Exploitation and Optimization of Reservoir Performance in Hunton Formation, Oklahoma

QUARTERLY TECHNICAL PROGRESS REPORT

Submitted by

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Contract Date: March 7, 2000

Completion Date: June 30, 2006

Reporting Period: July 1 – September 30, 2005

Date Issued: October 2005

DOE Contract No. DE-FC26-00NT15125

Prepared for

U.S. Department of Energy
Assistant Secretary for Fossil Energy

Contracting Officer's Representative:

Mr. Paul West
U.S. Department of Energy
National Petroleum Technology Office/DOE
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Disclaimer

Abstract

West Carney field – one of the newest fields discovered in Oklahoma – exhibits many unique production characteristics. These characteristics include:

1) decreasing water-oil ratio;
2) decreasing gas-oil ratio followed by an increase;
3) poor prediction capability of the reserves based on the log data; and
4) low geological connectivity but high hydrodynamic connectivity.

The purpose of this investigation is to understand the principal mechanisms affecting the production, and propose methods by which we can extend the phenomenon to other fields with similar characteristics.

In our experimental investigation section, we continue to describe the use of surfactant to alter the wettability of the rock. By altering the wettability, we should be able to change the water-gas ratio in the reservoir and, hence, improve productivity from the well.

In our Engineering and Geological Analysis section, we present our rock typing analysis work which combines the geological data with engineering data to develop a unique rock characteristics description. By using porosity as a variable, we can generate alternate rock type descriptions at logged wells. This procedure also allows us to quantify uncertainties in rock type description.

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Executive Summary

The analysis of available data continued during this quarter. Based on our analysis, we realize that it is possible to improve hydrocarbon recovery by altering the wettability of rock. We also carefully examined the relationship between rock types and log data. Based on our evaluation, we developed a procedure for generating rock types at logged wells along with the associated uncertainties. The development of the procedure and the results are included in the report.

Experimental

Kishore Mohanty, University of Houston

Objective

The objectives of the third phase of this project are to test the feasibility of using the Hunton reservoir as a gas storage reservoir and improve near-well bore wettability. The feasibility of the gas storage was tested in the laboratory scale by conducting huff-puff test with gas. For a water-wet reservoir, water and condensate accumulate near the well bore increasing the wetting phase saturation; this reduces the gas permeability which can result in decreased gas productivity. The idea of wettability alteration to gas-wetting in nature would help the productivity by increasing water and condensate relative permeability and decreasing the saturation of water and condensates near the well bore. Treatment of the near-well bore region by a surfactant solution can bring about this gas-wetting behavior. The wettability alteration due to a surfactant treatment and resulting relative permeability alterations are described in this report.

Methodology

In this study, we are investigating a surfactant treatment that can make the near-well formation non-wetting with respect to water and condensates. The laboratory studies were conducted in two scales. The first set of experiments was done on a surface scale, where carbonate surfaces (Calcite) were treated with a surfactant solution to study its effect on wettability. Synthetic brine (0.1 N NaCl prepared in distilled water) and field brine were used as the liquid phase. The temperature was at ambient conditions in the lab, which varied from 22°C to 24°C. Air was used as the gas phase. A calcite plate was made smooth by grinding on a diamond plate. The plate was equilibrated with the synthetic brine for a day and then dried. Then it was equilibrated with the surfactant solution for a day. The plate was then dried, a drop of brine or oil was placed on the plate and the contact angle was measured by a contact angle goniometer.

