THE EFFECT OF ALKALINE ADDITIVES ON THE PERFORMANCE OF
SURFACTANT SYSTEMS DESIGNED TO RECOVER LIGHT CRUDE OILS

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By T. R. French, C. B. Josephson, and D. B. Evans

ABSTRACT

Surfactant flooding is flexible because of the ability to optimize formulations for a wide range of reservoir conditions and crude oil types. The objective for this work was to determine if the addition of alkaline additives will allow the design of surfactant formulations that are effective for the recovery of crude oil, while, at the same time, maintaining the surfactant concentration at a much lower level than has previously been used for micellar flooding. Specifically, the focus of the work was on light, midcontinent crudes that typically have very low acid contents. These oils are typical of much of the midcontinent resource.

The positive effect of alkaline additives on the phase behavior of surfactant formulations and acidic crude oils is well known. The extension to nonacidic and slightly acidic oils is not obvious. Three crude oils, a variety of commercial surfactants, and several alkaline additives were tested. The oils had acid numbers that ranged from 0.13, which is quite low, to less than 0.01 mg KOH/g of oil.

Alkaline additives were found to be very effective in recovering Delaware-Childers (OK) oil at elevated temperatures, but much less effective at reservoir temperatures. Alkaline additives were very effective with Teapot Dome (WY) oil. With Teapot Dome oil, surfactant/alkali systems produced ultralow IFT values and recovered 60% of the residual oil that remained after waterflooding. The effect of alkaline additives on recovering Hepler (KS) oil was minimal.

The results of this work indicate that alkaline additives do have merit for use in surfactant flooding of low acid crude oils; however, no universal statement about applicability can be made. Each oil behaves differently, with this treatment, and the effect of alkaline additives must be determined (at reservoir conditions) for each oil.

INTRODUCTION

Background

Of the various enhanced oil recovery (EOR) technologies, surfactant flooding is the most flexible method because of the ability to optimize formulations for a wide range of reservoir conditions and crude oil types. By varying the type and concentration of surfactant and cosurfactant, formulations with optimal displacement efficiencies can be designed to recover crude oil from a reservoir with a specific salinity, brine composition, temperature, and rock mineralogy. In 1984, the National Petroleum Council reported that chemical flooding has the potential to recover up to 2.5 billion bbl of crude oil in the United States.¹

Several chemical flooding field pilot tests have produced significant amounts of incremental oil and have been technically, but not economically, successful. The goal of the NIPER research program in surfactant flooding is to develop systems that are cost-effective for recovering light crude oils. The focus has been on (1) identifying surfactant formulations or methods that are more cost effective than those currently available and (2) mitigating the problems that have adverse effects on the performance and economics of surfactant flooding processes.

Midterm research and development efforts at NIPER have focused on screening various novel surfactants to identify those that are tolerant to changes in salinity and divalent ion concentration and are applicable over wider temperature ranges. Some surfactants are less expensive than others; however, surfactant is an expensive component in all micellar formulations because of the large quantity that must be injected into a reservoir. The selection of multicomponent formulations that minimize chromatographic separation and the use of relatively inexpensive sacrificial agents have been investigated for the reduction of losses of surfactant. Another way to reduce chemical costs is to reduce the concentration of the surfactant.

In early research on surfactant flooding, a search was made for cost-effective surfactants that were capable of reducing interfacial tension (IFT) and were stable at typical reservoir brine concentrations and temperatures. Petroleum sulfonates were usually the class of surfactant that was investigated, primarily because they were stable at reservoir temperatures and relatively inexpensive. Even though petroleum sulfonates are relatively inexpensive, the economics of field pilots are adversely impacted by the large amounts of surfactant required. Surfactant formulations capable of producing ultralow IFT values typically contain 3 to 5% concentrations of active surfactants.

Researchers have been motivated to design surfactant formulations that will produce ultralow IFT values with much lower surfactant concentrations. Reducing the concentration of surfactant that must be injected to maintain effective displacement for a distance into a reservoir will make a direct improvement in the economics of applying the process. With these systems, possible losses of the surfactant in a reservoir by adsorption and phase trapping become more important.

Addition of alkaline additives to surfactant formulations has been found to be beneficial by reducing losses of surfactant and polymer, reducing concentrations of divalent cations that cause losses of surfactant by partitioning and precipitation, and by affecting interfacial properties. The effects of alkaline/surfactant formulations on heavy, acidic oil have been known for some time.²⁻⁶ Recent research has shown that weakly alkaline additives to surfactant formulations may also be effective for the recovery of light crude oils, and with greatly reduced concentrations of surfactant.⁷⁻⁹

Further research on interactions between complex components of crude oils and both alkaline and surfactant chemicals is needed to determine how best to utilize the benefits obtained by adding alkaline additives to surfactant formulations. This report addresses the use of surfactant/alkaline formulations for recovery of light crude oils.

In 1984, NIPER began testing weak alkaline agents, such as sodium bicarbonate and sodium carbonate, for their ability to mobilize residual oil. The use of weak alkalis was shown to avoid or reduce some of the adverse reactions that usually occur between reservoir rock and strong alkalis. The lower pH alkalis reacted with acidic components of crude oils to produce surfactants in situ, but the amount of natural surfactants extracted from the crude oil were less than that obtained with stronger alkaline agents; therefore, the reduction in IFT was also less.

During attempts to increase the amount of oil solubilized, it was discovered that very low concentrations of synthetic surfactants could be added to an alkaline slug and be very effective in oil recovery.¹⁰ It was also observed that alkaline conditions resulted in lower losses of surfactant by precipitation and adsorption. Most of the research was conducted with heavy oils that contained significant amounts of acidic components. In these experiments, the total acid number, which is an indication of the amount of acidic components in an oil, was usually above 1.0 mg KOH/g of oil. During the initial work, it was assumed that an appreciable acid number would be necessary for alkaline additives to have a significant impact on the lowering of IFT by a surfactant formulation. It was realized, however, that some of the other effects of alkaline additives would be beneficial in reservoirs that contain non-acidic oils.

Studies with an acidic oil and surfactant/alkaline formulations showed that a very low initial IFT was predominantly the result of natural surfactants generated by reaction with alkaline agents, and sustained low IFT was primarily the result of synthetic surfactant.² A mixture of synthetic surfactant and alkali produced lower IFT and sustained low IFT longer than either reactant alone. It was also observed that the extraction of acids from acidic crude oils by alkalis appeared to render the oil more interfacially reactive to synthetic surfactant. Many midcontinent crudes have very low acid numbers, and this latter observation led to tests with oils that have low acid numbers.

The behaviors of three light midcontinent crude oils and surfactant mixtures that contain alkaline additives are described in this report. The three light oils have acid numbers that range from 0.01 to 0.13 mg KOH/g of oil, typical of many midcontinent reservoirs, and the results are compared with the behavior of a representative acidic crude oil. The work with the acidic crude was previously performed under another project. Finally, suggestions are made about the use of alkaline additives for recovery of light crude oils.

EXPERIMENTAL PROCEDURES

Chemicals and Reagents

Crude Oils

The crude oils were selected to represent light midcontinent oils with a range of acid contents. The crude oils were obtained from Delaware-Childers (OK), Teapot Dome (WY), and Hepler (KS) oil fields. The crude oil properties are summarized in table 1.

Surfactants

Three surfactants, one nonionic and two anionic, were used in the experiments. Petrostep B-100 is a medium-molecular-weight alkyl aryl sodium sulfonate produced by Stepan Company. It is designed for use in low-concentration surfactant flooding. Petrostep B-120 is a low-molecular-weight sodium sulfonate manufactured by the same company. Neodol 25-9 is a nonionic ethoxylated alcohol produced by Shell Chemical Company. It contains, on average, 9.2 ethylene oxide groups per mole.

Brines

The synthetic brines contained sodium chloride. The alkaline additives were sodium bicarbonate and mixtures of sodium bicarbonate with sodium carbonate. Compositions of brines and chemical formulations are given in appendix B.

Interfacial Activity

Phase Behavior

Equal volumes (4 mL) of oil and aqueous phase were sealed in 10-mL graduated ampoules, and the samples were placed in a temperature-controlled oven. Observations were made after 1 day. The samples were observed at that time and evaluated. The samples were then evaluated while being shaken. Finally, the samples were evaluated again after 1 more day. Observations while shaking provided information about the type of emulsion formed (oil-in-water or water-in-oil), the ease of emulsification, the stability of the emulsion (while shaking), and the amount (qualitative) of oil emulsified. The final evaluation (1 day after shaking) provided additional data on emulsion stability.

TABLE 1 - Crude oils

Oil	Gravity, °API	Total Acid Number, mg KOH/g
Delaware - Childers	33.0	0.13
Teapot Dome	34.1	0.01
Hepler	26.1	<0.01

The emulsions formed were evaluated according to the following criteria:

Emulsion quality

Criteria

0	No visible emulsification.
1	Black emulsion.
2	Brown emulsion that changes to black while shaking.
3	Brown emulsion.
4	Brown emulsion containing >90% of the oil in the sample.

Higher values of "emulsion quality" correlate with greater interfacial activity and nearness to optimal conditions. This visual method for determining optimal salinity for producing interfacially active systems is only slightly different from visual methods used by others.¹¹⁻¹²

Interfacial Tension

Interfacial properties of selected systems were measured with a controlled-temperature, spinning drop interfacial tensiometer. The transient IFT behavior of nonequilibrated samples was monitored over a time interval of several hours.

Oil Displacement Tests

Unfired, oil-free Berea sandstone cores (25.4 X 3.8 cm) were saturated with brine and mounted in Hassler-type coreholders. The cores were oil flooded to residual water saturation and then waterflooded to residual oil saturation before starting the chemical flood. Injection strategies for the corefloods are given in appendix B. Frontal advance rates were approximately 1 ft/d, providing a core residence time of about 0.8 day.

Native-state cores from Delaware-Childers (OK) field were stored under brine, then horizontal core plugs (3.8 cm diameter) were cut. Sufficient core plugs were butted together (without filler between plugs) to produce cores about 25 cm long. The cores were then waterflooded before starting the chemical flood. Frontal advance rates were approximately 1 ft/d.

Analytical

Surfactant

The analytical methods used for measurement of surfactant concentration were two-phase titration and HPLC. The two-phase titration was described by Rosen and Goldsmith,¹³ and the HPLC procedure is very similar to that described by Hofman and Angstadt.¹⁴ The wavelength used for absorbance

measurement of Petrostep B-100 surfactant was 222 nm, which is very close to the wavelength selected by Hofman and Angstadt.

Alkalinity

Effluent samples were collected in 5-mL increments and centrifuged before the volume of oil collected was determined. The aqueous phase was then separated and analyzed for alkalinity by titration to pH 4 with 0.1 N HCl.

RESULTS AND DISCUSSION

Acid Number

The positive effect of alkaline additives on the phase behavior of surfactant formulations and acidic crude oil is well known, and the extension to non-acidic and slightly acidic oils is not obvious. The acid number of a crude oil, expressed as milligrams of potassium hydroxide required to neutralize the acids in 1 gram of the oil, is an important parameter for traditional alkaline flooding; however, a detailed study of 24 alkaline field projects failed to show a correlation between oil acid number and project success.¹⁵ The focus of this work is the effect of alkaline additives in surfactant formulations designed to recover light, midcontinent crudes that typically have very low acid contents.

Effects of Alkaline Additives on IFT

Delaware-Childers (OK) Crude Oil

Crude oil from Delaware-Childers (OK) oil field was used for testing the use of alkaline additives in surfactant formulations. The oil is 33° API gravity and has an acid number of 0.13 mg KOH/g oil, a very low acid number. In prior work, it was demonstrated that, under certain conditions, low values of IFT that are favorable to the mobilization of residual oil could be achieved between Delaware-Childers crude oil and formulations that contain alkaline additives and dilute concentration of synthetic surfactants.^{3,7} This behavior was demonstrated during a series of tests conducted with several crude oils at 52° C. The results are shown in figures 1 and 2.

