

Reservoir Fluid Properties Measured Downhole

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Over the years, oil companies have started recognizing that a disturbing number of reservoir- and production-management problems could be traced back to a single root cause—inadequate understanding of reservoir fluid properties. After performing detailed analyses and calculations, scientists and engineers were able to quantify the cumulative economic effect of these shortcomings in reservoir knowledge. This provided encouragement to pursue a solution, but the process was difficult.

Although it may seem obvious, a prerequisite to accurate reservoir fluid analysis is the ability to acquire a rep-

resentative sample of downhole fluids. In the late 1980s, a promising piece of the puzzle was developed—a pumpout module that could be incorporated in modular formation-dynamics testing tools. Until this time, highly contaminated fluid samples had been the norm because previous formation-testing tools were a closed system, whereby invaded mud filtrate was produced into a segregated sample chamber before an unknown quantity of formation fluid could be sampled. The pumpout module enabled the field engineer to pump undesirable fluids from the formation—via the sample probe—directly into the borehole, ensuring sample

acquisition was performed after the produced fluid had been cleaned up to lower levels of contamination.

However, a breakthrough came in 2006 with the introduction of a focused probe tool that consistently provided a formation fluid sample virtually free of contamination from the invaded drilling mud filtrate. By using dual pumps to withdraw both the reservoir fluid and the surrounding mud filtrate simultaneously into separate flowlines, the mud filtrate could be diverted into the borehole, while the relatively pure stream of formation fluid could be obtained for measurement and collection by the field engineer in real time.