The second set of experiments was conducted with a Hunton carbonate core to study the effect of surfactants on water and gas relative permeability. To quantify the effect on the gas phase relative permeability with wettability alteration, the gas relative permeabilities are measured at varying pressure drops across the core, before and after treatment. The porosity of the rock is independently measured using a porosimeter. First, the core is saturated to 100% brine and then the absolute permeability of the rock is estimated. Then water-saturated gas, N_2, is used at constant pressure drops of 62.5 psi/ft, 125 psi/ft, 500 psi/ft and 835 psi/ft. The flow is carried out for roughly 10 PV. At the end of each step, the core water saturation and the relative permeability of gas at this saturation is measured. Then, the core is again flooded with brine to achieve brine saturation at residual gas, and brine permeability is measured at this residual gas saturation. After that, the core is flooded with 0.2 wt % surfactant in soft brine for 1 PV. After the surfactant flood, the rock is left for equilibration for 2 days, and then the surfactant solution is flushed by a soft brine solution for 2 PV. At this point the brine permeability is also noted. The core is then taken and the injecting side is reversed to producing side, as would happen in a real reservoir flow. Now, the core is flooded with saturated gas as previously at various pressure drops of 62.5 psi/ft, 125 psi/ft, 500 psi/ft and 835 psi/ft and water saturation and gas relative permeabilities are measured. After that the core is flooded again by brine to observe brine permeability at residual gas saturation.

Results

On a clean calcite plate, the water contact angle is ~33°. Figure 1 shows a water drop on a calcite plate treated with a 0.2 wt % surfactant solution. The contact angle for water after the treatment is ~180°.

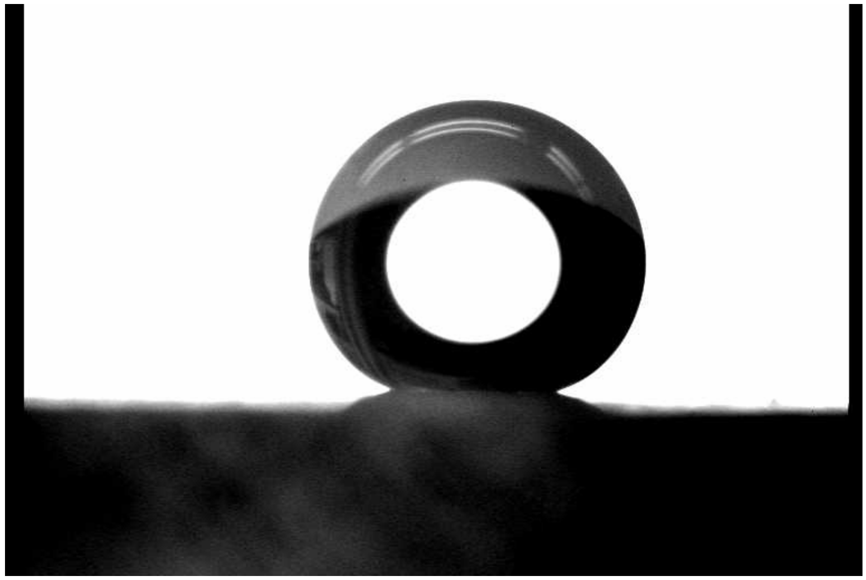

Figure 1: A drop of brine on a calcite plate treated with 0.2 wt% surfactant

Thus, the treatment with this surfactant makes the calcite surface hydrophobic. The stability of this wettability alteration in field brine was tested by immersing the treated calcite plate in a field brine for 7 days and then measuring the contact angle. The contact angle decreases, but remains above 90°, *i.e.*, water-nonwetting, as shown in Figure 2.

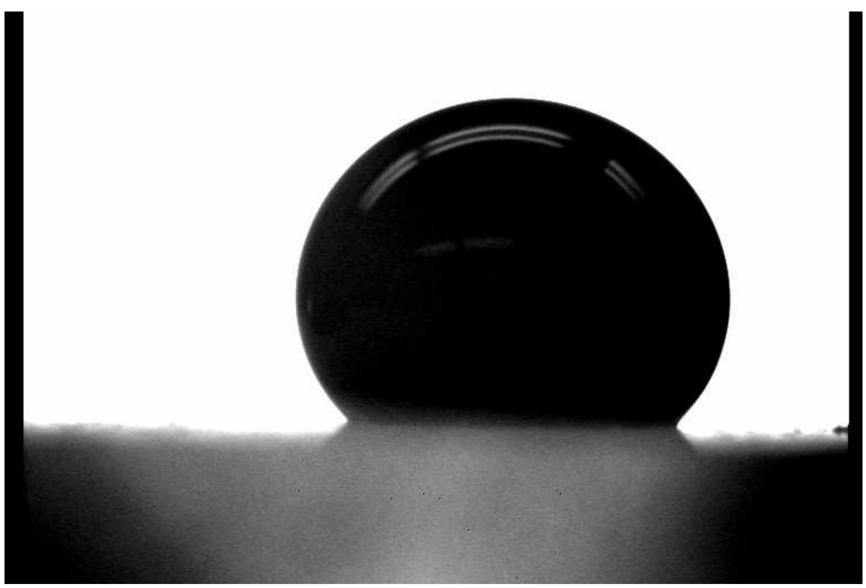

Figure 2: A drop of brine on a calcite plate treated with 0.2 wt% surfactant and aged in a field brine for 7 days