The Delaware-Childers oil is slightly acidic and relatively unreactive to alkali. Figure 1 shows that alkali alone produced only a small reduction in IFT. The addition of 0.1% Petrostep B-100 anionic surfactant to the alkali resulted in a very rapid lowering of IFT to a low value, which was sustained for a long period. This behavior is very similar to the behavior observed previously with acidic oils. The minimum IFT of 2.9 $\mu\text{N/m}$ for the combination of synthetic surfactant and alkali was much lower than was achieved with either component alone. The IFT behavior for 0.1% surfactant alone is shown in figure 2. The results with the Delaware-Childers crude indicated that even for crude oil with very low acid number, the combination of alkali and a low concentration of synthetic surfactant can produce very low IFT values.

FIGURE 1. - Dynamic IFT of Delaware-Childers oil, 52° C, pH 9.5.

FIGURE 2. - Dynamic IFT of Delaware-Childers oil and 0.1% Petrostep B-100 anionic surfactant, 52° C, pH 6.3.

Since 52° C is above the reservoir temperature, additional IFT measurements were performed at 30° C, which is nearer the reservoir temperature. Dynamic (with time) IFT values at 30° C for Delaware-Childers crude oil and several surfactant formulations that contain weak alkaline additives are shown in

figures 3, 4, and 5. The results show that equilibrium IFT values below $10 \mu\text{N/m}$ were achieved at some conditions, but that very low initial IFT values were not achieved. This contrasts with the IFT values previously measured at the higher temperature.

FIGURE 3. - Dynamic IFT of Delaware-Childers oil and 0.2% Petrostep B-100 anionic surfactant, 30°C , pH 9.5.

FIGURE 4. - Dynamic IFT of Delaware-Childers oil and 0.2% Neodol 25-9 (ethoxylated alcohol) surfactant, 30°C , pH 9.5.

FIGURE 5. - Dynamic IFT of Delaware-Childers oil and 0.2% Petrostep B-100 anionic surfactant, 30° C, pH 8.3.

Since it was previously shown that the IFT value that results immediately after oil and surfactant solution come into contact is very important for mobilization of residual oil,¹⁶ the initial values for IFT of selected surfactant systems are shown in figure 6. The addition of an alkaline additive to a dilute solution of Petrostep B-100 anionic surfactant substantially reduces the initial IFT at 30° C. The IFT of the surfactant solution without pH adjustment (pH 6.3) at 1.5% NaCl concentration is nearly as low as the IFT of the alkaline/surfactant solution at 0% NaCl. However, the alkaline/surfactant solution (at 0% NaCl) has much less turbidity than the pH 6.3 surfactant solution at 1.5% NaCl concentration. It was shown that this turbidity can result in severe phase trapping in porous media. Therefore, one advantage of the alkaline solution is that low IFT was achieved at a condition where phase trapping is expected to be less of a problem.

A series of phase behavior tests were performed at 30° C with several surfactant and alkali mixtures. The conditions tested are shown in appendix A. The results of the phase behavior tests indicated that ultralow IFT values were obtained only with a mixture that contained Petrostep B-100 and 0.8% sodium bicarbonate. The dynamic IFT values of Delaware-Childers oil, Petrostep B-100 surfactant, and two different concentrations of sodium bicarbonate are shown in figure 7. Neither system gives ultralow initial IFT; however, the lower sodium bicarbonate concentration gives substantially better dynamic behavior. The IFT is below 1 μN/m in 5 minutes, which is a short time period in the time-scale of a chemical flood.

FIGURE 6. - Dynamic Initial IFT values measured with Delaware-Childers oil and 0.2% Petrostep B-100 anionic surfactant, 30° C, pH 6.3 and pH 8.3.

FIGURE 7. - Comparison of Dynamic IFT of Delaware-Childers oil and Petrostep B-100 anionic surfactant at two alkali concentrations, 30° C, pH 8.3.

Polymer, for mobility control, is often included as part of a chemical injection formulation. This is one of several injection strategies that can be used. Comparison of figures 7 and 8 shows that addition of Pfizer Flocon 4800 CX biopolymer to the alkali/surfactant solution has little effect on the dynamic IFT behavior of Petrostep B-100 surfactant in 1.6% sodium bicarbonate solution. The effect is, however, to degrade the IFT behavior of the solution that contains 0.8% sodium bicarbonate. This indicates that the interactions of the several EOR chemicals must be taken into account when attempting to find the optimal injection strategy.

Results of oil recovery (coreflood) tests are summarized in table 2, and the individual coreflood reports are presented in appendix B. One of the tests was conducted with Teapot Dome oil and will be discussed later. The other four tests were conducted at 30° C with Delaware-Childers oil. As previously discussed, some of the chemical systems used for these tests gave very low equilibrium IFT values, but not ultralow equilibrium IFT values. Two of the corefloods (DCNS-1 and DCNS-3) were conducted with native state cores that had very low initial oil saturations. No oil was recovered from these cores during the chemical floods.

FIGURE 8. - Effect of polymer on the Dynamic IFT of Delaware-Childers oil and 0.2% Petrostep B-100, anionic surfactant, 30° C, pH 8.3.

TABLE 2. - Corefloods conducted with surfactant formulations that contain alkaline additives.

Coreflood	Core type	K _{abs} , md	Ø %	ASP Solutions ¹		
				Surfactant	Surfactant, %	pH
TP-1	Berea	811	22.9	Petrostep B-100	0.1	9.5
DCNS-1	Native-state	214	22.9	Petrostep B-100	0.2	8.3
DCNS-2	Native-state	143	20.7	Petrostep B-100	0.2	8.3
DCNS-3	Native-state	259	21.0	Neodol 25-9	0.2	9.5
DC-1	Berea	1151	21.7	Petrostep B-100	0.2	8.3

Coreflood	PV	S _{oi} , %	S _{ow} , %	S _{ocf} , %	Reff _o , %
TP-1	1.01	73.6	39.6	15.5	60.8
DCNS-1	0.73	22.0	22.0	22.0	0
DCNS-2	0.82	64.6	38.7	32.3	16.4
DCNS-3	(1.0)	30.13	30.13	30.13	0
DC-1	0.78	78.2	43.6	35.4	18.8

¹ Alkaline/surfactant/polymer (ASP) solutions contain weak alkali, low concentration surfactant, and Flocon 4800 CX biopolymer.

Coreflood DCNS-2 was conducted in a native-state core that was first restored to initial oil saturation, and coreflood DC-1 was conducted with a Berea sandstone core. In both cases, the chemical flood was conducted after waterflooding the cores to residual oil saturation. The changes in oil saturations during these chemical floods are shown in figure 9. The oil recovery results from the two core tests are remarkably close. Recovery from the restored native state core was 16.4%, and recovery from Berea was 18.8%.

The oil recoveries with Delaware-Childers oil were low and indicated that the surfactant formulations did not have low enough IFT values to mobilize significant residual oil. Work is continuing in an effort to find a surfactant formulation that will be more effective at reservoir temperature. It appears that low initial IFT may be more important for mobilization of oil than equilibrium values. A more encouraging result is shown in figure 10. The consumption of the alkaline additive by Delaware-Childers core was relatively low, despite the presence of substantial amounts of kaolinite.

Teapot Dome (WY) Crude Oil

Crude oil from Teapot Dome (WY) oil field was also used for oil recovery tests. Teapot-Dome oil has essentially no acid content (i.e. acids that can be measured by titration with potassium hydroxide) and represents an extreme case for testing the effects of alkaline additives. The oil has an API gravity of 34.1° and an acid number of 0.01 mg KOH/g of oil. Results of dynamic IFT measurements are shown in figure 11. Addition of an alkaline additive to a dilute surfactant solution had a beneficial effect on the lowering of IFT. The effect on initial IFT is especially pronounced, with the additive lowering the initial IFT by three magnitudes. The initial IFT with alkaline additive was ultra-low.

FIGURE 9. - Changes in oil saturations during chemical floods conducted with surfactant formulations that contain alkaline additives.

FIGURE 10. - Effluent analysis for chemical flood DCNS-1.

FIGURE 11. - Dynamic IFT of Teapot Dome oil and 0.1% Petrostep B-100 anionic surfactant, 52° C, pH 6.3 and pH 9.5.

The results of an oil recovery test with Teapot Dome oil are shown in table 2. The coreflood was conducted with Teapot Dome oil at 0.3% NaCl concentration where the initial IFT was measured to be 0.6 $\mu\text{N/m}$ and the equilibrium IFT was 9.6 $\mu\text{N/m}$. Injection of the surfactant formulation resulted in recovery of 60.8% of the oil that remained in the core after a previous waterflood. The oil saturation (fig. 9) was lowered from 39.5% (S_{ow}) to 15.5% (S_{oc}) during chemical flood. The extremely good incremental oil recovery demonstrates the high recovery potential of properly designed dilute surfactant solutions that contain weakly alkaline additives.

The results of initial and equilibrium IFT measurements are shown in table 3. Examination of the table reveals that the initial IFT values for the Teapot Dome oil and Petrostep B-100 surfactant were almost 2 orders of magnitude lower than the best results achieved with the Delaware-Childers oil. This is, presumably, the explanation for the good oil recovery results with Teapot Dome oil and the poorer results previously discussed for Delaware-Childers oil.

The effluent analysis for the flood conducted with Teapot Dome oil is shown in figure 12. Surfactant adsorption was 0.129 meq/kg, which is low. There was, however, an interesting separation of the surfactant and polymer in the effluent. The magnitude of this separation, over 0.5 PV, would be significant in a field situation. It may be possible to mitigate this effect with a different injection strategy.

TABLE 3. - Dynamic interfacial tension of surfactant formulations that contain alkaline additive

pH	Temperature, °C	NaCl, %	Initial IFT, μN/m	Equilibrium IFT, μN/m
Teapot Dome, 0.1% Petrostep B-100, carbonate mixture				
9.5	52	0	5.4	21.1
		0.3	0.6	9.6
		0.6	0.9	5.4
		1.0	10.0	8.7
Teapot Dome, 0.1% Neodol 25-9, carbonate mixture				
9.5	52	0	311.5	86.3
		1	564.6	228.6
		3	361.5	104.1
		5	525.3	154.2
		9	595.5	82.1
Delaware/Childers, 0.2% Petrostep B-100, sodium bicarbonate				
8.3	30	0	34.5	9.0
		0.3	61.3	23.6
		0.6	57.6	6.3
		1.0	121.9	13.8
Delaware/Childers, 0.2% Petrostep E-100, carbonate mixture				
9.5	30	0	67.1	7.4
		0.3	70.8	11.3
		0.6	67.1	13.8
		1.0	108.3	20.6
Delaware/Childers, 0.2% Neodol 25-9, carbonate mixture				
9.5	30	0	209.3	195.5
		1	261.7	326.6
		3	198.9	301.4
		5	188.4	253.5

FIGURE 12. - Effluent analysis for chemical flood TP-1.

Hepler (KS) Crude Oil

Oil was obtained from the Tucker sand in Hepler (KS) oil field. Hepler field is the potential site of a test of surfactant flooding formulation that may contain alkaline additives. Favorable reservoir characteristics are low salinity and low divalent ion levels. However, low acid number is a reservoir characteristic that is not especially encouraging for the use of alkaline additives. The oil is 26.1° API gravity, and the acid number is less than 0.01 mg KOH/g of oil.

