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Advanced Fluids Key In IOR Economics

By Deepankar "Dee" Biswas

PLANO, TX.–The methods of oil extraction become more technically complex and costly for each successive phase of a producing reservoir's life cycle. By the time a well reaches the tertiary recovery phase, the operational objective shifts from optimizing reservoir pressures and sweep efficiencies to altering the physics of how oil is trapped within the rocks in order to improve its extractability.

Most thermal, gas and chemical tertiary recovery processes seek to decrease the interfacial forces holding oil in pores within the rock formation, and to modify reservoir and oil properties to release oil more easily.

Chemical flooding methods inject polymer, surfactant and/or alkali formulations to modify reservoir and oil properties to release oil more easily, including reducing the interfacial tension (IFT) between water and oil to release oil molecules from pores within the rock formation, altering wettability, and decreasing the mobility ratio and viscosity difference between water and oil phases. In conventional reservoirs, implementing chemical flooding after primary and secondary production phases typically recovers an additional 10-20 percent of reserves.

Despite the significant enhanced recovery potential, the capital costs, geologic risks and long cycle times associated with chemical EOR methods have understandably left operating companies reluctant to invest in projects. However, a new approach offers an alternative to traditional chemical flooding with dramatically lower costs, risks and cycle times. It takes advantage of an advanced surfactant-solvent "nanofluid" derived from citrus fruit that is a more effective, nontoxic alternative to traditional surfactants.

This environmentally friendly surfactant-solvent system is a thermodynamically stable and balanced combination of water, naturally occurring solvent, an alcohol co-solvent, and a nonionic surfactant that appears optically isotropic and maintains high contact efficiencies even at low concentrations of 0.1-0.5 percent by volume. It has proven effective as an additive in a variety of applications, including remediation, fracturing fluids, restimulation, acidizing, and even drilling fluids. The technology is showing promise in ongoing field trials to increase production in tertiary recovery applications at minimal incremental cost.

In mature waterfloods with appreciable residual oil, injecting the nanofluid additive enhances incremental production by reducing IFT and altering wettability, as well as by lowering oil viscosity for improved oil mobility by solvent partitioning in in-situ oil. Moreover, in tertiary recovery applications in fields already undergoing water injection and approaching the economic limits of secondary recovery, the method can demonstrate increased oil production within only six to nine months, rather than the years commonly required in traditional chemical floods.

Self-Forming Nanostructures

The surface tension at a plain oil/water interface typically is of the order of 25 dynes per centimeter (dyn/cm). Emulsions formed by mixing oil, water and non-microemulsion-forming surfactants typically are characterized by IFT values on the order of 20-50 dyn/cm. In contrast, the nanofluid additive can achieve IFTs below 1 dyn/cm.

The additive consists of multifaceted, self-forming "nanodroplet" structures that pack together. When dispersed in an injected fluid, the nanostructures dilute to spherical, oil-swollen micelles that each carry the three components of water, oil and surfactant. Literally, millions of these structures accumulate at interfaces, providing faster alterations of surface phenomena such as surface and interfacial tension, contact angle, and interfacial viscosity at the oil/water interface.

When applied to oil reservoirs, the additive is dispersed into the treating fluid prior to injection into the wellbore. There is sufficient lessening of the IFT between the additive treating fluid and the oil and/or water phases contacted by the treating fluid in the wellbore and formation. The reduction of IFT overcomes the capillary forces that "trap" oil or water in the porous medium.

The combination of these modes of action outperforms organic solvents and surfactant systems. The additive's mode of action may be threefold:

- The penetration of the oil or water layer through the solvent additive mechanism;
- The microemulsification of the oil and water components into the aqueous phase; and
- The water-wetting of the underlying solid surfaces through the surfactant action.