The contact angle of decane on the surfactant treated calcite surface was measured to be 130°, as shown in Figure 3. Thus this surface is also lipophobic, *i.e.*, nonwetting to oil. This treatment makes a surface that is gas-wetting with respect to both oil and water.

Figure 3: A drop of decane (surrounded by air) on a calcite plate treated with the surfactant

The Hunton coreflood results are shown in Figure 4. Before surfactant treatment, as the pressure gradient increased, the water saturation decreased (to a minimum value of 0.68) and the gas permeability increased (to a maximum value of 0.43). After the surfactant treatment, as the pressure gradient increased, the water saturation decreased (to a minimum value of 0.6) and the gas permeability increased (to a maximum value of 0.25). Gas permeability decreased because it became the wetting phase. Thus, the gas relative permeability decreased. The water relative permeability at the residual gas saturation increased from 0.17 to 0.9. Because water became the non-wetting phase its relative permeability increased. The total mobility of fluids can be computed if the water relative permeability is known at all saturations. The total mobility is probably increased at high water-cut because of the increase in water relative permeability. It is possible that this surfactant treatment could enhance the well productivity at a high water-cut.

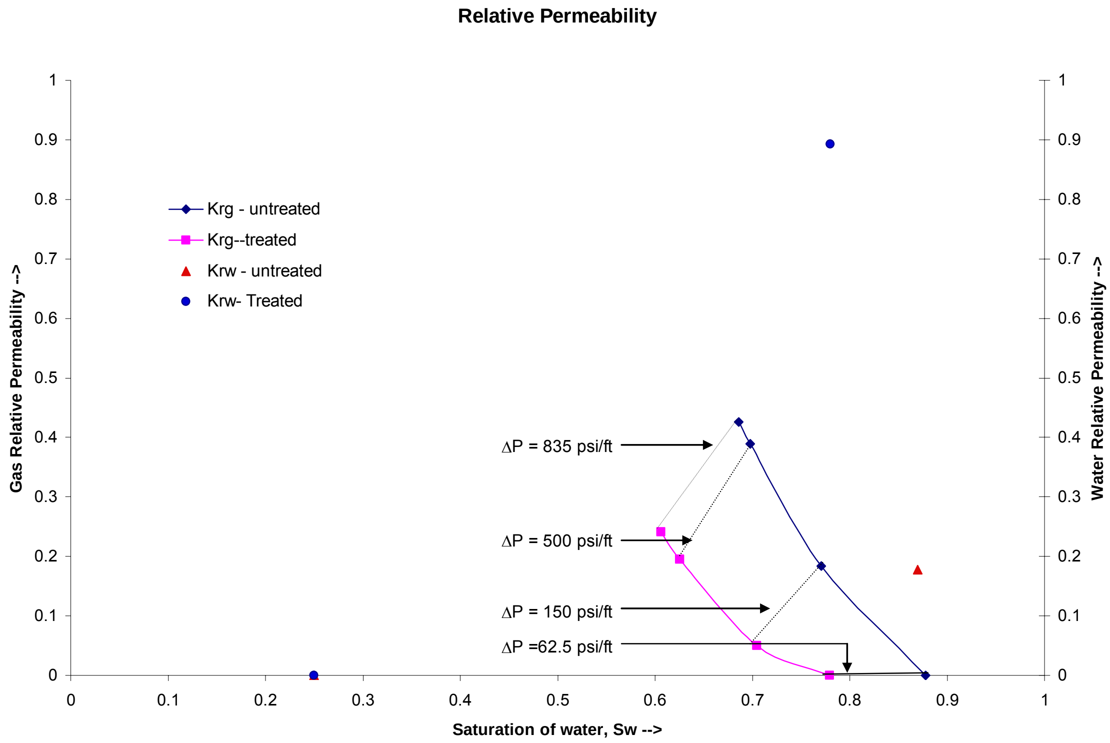

Figure 4: Gas and water relative permeabilities before and after surfactant treatment

Conclusions

The surfactant treatment changed the wettability to gas-wetting with respect to both water and oil and resulted in higher water permeability and lower gas permeability.

