Despite the credit crunch, worldwide subsea activity is still forecast to grow rapidly. In its recent 2009 subsea forecast, Infield Systems indicated that subsea drilling and completion expenditure will more than double to USD 80.5 billion between 2009 and 2013, from a total of USD 31.9 billion during the period from 2003 to 2007 (Infield 2009). Coupled with the increase in expenditure, Infield forecasts 3,222 subsea wells to be installed from 2009 through 2013, vs. 1,958 wells installed between 2004 and 2008. A large percentage of these wells will require sand control.

In market-share terms, Infield forecasts that Africa will remain the largest sector, representing 29% of the forecast capital expenditures between 2009 and 2013, followed by North America (25%), Latin America (19%), and Europe (13%). The remaining spending will be spread between Australasia, Asia, and the Middle East and Caspian region.

Despite this growth in the number of subsea wells, the expense of subsea well intervention often leads to insufficient reservoir information for accurately understanding reservoir connectivity, drainage, and flow assurance. This has led to an industry need for real-time data from sensors located on the sandface. For those wells requiring sand control, an additional constraint is that sandface sensors must be deployed on a separate completion run.

Reservoir-Monitoring Challenges in Dual-Stage Completions

Most wells with sand control use completion components that are deployed in multiple stages. This presents a challenge to achieving measurements from monitoring equipment located in the lowest stage of the completion because sensor power and data are required to be transferred across the junction between the lower and upper completion stages.

Consequently, reservoir monitoring in dual-stage completions has generally been limited to measurements of pressure and temperature near the production packer in the upper completion. These types of sensors cannot distinguish the downhole conditions of individual zones. Placing the sensors at the sandface, where the fluid...
enters, would take permanent monitoring to the next level because it enables operators to better understand the flow from each producing zone. This has now been achieved by an operator in southeast Asia who has deployed the Schlumberger WellWatcher Flux digital-sensor array system onto the screens of six openhole gravel packs in a subsea gas field. Data from these sensors has been transmitted to shore during cleanup, with the output used to make interpretations of permeability and cleanup efficiency for each producing zone.

**Sandface Temperature Monitoring**

Fluids enter a wellbore at different temperatures and, after entry, they mix with fluids from lower zones so that the wellbore temperature becomes a weighted average. The weighting depends on the ratio of incoming fluid to that being produced from lower zones. Measuring the temperature along the producing sandface enables the flow contribution from the different zones to be calculated (Brown 2005). The resulting flow-allocation profile does not provide as much information as a complete suite of production logs, but the sandface data arrive in real time, so changes in the flow profile can be identified as they occur, without any interruption in production.

Optical distributed temperature systems are well known in the industry and, recently, have had good success in dual-stage completions in Baku (Pinzon et al. 2007). The Baku setup employed a multimode optical fiber that was pumped down a control line and through a wet mate, which bridged the interface to the lower completion stage. The pumped fibers provided continuous temperature logs across each sandface. Unfortunately, optical fibers cannot be conveniently pumped down the well in subsea applications, so a new solution was required.

In subsea applications, transmitting power and data from sensors in the lower completion to the upper completion has been a major challenge. Many previously employed options require rotating the upper completion to align with cable in the lower completion, which is not straightforward in large water depths. Attempts to establish electrical contacts have proven prone to corrosion or obstruction by debris that inhibits communication. Optical fibers...
have been embedded into permanent downhole cables but, for application in the gravel pack, these still require orientation and a downhole wet mate.

**Inductive Coupling**

The objective of a recent engineering development program was to create a new deployment system that directly addressed subsea constraints. The award-winning system has three distinct components: a miniaturized digital temperature-sensor array that can be transported to the rig spooled onto a reel; a large-bore coupler mechanism to provide wireless power and communication between upper and lower completions; and a reservoir-modeling package to interpret the temperature response in terms of reservoir performance and flow allocation.

Instead of using individual gauges on mandrels, this new system uses miniaturized digital sensors distributed along a single spoolable bridle. Building upon laboratory-reference thermometry, platinum-resistance thermometers have been miniaturized and incorporated into a 0.75-in.-diameter sensor module. The sensors have no moving parts and have been subjected to rigorous temperature, shock, and vibration testing, which qualifies them to meet the long-term data-transmission requirements. Multiple safety systems have been implemented in the firmware and hardware so that no single point of failure in the array can bring down the entire array. Specific attention was given to the robustness for deployment. For example, the sensor housing was welded to a cable, which then was subjected to maximum bending of more than 800 times, during which no damage occurred at the connection between the cable and the sensor housing. The last testing stage was to verify continuity before packing the system for transportation to the rig. Operator approval was obtained at each stage of the testing (Fig. 1).

The telemetry is conveyed by an electromagnetic field that is largely immune to debris and tolerant of downhole vibration during production. A solenoid coil in the upper completion is aligned by a snap latch so that it mates with a second solenoid coil in the lower completion. Electrical currents in one coil induce an electromagnetic field and hence electrical currents in the other coil. The system can transmit power down to the lower completion and provide two-way communication between the upper and lower completions. This enables data to be transferred uphole and instructions, such as a change in sampling rate, to be sent downhole.