Phase behavior tests were conducted with several surfactant/alkali systems. The actual systems tested are given in appendix A. None of these systems exhibited the type of phase behavior that indicates ultralow IFT. The initial (after 1 to 2 minutes) IFT of the most promising system is shown in figure 13. The lowest initial IFT measured was 97 $\mu\text{N/m}$, which was with a chemical system that contained 2.12% NaCl, a pH 9.5 carbonate mixture, and 0.2% Petrostep B-120, a low-molecular-weight anionic surfactant. The same figure shows the IFT values for 0.2% Petrostep B-120 without pH adjustment (pH 6.3) at three NaCl concentrations. Comparison reveals that the alkaline additive lowered the initial IFT only slightly. It was noted, however, that the repeatability of IFT measurements was much better for formulations that contained the alkaline additive.

FIGURE 13. - Dynamic initial IFT values measured with Hepler oil and Petrostep B-120 anionic surfactant, 27° C, pH 6.3 and pH 9.5.

Other Effects of Alkaline Additives

In addition to the effect on lowering the IFT with some crude oils, alkaline additives have other beneficial effects during surfactant floods. These effects should be considered when designing a flood. Calcium and magnesium ions present in reservoirs can precipitate the surfactants used in EOR applications. Alkalis are effective for reducing the levels of divalent ions in petroleum reservoirs.^{7,17} The effectiveness of the different alkalis for reducing divalent ion levels are: hydroxide < carbonate < silicate. For this purpose, the preferred injection strategy is probably to use an alkaline preflush to reduce divalent ion levels before injecting the formulation that contains surfactant.

Surfactant levels in the injected solution can also be reduced by adsorption onto reservoir rock. Alkali reduces the loss of surfactants by adsorption. Adsorption of anionic surfactants onto pure clay minerals is reduced as much as 93%. Reductions of 7 to 49% were reported when reservoir sandstones are used.^{3,5,18-19}

When To Use Alkaline Additives

The reservoir mineral and brine properties that are most important for determining the feasibility of alkaline flooding were previously identified. The criteria were identified after a detailed study of the alkaline field projects conducted since 1960.¹⁵ Some of the data published in the chemical literature and the results of laboratory experiments were especially useful in correlation of mineralogy and the allowable pH level of the injected fluids. This is particularly important because the very high pH alkalis are completely consumed by some of the minerals in petroleum reservoirs. A summary of the screening criteria follows.

Carbon Dioxide

The CO₂ content of petroleum reservoirs is reported only infrequently. Yet, it is one of the most important parameters for determining if a reservoir is a candidate for alkaline flooding. Alkaline flooding should usually not be considered in reservoirs of high CO₂ content: mole fraction of CO₂ (in produced gas) > 0.01 or pH < 6.5.^{15,20}

Mineralogy

Gypsum

The presence of gypsum (anhydrite) is a deterrent to any type of alkaline (or surfactant) flooding. It has been shown that 1% gypsum in a reservoir can consume 10 PV of a 1% solution of NaHCO₃. Alkaline flooding should be rejected for any reservoir with greater than 0.1% gypsum. This amount of gypsum can be inferred from 1,000 ppm sulfate ion in the brine.¹⁵

Kaolinite

The presence of kaolinite is a serious deterrent to flooding with the higher pH alkalis.²¹ Only low pH (about 8.2 - 10) alkalis should be considered for use in reservoirs that contain appreciable amounts of kaolinite.

Montmorillonite (smectite)

Montmorillonite, which is less reactive with alkalis, is detrimental to alkaline flooding processes because of its high surface area and very high cation exchange capacity. High CEC values are associated with high montmorillonite content. If divalent ions occupy the exchange sites, much of the injected alkali can be consumed by adverse precipitation reactions. The screening criterion for ion exchange capacity is 5 meq/kg. This corresponds roughly with the presence of 1% montmorillonite and 0.4 wt % of divalent ions in the brine.^{15,22}

Limestone

The high pH alkalis are reactive with limestone and should be avoided in dolomitic reservoirs. Low (NaHCO_3) and moderate (Na_2CO_3) pH carbonates have been shown to be compatible with dolomitic cores.^{5,9,23}

Other Parameters

Other parameters such as temperature, permeability, salinity, and oil viscosity have the familiar limits for chemical flooding, whose values depend on the specific limitations of the surfactant and polymer.¹⁵

SUMMARY AND CONCLUSIONS

The motivation for this work was to determine if the addition of alkaline additives will allow the design of surfactant formulations that are effective for the recovery of crude oils with a wide range of properties, while at the same time maintaining the surfactant concentration at a much lower level than has previously been used for micellar flooding. Specifically, the focus of the work is on light, midcontinent crudes that typically have very low acid contents. These oils are typical of much of the midcontinent resource.

The positive effect of alkaline additives on the phase behavior of surfactant formulations and acidic crude oils is well known. The extension to non-acidic and slightly acidic oils is not deductively obvious. Three crude oils, a variety of commercial surfactants, and several alkaline additives were tested during this project. The oils had acid numbers that ranged from 0.13, which is quite low, down to less than 0.01 mg KOH/g of oil.

Additives were found to be very effective with Delaware-Childers (OK) oil at elevated temperature, but much less effective at reservoir temperature. Alkaline additives were very effective with Teapot-Dome (WY) oil. Surfactant/alkali systems produced ultra-low IFT values and recovered 60% of the residual oil that remained after waterflooding. The effect of alkaline additives on the Hepler (KS) oil was minimal.

The overall conclusion is that alkaline additives do have merit for use in surfactant flooding of low acid crude oils; however, as shown above, each oil behaves differently, and the effect of alkaline additives must be determined at reservoir conditions for each oil.

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APPENDIX A
Phase Behavior tests, 30° C

Oil	Surfactant	NaCl, %	pH
Delaware/Childers	0.1% Neodol 25-9	1.0	9.5
Delaware/Childers	.1% Neodol 25-9	3.0	9.5
Delaware/Childers	.1% Neodol 25-9	6.0	9.5
Delaware/Childers	.1% Neodol 25-9	10.0	9.5
Delaware/Childers	.2% Neodol 25-9	1.0	9.5
Delaware/Childers	.2% Neodol 25-9	3.0	9.5
Delaware/Childers	.2% Neodol 25-9	6.0	9.5
Delaware/Childers	.2% Neodol 25-9	10.0	9.5
Delaware/Childers	.4% Neodol 25-9	1.0	9.5
Delaware/Childers	.4% Neodol 25-9	3.0	9.5
Delaware/Childers	.4% Neodol 25-9	6.0	9.5
Delaware/Childers	.4% Neodol 25-9	10.0	9.5
Delaware/Childers	.8% Neodol 25-9	1.0	9.5
Delaware/Childers	.8% Neodol 25-9	3.0	9.5
Delaware/Childers	.8% Neodol 25-9	6.0	9.5
Delaware/Childers	.8% Neodol 25-9	10.0	9.5
Delaware/Childers	.1% Neodol 25-9	1.0	10.0
Delaware/Childers	.1% Neodol 25-9	3.0	10.0
Delaware/Childers	.1% Neodol 25-9	6.0	10.0
Delaware/Childers	.1% Neodol 25-9	0.0	10.0
Delaware/Childers	.2% Neodol 25-9	1.0	10.0
Delaware/Childers	.2% Neodol 25-9	3.0	10.0
Delaware/Childers	.2% Neodol 25-9	6.0	10.0
Delaware/Childers	.2% Neodol 25-9	10.0	10.0
Delaware/Childers	.4% Neodol 25-9	1.0	10.0
Delaware/Childers	.4% Neodol 25-9	3.0	10.0
Delaware/Childers	.4% Neodol 25-9	6.0	10.0
Delaware/Childers	.4% Neodol 25-9	10.0	10.0
Delaware/Childers	.8% Neodol 25-9	1.0	10.0
Delaware/Childers	.8% Neodol 25-9	3.0	10.0

Oil	Surfactant	NaCl, %	pH
Delaware/Childers	.8% Neodol 25-9	6.0	10.0
Delaware/Childers	.8% Neodol 25-9	10.0	10.0
Delaware/Childers	.1% Neodol 25-9	1.0	10.5
Delaware/Childers	.1% Neodol 25-9	3.0	10.5
Delaware/Childers	.1% Neodol 25-9	6.0	10.5
Delaware/Childers	.1% Neodol 25-9	10.0	10.5
Delaware/Childers	.2% Neodol 25-9	1.0	10.5
Delaware/Childers	.2% Neodol 25-9	3.0	10.5
Delaware/Childers	.2% Neodol 25-9	6.0	10.5
Delaware/Childers	.2% Neodol 25-9	10.0	10.5
Delaware/Childers	.4% Neodol 25-9	1.0	10.5
Delaware/Childers	.4% Neodol 25-9	3.0	10.5
Delaware/Childers	.4% Neodol 25-9	6.0	10.5
Delaware/Childers	.4% Neodol 25-9	10.0	10.5
Delaware/Childers	.8% Neodol 25-9	1.0	10.5
Delaware/Childers	.8% Neodol 25-9	3.0	10.5
Delaware/Childers	.8% Neodol 25-9	6.0	10.5
Delaware/Childers	.8% Neodol 25-9	10.0	10.5
Delaware/Childers	.1% Petrostep B-100	0.3	9.5
Delaware/Childers	.1% Petrostep B-100	0.6	9.5
Delaware/Childers	.1% Petrostep B-100	1.0	9.5
Delaware/Childers	.1% Petrostep B-100	3.0	9.5
Delaware/Childers	.2% Petrostep B-100	0.3	9.5
Delaware/Childers	.2% Petrostep B-100	0.6	9.5
Delaware/Childers	.2% Petrostep B-100	1.0	9.5
Delaware/Childers	.2% Petrostep B-100	3.0	9.5
Delaware/Childers	.4% Petrostep B-100	0.3	9.5
Delaware/Childers	.4% Petrostep B-100	0.6	9.5
Delaware/Childers	.4% Petrostep B-100	1.0	9.5
Delaware/Childers	.4% Petrostep B-100	3.0	9.5
Delaware/Childers	.8% Petrostep B-100	0.3	9.5
Delaware/Childers	.8% Petrostep B-100	0.6	9.5
Delaware/Childers	.8% Petrostep B-100	1.0	9.5
Delaware/Childers	.8% Petrostep B-100	3.0	9.5

Oil	Surfactant	NaCl, %	pH
Delaware/Childers	.1% Petrostep B-100	0.3	10.0
Delaware/Childers	.1% Petrostep B-100	0.6	10.0
Delaware/Childers	.1% Petrostep B-100	1.0	10.0
Delaware/Childers	.1% Petrostep B-100	3.0	10.0
Delaware/Childers	.2% Petrostep B-100	0.3	10.0
Delaware/Childers	.2% Petrostep B-100	0.6	10.0
Delaware/Childers	.2% Petrostep B-100	1.0	10.0
Delaware/Childers	.2% Petrostep B-100	3.0	10.0
Delaware/Childers	.4% Petrostep B-100	0.3	10.0
Delaware/Childers	.4% Petrostep B-100	0.6	10.0
Delaware/Childers	.4% Petrostep B-100	1.0	10.0
Delaware/Childers	.4% Petrostep B-100	3.0	10.0
Delaware/Childers	.8% Petrostep B-100	0.3	10.0
Delaware/Childers	.8% Petrostep B-100	0.6	10.0
Delaware/Childers	.8% Petrostep B-100	1.0	10.0
Delaware/Childers	.8% Petrostep B-100	3.0	10.0
Delaware/Childers	.1% Petrostep B-100	0.3	10.5
Delaware/Childers	.1% Petrostep B-100	0.6	10.5
Delaware/Childers	.1% Petrostep B-100	1.0	10.5
Delaware/Childers	.1% Petrostep B-100	3.0	10.5
Delaware/Childers	.2% Petrostep B-100	0.3	10.5
Delaware/Childers	.2% Petrostep B-100	0.6	10.5
Delaware/Childers	.2% Petrostep B-100	1.0	10.5
Delaware/Childers	.2% Petrostep B-100	3.0	10.5
Delaware/Childers	.4% Petrostep B-100	0.3	10.5
Delaware/Childers	.4% Petrostep B-100	0.6	10.5
Delaware/Childers	.4% Petrostep B-100	1.0	10.5
Delaware/Childers	.4% Petrostep B-100	3.0	10.5
Delaware/Childers	.8% Petrostep B-100	0.3	10.5
Delaware/Childers	.8% Petrostep B-100	0.6	10.5
Delaware/Childers	.8% Petrostep B-100	1.0	10.5
Delaware/Childers	.8% Petrostep B-100	3.0	10.5
Delaware/Childers	.1% Petrostep B-100	0.3	8.3
Delaware/Childers	.1% Petrostep B-100	0.6	8.3