The technology has the added benefit of altering the IFT between the rock and the fluid with oil. As the additive-containing fluid enters the formation, the rock fluid contact angle is altered to a mixed-wet state. This results in a lower required pressure to move the fluids from

FIGURE 1A

Pilot 1 3-D Grid

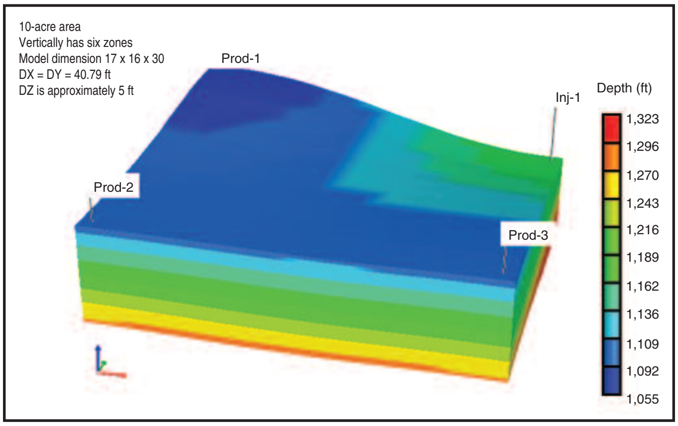
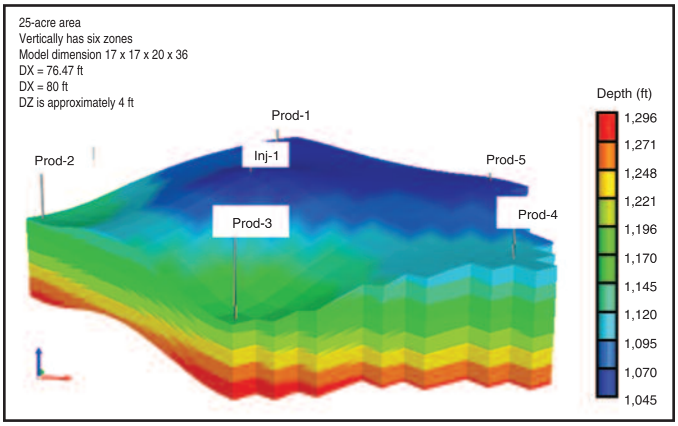


FIGURE 1B

Pilot 2 3-D Grid



the pores. It also can exhibit a lower water saturation, creating a higher relative permeability to oil or gas.

Versatile Applications

When utilized at an optimal concentration as a solvent/surfactant/aqueous fluid, the additive produces a versatile treatment system with many simultaneous functions and applications, ranging from drilling and stimulation to intervention and EOR. It improves maximum penetration, contact efficiency, and dispersion of various paraffins, asphaltenes, scales, bacterial films, concentrated gel filter cakes, formation fines, and drilling fluids.

For example, the technology was used to increase production in a well that was on a severe decline and had become uneconomic. The D sand reservoir appeared to suffer from paraffin and formation-fines plugging and condensate coning. These problems also increased workover frequency.

Prior to being treated with nanofluid, production averaged less than 30 barrels of oil and 10 Mcf of gas a month. After treatment, monthly production immediately increased to more than 260 barrels of oil and 800 Mcf of gas. The treatment costs were amortized in less than one week, and the operator realized a 14-to-1 return on investment in the first 90 days. The well required no more workover maintenance during the succeeding 12 months.

Mixing the additive with acid allows uniform fines suspension in wellbore breakdown treatments to aid in solids/damage recovery and improved oil flow. The additive retards the reaction of inorganic and organic (hydrochloric/acetic) acids and provides efficient reaction kinetics control to generate longer, narrower wormholes. The nanofluid also maximizes the breakdown and dissolution of heavy or complex hydrocarbons such as paraffins and asphaltenes when pumped with acid, carbon dioxide, water, and hydrocarbon-based carrier fluids.

It controls and maintains ideal reservoir wettability, resulting in effective surface cleaning without permanent alteration to maximize subsequent treatment efficiency. Moreover, the technology provides significant friction reduction in aqueous, acidic, CO_2 or nitrogen stimulation fluids when pumped through treating tubulars, and improves injectivity, especially in polymer floods where sustained oil production is directly proportional to maintaining injection rates at a constant pressure.

