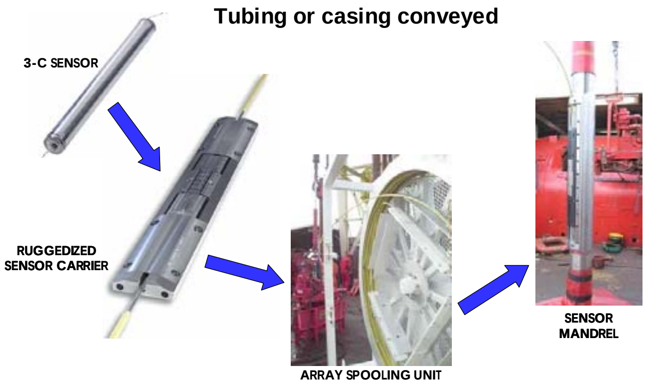


Figure 9 – Seismic System Deployment

Seismic Installation Case History

In southwest France, natural gas is stored underground in a shallow, porous reservoir in a populated area. A good knowledge and understanding of the storage process was very important for the field operator. In addition to using well logging information, the operator had been looking into new seismic technology to increase understanding of the location and behaviour of the stored gas. Because surface seismic imaging is poor in this area (and because repeated surface seismic studies are expensive and disruptive), the technique is not suitable for reservoir monitoring. For this reason, the operator installed an optical seismic sensor system in an observation well. The system is production tubing conveyed, with sensor stations located outside the tubing. This causes no disruption to the regularly planned wireline logging surveys, and repeat seismic imaging is easily accomplished using a single surface seismic vibrator as an energy source. The high-resolution in-well seismic results have showed the gas/water boundary that has been undetectable with surface seismic, allowing reservoir engineers to more accurately map the location of the gas in storage.

Anciliary Products

Besides the sensors themselves surface instrumentation, in-well cables and protectors, wellhead outlets, dry and wet connection systems for both tubing hanger/subsea and in-well needs and other components are required to install an optical gauge. These products are now proven, readily available and used to support the optical sensing system installations worldwide.

Project Planning And Installation

Valuable experience has been gained in installation processes since the first installation back in 1993.

As in any well completion operation, successful deployment of fiber optic systems depends not only on the durability and reliability of the hardware, but also on careful and efficient planning and execution of the installation. Planning for deployments involves extensive preparation and coordination among the customer, the vendor, and the installation company. A project team is formed consisting of representatives from each company. The team includes the completion engineer, production engineer, reservoir engineer, instrumentation engineers and installation specialists. Prior to deployment, regular, weekly teleconferences are held to coordinate planning and logistics. Several site visits to the installation location and face-to-face meetings at the operator's office are also conducted to ensure a common understanding of the specifics of the completion and installation procedures.

Also crtical are appropriate Qualificiation and Factory Acceptance Tests (FAT's) as well as Site Integration Testing (SIT) prior to installation.

Future Optical Sensing Capabilities

With the value of permanent optical sensing systems becoming increasingly recognized in our industry there comes the desire for more accurate data and more information concerning well and reservoir performance. The following are some areas where development work is in various stages of preparation from concept demonstration to approaching field trials.

Array Temperature Sensing (ATS)

The ATS system is based on proven optical cane based BG technology used in the Optical Pressure and Temperature gauge and takes advantage of the WDM capability of BG's. The ATS system is under development with field trials planned in the second half of 2006. Multiple temperature sensors are incorporated into a 0.25" diameter cable system with the location of the sensors defined by location temperature sensing requirements. The ATS sensors are designed with a temperature resolution performance in the order of 0.01C. The high temperature resolution of the ATS could potentially provide the capability required to monitor the very small temperature changes associated with a gas leak.

Distributed Pressure Sensing (DPS)

A DPS system would be required to measure actual pressure along its complete length or over a designated interval of interest. The technology for developing such a system has long existed but what has prevented development of in-well systems in the past is a lack of a clear value proposition. Cost and time to develop could be high, as could the cost of commercial systems when compared to currently available optical sensing systems (e.g. P/T, and DTS). Also a key technical parameter that requires specification is the resolution of pressure measurements.

Brillouin scattering can be used for distributed strain sensing, since the frequency shift of the backscattered light will depend on the local strain of the fiber. So Brillouin scattering can be used if pressure is made to effect the strain in the fiber. However, high accuracy pressure measurements (<1 bar) may prove difficult to attain. There are techniques to enhance the pressure-induced strain in the fiber, such as using special fiber coatings which would need to be evaluated. Temperature compensation is required, and a combination of Brillouin and Raman backscatter detection could in principle be exploited to measure both distributed strain/pressure and temperature.