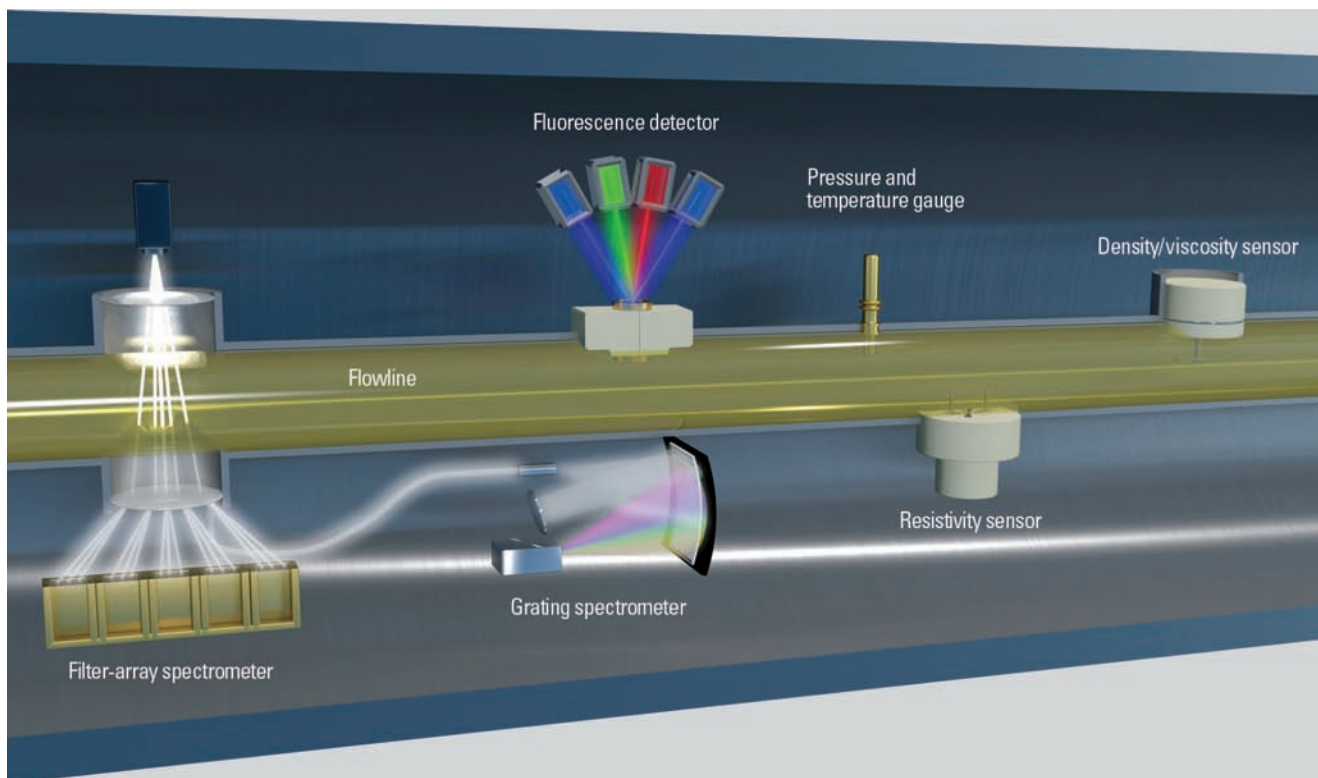


Fig. 1—A schematic of the downhole fluid sensors used in the in-situ fluid analysis system.

Variety of In-Situ Measurements Enabled

Once it became possible to acquire a pure sample, representative of formation fluid in reasonable time under downhole conditions, a variety of real-time measurements became feasible. Advanced instrumentation was packaged by Schlumberger into its modular formation-dynamics testing tool to perform nine separate field-selectable measurements, characterizing and describing produced fluid to enable real-time downhole analysis. The technology package, called the InSitu Fluid Analyzer system, can measure

- Hydrocarbon fluid composition ($C_1, C_2, C_{3-5}, C_{6+}$)
- Reservoir fluid gas/oil ratio (GOR)
- Reservoir fluid CO_2
- Reservoir fluid density
- Reservoir fluid viscosity
- Reservoir fluid pH
- Reservoir fluid color
- Reservoir fluid fluorescence
- Reservoir fluid resistivity

Flowline pressure and temperature are measured in addition, which is necessary to position the above fluid properties at the correct point in the pressure-volume-temperature (PVT) space.

Performing quantitative measurements on the downhole reservoir fluid, the system can provide laboratory-quality data in real time. The emphasis is on metrology for a high degree of accuracy and resolution, which brings a rigor to interpretation of downhole fluid properties and provides reliable data to a wide range of engineering disciplines. This allows contemporary workflows of reservoir characterization to progress, enabling the variation in reservoir fluid properties to be mapped across the reservoir column—or even the entire field—with a real-time technique for profiling the fluid system. This extends the traditional approach of sampling one depth per producing unit to analyzing fluid connectivity across multiple zones, without being limited by the number of sampling bottles.

The in-situ fluid analysis system includes a 16-channel grating spectrometer for hydrocarbon composition, with accuracy comparable to instruments used in PVT laboratories worldwide; a 20-channel filter-array spectrometer for CO_2 , pH, and color; a fluorescence and gas detector to detect if the hydrocarbon falls below saturation

pressure; and devices to measure formation-fluid density/viscosity, water resistivity, and fluid pressure and temperature (Fig. 1).

The principle of optical absorption spectroscopy is employed by both grating and filter-array spectrometers to increase the accuracy of the compositional analysis, resulting in quantifiable fluid data. Real-time calibration of the dual spectrometers is performed downhole to ensure continuous measurement accuracy in transient conditions. Accuracy has been verified by comparison of measured results with an extensive laboratory fluid database.

General benefits include an enhanced compositional range, independent separation of ethane (C_2) to derive C_1/C_2 ratio, and crosswell or multiwell downhole fluid analyses for reservoir studies. Increased CO_2 and pH accuracy facilitates corrosion- and scale-risk analyses, as well as water fingerprinting between aquifers, connate water, water-based mud filtrate, or injection water. In the field-acquisition system, flowline contamination-monitoring accuracy has also been advanced.

