Coupling the Alkaline-Surfactant-Polymer Technology and The Gelation Technology to Maximize Oil Production

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Abstract

Gelation technologies have been developed to provide more efficient vertical sweep efficiencies for flooding naturally fractured oil reservoirs or more efficient areal sweep efficiency for those with high permeability contrast "thief zones". The field proven alkaline-surfactant-polymer technology economically recovers 15% to 25% OOIP more oil than waterflooding from swept pore space of an oil reservoir. However, alkaline-surfactant-polymer technology is not amenable to naturally fractured reservoirs or those with thief zones because much of injected solution bypasses target pore space containing oil. This work investigates whether combining these two technologies could broaden applicability of alkaline-surfactant-polymer flooding into these reservoirs.

A prior fluid-fluid report discussed interaction of different gel chemical compositions and alkaline-surfactant-polymer solutions. Gel solutions under dynamic conditions of linear corefloods showed similar stability to alkaline-surfactant-polymer solutions as in the fluid-fluid analyses. Aluminum-polyacrylamide, flowing gels are not stable to alkaline-surfactant-polymer solutions of either pH 10.5 or 12.9. Chromium acetate–polyacrylamide flowing and rigid flowing gels are stable to subsequent alkaline-surfactant-polymer solution injection. Rigid flowing chromium acetate-polyacrylamide gels maintained permeability reduction better than flowing chromium acetate-polyacrylamide gels. Silicate-polyacrylamide gels are not stable with subsequent injection of either a pH 10.5 or a 12.9 alkaline-surfactant-polymer solution. Chromium acetate–xanthan gum rigid gels are not stable to subsequent alkaline-surfactant-polymer solution injection. Resorcinol-formaldehyde gels were stable to subsequent alkaline-surfactant-polymer solution injection. When evaluated in a dual core configuration, injected fluid flows into the core with the greatest effective permeability to the injected fluid. The same gel stability trends to subsequent alkaline-surfactant-polymer injected solution were observed.

Aluminum citrate-polyacrylamide, resorcinol-formaldehyde, and the silicate-polyacrylamide gel systems did not produce significant incremental oil in linear corefloods. Both flowing and rigid flowing chromium acetate-polyacrylamide gels and the xanthan gum-chromium acetate gel system produced incremental oil with the rigid flowing gel producing the greatest amount. Higher oil recovery could have been due to higher differential pressures across cores. None of the gels tested appeared to alter alkaline-surfactant-polymer solution oil recovery. Total waterflood plus chemical flood oil recovery sequence recoveries were all similar.

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Introduction

Gelation technologies provide more efficient vertical sweep efficiencies for flooding naturally fractured oil reservoirs or more efficient areal sweep efficiency for those with high permeability contrast "thief zones". Field proven alkaline-surfactant-polymer technology economically recovers 15% to 25% OOIP more oil than waterflooding from swept pore space of an oil reservoir. However, alkaline-surfactant-polymer technology is not amenable to naturally fractured reservoirs or those with thief zones because much of the injected solution bypasses target pore space containing oil. This work investigates whether combining these two technologies could broaden applicability of alkaline-surfactant-polymer flooding.

Executive Summary

Linear corefloods evaluations indicate that rigid flowing chromium acetate-xanthan gum gel was not stable to subsequent injection of NaOH and Na_2CO_3 alkaline-surfactant-polymer solutions. Resorcinol-formaldehyde gel system was stable to subsequent injection of NaOH and Na_2CO_3 alkaline-surfactant-polymer solutions in linear corefloods. Dual cores radial corefloods with isolated cores connected to a common manifold showed that the aluminum citrate-polyacrylamide gel was not stable to subsequent alkaline-surfactant-polymer injection even though a second rock containing less gel was available for chemical injection. Chromium acetate-polyacrylamide gel was stable to subsequent injection of an alkaline-surfactant-polymer solution in dual isolated cores, common manifold, and dual stacked cores, same well bore configuration. Alkaline-surfactant-polymer solutions produce incremental oil regardless of prior gel injection.

Experimental

Big Sinking crude oil was supplied by Bretagne in Lexington, Kentucky. Big Sinking crude oil is a 42^o API gravity, 3 cp crude oil. It's characteristics have been described elsewhere.[1] Polymers used in the linear corefloods are listed in Table 1. Chemicals were dissolved in 1.0 wt% sodium chloride.