Oil	Surfactant	NaCl, %	pH
Delaware/Childers	.1% Petrostep B-100	1.0	8.3
Delaware/Childers	.1% Petrostep B-100	3.0	8.3
Delaware/Childers	.2% Petrostep B-100	0.3	8.3
Delaware/Childers	.2% Petrostep B-100	0.6	8.3
Delaware/Childers	.2% Petrostep B-100	1.0	8.3
Delaware/Childers	.2% Petrostep B-100	3.0	8.3
Delaware/Childers	.4% Petrostep B-100	0.3	8.3
Delaware/Childers	.4% Petrostep B-100	0.6	8.3
Delaware/Childers	.4% Petrostep B-100	1.0	8.3
Delaware/Childers	.4% Petrostep B-100	3.0	8.3
Delaware/Childers	.8% Petrostep B-100	0.3	8.3
Delaware/Childers	.8% Petrostep B-100	0.6	8.3
Delaware/Childers	.8% Petrostep B-100	1.0	8.3
Delaware/Childers	.8% Petrostep B-100	3.0	8.3
Teapot Dome	.1% Petrostep B-100	0.0	8.3 and 9.5
Teapot Dome	.1% Petrostep B-100	0.15	8.3 and 9.5
Teapot Dome	.1% Petrostep B-100	0.30	8.3 and 9.5
Teapot Dome	.1% Petrostep B-100	0.60	8.3 and 9.5
Teapot Dome	.1% Petrostep B-100	1.0	8.3 and 9.5
Teapot Dome	.1% Petrostep B-100	1.5	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	0.0	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	1.0	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	2.0	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	3.0	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	6.0	8.3 and 9.5
Teapot Dome	.1% Neodol 25-9	10.0	8.3 and 9.5
Hepler	.1% GAF T-33	3.0	unadjusted and pH 9.5
Hepler	.1% GAF T-33	5.0	unadjusted and pH 9.5
Hepler	.1% GAF T-33	7.0	unadjusted and pH 9.5
Hepler	.1% GAF T-33	9.0	unadjusted and pH 9.5
Hepler	.1% GAF CA-720	3.0	unadjusted and pH 9.5
Hepler	.1% GAF CA-720	5.0	unadjusted and pH 9.5
Hepler	.1% GAF CA-720	7.0	unadjusted and pH 9.5
Hepler	.1% GAF CA-720	9.0	unadjusted and pH 9.5

Oil	Surfactant	NaCl, %	pH
Hepler	.1% GAF CO-730	3.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-730	5.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-730	7.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-730	9.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-850	3.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-850	5.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-850	7.0	unadjusted and pH 9.5
Hepler	.1% GAF CO-850	9.0	unadjusted and pH 9.5
Hepler	.1% Petrostep B-120	2.0	9.5
Hepler	.1% Petrostep B-120	2.12	9.5
Hepler	.1% Petrostep B-120	2.25	9.5
Hepler	.1% Petrostep B-120	2.38	9.5
Hepler	.1% Petrostep B-120	2.50	9.5
Hepler	.2% Petrostep B-120	2.0	9.5
Hepler	.2% Petrostep B-120	2.12	9.5
Hepler	.2% Petrostep B-120	2.25	9.5
Hepler	.2% Petrostep B-120	2.38	9.5
Hepler	.2% Petrostep B-120	2.50	9.5
Hepler	.3% Petrostep B-120	1.0	9.5
Hepler	.3% Petrostep B-120	1.5	9.5
Hepler	.3% Petrostep B-120	2.0	9.5
Hepler	.3% Petrostep B-120	2.5	9.5
Hepler	.3% Petrostep B-120	3.0	9.5
Hepler	.4% Petrostep B-120	1.0	9.5
Hepler	.4% Petrostep B-120	1.5	9.5
Hepler	.4% Petrostep B-120	2.0	9.5
Hepler	.4% Petrostep B-120	2.5	9.5
Hepler	.4% Petrostep B-120	3.0	9.5
Hepler	.4% Neodol 25-3	0.0	9.5
Hepler	.4% Neodol 25-3	0.5	9.5
Hepler	.4% Neodol 25-3	1.0	9.5
Hepler	.4% Neodol 25-3	1.5	9.5
Hepler	.4% Neodol 25-3	2.0	9.5
Hepler	.4% Neodol 25-3	3.0	9.5

Oil	Surfactant	NaCl, %	pH
Hepler	.4% Neodol 25-3	5.0	9.5
Hepler	.4% Neodol 25-3S	0.0	9.5
Hepler	.4% Neodol 25-3S	0.5	9.5
Hepler	.4% Neodol 25-3S	1.0	9.5
Hepler	.4% Neodol 25-3S	1.5	9.5
Hepler	.4% Neodol 25-3S	2.0	9.5
Hepler	.4% Neodol 25-3S	3.0	9.5
Hepler	.4% Neodol 25-3S	5.0	9.5
Hepler	.4% Neodol 91-2.5	0.0	9.5
Hepler	.4% Neodol 91-2.5	0.5	9.5
Hepler	.4% Neodol 91-2.5	1.0	9.5
Hepler	.4% Neodol 91-2.5	1.5	9.5
Hepler	.4% Neodol 91-2.5	2.0	9.5
Hepler	.4% Neodol 91-2.5	3.0	9.5
Hepler	.4% Neodol 91-2.5	5.0	9.5
Hepler	.4% Neodol 91-6	0.0	9.5
Hepler	.4% Neodol 91-6	0.5	9.5
Hepler	.4% Neodol 91-6	1.0	9.5
Hepler	.4% Neodol 91-6	1.5	9.5
Hepler	.4% Neodol 91-6	2.0	9.5
Hepler	.4% Neodol 91-6	3.0	9.5
Hepler	.4% Neodol 91-6	5.0	9.5
Hepler	.4% Neodol 45-13	0.0	9.5
Hepler	.4% Neodol 45-13	0.5	9.5
Hepler	.4% Neodol 45-13	1.0	9.5
Hepler	.4% Neodol 45-13	1.5	9.5
Hepler	.4% Neodol 45-13	2.0	9.5
Hepler	.4% Neodol 45-13	3.0	9.5
Hepler	.4% Neodol 45-13	5.0	9.5
Hepler	.2% Neodol 25-7	0.0	9.5
Hepler	.2% Neodol 25-7	0.5	9.5
Hepler	.2% Neodol 25-7	1.5	9.5
Hepler	.2% Neodol 25-7	2.0	9.5
Hepler	.2% Neodol 25-7	3.0	9.5

Oil	Surfactant	NaCl, %	pH
Hepler	.2% Neodol 25-7	5.0	9.5
Hepler	.4% Neodol 25-7	0.0	9.5
Hepler	.4% Neodol 25-7	0.5	9.5
Hepler	.4% Neodol 25-7	1.0	9.5
Hepler	.4% Neodol 25-7	1.5	9.5
Hepler	.4% Neodol 25-7	2.0	9.5
Hepler	.4% Neodol 25-7	3.0	9.5
Hepler	.4% Neodol 25-7	5.0	9.5
Hepler	.6% Neodol 25-7	0.0	9.5
Hepler	.6% Neodol 25-7	0.5	9.5
Hepler	.6% Neodol 25-7	1.0	9.5
Hepler	.6% Neodol 25-7	1.5	9.5
Hepler	.6% Neodol 25-7	2.0	9.5
Hepler	.6% Neodol 25-7	3.0	9.5
Hepler	.6% Neodol 25-7	5.0	9.5
Hepler	.2% Neodol 25-9	0.0	9.5
Hepler	.2% Neodol 25-9	0.5	9.5
Hepler	.2% Neodol 25-9	1.0	9.5
Hepler	.2% Neodol 25-9	1.5	9.5
Hepler	.2% Neodol 25-9	2.0	9.5
Hepler	.2% Neodol 25-9	3.0	9.5
Hepler	.2% Neodol 25-9	5.0	9.5
Hepler	.4% Neodol 25-9	0.0	9.5
Hepler	.4% Neodol 25-9	0.5	9.5
Hepler	.4% Neodol 25-9	1.0	9.5
Hepler	.4% Neodol 25-9	1.5	9.5
Hepler	.4% Neodol 25-9	2.0	9.5
Hepler	.4% Neodol 25-9	3.0	9.5
Hepler	.4% Neodol 25-9	5.0	9.5
Hepler	.6% Neodol 25-9	0.0	9.5
Hepler	.6% Neodol 25-9	0.5	9.5
Hepler	.6% Neodol 25-9	1.0	9.5
Hepler	.6% Neodol 25-9	1.5	9.5
Hepler	.6% Neodol 25-9	2.0	9.5

Oil	Surfactant	NaCl, %	pH
Hepler	.6% Neodol 25-9	3.0	9.5
Hepler	.6% Neodol 25-9	5.0	9.5
Hepler	.2% Neodol 25-12	0.0	9.5
Hepler	.2% Neodol 25-12	0.5	9.5
Hepler	.2% Neodol 25-12	1.0	9.5
Hepler	.2% Neodol 25-12	1.5	9.5
Hepler	.2% Neodol 25-12	2.0	9.5
Hepler	.2% Neodol 25-12	3.0	9.5
Hepler	.2% Neodol 25-12	5.0	9.5
Hepler	.4% Neodol 25-12	0.0	9.5
Hepler	.4% Neodol 25-12	0.5	9.5
Hepler	.4% Neodol 25-12	1.0	9.5
Hepler	.4% Neodol 25-12	1.5	9.5
Hepler	.4% Neodol 25-12	2.0	9.5
Hepler	.4% Neodol 25-12	3.0	9.5
Hepler	.4% Neodol 25-12	5.0	9.5
Hepler	.6% Neodol 25-12	0.0	9.5
Hepler	.6% Neodol 25-12	0.5	9.5
Hepler	.6% Neodol 25-12	1.0	9.5
Hepler	.6% Neodol 25-12	1.5	9.5
Hepler	.6% Neodol 25-12	2.0	9.5
Hepler	.6% Neodol 25-12	3.0	9.5
Hepler	.6% Neodol 25-12	5.0	9.5

Coreflood Reports

NOTEBOOK: A528	P. 41	OPERATOR: C. JOSEPHSON
CORE NUMBER: TP-1		DATE: 5/15/90
CORE TYPE: Berea Hi Perm		CLIENT: BE4A

CORE DIMENSIONS	
LENGTH(cm): 25.56	DIAMETER(cm): 3.81
BULK VOLUME(cc): 291.41	

COREFLOOD SET-UP:	
ENCAPSULATION: Hassler	TEMP (°C): 52° C
OVERBURDEN(psi): 175	BACKPRESSURE(psi): atmosphere

COREFLOOD FLUIDS
BRINE COMP: 0.3g NaCl/100ml
OIL: Teapot Dome Naval Petroleum Reserve
SURF(S). COMP: 0.1% Petrostep B-100, .095N Na ₂ CO ₃ , .095 N NaHCO ₃ , 2000ppm Pfizer 4800 Cx polymer, 500ppm HCHO, μ at 52° C: 60 rpm = 7.36, 3 rpm = 39.0 cp 0.3% NaCl.
0.1% Petrostep B-100, .095N Na ₂ CO ₃ , .095 N NaHCO ₃ , 1000ppm Pfizer 4800 Cx polymer, 500ppm HCHO μ at 52°C: 60 rpm = 3.61, 3 rpm = 12.6 cp
POLYMER: no separate polymer slug following the chemical slug
TRACER: none

PURPOSE OF THE FLOOD:
Test ASP flood after waterflood to residual So.
This report contains only the waterflood recovery.