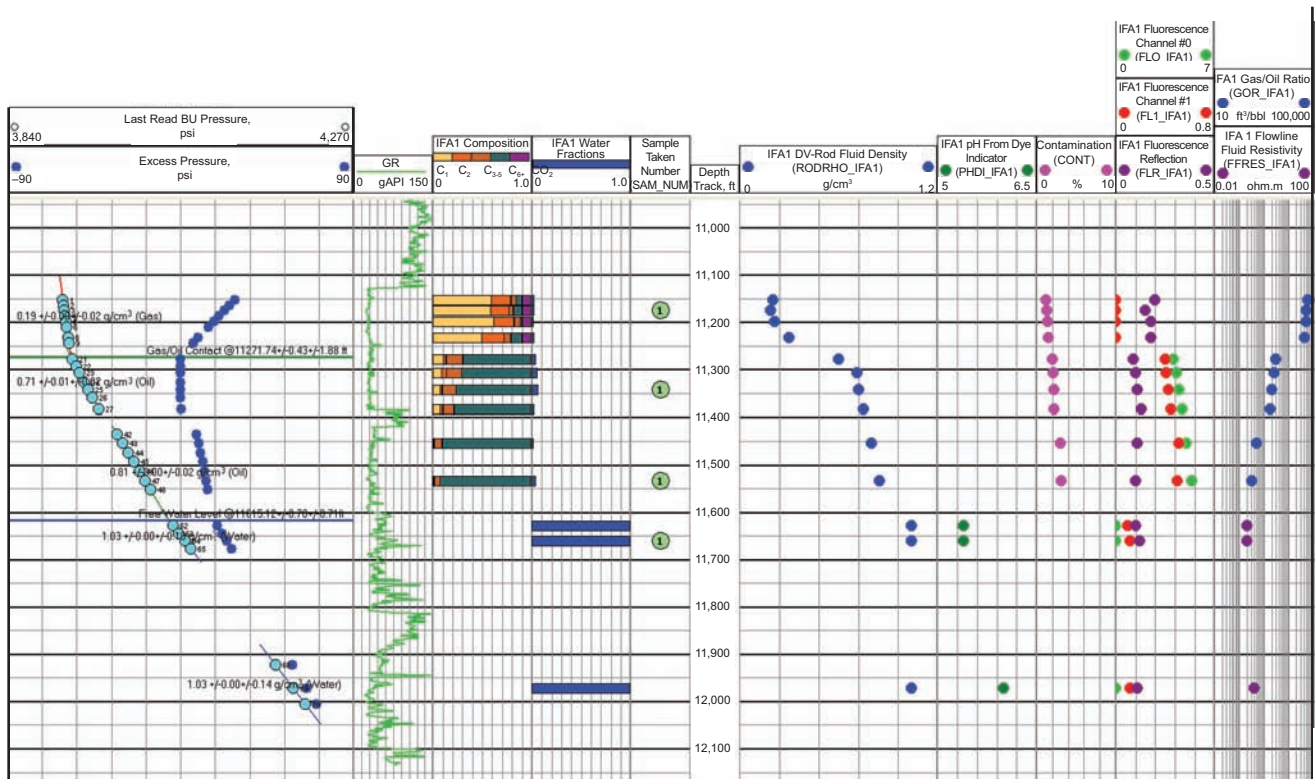


Fig. 2—Real-time quality-control and interpretation software presentation combines pressure and fluid analyses from multiple sources. Compositional-gradient data (track 3) acquired by the in-situ fluid analysis tool provide critical reservoir information affecting completion and production decisions.

These measurements open a new window for description of thinly bedded zones, low-resistivity pay, characterization of transition zones in carbonates, increased accuracy in calculation of reserves, equation-of-state fluid modeling, identification of compartmentalization, and quantification of compositional grading within the reservoir column.

