Learning curve leads to production gains

NORTH AMERICAN KNOW-HOW
Learning curve leads to production gains
Fluid fingerprinting – a real-time analysis tool for deep water

New in situ fluid analysis combines with asphaltene nanoscience to deliver a major breakthrough in reservoir reconnaissance.

Just as modern detectives use trace evidence for forensic analyses, geoscientists have developed ways to better understand and classify reservoir fluids using nanoscience to measure compositional gradients in oil columns. In this case, the “trace evidence” is the asphaltenes.

Particularly in offshore field development, produced fluids may be commingled at seabed gathering stations and manifolds before being fed into high-capacity production risers or umbilicals. Although it is well established that over time gravity will result in separation of crude oil components of different densities, accurate in situ reservoir fluid measurements were unavailable to measure the resultant compositional gradients.

Why are gradients important?
Critical information such as compartmentalization, connectivity, and fluid gradients can make the difference between economic success and disaster, especially in high-cost deepwater developments. In crude oil, for example, one of the easiest parameters to understand – viscosity – can be materially affected by even small amounts of asphaltene. Therefore, it is important to know if asphaltenes are present and, more importantly, to understand how they are distributed across the oil column. The commercial viability of an oil reservoir could be completely compromised by a tar mat, effectively impairing reservoir drive.

Better technology to the rescue
Recent advances in downhole fluid sampling and analysis have allowed scientists and engineers to solve the asphaltene puzzle by enabling the accurate measurement of asphaltene content variation across the oil column.

One component of the MDT Modular Formation Dynamics Tester formation testing system is the InSitu Fluid Analyzer (IFA). Using a combination of sensors, clues of asphaltene content and distribution are gathered. The clues include measured gradients in coloration, fluid density, gas/oil ratio (GOR), hydrocarbon composition, fluorescence intensity, and viscosity, all measured in situ.

It is not necessary to retrieve all samples to surface to obtain this information. Instead, fluid property measurements are performed downhole and transmitted to surface in real time.

When the real-time IFA data are coupled with asphaltene equation of state (EoS) models, reservoir complexities such as flow barriers, complicated fluid distributions, and compartmentalization can be resolved. Gas-liquid equilibriums are treated with cubic EoS. However, asphaltenes are solid and must be treated with a different EoS. A proper colloidal EoS has been constructed – the Flory-Huggins-Zuo (FHZ) EoS. With downhole fluid analysis data and with the new FHZ EoS, it is now possible to determine if asphaltenes are distributed in thermodynamic equilibrium across a reservoir.

Dead oil samples from a single oil column are shown with the IFA Module schematic of the MDT tool. The new Flory-Huggins-Zuo Equation of State successfully models the asphaltene (color) gradient in the oil column (continuous color scale). (Top image courtesy of Shell, all other images courtesy of Schlumberger)
Approach has been recognized to provide seven orders of magnitude more stringent analysis for connectivity than pressure communication alone.

**Convincing evidence from deep water**

In one case study, an offshore clastic reservoir comprised three sand layers penetrated by two wells. Light hydrocarbons acquired from Well #1 gas stream had globules of precipitated asphaltene, indicating that the asphaltene in the reservoir was destabilized. The operator wanted to address critical reservoir uncertainties that could be causing the production limitations. Among the hypotheses to be tested were reservoir discontinuities, potential downward oil rim, accurate location of fluid contacts, and asphaltene deposition. These conditions were ideal for the IFA application combined with asphaltene EoS modeling.

Formation pressure testing showed that each sand reservoir exhibited different pressures. Pressure data had been acquired over the years using a variety of sensors ranging from older strain gauges to the more accurate and precise quartz gauges. In addition to depth and pressure uncertainties, other sources of error were suspected, including supercharging during the pressure measurements and compositional fluid density variations within each sand.

History matching of production indicated impaired well performance compared to expectations from logs, cores, and offset wells. Either greater heterogeneity or asphaltene dropout was suspected. A variety of scenarios were hypothesized to explain well performance, but none were unequivocal.

**Asphaltene EoS modeling solves the puzzle**

Combining relevant real-time data with a robust EoS model revealed the interrelationships that exist between solution gas and solids in reservoir crude oil. Since the asphaltene molecules are so small, gravity has little effect on them and no gradients are apparent. As they agglomerate, however, they gain mass and density, which causes an inexorable settling over geologic time, initially reflecting GOR changes in the column and eventually lumping into nanoaggregates and clusters. The disequilibrium rate is a function of gas-charging. In the case wells, the middle sand gas charging was caused by a late biogenic gas influx.

Accordingly, the asphaltenes formed lower in the column. In fields that experience gas charging, large clusters form, migrate downward, and accumulate toward the base of the oil column. These clusters are still only 5 nanometers in size and are stably suspended in the liquid without hanging up on rock surfaces. An excessive gas charge can reduce the remaining asphaltene in the oil column to very low levels. The increased asphaltene concentration at the base of the oil column can exceed the dissolving capacity of the oil and deposit a tar mat. Indeed, the interplay between the two colloidal asphaltene particles caused here by asphaltene instability due to gas charging is a key mechanism of tar mat formation.

A major stride forward has been to combine the Flory-Huggins-Zuo model with real-time reservoir fluid analysis from the IFA tool. The IFA data thus combined with cubic EoS models and Flory-Huggins-Zuo Eos Models can evaluate key issues including connectivity of the sand layers, variations in fluid composition, GOR, asphaltene content, API gravity, and fluorescence intensity.

The result of the combined analysis is significantly enhanced determination of fluid properties distribution, reservoir connectivity across the sand bodies, and assessment of the potential presence of a downdip oil rim. This has helped optimize field performance by eliminating the guesswork regarding the conditions affecting production. It also proved that the combination of downhole real-time acquisition of properties with asphaltene science is effective in assessing reservoir connectivity on a field scale.