Table 1
Polymers Used in Gelation Linear Corefloods

Polymer Name	Type/Degree of Hydrolysis	Supplier
Flocon 4800	xanthan gum	SNF Floerger
Watercut 204	polyacrylamide/7%	Tiorco, Inc.
HiVis 350	polyacrylamide/30%	Tiorco, Inc.

Linear core floods were performed using 1 inch diameter by 5 inches long, unfired Berea sandstone. Radial corefloods used 6 inches diameter by 2 inches high, unfired Berea sandstone. Table 2 lists the core properties.

Table 2
Berea Core Properties

Coreflood	100% NaCl Brine Saturated Permeability $K_{T,\,abs}$(md)	Porosity(%)	---Oil Saturation--- $S_{oi}(V_P)$	$S_{or}(V_p)$
Linear Corefloods				
Cr^{+3}-XG flowing – NaOH	518	23.0	0.628	0.367
Cr^{+3}-XG flowing - Na_2CO_3	349	22.4	0.613	0.364
Resorcinol-Formaldehyde rigid – NaOH	625	23.3	0.549	0.307
Resorcinol-Formaldehyde rigid –Na_2CO_3	467	22.3	0.579	0.307
Radial Corefloods				
dual core, common manifold, separate coreholders				
Al^{+3}-PHPA- Na_2CO_3	622	22.1	0.502	0.314
Al^{+3}-PHPH-Na_2CO_3	53	17.5	0.545	0.399
Cr^{+3}-PHPA rigid flowing – NaOH	435	22.0	0.545	0.353
Cr^{+3}-PHPA rigid flowing – NaOH	33	19.1	0.540	0.404
dual core, common well bore, same coreholder				
Cr^{+3}-PHPA rigid flowing – NaOH	631	22.5	0.581	0.251
Cr^{+3}-PHPA rigid flowing - Na_2CO_3	58	18.5	0.494	-----

S_{oi} and S_{or} are initial and waterflood residual oil saturation, respectively. PHPA is partially hydrolyzed polyacrylamide, and XG is xanthan gum.

Corefloods were performed at room temperature. Single core linear coreflood injected fluid sequence is listed below.

1. Saturate core with 1.0 wt% NaCl by evacuation and determine porosity and pore volume
2. Inject 1.0 wt% NaCl and determine the absolute permeability to water (k_{abs}).
3. Inject Big Sinking crude oil to immobile water and determine the effective permeability to oil at immobile water (k_{orw}).
4. Inject 1.0 wt% NaCl at 12 ft/day fluid frontal advance rate to residual oil and determine the effective permeability to water at residual oil (k_{orw}).
5. Inject gel fluids at 12 ft/day.
6. Stop injection. Pull coreholder apart, clean gel out of injection and production lines. Fill injection lines with 1.0 wt% NaCl before assembling coreholder.
7. Re-assemble coreholder and allow gel to form overnight with no flow.
8. Inject 1.0 wt% NaCl at 12 ft/day to stable pressures.
9. Inject ASP solution at 12 ft/day. Inject 5 to 10 pore volumes.
10. Shut-in overnight.
11. Resume ASP solution injection at 12 ft/day. Inject 1 to 2 pore volumes.

12. Inject 1.0 wt% NaCl at 12 ft/day for 5 to 10 pore volumes to get stable pressures and determine permeability change from step 8.

Differential pressures were measured from the core injection face to one inch from the injection face, and from injection face to production face. Differential pressure from one inch behind the injection face to production face of the core was calculated by difference between the two measured values.

Dual individual core radial corefloods with a common manifold injected fluid sequence is listed below.

Individual Core holder Injection Manifold steps 1 - 3

1. Saturate core with 1.0 wt% NaCl and determine porosity and pore volume
2. Inject 1.0 wt% NaCl and determine the absolute permeability to water (k_{abs}).
3. Inject Big Sinking crude oil to immobile water and determine the effective permeability to oil at immobile water (k_{orw}).

Common Core holder Injection Manifold steps 4 - 10 - fluid frontal advance rates are average for two cores - calculate individual core rates and add the volumes to be injected.

4. Connect the two individual cores to a common injection manifold.
5. Inject 1.0 wt% NaCl at 5 ft/day fluid frontal advance rate to residual oil and determine k_{orw} for each core.
6. Inject 1 pore volumes (sum of two cores) of gel solution at 5 ft/day.
7. Stop injection. Pull coreholders apart and clean gel out of injection and production lines. Fill injection lines with 1.0wt% NaCl before assembling coreholder.
8. Re-assemble coreholder and allow gel to form for two days.
9. Inject 1.0 wt% NaCl at 5 ft/day and determine resistance factor.
10. Inject ASP solutions at 5ft/day and determine resistance factor.
11. Inject 1.0 wt% NaCl at 5 ft/day and determine residual resistance factor.