The original design for this patented system came from earlier uses of inductive coupling to retrieve data from downhole tools. In contrast with those applications, the new reservoir-monitoring system is designed to be permanently installed and provide data over the life of the reservoir. It requires no modifications or nonstandard connections to the subsea tree and can be integrated with standard completion equipment from multiple vendors (Fig. 2).

**System Testing**

Significant emphasis was placed on qualification testing during the engineering-development phase. A qualification-test plan was developed in cooperation with the operator, which defined all critical devices to be tested during the product-development phase—ranging from component level to subassemblies and system-level devices. This document was updated throughout the life of the project and demonstrated the ability of the final product to meet specific functional requirements while operating in expected environmental conditions.

Qualification was carried out on both mechanical and electrical components. For example, electronic components such as silicon dies were functionally tested at 365°F during long periods for an aging test. Pressure, vibration, transverse, and vertical shock tests were applied at subassembly level before integration. Functional tests under pressure and temperature cycles were performed on the final assemblies to ensure the proper operability. Measurements of sensor drift were made at 257°F for more than 12 months to confirm that this drift would be negligible in reservoir applications.

In addition to individual assembly tests, multiple integration tests were performed during the engineering-development phase. A factory-acceptance test took place, wherein all of the hardware was assembled as it would be in a downhole environment but with nonwelded electrical splices between components. The system included a bridle on a reel, a female inductive coupler, a male inductive coupler, two quartz pressure-temperature gauges, subsea computer-aided design, and surface-acquisition systems.

**Field Results**

The world’s first deployment of the system was in a deepwater gas field offshore India. This system deployment was the first of six such systems required for the field.

For the first installation, a coupler was attached to the top of a sensor bridle containing 18 miniaturized sensors clamped to the exterior of gravel-pack screens, and the assembly was deployed as part of an openhole, gravel-pack completion. Standard packers and gravel-pack tools were employed. The system became activated when a mating inductive coupler was landed as part of the upper completion. Surface indication of landing was provided by incorporating mechanical feedback into the lower assembly. With the coupler components in position, the tubing hanger was landed into the horizontal tree. Upon activation of the electrical penetrator, high-resolution temperature data were then immediately available across the length of the sandface—which was an industry first for a subsea producing well. No additional penetrations were required in the tree.

![Upper and lower completion assemblies ready to be transported to the rig. From left, upper pressure-temperature gauge, contraction joint, lower pressure-temperature gauge on the upper completion, and female coupler-control module on the lower completion.](image-url)
Temperature data were passed along the upper completion to the subsea tree to the offshore production platform, and from there to the company’s headquarters in Mumbai, where they were combined with thermal-modeling software—which used measured temperatures to establish permeability and flow-allocation profiles (Fig. 3).

Upon activation of the system, the interpreted permeability in a lower zone was found to be different from what had been expected, which led the operator to make modifications to the lower completion before cleanup. The operator will use profiles from multiple wells to monitor channel connectivity and reservoir depletion. This will help planning of subsequent infill drilling, so that reservoir drainage across the field can be optimized.

Summary
Digital measurements of sandface parameters have been made by means of inductive coupling to provide power and data communication from the upper to lower completion during cleanup of a subsea well. Data were transmitted in real time during the well cleanup. The system demonstrated its compatibility with standard equipment from multiple vendors, including sand screens, gravel-pack tools, packers, surface-controlled subsurface safety valve, and subsea trees. With minimal complexity, the system will result in an increase of reservoir information for the operator and an overall mitigation of risks inherent to subsea production.

References

Water cut when completing zones close to the oil/water contact, field-operator Salym Petroleum Development has found that good placement of swellable packers around known water-producing zones has greatly limited water cut. It was determined that an investment of USD 15,000 in additional swellable packers could prevent deferred production at a cost in excess of USD 200,000 per month. Since the initial test of swellables in 10 wells within the field, Salym Petroleum has made carefully planned and positioned deployment of swellable packers a standard practice throughout the field.

Swellable elastomers now are being used to support cement in wells around the world and in some cases as a cement alternative. They also are allowing operators to perform innovative new well completions and adopt cost-saving drilling approaches, such as horizontal sidetracking with through-tubing rotary drilling that already has proven successful in the North Sea.

One of the key benefits of swellable elastomers is that they can be deployed for the life of the well. It does not matter when the elastomer is actually expanded; performance will not be affected. Unswelled packers lie dormant in the well, ready to react when water enters the well either through the formation or through microannuli that form in cement. For example, if water breakthrough occurs 10 years or more into a well’s production life and a water-swellable packer is in place, it will swell to provide the required isolation, just as if it had been installed only days before. Even in cases were swelling already has occurred, the built-in, reserve swell capability of the elastomer can quickly deploy, should hole diameter unexpectedly increase.

With a careful, engineering-led approach, operators can secure significant cost savings and increased productivity by deploying swellable elastomers in their wells, and this technology is likely to spread considerably in well completions around the world.