Preferential Flow Paths

The biggest challenge in testing the feasibility of any new chemical technology in a tertiary recovery mode in watered-

FIGURE 2A

Increased Oil Cuts (Pilot 1)

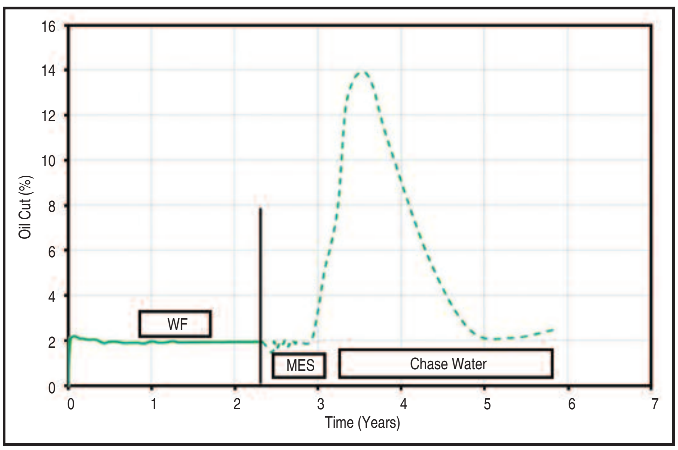


FIGURE 2B

Increased Oil Cuts (Pilot 2)

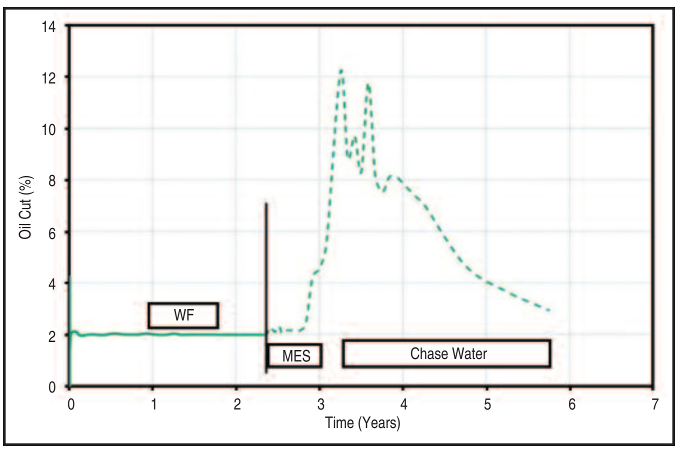


FIGURE 3A

Pretreatment Oil Saturation in Thief Layers

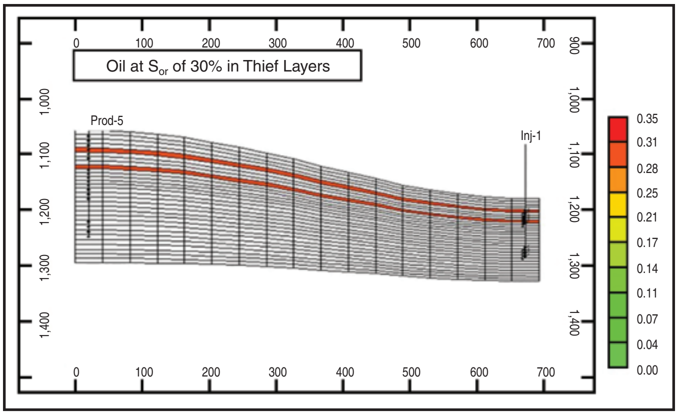
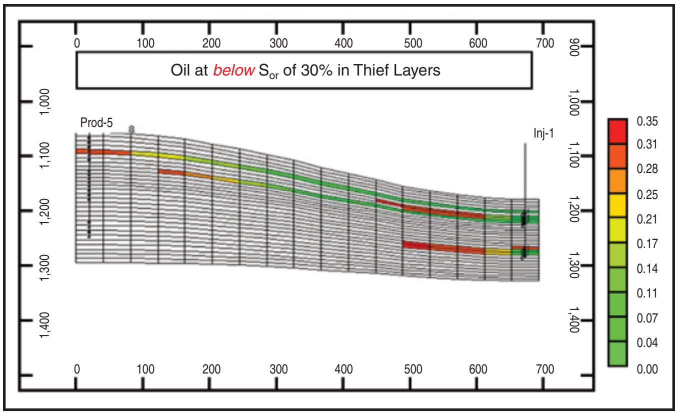


FIGURE 3B

Post-Treatment Oil Saturation in Thief Layers



out waterfloods is mitigating the associated geologic and economic risks, especially in a low commodity price environment.