ADDITIONAL NOTES:
During saturation with oil, 49.10 ml of brine was displaced. WF displaced 22.74 ml of oil. (See report -ASP.) ASP formulation displaced 16.04 ml of oil. The report section for this coreflood report includes ONLY THE WF RESULTS.
Porosity = 22.89% K brine = 811 md.

REPORT SECTION

PV (ml):	66.71	Sat. %	Oil Rec. ml	POROSITY:	22.89	Percent
INITIAL OIL SATN.(ml):	49.10	73.60	---	PERMEABILITY:	see above	md
INITIAL OIL SATN.(ml):	49.10	73.60		OIL TYPE:	Teapot Dome	
REM. OIL AFTER WATERFLOOD(ml):	26.36	39.51	22.74	OIL VISCOSITY:	9.07	cP
RECOVERY EFFICIENCY (%):	46.31			OIL DENSITY:		g/cc

WATERFLOOD RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socf (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)
0	0.00	0.00	0.00	0.00	0.00	73.60	0.00	0.0000		
1	2.00	0.00	2.00	2.00	2.00	70.60	4.07	0.0300	∞	100.00
2	5.50	0.00	5.50	7.50	7.50	62.36	15.27	0.1124	∞	100.00
3	5.35	0.00	5.35	12.85	12.85	54.34	26.17	0.1926	∞	100.00
4	5.45	0.00	5.45	18.30	18.30	46.17	37.27	0.2743	∞	100.00
5	5.40	1.50	3.90	23.70	22.20	40.32	45.21	0.3553	2.6000	72.22
6	5.70	5.65	0.05	29.40	22.25	40.25	45.32	0.4407	0.0088	0.88
7	5.80	5.60	0.20	35.20	22.45	39.95	45.72	0.5277	0.0357	3.45
8	5.70	5.60	0.10	40.90	22.55	39.80	45.93	0.6121	0.0179	1.75
9	5.82	5.80	0.02	46.72	22.57	39.77	45.97	0.7003	0.0034	0.34
10	5.75	5.70	0.05	52.47	22.62	39.69	46.07	0.7865	0.0088	0.87
11	5.77	5.75	0.02	58.24	22.64	39.66	46.11	0.8730	0.0035	0.35
12	5.72	5.70	0.02	63.96	22.66	39.63	46.15	0.9588	0.0035	0.35
13	5.81	5.80	0.01	69.77	22.67	39.62	46.17	1.0459	0.0017	0.17
14	5.75	5.75	0.00	75.52	22.67	39.62	46.17	1.1321	0.0000	0.00
15	5.71	5.70	0.01	81.23	22.68	39.60	46.19	1.2177	0.0018	0.18
16	5.66	5.65	0.01	86.89	22.69	39.59	46.21	1.3025	0.0018	0.13
17	5.81	5.80	0.01	92.70	22.70	39.57	46.23	1.3896	0.0017	0.17
18	5.75	5.75	0.00	98.45	22.70	39.57	46.23	1.4758	0.0000	0.00
19	5.70	5.70	0.00	104.15	22.70	39.57	46.23	1.5612	0.0000	0.00
20	5.70	5.70	0.00	109.85	22.70	39.57	46.23	1.6467	0.0000	0.00
21	5.65	5.65	0.00	115.50	22.70	39.57	46.23	1.7314	0.0000	0.00
22	5.81	5.80	0.01	121.31	22.71	39.56	46.25	1.8185	0.0017	0.17
23	5.60	5.60	0.00	126.91	22.71	39.56	46.25	1.9024	0.0000	0.00
24	7.13	7.10	0.03	134.04	22.74	39.51	46.31	2.0093	0.0042	0.42

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 41	OPERATOR: C. JOSEPHSON
CORE NUMBER: TP-1	DATE: 5/15/90
CORE TYPE: Berea Hi Perm	CLIENT: BE4A

LENGTH(cm): 25.56	DIAMETER(cm): 3.81	BULK VOLUME(cc): 291.41
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ENCAPSULATION: Hassler	TEMP (°C): 52° C
OVERBURDEN(psi): 175	BACKPRESSURE(psi): atmosphere

COREFLOOD SET-UP:
BRINE COMP: 0.3g NaCl/100ml
OIL: Teapot Dome Naval Petroleum Reserve
SURF(S). COMP: 0.1% Petrostep B-100, .095N Na ₂ CO ₃ , .095 N NaHCO ₃ , 2000ppm Pfizer 4800 CX polymer, 500ppm HCHO, 0.3% NaCl. μ at 52° C: 60 rpm = 7.36, 3 rpm = 39.0 cP
0.1% Petrostep B-100, .095N Na ₂ CO ₃ , .095 N NaHCO ₃ , 1000ppm Pfizer 4800 CX polymer, 500ppm HCHO μ at 52° C: 60 rpm = 3.61, 3 rpm = 12.6 cP
POLYMER: no separate polymer slug following the chemical slug
TRACER: none

PURPOSE OF THE FLOOD:
Test ASP flood after waterflood to residual So.
This report contains only the 3° recovery.

ADDITIONAL NOTES:
During saturation with oil, 49.10 ml of brine was displaced.
WF displaced 22.74 ml of oil. (See report -WF.)
ASP formulation displaced 16.04 ml of oil.
The report section for this coreflood report includes ONLY THE 3° RESULTS.
All CTAB samples were 2.000 ml
Titration of 2.000 ml inj solution required 1.013 ml CTAB, 0.00243 Meq/ml

REPORT SECTION

PV (ml):	66.71	Sat. %:	22.89	Percent
INITIAL OIL SATN (ml):	49.10	73.60	see above	md
REM. OIL AFTER WATERFLOOD(ml):	26.36	39.51	OIL TYPE: Teapot Dome	
REM. OIL AFTER CHEMICAL FLOOD (ml):	10.32	15.47	OIL VISCOSITY: 9.07	cP
RECOVERY EFFICIENCY (%):	60.85		OIL DENSITY:	g/cc

TERTIARY RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT VOL (ml)	SUM of OIL VOL (ml)	Res Oil Sat: Socd (%PV)	Oil Rec (%OIP)	PV Injected	Oil:Water Ratio	Oil Cut (%)	Initial pH	Alkalinity meq/gm	Comments	μ , cP 52°C 60 rpm	Surf Conc meq/ml
25	4.40	4.30	0.10	4.40	0.10	39.36	0.38	0.0660	0.0233	0.18	7.68	0.00178	begin 2K ppm slug	0.55	0
26	5.61	5.60	0.01	10.01	0.11	39.35	0.42	0.1501	0.0018	0.52					0
27	5.73	5.70	0.03	15.74	0.14	39.30	0.53	0.2359	0.0053	0.35	8.08	0.00279		0.62	0
28	5.67	5.65	0.02	21.41	0.16	39.27	0.61	0.3209	0.0035	2.65					0
29	5.65	5.50	0.15	27.06	0.31	39.05	1.18	0.4056	0.0273	40.35					0
30	5.70	3.40	2.30	32.76	2.51	35.60	9.90	0.4911	0.6765	37.50					0
31	5.60	3.50	2.10	38.36	4.71	32.45	17.87	0.5750	0.6000	36.28					
32	5.65	3.60	2.05	44.01	6.76	29.38	25.64	0.6597	0.5694	27.93	7.96	0.00252	end 2K ppm slug	1.4	
33	5.55	4.00	1.55	49.56	8.31	27.06	31.53	0.7429	0.3875	23.08			begin 1K ppm slug		0
34	1.30	1.00	0.30	50.86	8.61	25.61	32.66	0.7624	0.3000	22.52					
35	5.55	4.30	1.25	56.41	9.86	24.73	37.41	0.8456	0.2907	22.41	9.30	0.05251	end 1K ppm slug	5.24	
36	5.80	4.50	1.30	62.21	11.16	22.79	42.34	0.9325	0.2889	15.74			begin chase brine		
37	5.40	4.55	0.85	67.61	12.01	21.51	45.56	1.0135	0.1868	15.09					0
38	5.30	4.50	0.80	72.91	12.81	20.31	48.60	1.0929	0.1778	14.53					
39	5.85	5.00	0.85	78.76	13.66	19.04	51.82	1.1806	0.1700	12.71	9.58	0.16918			0.0000624
40	5.90	5.15	0.75	84.66	14.41	17.91	54.67	1.2691	0.1456	9.48					0.0008352
41	5.80	5.25	0.55	90.46	14.96	17.09	56.75	1.3560	0.1048	0.51	9.71	0.16008		4.08	0.001128
42	5.83	5.80	0.03	96.29	14.99	16.67	56.87	1.4434	0.0052	4.27					
43	5.85	5.60	0.25	102.14	15.24	16.37	57.81	1.5311	0.0446	3.39					
44	5.90	5.70	0.20	108.04	15.44	16.37	58.57	1.6195	0.0351	0.51	9.68	0.10833		1.86	0.0016728
45	5.83	5.80	0.03	113.87	15.47	16.32	58.69	1.7069	0.0052	0.34					0.00156
46	5.82	5.80	0.02	119.69	15.49	16.29	58.76	1.7942	0.0034	0.00	9.62	0.07015		1.24	0.001416
47	5.80	5.80	0.00	125.49	15.49	16.29	58.95	1.8811	0.0000	0.85	9.59	0.04982			0.00108
48	5.85	5.80	0.05	131.34	15.54	16.22	59.25	2.0558	0.0086	8.62					
49	5.80	5.30	0.50	137.14	16.04	15.47	60.85	2.1427	0.0943	0.00	9.47	0.03730		0.97	0.000576
50	5.80	5.80	0.00	142.94	16.04	15.47	60.85	2.2297	0.0000	0.00					
51	5.80	5.80	0.00	148.74	16.04	15.47	60.85	2.3158	0.0000	0.00					
52	5.75	5.75	0.00	154.49	16.04	15.47	60.85	2.4028	0.0000	0.00					
53	5.80	5.80	0.00	160.29	16.04	15.47	60.85	2.4897	0.0000	0.00	9.41	0.02497		0.89	0.0002928
54	5.80	5.80	0.00	166.09	16.04	15.47	60.85	2.5752	0.0000	0.00					
55	5.70	5.70	0.00	171.79	16.04	15.47	60.85	2.6606	0.0000	0.00					
56	5.70	5.70	0.00	177.49	16.04	15.47	60.85	2.7446	0.0000	0.00	9.27	0.01781		0.76	
57	5.60	5.60	0.00	183.09	16.04	15.47	60.85	2.8338	0.0000	0.00					
58	5.95	5.95	0.00	189.04	16.04	15.47	60.85	2.9207	0.0000	0.00					0.0002112
59	5.80	5.80	0.00	194.84	16.04	15.47	60.85	3.0051	0.0000	0.00	9.20	0.01296		0.76	
60	5.70	5.70	0.00	200.54	16.04	15.47	60.85	3.0923	0.0000	0.00					
61	5.75	5.75	0.00	206.29	16.04	15.47	60.85	3.1778	0.0000	0.00					
62	5.70	5.70	0.00	211.99	16.04	15.47	60.85	3.2572	0.0000	0.00	8.87	0.01143		0.67	0.0003144
63	5.30	5.30	0.00	217.29	16.04	15.47	60.85								

DCNS -1 COREFLOOD

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 30
 CORE NUMBER: DCNS 1
 CORE TYPE: NATIVE STATE DELAWARE CHILDERS
 PLUGS 649.93, 649.78, 649.47, 652.36
 OPERATOR: C. JOSEPHSON
 DATE: 4/26/90
 CLIENT: BE4A