Future Work

Effect of wettability alteration on oil relative permeability will be measured. Total mobility will be measured for simultaneous injection of two phases (water-gas or oil-gas).

Results and Discussion

Engineering and Geological Analysis

Mohan Kelkar, The University of Tulsa

In the last report, we developed a scheme for describing the rock types. Using the geological input, as well as porosity data, we developed a scheme to generate rock type description such that each rock type has a unique geological characteristic, as well as unique petro-physical behavior. The petro-physical behavior includes different porosity distributions, as well as different permeability-porosity correlation.

The next task in the description is to develop a procedure such that log data can be used to generate rock types at wells where no core data are available. This is important since the core data are sparse and not available at every well. We examined the relationships between rock types and logs at the cored wells, and concluded that the only relationship we have between rock types and log data is the porosity information. That is, we can relate neutron and density porosity logs to rock types.

To generate rock types at logged wells, we first assigned probability of rock type for a given porosity class. See Figure 5 for an example. In this figure, the observation of rock types for a porosity range between 0 to 2% is plotted. The number of occurrences for a given rock type are indication of the probability of occurrence for a given rock type. So, for example, for the porosity range in Figure 5, rock type 1 and rock type 2 are much more common than other rock types. In contrast, in Figure 6, for a porosity distribution of 10 to 20%, rock types 3 and 4 are much more common. Using the information for each porosity class, we can determine the probability of occurrence of a given rock types.