Consequently, the first step in field testing the nanofluid was selecting candidates with known preferential flow paths for the injected fluids. Injected fluids tend to travel through high-permeability channels (thief zones) between pairs of injection and producing wells. These high-permeability channels create a path of least-resistance volume (PLRV), or a short-circuit of injected fluids that leaves residual oil in the channels and renders a large volume of other parts of the reservoir unswept.

As with the preceding injected water, the additive should follow similar pathways in the reservoir. Unlike water, however, the nanofluid should mobilize residual oil in the high-permeability channels to the waterflood. Because the PLRV is a smaller fraction of the total hydrocarbon pore volume (HCPV) of the thief zone, pilot testing in the reservoir PLRV minimizes economic risks by enabling smaller-sized treatment designs. It also allows the mobilized oil to be produced quicker, resulting in more attractive economics.

Economics are further derisked through being able to circumvent some of the steps in the lengthy laboratory/model/field workflow associated with traditional chemical EOR projects. In addition, minimal preparation or facility/injection infrastructure changes are required in existing waterfloods to deliver additive to the reservoir.

Once the field trial is completed, the data acquired can then be evaluated to decide whether to expand treatment on a fieldwide basis, perform conformance treatments at the end of the trial, or add the nanofluid additive in the subsequent chase water injection.

Test Results

The nanofluid-based process works on the principle that an increase in capillary number increases oil recovery. Since the capillary number is a function of viscosity, velocity and IFT, any positive alteration of these parameters leads to an increase in the capillary number and increased oil recovery.

Laboratory core flood experiments show that a 1.0 pore volume slug of one gallon per 1,000 gallons of the nanofluid additive would recover 9-12 percent of original oil in place, with a 1-12 percent increase in oil cut. The lab results were scaled up to test two pilot configurations where the remaining oil in the channels was the primary target.

As noted, treatment volumes were based on the HCPV of the thief zones in each pilot. Both pilot areas had been under waterflood for more than 15 years, and the water injection data showed that the majority of the injected water circulated through the thief zones. The thief zones are believed to be at residual oil saturation (S_{or}). The first pilot is a quarter nine-spot with one injector and three producers. The second pilot has a central injector updip of the structure with five producers.

Figures 1A and 1B show the 3-D simulation grids for both pilots. Results show significant peak oil production related to additive injection. Figures 2A and 2B show the predicted increase in oil cuts for both pilots. The S_{or} in the thief layers was set to 30 percent during simulation. During waterflooding, S_{or} had remained unchanged.

However, as seen in Figures 3A and 3B, there was significant mobilization of the residual oil at the end of the additive treatment. Economic analysis indicates attractive returns over continued waterflooding for both pilots, and significant net present value enhancement is predicted for both the pilots.

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Daily production and injection data, injection pressures, periodic effluent oil analysis, and attempts to maintain similar operational procedure through the completion of the injection period are some of the surveillances and monitoring performed on the pilots.

At present, three pilots (with individual pilots having more than one injector) are being tracked. The production and injection data are regularly updated in the model. In some cases, a dynamic model is used to constantly calibrate and estimate the location of mobilized oil bank. In other cases, in the absence of a dynamic model, simple cost/benefit calculations are performed in a spreadsheet to assess performance.

As demonstrated in ongoing simulations and field testing, advanced chemical technologies are critical in developing simpler and more efficient methods to increase oil mobilization while lowering cost/risk profiles and protecting the environment to allow chemical flooding to achieve its full potential in tertiary recovery. ❐

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