Oil was collected in graduated cylinders with each step. Differential pressures were measured from the injection well bore to the production annulus port of for each core.

Dual stacked core radial corefloods with a common well bore injected fluid sequence is listed below.

Individual Injection Manifold in separate radial core holders in steps 1 - 3

1. Saturate core with 1.0 wt% NaCl and determine porosity and pore volume.
2. Inject 1.0 wt% NaCl and determine the absolute permeability to water (k_{abs}).
3. Inject Big Sinking crude oil to immobile water and determine k_{orw}.

Place core in stacked core radial core holder. A piece of cellulose paper was placed between the core to facilitate capillary continuity. An O-ring was placed on the outer edge of the cores at their junction that will seal to the annulus edge to facilitate separate collection of fluids from each core. Place an overburden of 1000 psi on the cores. Stacked core injection steps 4 - 10 - fluid frontal advance rates are summed height, average porosity, and average diameter for two cores.

4. Stack cores so that a common well bore is present.
5. Inject 1.0 wt% NaCl at 5 ft/day fluid frontal advance rate to residual oil saturation and determine k_{orw} for each core.

6. Inject gel fluids at 5 ft/day 1 pore volumes (sum of two core) and monitor injection pressure.
7. Stop injection. Pull coreholders apart and clean out gel from injection and production lines. Fill injection lines with 1.0 wt% NaCl before assembling coreholder.
8. Re-assemble coreholder and allow gel to form for two days.
9. Inject 1.0 wt% NaCl at 5 ft/day for 5 pore volumes and determine resistance factor.
10. Inject ASP solution at 5ft/day and monitor injection pressure.
11. Inject 1.0 wt% NaCl at 5 ft/day for 5 pore volumes and determine residual resistance factor.

Produced fluids were collected in test tubes on a fraction collector.

Resistance factor for all corefloods was calculated according to $RF_i ? \frac{(? P/q)_i}{(? P/q)_{baseline}}$, where ? P is differential pressure, psi, and q is injection rate, ml/hr. Baseline values are after 1.0 wt% NaCl injection at S_{orw} and before initial chemical injection.

Oil saturation is determined by mass balance of injected and produced fluids. Final oil saturation was cross-checked by extraction of fluids by hot toluene.

Gel chemical compositions are listed in Table 3.

Table 3
Gel Chemical Composition

	Polymer		Cross Linking Agent (Bulk)	
Gel	Type	mg/L	Type	mg/L
Cr^{+3}-Xanthan Gum	Flocon 4800	5,000	Watercut 684	3,250
Resorcinol	analytical grade	20,000	Formaldehyde	17,1000
Al^{+3} citrate - PHPA	HiVis 350	400	Watercut 677N	415
Cr^{+3}-PHPA rigid flowing	Watercut 204	7,500	Watercut 684	2,425

Single Core Linear Corefloods

?? Chromium acetate-xanthan gum solutions were mixed in a 1.0 wt% NaCl solution in an injection tank as a single solution just prior to injection. Composition is listed in Table 3.

?? Resorcinol-formaldehyde solutions were also mixed a 1.0 wt% NaCl solution in an injection tank as a single solution just prior to injection. Table 3 again list the gel composition

Dual Individual Core, Common Manifold Radial Corefloods

?? Colloidal dispersion gel, aluminum citrate-polyacrylamide solutions were mixed as defined in Table 3. Injection of gel solution from each tank was 2.5 hours maximum as defined by Smith et.al.[2] Multiple tanks of gel solution were used during gel injection.

?? Rigid chromium acetate-polyacrylamide solutions were according to Table 3 composition.

Dual Stacked Core, Common Well Bore Stacked Radial Corefloods

?? Rigid chromium acetate-polyacrylamide solutions were mixed as defined in Table 3.

Alkaline-Surfactant-Polymer Solutions

Single Core Linear Corefloods and Dual Individual Core, Common Manifold Radial Corefloods

Sodium carbonate and sodium hydroxide alkaline-surfactant-polymer solutions were injected into the linear corefloods following gel treatment. Sodium carbonate solution was 0.885 wt% Na_2CO_3 plus 0.06 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275. Sodium hydroxide solution was 1.0 wt% NaOH plus 0.06 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275. ORS-46HF was supplied by OCT, Inc. Interfacial tension between the two alkaline-surfactant-polymer solutions and Big Sinking crude oil was 0.207 and 0.191 dyne/cm, respectively. Injected alkaline-surfactant-polymer solutions were chosen for two reasons. First, interfacial tension between crude oil and the NaOH and Na_2CO_3 solutions are similar. Second, a high interfacial tension solution was injected to minimize potential effect on gel of an ultra low interfacial tension solution.