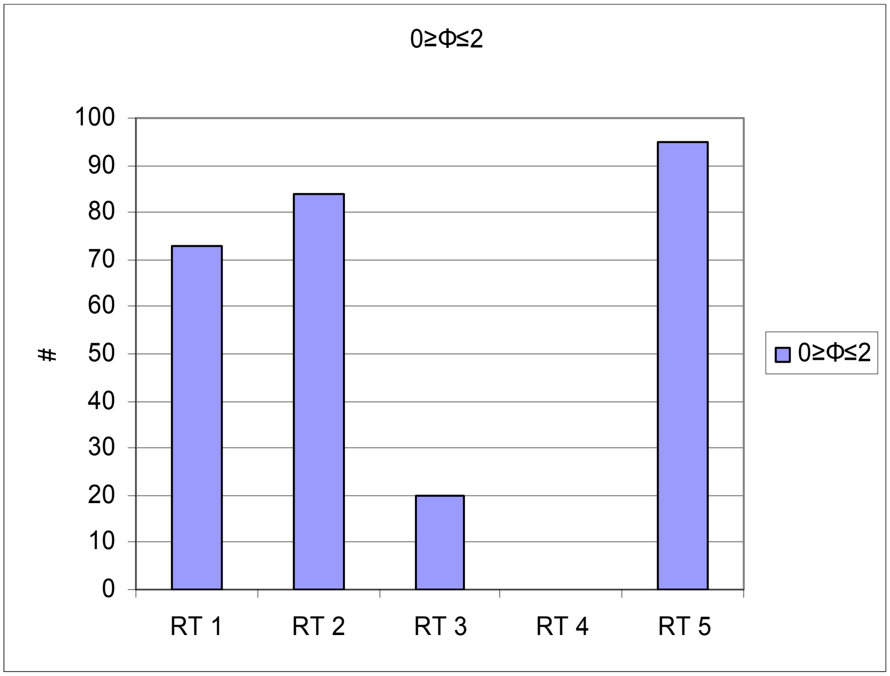

Figure 5: Rock Type Distribution for porosity in the range of 0 to 2 %

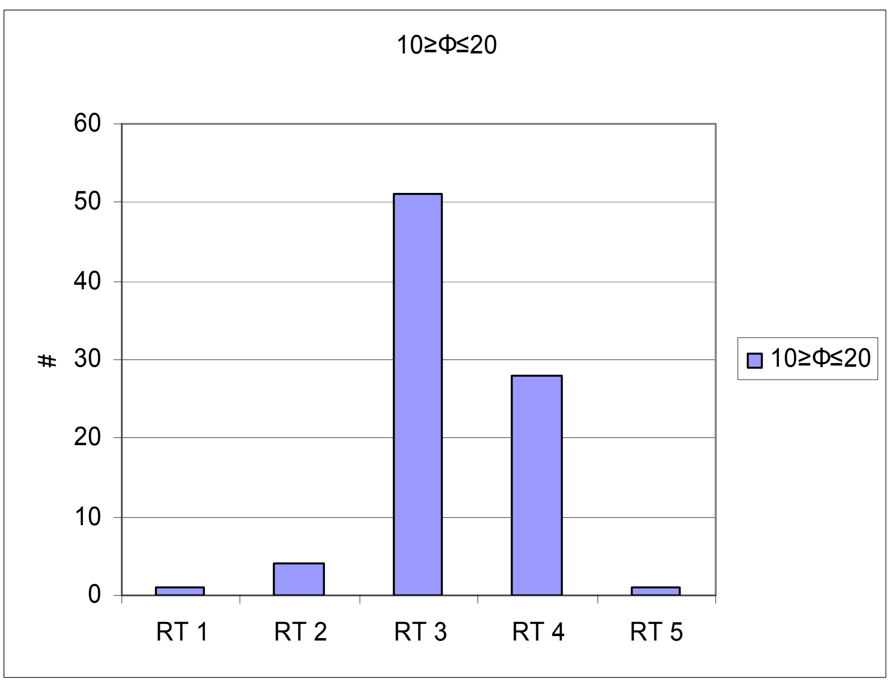

Figure 6: Rock Type Distribution for porosity in the range of 10 to 20 %

Once the information about the probabilities is known, we can sample a rock type at logged wells by using a random number generator – a number which falls between 0 and 1, and can be assigned to a particular depth. By comparing that number with cumulative probability distribution, we can assign a rock type at a given depth. For example, in Figure 7, we see alternate descriptions of rock types created at the Anna well using the porosity description. A total of five different realizations are generated at Anna to indicate the uncertainty with respect to rock type description. Many more realizations can be constructed using a similar approach. Figure 8 shows a similar plot for the Bailey well. We intend to generate multiple rock type descriptions using a similar approach and then generate alternate permeability descriptions. Ultimately, we would like to generate alternate reservoir descriptions at inter well locations to capture uncertainties in reservoir description.