CORE DIMENSIONS
 LENGTH(cm): 24.14 DIAMETER(cm): 3.81 BULK VOLUME(cc): 275.22

COREFLOOD SET-UP:
 ENCAPSULATION: HASSLER
 OVERBURDEN(psi): 175
 TEMP (°C): 30.00
 BACKPRESSURE(psi): ATMOSPHERIC

COREFLOOD FLUIDS
 BRINE COMP: 0.88 g NaCl/100ml
 OIL: Delaware Childers (native-state, no oil added after receiving core)
 SURF(S). COMP: 0.2% Petrostep B-100, 1.6% NaHCO₃, 1200ppm Pfizer 4800 CX polymer, 500ppm HCHO
 POLYMER: no separate polymer, μ of inj. fluid = 5.47 at 60 rpm, 30° C
 TRACER: none
 ALKALINITY: measured alkalinity = 0.1849 Meq/g

PURPOSE OF THE FLOOD:

Test ASP flood for recovery of oil from native state core.
 No recovery from WF.
 Max WF frontal advance rate 24.85 ft./D

ADDITIONAL NOTES:

Waterflood produced no oil at low or high water inj. rates.
 3° flood at 1 ft/D and no oil was produced from cores.
 Core Dean Stark extraction gave following results:
 95.9% of inj. alkalinity measured in effluent.
 Porosities = 23.4, 22.6, 22.65, 23.05 (Mean = 22.92)
 Kair = 247, 195, 199, 218
 So = 20.0, 24.1 Sw = 75.7, 73.5 Sg = 4.3, 2.4

REPORT SECTION

PV (ml):	63.37	Sat. %	Oil Rec. ml	POROSITY: 23.03	Percent
INITIAL OIL SATN. (ml):	14.00	22.09	---	PERMEABILITY: see above	md
REM. OIL AFTER WATERFLOOD (ml):	14.00	22.09	0.00	OIL TYPE: Del. Childers	cP
REM. OIL AFTER CHEMICAL FLOOD (ml):	14.00	22.09	0.00	OIL VISCOSITY: 9.80	g/cc
RECOVERY EFFICIENCY (%):	0.00			OIL DENSITY: 0.8501	

TERTIARY RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL. (ml)	Res Oil Satn. (%PV)	Oil Rec. (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	Initial pH	Alkalinity meq/gm	Comments	μ, 60 rpm, 30°C
0	0.00	0.00	0.00	0.00	0.00	22.09	0.00	0.0000	0.0000	0.00	7.1500	0.0020	Begin 3 rd Flood	0.96
1	4.10	4.10	0.00	4.10	0.00	22.09	0.00	0.0647	0.0000	0.00				
2	4.75	4.75	0.00	8.85	0.00	22.09	0.00	0.1397	0.0000	0.00	7.89	0.0051		0.96
3	4.60	4.60	0.00	13.45	0.00	22.09	0.00	0.2122	0.0000	0.00				
4	4.60	4.60	0.00	18.05	0.00	22.09	0.00	0.2848	0.0000	0.00	8	0.0053		
5	4.70	4.70	0.00	22.75	0.00	22.09	0.00	0.3590	0.0000	0.00				
6	4.55	4.55	0.00	27.30	0.00	22.09	0.00	0.4306	0.0000	0.00	7.37	0.0041		1.1
7	4.70	4.70	0.00	32.00	0.00	22.09	0.00	0.5050	0.0000	0.00	7.67	0.0051		1.48
8	4.80	4.80	0.00	36.80	0.00	22.09	0.00	0.5807	0.0000	0.00		0.0065		2.64
9	4.90	4.90	0.00	41.70	0.00	22.09	0.00	0.6580	0.0000	0.00				3.63
10	4.30	4.30	0.00	46.00	0.00	22.09	0.00	0.7259	0.0000	0.00			last tube of 3 rd inj.	4.08
11	3.65	3.65	0.00	49.65	0.00	22.09	0.00	0.7835	0.0000	0.00	8.81	0.0607	begin chase brine	4.37
12	4.80	4.80	0.00	54.45	0.00	22.09	0.00	0.8592	0.0000	0.00				4.54
13	4.95	4.95	0.00	59.40	0.00	22.09	0.00	0.9374	0.0000	0.00	8.83	0.1313		4.7
14	4.90	4.90	0.00	64.30	0.00	22.09	0.00	1.0147	0.0000	0.00				4.28
15	4.90	4.90	0.00	69.20	0.00	22.09	0.00	1.0920	0.0000	0.00	8.92	0.1647		3.47
16	4.80	4.80	0.00	74.00	0.00	22.09	0.00	1.1677	0.0000	0.00	8.88	0.1260		2.55
17	5.05	5.05	0.00	79.05	0.00	22.09	0.00	1.2474	0.0000	0.00	8.91	0.1049		
18	4.90	4.90	0.00	83.95	0.00	22.09	0.00	1.3248	0.0000	0.00	8.93	0.0866		2.08
19	4.95	4.95	0.00	88.90	0.00	22.09	0.00	1.4029	0.0000	0.00	8.85			
20	5.00	5.00	0.00	93.90	0.00	22.09	0.00	1.4818	0.0000	0.00	8.83	0.0797		1.86
21	5.10	5.10	0.00	99.00	0.00	22.09	0.00	1.5623	0.0000	0.00				
22	5.05	5.05	0.00	104.05	0.00	22.09	0.00	1.6419	0.0000	0.00	8.8	0.0656		1.46
23	4.80	4.80	0.00	108.85	0.00	22.09	0.00	1.7177	0.0000	0.00				
24	4.85	4.85	0.00	113.70	0.00	22.09	0.00	1.7942	0.0000	0.00	8.78	0.0391		1.39
25	2.35	2.35	0.00	116.05	0.00	22.09	0.00	1.8313	0.0000	0.00				

DCNS-2-WF COREFLOOD

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 37 CORE NUMBER: 649.17, 649.33, 652.08, 652.22 CORE TYPE: <u>NATIVE STATE DELAWARE-CHILDERS</u>		OPERATOR: C. JOSEPHSON DATE: 5/10/90 CLIENT: BE4A	
CORE DIMENSIONS			
LENGTH(cm):	23.06	DIAMETER(cm):	3.81
		BULK VOLUME(cc):	262.91
ENCAPSULATION: Hassler		TEMP (°C): 30.00	
OVERBURDEN(psi): 175		BACKPRESSURE(psi): <u>ATMOSPHERIC</u>	
COREFLOOD SET-UP:			
COREFLOOD FLUIDS			
BRINE COMP: 0.88g NaCl/100ml OIL: Delaware Childers (this native state core was oil flooded before WF) SURF(S). COMP: 0.2% Petrostep B-100, 1.6% NaHCO ₃ , 1200ppm Pfizer 4800 Cx polymer, 500ppm HCHO POLYMER: no separate polymer slug following the chemical slug TRACER: none			
PURPOSE OF THE FLOOD:			
Test ASP flood at higher initial So than flood DCNS-1. For this purpose, saturate core plugs with D. C. oil before WF.			
A WF was performed before oil saturation and produced no oil (1 ft/D).			
ADDITIONAL NOTES:			
Kair = 33.54, 136.24, 183.64, 218.11 Native state saturations (back calculated): So =< 28.52, Sw >= 66.96, Sg >= 4.51 Porosity = 17.74, 21.48, 22.05, 21.48			
During saturation with oil, 20.55 ml of brine was displaced. WF displaced 14.75 ml of oil. ASP formulation displaced 3.62 ml of oil. The report section for this coreflood report (DCNS-2-WF) includes ONLY THE WF RESULTS.			

REPORT SECTION

PV (ml):	57.01	Sat. %	Oil Rec., ml	POROSITY:	20.63	Percent
INITIAL OIL SATN.(ml):	36.81	64.56	---	PERMEABILITY:	see above	md
REM. OIL AFTER WATERFLOOD(ml):	22.06	38.69	14.75	OIL TYPE:	D. Childers	
REM. OIL AFTER CHEMICAL FLOOD(ml):				OIL VISCOSITY:	9.80	cP
RECOVERY EFFICIENCY (%):				OIL DENSITY:	0.8479@30	g/cc

WATERFLOOD RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socr (%PV)	Oil Rec (% OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)
0	0.00	0.00	0.00	0.00	0.00	64.56	0.00	0.0000		
1	3.95	0.00	3.95	3.95	3.95	57.64	10.73	0.0693	∞	100.00
2	4.85	0.00	4.85	8.80	8.80	49.13	23.91	0.1544	∞	100.00
3	4.95	2.55	2.40	13.75	11.20	44.92	30.43	0.2412	0.9412	48.48
4	4.90	4.10	0.80	18.65	12.00	43.52	32.60	0.3271	0.1951	16.33
5	4.90	4.50	0.40	23.55	12.40	42.81	33.69	0.4131	0.0889	8.16
6	5.00	4.60	0.40	28.55	12.80	42.11	34.77	0.5008	0.0870	8.00
7	4.95	4.60	0.35	33.50	13.15	41.50	35.72	0.5876	0.0761	7.07
8	5.00	4.70	0.30	38.50	13.45	40.97	36.54	0.6753	0.0638	6.00
9	5.00	4.70	0.30	43.50	13.75	40.45	37.35	0.7630	0.0638	6.00
10	5.05	4.75	0.30	48.55	14.05	39.92	38.17	0.8516	0.0632	5.94
11	5.15	5.05	0.10	53.70	14.15	39.75	38.44	0.9419	0.0198	1.94
12	5.05	4.90	0.15	58.75	14.30	39.48	38.85	1.0305	0.0306	2.97
13	5.00	4.90	0.10	63.75	14.40	39.31	39.12	1.1182	0.0204	2.00
14	5.00	4.90	0.10	68.75	14.50	39.13	39.39	1.2059	0.0204	2.00
15	5.05	4.95	0.10	73.80	14.60	38.96	39.66	1.2944	0.0202	1.98
16	4.95	4.90	0.05	78.75	14.65	38.87	39.80	1.3813	0.0102	1.01
17	4.20	4.10	0.10	82.95	14.75	38.69	40.07	1.4549	0.0244	2.38

DCNS-2-ASP COREFLOOD

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 37 CORE NUMBER: 649.17, 649.33, 652.08, 652.22 CORE TYPE: NATIVE STATE DELAWARE-CHILDERS		OPERATOR: C. JOSEPHSON DATE: 5/10/90 CLIENT: BE4A	
CORE DIMENSIONS			
LENGTH(cm):	23.06	DIAMETER(cm):	3.81
		BULK VOLUME(cc):	262.91
COREFLOOD SET-UP:			
ENCAPSULATION: Hassler		TEMP (°C): 30.00	
OVERBURDEN(psi): 175		BACKPRESSURE(psi): atmospheric	
COREFLOOD FLUIDS			
BRINE COMP: 0.85g NaCl/100ml OIL: Delaware Childers (this native state core was oil flooded before WF) SURF(S). COMP: 0.2% Petrostep B-100, 1.6% NaHCO ₃ , 1200ppm Pfizer 4800 Cx polymer, 500ppm HCHO POLYMER: no separate polymer slug following the chemical slug TRACER: none			
PURPOSE OF THE FLOOD:			
Test: ASP flood at higher initial So than flood DCNS-1. For this purpose, saturate core plugs with D. C. oil before WF. This report contains only the 3° recovery.			
ADDITIONAL NOTES:			
During saturation with oil, 20.55 ml of brine was displaced. WF displaced 14.75 ml of oil. (See report DCNS-2-WF.) ASP formulation displaced 3.62 ml of oil. The report section for this coreflood report (DCNS-2-ASP) includes ONLY THE 3° RESULTS.			