There are also optical fiber polarimetric techniques which can be exploited for distributed pressure sensing, where the pressure affects the local polarisation properties of the fiber (birefringence) and special techniques, typically backscattering measurement techniques can be used to determine the spatial distribution of these properties and hence pressure distribution along the fiber.

An alternative to the truly distributed pressure sensing techniques exploiting backscattering along a sensing cable, is to use an array of wavelength or time-multiplexed BG sensors positioned along one or more optical fibers, with the BG's being positioned at predetermined locations to form a quasi-distributed sensing network. Tens of BGs can be multiplexed along the same fiber with spatial separation down to a few centimetres.

Sand Detection

Sand production in oil and gas wells is a serious problem that can cause frequent shut-ins for cleaning up separators, serious erosion problems and can even "kill" production if the well bore fills up with sand. It is therefore of great interest to accurately detect the presence of sand and quantify the amount of sand produced to maximise the oil/gas production rate and still maintain sand-free production, and in the case of Smart Wells, ensure the continued reliable operation and sealing integrity of remotely operated interval control valves in multi-zone wells. Distributed downhole sand monitoring systems could also measure the individual sand production from each zone. From development work on optical in-well flow and fraction meters encouraging data has been found that supports the opinion that this technology has promise in detecting sand production/flow inside the production tubing. There are some major challenges in such a development project, for example quantitative sand measurement and evaluation of how gas in the production fluid will affect the detection of sand.

Distributed Strain e.g. for riser monitoring

Incorporation of Optical Sensing Systems in Expandable Completions

Some of the key issues and challenges to be addressed for this system are:

- accounting for expansion
- provision of cable protection
- positioning of the cable – inside versus outside the expandable section

Subsea Applications

Several optical sensors were successfully installed and tested in subsea wells in the 1990's but we have yet to see broad use of this technology in the subsea environment.

In some applications it will be possible to include an optical fiber in the umbilical from subsea operations to topsides thereby providing a direct link from the in-well optical sensors to the instrumentation topsides. This option is not always available and therefore the instrumentation needs to be packaged in a subsea POD cannister and somehow integrated with the subsea controls infrastructure. In addition subsea tubing hanger optical wet connector systems are required for both vertical and horizontal tree types and for single and multiple fiber pin connection options.

With the success of optical sensors and the increased importance of subsea producing assets around the world it is important that the industry moves quickly towards addressing the issues associated with subsea deployment of optical sensing systems. An SPE ATW is to be held in Galveston on February 7th and 8th , 2006 "In-Well Optical Sensing – Subsea Well Applications – Are We Ready?". In the presentation of this paper a synopsis from this ATW will be included.

Conclusion

The number of types of optical sensing systems available to support production optimization programs is already significant and with more already in various stages of development the portfolio will be even healthier in the coming years.

The increase in popularity of optical systems will contimue to be driven by proven reliability and measurement stability. This is especially true for those operators who need a monitoring system that will last for the life of the well. For obvious economical reasons this is particularly important for multi-zone intelligent wells and subsea operations. Optical sensing also provides optimization and production management options that are not readily available with other technologies.

So what was once seen as a "pipe" dream (**Fig. 10**) is now truly a reality!

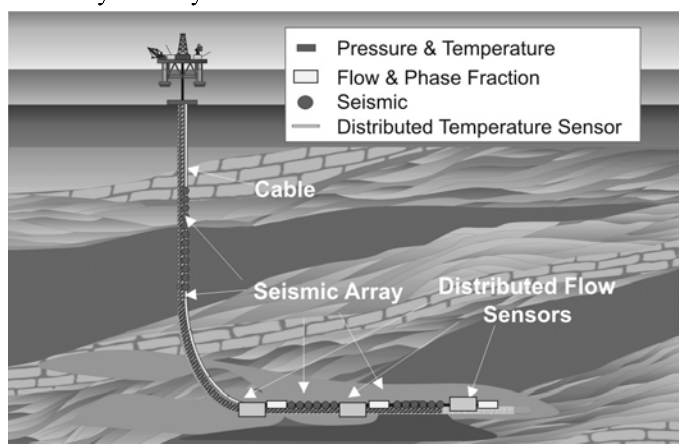


Figure 10. Optical Permanent Monitoring System