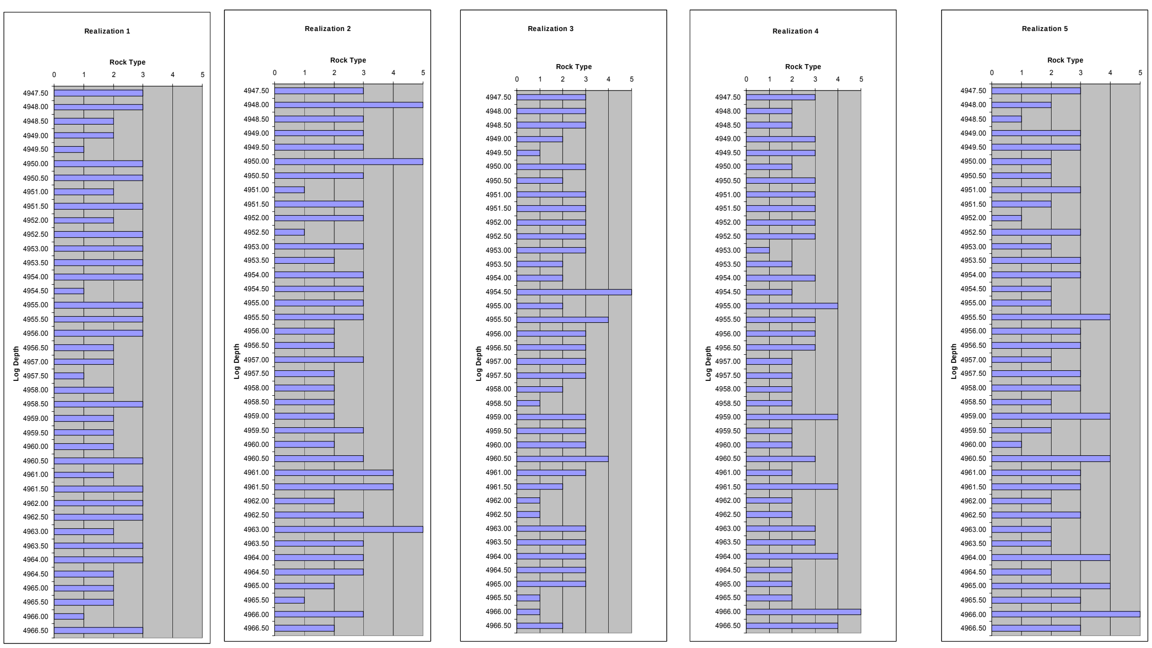

Figure 7: Alternate Rock Types for Anna

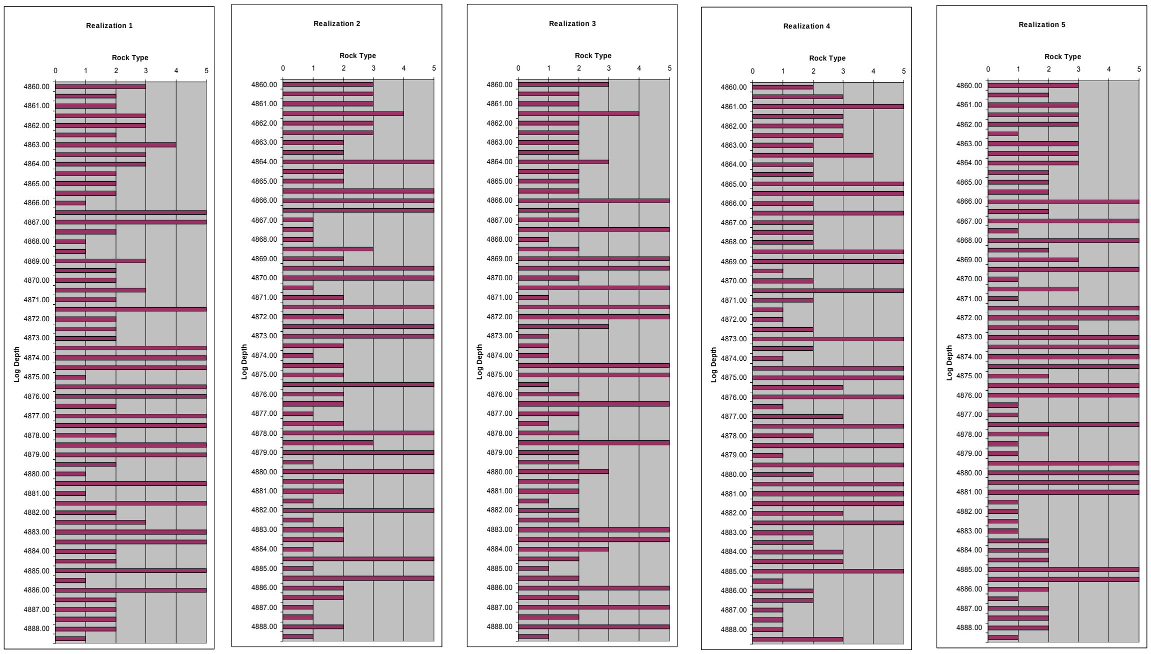

Figure 8: Alternate Rock Type Description for Bailey

<u>Technology Transfer</u>

No technology transfer activity was conducted during this quarter.

Conclusions

Based on the material presented in this report, the following conclusions may be drawn:

- Use of surfactants can help us to change the wettability of the rock. This is important if we ever want to use Hunton formation for gas storage purposes.
- A new method is developed to generate alternate rock type descriptions at logged wells using the information available from core data.