REPORT SECTION

PV (ml):	57.01	Sat. %	Oil Rec. ml	POROSITY: 20.69	Percent
INITIAL OIL SATN.(ml):	36.81	64.56	---	PERMEABILITY: see above	md
REM. OIL AFTER WATERFLOOD(ml):	22.06	38.69	14.75	OIL TYPE: D. Childers	
REM. OIL AFTER CHEMICAL FLOOD (ml)	18.44	32.34	3.62	OIL VISCOSITY: 9.80	cP
RECOVERY EFFICIENCY (%):	16.41			OIL DENSITY: 0.8479@30	g/cc

TERTIARY RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socf (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	pH	Comments
18	3.40	3.30	0.10	3.40	0.10	38.52	0.45	0.0596	0.0303	2.94		begin chem flood
19	3.73	3.70	0.03	7.13	0.13	38.46	0.59	0.1251	0.0081	0.80		
20	3.62	3.60	0.02	10.75	0.15	38.43	0.68	0.1886	0.0056	0.55		
21	3.77	3.75	0.02	14.52	0.17	38.39	0.77	0.2547	0.0053	0.53		
22	3.85	3.80	0.05	18.37	0.22	38.31	1.00	0.3222	0.0132	1.30		
23	3.80	3.55	0.25	22.17	0.47	37.87	2.13	0.3889	0.0704	6.58		
24	3.90	3.70	0.20	26.07	0.67	37.52	3.04	0.4573	0.0541	5.13		
25	3.95	3.60	0.35	30.02	1.02	36.90	4.62	0.5255	0.0972	8.86		
26	3.85	3.35	0.50	33.87	1.52	36.03	6.89	0.5941	0.1493	12.99		
27	3.75	3.25	0.50	37.62	2.02	35.15	9.16	0.6598	0.1538	13.33		
28	3.90	3.65	0.25	41.52	2.27	34.71	10.29	0.7283	0.0685	6.41		
29	3.75	3.45	0.30	45.27	2.57	34.19	11.65	0.7940	0.0870	8.00		end chem flood
30	1.70	1.50	0.20	46.97	2.77	33.83	12.56	0.8238	0.1333	11.76		begin brine
31	2.55	2.35	0.20	49.52	2.97	33.48	13.46	0.8686	0.0851	7.84		
32	4.05	3.90	0.15	53.57	3.12	33.22	14.14	0.9396	0.0385	3.70		
33	4.00	3.85	0.15	57.57	3.27	32.96	14.82	1.0098	0.0390	3.75		
34	4.00	3.85	0.15	61.57	3.42	32.69	15.50	1.0799	0.0390	3.75		
35	3.90	3.85	0.05	65.47	3.47	32.61	15.73	1.1483	0.0130	1.28		
36	4.00	3.90	0.10	69.47	3.57	32.43	16.18	1.2185	0.0256	2.50		
37	3.91	3.90	0.01	73.38	3.58	32.41	16.23	1.2871	0.0026	0.26		
38	3.82	3.80	0.02	77.20	3.60	32.38	16.32	1.3541	0.0053	0.52		
39	3.85	3.85	0.00	81.05	3.60	32.38	16.32	1.4216	0.0000	0.00		
40	3.92	3.90	0.02	84.97	3.62	32.34	16.41	1.4904	0.0051	0.51		
41	3.70	3.70	0.00	88.67	3.62	32.34	16.41	1.5553	0.0000	0.00		
42	3.60	3.60	0.00	92.27	3.62	32.34	16.41	1.6184	0.0000	0.00		
43	3.90	3.90	0.00	96.17	3.62	32.34	16.41	1.6868	0.0000	0.00		
44	3.70	3.70	0.00	99.87	3.62	32.34	16.41	1.7517	0.0000	0.00		
45	3.80	3.80	0.00	103.67	3.62	32.34	16.41	1.8184	0.0000	0.00		
46	3.85	3.85	0.00	107.52	3.62	32.34	16.41	1.8859	0.0000	0.00		
47	3.80	3.80	0.00	111.32	3.62	32.34	16.41	1.9525	0.0000	0.00		

DCNS-2-ASP COREFLO00

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat (Soct) (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	pH	Comments
48	3.70	3.70	0.00	115.02	3.62	32.34	16.41	2.0174	0.0000	0.00		
49	3.80	3.80	0.00	118.82	3.62	32.34	16.41	2.0841	0.0000	0.00		
50	3.85	3.85	0.00	122.67	3.62	32.34	16.41	2.1516	0.0000	0.00		
51	3.85	3.85	0.00	126.52	3.62	32.34	16.41	2.2191	0.0000	0.00		
52	3.80	3.80	0.00	130.32	3.62	32.34	16.41	2.2858	0.0000	0.00		
53	3.70	3.70	0.00	134.02	3.62	32.34	16.41	2.3507	0.0000	0.00		
54	3.90	3.90	0.00	137.92	3.62	32.34	16.41	2.4191	0.0000	0.00		
55	3.80	3.80	0.00	141.72	3.62	32.34	16.41	2.4857	0.0000	0.00		
56	3.85	3.85	0.00	145.57	3.62	32.34	16.41	2.5533	0.0000	0.00		
57	3.80	3.80	0.00	149.37	3.62	32.34	16.41	2.6199	0.0000	0.00		
58	1.90	1.90	0.00	151.27	3.62	32.34	16.41	2.6533	0.0000	0.00		

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 48	OPERATOR: C. JOSEPHSON
CORE NUMBER: DCNS 1	DATE: 6/7/90
CORE TYPE: NATIVE STATE DELAWARE CHILDERS	CLIENT: BE4A
PLUGS 676.53, 676.93, 676.79, 677.07	

CORE DIMENSIONS	
LENGTH(cm): 22.39	DIAMETER(cm): 3.81
BULK VOLUME(cc): 255.27	

COREFLOOD SET-UP:	
ENCAPSULATION: HASSLER	TEMP (°C): 30.00
OVERBURDEN(psi): 175	BACKPRESSURE(psi): ATMOSPHERIC

COREFLOOD FLUIDS	
BRINE COMP: 0.88 g NaCl/100ml	
OIL: Delaware Childers (native-state, no oil added after receiving core)	
SURF(S). COMP: 0.2% NEODOL 25-9, 0.095N NaHCO ₃ +0.095N Na ₂ CO ₃ , 2000ppm Pfizer 4800 CX polymer, 500ppm HCHO	
0.2% NEODOL 25-9, 0.095N NaHCO ₃ +0.095N Na ₂ CO ₃ , 1000ppm Pfizer 4800 CX polymer, 500ppm HCHO	
POLYMER: no separate polymer	
TRACER: none	

PURPOSE OF THE FLOOD:	
Test ASP flood for recovery of oil from native state core.	
No recovery from WF.	
WF frontal advance rate 1 ft/D.	

ADDITIONAL NOTES:	
Waterflood produced no oil.	Porosities = 20.7, 20.9, 21.8, 20.4 (Mean = 20.95)
3° flood at 1 ft/D and no oil was produced from cores.	Kair = 312, 266, 205, 252
Core Dean Stark extraction gave following results:	So = 29.29, 30.92 Sw = 68.20, 67.81 Sg = 2.52, 1.35

DCNS -3 COREFLOOD

REPORT SECTION

PV (ml):		53.41	Sat. %	Oil Rec. ml	POROSITY: 20.92	Percent
INITIAL OIL SATN.(ml):		16.09	30.13	---	PERMEABILITY: see above	md
REM. OIL AFTER WATERFLOOD(ml):		16.09	30.13	0.00	OIL TYPE: Del. Childers	
REM. OIL AFTER CHEMICAL FLOOD (ml):		16.09	30.13	0.00	OIL VISCOSITY: 9.80	cP
RECOVERY EFFICIENCY (%):		0.00			OIL DENSITY: 0.8501	g/cc

TERTIARY RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socf (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	pH	Comments
0	0.00	0.00	0.00	0.00	0.00	30.13	0.00	0.0000				End WF
19	3.80	3.80	0.00	3.80	0.00	30.13	0.00	0.0711	0.0000	0.00		Start 3° Fluid #1
20	4.90	4.90	0.00	8.70	0.00	30.13	0.00	0.1629	0.0000	0.00		
21	4.85	4.85	0.00	13.55	0.00	30.13	0.00	0.2537	0.0000	0.00		
22	4.85	4.85	0.00	18.40	0.00	30.13	0.00	0.3445	0.0000	0.00		
23	4.95	4.95	0.00	23.35	0.00	30.13	0.00	0.4372	0.0000	0.00		
24	4.90	4.90	0.00	28.25	0.00	30.13	0.00	0.5289	0.0000	0.00		
25	5.20	5.20	0.00	33.45	0.00	30.13	0.00	0.6263	0.0000	0.00		
26	5.10	5.10	0.00	38.55	0.00	30.13	0.00	0.7218	0.0000	0.00		
27	5.30	5.30	0.00	43.85	0.00	30.13	0.00	0.8210	0.0000	0.00		
28	0.30	0.30	0.00	44.15	0.00	30.13	0.00	0.8266	0.0000	0.00		End 3° Fluid #1
29	4.35	4.35	0.00	48.50	0.00	30.13	0.00	0.9081	0.0000	0.00		Start 3° Fluid #2
30	5.40	5.40	0.00	53.90	0.00	30.13	0.00	1.0092	0.0000	0.00		End 3° Fluid #2
31	5.40	5.40	0.00	59.30	0.00	30.13	0.00	1.1103	0.0000	0.00		Start 3° Fluid #2
32	4.80	4.80	0.00	64.10	0.00	30.13	0.00	1.2001	0.0000	0.00		End 3° Fluid #2
33	5.50	5.50	0.00	69.60	0.00	30.13	0.00	1.3031	0.0000	0.00		Start Chasse Brine
34	5.45	5.45	0.00	75.05	0.00	30.13	0.00	1.4052	0.0000	0.00		
35	5.50	5.50	0.00	80.55	0.00	30.13	0.00	1.5081	0.0000	0.00		
36	5.40	5.40	0.00	85.95	0.00	30.13	0.00	1.6092	0.0000	0.00		
37	5.40	5.40	0.00	91.35	0.00	30.13	0.00	1.7104	0.0000	0.00		
38	5.40	5.40	0.00	96.75	0.00	30.13	0.00	1.8115	0.0000	0.00		
39	5.25	5.25	0.00	102.00	0.00	30.13	0.00	1.9098	0.0000	0.00		
40	5.30	5.30	0.00	107.30	0.00	30.13	0.00	2.0090	0.0000	0.00		
41	5.35	5.35	0.00	112.65	0.00	30.13	0.00	2.1092	0.0000	0.00		
42	5.35	5.35	0.00	118.00	0.00	30.13	0.00	2.2093	0.0000	0.00		
43	5.35	5.35	0.00	123.35	0.00	30.13	0.00	2.3095	0.0000	0.00		
44	5.40	5.40	0.00	128.75	0.00	30.13	0.00	2.4106	0.0000	0.00		
45	5.40	5.40	0.00	134.15	0.00	30.13	0.00	2.5117	0.0000	0.00		
46	5.30	5.30	0.00	139.45	0.00	30.13	0.00	2.6109	0.0000	0.00		

DCNS -3 COREFLOOD

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	pH	Comments
47	5.35	5.35	0.00	144.80	0.00	30.13	0.00	2.7111	0.0000	0.00		
48	5.30	5.30	0.00	150.10	0.00	30.13	0.00	2.8103	0.0000	0.00		
49	5.50	5.50	0.00	155.60	0.00	30.13	0.00	2.9133	0.0000	0.00		
50	5.35	5.35	0.00	160.95	0.00	30.13	0.00	3.0135	0.0000	0.00		
51	5.30	5.30	0.00	166.25	0.00	30.13	0.00	3.1127	0.0000	0.00		
52	5.45	5.45	0.00	171.70	0.00	30.13	0.00	3.2148	0.0000	0.00		
53	5.35	5.35	0.00	177.05	0.00	30.13	0.00	3.3149	0.0000	0.00		
54	5.50	5.50	0.00	182.55	0.00	30.13	0.00	3.4179	0.0000	0.00		
55	5.30	5.30	0.00	187.85	0.00	30.13	0.00	3.5171	0.0000	0.00		End Chase Brine

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 52 OPERATOR: C. JOSEPHSON
CORE NUMBER: DC 1 DATE: 4/26/90
CORE TYPE: UNFIREB BEREА CLIENT: BE4A

CORE DIMENSIONS
LENGTH(cm): 25.96 DIAMETER(cm): 3.82 BULK VOLUME(cc): 297.52

COREFLOOD SET-UP:
ENCAPSULATION: HASSLER TEMP (°C): 30.00
OVERBURDEN(psi): 175 BACKPRESSURE(psi): ATMOSPHERIC

COREFLOOD FLUIDS
BRINE COMP: 0.88 g NaCl/100ml
Oil: Delaware Childers
SURF(S). COMP: 0.2% Petrostep B-100, 1.6% NaHCO₃, 1200ppm Pfizer 4800 CX polymer, 500ppm HCHO
POLYMER: no separate polymer, μ of inj. fluid = 5.47 at 60 rpm, 30° C
TRACER: none
ALKALINITY: measured alkalinity = 0.1849 Meq/g

PURPOSE OF THE FLOOD:

Test ASP flood for recovery of oil from BEREА for comparison to NS cores.