Dual Stacked Core, Common Well Bore Stacked Radial Corefloods

Sodium hydroxide alkaline-surfactant-polymer solution was injected into the dual, stacked radial coreflood following gel treatment. Sodium hydroxide solution was 1.0 wt% NaOH plus 0.06 wt% ORS-46HF plus 1300 mg/L Alcoflood 1275.

Results and Discussion

Xanthan Gum-Chromium Acetate Gel Linear Corefloods

The linear corefloods are a continuation of the prior study to determine if gel solutions are stable to subsequent injection of an alkaline-surfactant-polymer solution.[3] Injected gel mixture was 7500 mg/L Flopaam 4800 plus 335 mg/L Watercut 684 as Cr^{+3}. Figures 1 and 2 depict resistance factor changes for NaOH and Na_2CO_3 alkaline-surfactant-polymer corefloods.

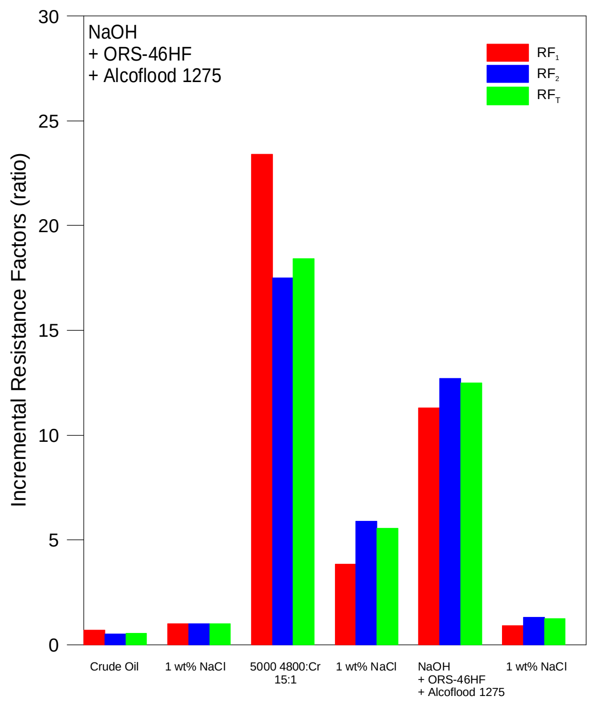

Figure 1 Ending Resistance Factors for Chromium Acetate-Xanthan Gum Gel followed by NaOH-ORS-46HF-Alcoflood 1275 Linear Coreflood, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

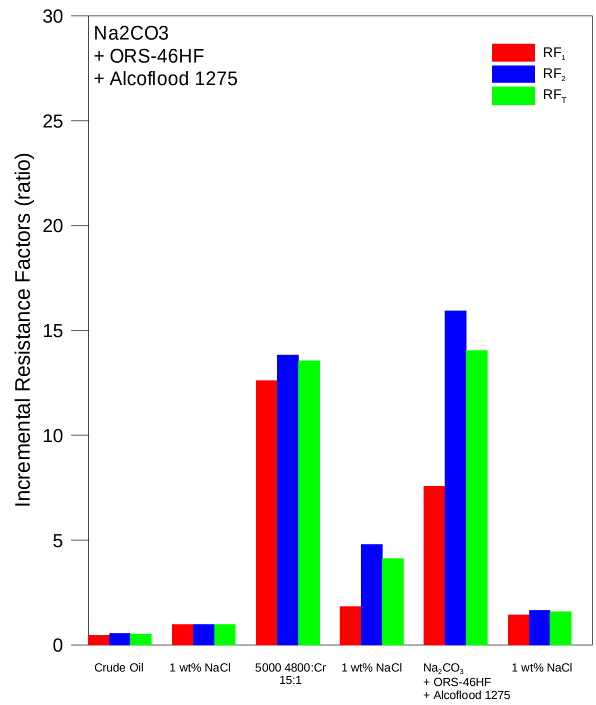

Figure 2 Ending Resistance Factors for Chromium Acetate-Xanthan Gum Gel followed by Na_2CO_3-ORS-46HF-Alcoflood 1275 Linear Coreflood, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

Residual resistance factors after gel injection and before alkaline-surfactant-polymer solution indicated gel was placed uniformly through the core. Displacement of gel throughout the core is shown by the similar RF_1 and RF_2 values. Average permeability reduction of 5 was observed with the xanthan gum-chromium acetate gel.