Field data are presented in a format that simplifies interpretation and report generation, facilitated by real-time quality-control and interpretation software. The universal application of in-situ data can be seen in an example correlating pressure and fluid analysis from multiple sources to give a clearer picture of fluid compositional transition in the reservoir (**Fig. 2**). Tests taken only a few feet apart can indicate dramatic changes in composition. For example, condensates near the critical point can exhibit similar pressure gradients, but markedly different fluid compositions.

Three Case Histories

A reservoir with near-critical fluids in the North Sea required foot-by-foot analysis to map the spatial distribution of fluid properties accurately to make appropriate completion decisions and to size the production facilities. Was the reservoir charged with volatile oil or retrograde condensate? This is an increasingly common challenge in many appraisal scenarios, and prerequisite knowledge is needed before the design of a production test. In this field example, real-time in-situ density and GOR data were used in the reservoir simulator to optimize the sampling process. The in-situ fluorescence measurements identified the reservoir fluid as retrograde condensate, subsequently enabling representative zonal characterization and defining the required parameters for further development.

In a deepwater appraisal well offshore Nigeria, accurate fluid density and composition were critical elements affecting decisions regarding subse-

quent logging and drillstem tests. The precise fluid gradients obtained enabled delineation of fluid contacts and ruled out any reservoir compartmentalization, while providing downhole compositional analysis and fluid mobility information. The operator received virtual real-time guidance for optimizing subsequent operations.

An appraisal well for another offshore development was used to make final production-strategy decisions and plans for a 60-mile subsea pipeline. In-situ pH measurements are particularly valuable because of the irreversible changes to water chemistry when fluid-sample pressure and temperature are altered from downhole conditions during flashing in the laboratory. In this case, the operator used in-situ pH measurements to identify unexpectedly high CO₂ concentrations, leading to a revised design of surface facilities and choice of pipeline material to withstand the corrosive environment. Laboratory tests did not reveal the presence of corrosives or scal-

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ing potential because of pH alteration in retrieved fluid samples.

Dynamic Earth Models Improved

Reservoir engineers depend on dynamic earth models to enable prudent reservoir-management decisions, but often these models have been based on inaccurate static models because the reservoir fluid properties incorporated were not always representative, or correct. Predictions of a reservoir's propensity to produce wax or asphaltene depend upon accurate compositional analyses. Although there are independent ways to measure paraffin, asphaltene, or hydrate, a complementary methodology helps remove all doubt from the predictions.

Possibly one of the most important benefits of in-situ analysis is the ability to confirm reservoir compartmentalization by means of color and GOR measurements obtained in real time, while the modular formation-dynamics testing tool is still in open hole. This allows guesswork to be eliminated from the

assumption of zonal connectivity. This is particularly important in risk reduction for deepwater offshore fields.

Summary

The in-situ fluid analysis system performs new downhole measurements at reservoir conditions in real time, providing a degree of accuracy and resolution comparable to laboratory measurements. Results are corroborated through the combination of multiple sensors using different physics of measurement, giving confidence for application in a wide range of oilfield disciplines.

Downhole fluid analysis addresses three major flaws in contemporary workflows:

- The reservoir model is normally implemented later in the development cycle, after costly decisions have already been made on completions and facilities. Production-test data are used to test the reservoir model; however these results are usually from commingled zones, thereby masking the

individual fluid contributions of producing layers.

- The dynamic model is presumed to be essential to understanding the reservoir; however, the static model (on which the dynamic model is based) may be flawed without timely fluid analysis and representative compositional data.

- Typical deepwater workflows determine prediction errors by computer simulations, not by measurements. This introduces an element of unacceptable risk, particularly in high-cost development scenarios.

Today, these workflows can be optimized by means of real-time data acquisition and analysis, while there is still time to remediate problem scenarios or before irreversible decisions are taken. The advantages of accurate downhole fluid analysis for identifying compartmentalization and quantifying fluid variation across the reservoir will have lasting economic impact on the appraisal and development of fields.

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