ADDITIONAL NOTES:

Waterflood produced 22.35 ml oil
3° flood at 1 ft/D and 5.298 ml oil was produced from cores.

REPORT SECTION

PV (ml):	64.67	Sat. %	Oil Rec., ml	POROSITY:	21.74	Percent
INITIAL OIL SATN.(ml):	50.55	78.17	---	PERMEABILITY: see above		md
REM. OIL AFTER WATERFLOOD(ml):	50.55	78.17		OIL TYPE: Del. Childers		
REM. OIL AFTER CHEMICAL FLOOD (ml)	28.20	43.60	22.36	OIL VISCOSITY: 9.80		cP
RECOVERY EFFICIENCY (%):	44.22			OIL DENSITY: 0.8501		g/cc

WATERFLOOD RECOVERY

TUBE NO.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	OIL VOLUME (ml)	SUM of TOT. VOL. (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socf (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)
0	0.00	0.00	0.00	0.00	0.00	78.17	0.00	0.0000		
1	1.30	0.00	1.30	1.30	1.30	76.16	2.57	0.0201	∞	100.00
2	5.20	0.00	5.20	6.50	6.50	68.12	12.86	0.1005	∞	100.00
3	5.25	0.00	5.25	11.75	11.75	60.00	23.24	0.1817	∞	100.00
4	5.40	0.00	5.40	17.15	17.15	51.65	33.93	0.2652	∞	100.00
5	5.40	0.20	5.20	22.55	22.35	43.61	44.21	0.3487	26.0000	96.30
6	5.45	5.45	0.00	28.00	22.36	43.60	44.22	0.4330	0.0009	0.09
7	5.45	5.45	0.00	33.45	22.36	43.60	44.22	0.5172	0.0000	0.00
8	5.45	5.45	0.00	38.90	22.36	43.60	44.22	0.6015	0.0000	0.00
9	5.40	5.40	0.00	44.30	22.36	43.60	44.22	0.6850	0.0000	0.00
10	5.45	5.45	0.00	49.75	22.36	43.60	44.22	0.7693	0.0000	0.00
11	5.40	5.40	0.00	55.15	22.36	43.60	44.22	0.8528	0.0000	0.00
12	5.30	5.30	0.00	60.45	22.36	43.60	44.22	0.9347	0.0000	0.00
13	5.50	5.50	0.00	65.95	22.36	43.60	44.22	1.0198	0.0000	0.00
14	5.50	5.50	0.00	71.45	22.36	43.60	44.22	1.1048	0.0000	0.00
15	5.45	5.45	0.00	76.90	22.36	43.60	44.22	1.1891	0.0000	0.00
16	5.50	5.50	0.00	82.40	22.36	43.60	44.22	1.2742	0.0000	0.00
17	5.50	5.50	0.00	87.90	22.36	43.60	44.22	1.3592	0.0000	0.00
18	5.35	5.35	0.00	93.25	22.36	43.60	44.22	1.4419	0.0000	0.00
19	5.50	5.50	0.00	98.75	22.36	43.60	44.22	1.5270	0.0000	0.00
20	5.35	5.35	0.00	104.10	22.36	43.60	44.22	1.6097	0.0000	0.00
21	5.50	5.50	0.00	109.60	22.36	43.60	44.22	1.6948	0.0000	0.00
22	5.45	5.45	0.00	115.05	22.36	43.60	44.22	1.7790	0.0000	0.00
23	5.40	5.40	0.00	120.45	22.36	43.60	44.22	1.8625	0.0000	0.00
24	5.50	5.50	0.00	125.95	22.36	43.60	44.22	1.9476	0.0000	0.00
25	3.20	3.20	0.00	129.15	22.36	43.60	44.22	1.9971	0.0000	0.00

NIPER COREFLOOD REPORT

NOTEBOOK: A528 P. 52 OPERATOR: C. JOSEPHSON
CORE NUMBER: DC 1 DATE: 4/26/90
CORE TYPE: UNFIRED BEREА CLIENT: BE4A

CORE DIMENSIONS
LENGTH(cm): 25.96 DIAMETER(cm): 3.82 BULK VOLUME(cc): 297.52

COREFLOOD SET-UP:
ENCAPSULATION: HASSLER TEMP (°C): 30.00
OVERBURDEN(psi): 175 BACKPRESSURE(psi): ATMOSPHERIC

COREFLOOD FLUIDS
BRINE COMP: 0.88 g NaCl/100ml
OIL: Delaware Childers
SURF(S). COMP: 0.2% Petrostep B-100, 1.6% NaHCO₃, 1200ppm Pfizer 4800 CX polymer, 500ppm HCHO
POLYMER: no separate polymer, μ of inj. fluid = 5.47 at 60 rpm, 30° C
TRACER: none
ALKALINITY: measured alkalinity = 0.1849 Meq/g

PURPOSE OF THE FLOOD:

Test ASP flood for recovery of oil from BEREА for comparison to NS cores.

ADDITIONAL NOTES:

Waterflood produced 22.35 ml oil
3° flood at 1 ft/D and 5.298 ml oil was produced from core.

REPORT SECTION

PV (ml):	64.67	Sat. %	78.17	Oil Rec. ml	---
INITIAL OIL SATN.(ml):	50.55	78.17	43.60	22.36	---
REM. OIL AFTER WATERFLOOD(ml):	28.20	43.60	21.65	5.30	---
REM. OIL AFTER CHEMICAL FLOOD(ml):	14.00	21.65	5.30	5.30	---
RECOVERY EFFICIENCY (%):	18.79				---

POROSITY: 21.74 Percent
 PERMEABILITY: see above md
 OIL TYPE: Del. Childers
 OIL VISCOSITY: 9.80 cP
 OIL DENSITY: 0.8501 g/cc

TERTIARY RECOVERY

TUBE No.	TOTAL VOLUME (ml)	WATER VOLUME (ml)	WATER VOLUME (ml)	SUM of TOT. VOL (ml)	SUM of OIL VOL (ml)	Res Oil Sat Socd (%PV)	Oil Rec (%OIP)	PV Injected	Oil/Water Ratio	Oil Cut (%)	Effluent pH	Comments
0	0.00	0.00	0.00	129.15	22.36	9.03	44.22	1.9971	0.0066	0.66	7.1500	first 3 rd effluent
26	4.58	4.55	0.03	133.73	22.39	8.98	44.28	2.0679	0.0000	0.00		
27	5.50	5.50	0.00	139.23	22.39	8.98	44.28	2.1529	0.0000	0.00	7.89	
28	5.50	5.50	0.00	144.73	22.39	8.98	44.28	2.2380	0.0000	0.00		
29	5.50	5.50	0.00	150.23	22.39	8.98	44.28	2.3230	0.0000	0.00		
30	5.40	5.40	0.00	155.63	22.39	8.98	44.28	2.4065	0.0000	0.00	8	
31	5.40	5.00	0.40	161.03	22.79	8.37	45.07	2.4900	0.0800	7.41		
32	5.50	4.60	0.90	166.53	23.69	6.97	46.85	2.5751	0.1957	16.36	7.37	
33	5.55	4.65	0.90	172.08	24.59	5.58	48.64	2.6609	0.1935	16.22	7.67	
34	5.55	4.45	1.10	177.63	25.69	3.88	50.81	2.7467	0.2472	19.82		
35	1.65	1.40	0.25	179.28	25.94	3.49	51.31	2.7722	0.1786	15.15		
36	4.95	4.40	0.55	184.23	26.49	2.64	52.39	2.8488	0.1250	11.11		last tube of 3 rd inj.
37	5.55	4.95	0.60	189.78	27.09	1.72	53.58	2.9346	0.1212	10.81		begin chase brine
38	5.60	5.20	0.40	195.38	27.49	1.10	54.37	3.0212	0.0769	7.14	8.83	
39	5.65	5.55	0.10	201.03	27.59	0.94	54.57	3.1086	0.0180	1.77		
40	5.51	5.50	0.01	206.54	27.60	0.93	54.59	3.1938	0.0018	0.18	8.92	
41	5.50	5.47	0.03	212.04	27.63	0.88	54.65	3.2788	0.0055	0.55	8.88	
42	5.56	5.55	0.01	217.60	27.64	0.87	54.67	3.3648	0.0018	0.18	8.91	
43	5.51	5.50	0.00	223.11	27.64	0.86	54.68	3.4499	0.0009	0.09	8.93	
44	5.61	5.50	0.00	228.51	27.64	0.86	54.68	3.5334	0.0000	0.00	8.85	
45	5.61	5.60	0.01	234.12	27.65	0.84	54.70	3.6201	0.0018	0.18		
46	5.50	5.50	0.00	239.62	27.65	0.84	54.70	3.7052	0.0000	0.00	8.83	
47	5.50	5.50	0.00	245.12	27.65	0.84	54.70	3.7902	0.0000	0.00		
48	5.55	5.55	0.00	250.67	27.65	0.84	54.70	3.8761	0.0000	0.00	8.8	
49	5.50	5.50	0.00	256.17	27.65	0.84	54.70	3.9611	0.0000	0.00		
50	5.55	5.55	0.00	261.72	27.65	0.84	54.70	4.0469	0.0000	0.00	8.78	
51	5.50	5.50	0.00	267.22	27.65	0.84	54.70	4.1320	0.0005	0.05	8.78	
52	5.50	5.50	0.00	272.72	27.65	0.84	54.70	4.2171	0.0000	0.00	8.78	
53	5.45	5.45	0.00	278.17	27.65	0.84	54.70	4.3013	0.0000	0.00	8.78	
54	5.40	5.40	0.00	283.57	27.65	0.84	54.70	4.3848	0.0000	0.00	8.78	
55	5.45	5.45	0.00	289.02	27.65	0.84	54.70	4.4691	0.0000	0.00	8.78	
56	5.40	5.40	0.00	294.42	27.65	0.84	54.70	4.5526	0.0000	0.00	8.78	
57	5.45	5.45	0.00	299.87	27.35	0.84	54.70	4.6369	0.0000	0.00	8.78	
58	5.60	5.60	0.00	305.47	27.65	0.84	54.70	4.7235	0.0000	0.00	8.78	
59	5.55	5.55	0.00	311.02	27.65	0.84	54.70	4.8093	0.0000	0.00	8.78	
60	3.20	3.20	0.00	314.22	27.65	0.84	54.70	4.8598	0.0000	0.00	8.78	

END

DATE FILMED

06 / 04 / 91