Resistance factors during alkaline-surfactant-polymer solution injection were of the same order of magnitude as alklaine-surfactant-polymer solutions without prior gel injection, in the 5 to 20 range. Residual resistance factors after alkaline-surfactant-polymer injection following gel injection were approximately the same as those after just alkaline-surfactant-polymer solution injecton, 1.6 after the Na_2CO_3 solution and 1.2 after the NaOH solution compared to 1.5 and 1.0, repectively. Xanthan gum-chromium acetate gels are not stable to either NaOH or Na_2CO_3 alkaline-surfactant-polymer solution injection. Permeability changes are summarized in Table 4.

Table 4
Berea Sandstone Physical Parameters
Chromium Acetate – Xanthan Gum Linear Corefloods

	----------Permeability (md)----------		
	K_1	K_2	K_T
NaOH-ORS-46HF-Alcoflood 1275 – 23.0% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	450	538	517
Effective Perm to Oil at Immobile Water, K_{orw}	522	528	527
Effective Perm to Water at Residual Oil, K_{wro}	56	43	45
Post Gel Sequence, K_{wro}	15	7	8
Post ASP Solution, K_{wro}	61	33	36
Na_2CO_3-ORS-46HF-Alcoflood 1275 – 22.9% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	298	366	349
Effective Perm to Oil at Immobile Water, K_{orw}	383	381	381
Effective Perm to Water at Residual Oil, K_{wro}	27	32	31
Post Gel Sequence, K_{wro}	15	7	8
Post ASP Solution, K_{wro}	18	19	19

Xanthan gum-chromium produced some incremental oil, as did alkaline-surfactant-polymer injection. Table 5 summarizes the oil production with each step.

Table 5
Oil Recovery of Chromium Acetate – Xanthan Gum Gel Linear Corefloods

	-------Cumulative Oil Recovery, % OOIP---------	
Injected Solution	NaOH-Coreflood	Na_2CO_3-Coreflood
1.0 wt% NaCl - Waterflood	41.5	40.6
Gel Sequence and NaCl flush	51.9	50.7
ASP Solution and NaCl flush	65.3	59.0
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	10.4	10.1
Gel+ASP Incremental Recovery	23.8	18.4

Some incremental oil was produced by chromium acetate – xanthan gum gel injection and the subsequent alkaline-surfactant-polymer solutions. Waterflood and chemical flood (gel plus ASP solution) oil recoveries are lower than those observed without prior gel injection. Prior gel injection does not affect subsequent alkaline-surfactant-polymer solution incremental oil production.

Resorcinol-Formaldehyde Gel Linear Corefloods

Two pairs of linear core floods were performed to evaluate if the resorcinol-formaldehyde gel technology is stable to subsequent injection of an alkaline-surfactant-polymer solution. A rigid resorcinol-formaldehyde gel was evaluated in linear corefloods. Injected gel mixture was 20,000 mg/L resorcinol plus 17,100 mg/L formaldehyde at pH 9. Figures 3 and 4 depict the resistance factor changes for the NaOH and Na_2CO_3 corefloods.

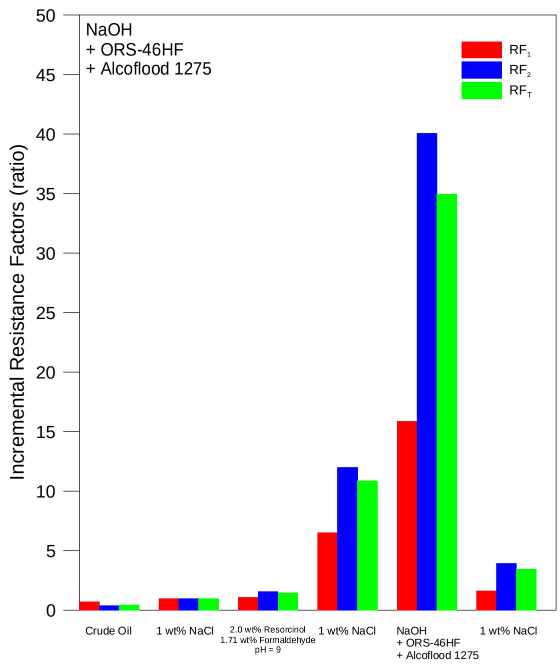

Figure 3 Ending Resistance Factors for the Rigid Resorcinol-Formaldehyde Gel followed by NaOH-ORS-46HF-Alcoflood 1275 Linear Coreflood, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

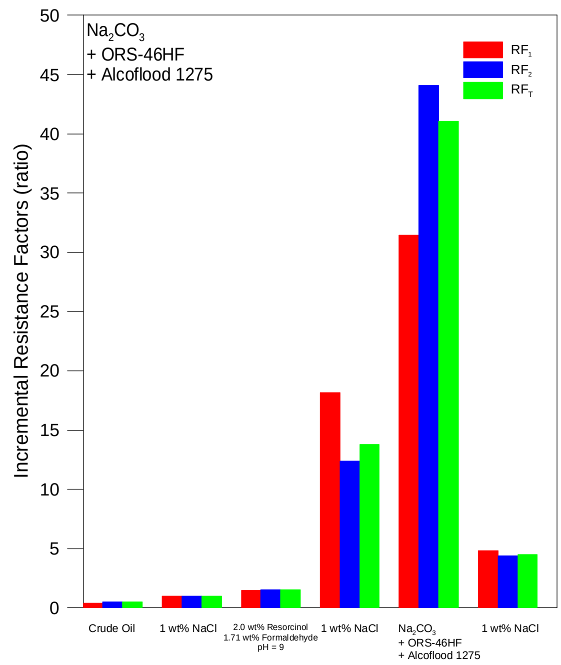

Figure 4 Ending Resistance Factors for the Rigid Resorcinol-Formaldehyde Gel followed by Na_2CO_3-ORS-46HF-Alcoflood 1275 Linear Coreflood, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

In both flowing rigid resorcinol-formaldehyde gel corefloods resistance factor after gel was reduced by alkaline-surfactant-polymer injection but not to levels of the base alkaline-surfactant-polymer injection. Gel coreflood resistance factors are 3.5 after the Na_2CO_3 solution and 6.2 after the NaOH solution compared to 1.5 and 1.0 for just alkaline-surfactant-polymer solutions, respectively. This suggests that resorcinol-formaldehyde gel permeability reduction was reduced but not eliminated by alkaline-surfactant-polymer solution injection. Permeability changes are summarized in Table 6.

Table 6
Berea Sandstone Physical Parameters
Rigid Resorcinol-Formaldehyde Gel Linear Corefloods

	Permeability (md)		
	K_1	K_2	K_T
$NaOH$-ORS-46HF-Alcoflood 1275 – 20.7% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	621	626	625
Effective Perm to Oil at Immobile Water, K_{orw}	369	681	589
Effective Perm to Water at Residual Oil, K_{wro}	42	43	42
Post Gel Sequence, K_{wro}	6	4	4
Post ASP Solution, K_{wro}	26	11	12
Na_2CO_3-ORS-46HF-Alcoflood 1275 – 20.0% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	316	530	467
Effective Perm to Oil at Immobile Water, K_{orw}	386	370	373
Effective Perm to Water at Residual Oil, K_{wro}	23	30	28
Post Gel Sequence, K_{wro}	1	3	2
Post ASP Solution, K_{wro}	5	4	4

Oil recovery was not affected by resorcinol-formaldhyed injection. Table 7 summarizes the oil production with each step.

Table 7
Oil Recovery of Rigid Resorcinol-Formaldehyde Gel Linear Corefloods

	Cumulative Oil Recovery, % OOIP	
Injected Solution	NaOH-Coreflood	Na_2CO_3-Coreflood
1.0 wt% NaCl - Waterflood	44.0	47.1
Gel Sequence and NaCl flush	45.2	47.2
ASP Solution and NaCl flush	53.9	51.8
	Incremental Oil Recovery, % OOIP	
Gel Incremental Oil Recovery	1.2	0.1
Gel+ASP Incremental Recovery	9.9	4.7

Little incremental oil was produced by either resorcinol-formaldehyde gel injection or the subsequent alkaline-surfactant-polymer solutions. Chemical flood (gel plus ASP solution) oil recoveries are lower than those observed without prior gel injection. Prior resorcinol-formaldehyde gel injection apprears to reduce subsequent alkaline-surfactant-polymer solution incremental oil production.

Colloidal Dispersion, Aluminum Citrate-Polyacrylamide Gel Dual Individual Core, Common Manifold Radial Coreflood

A dual individual core, common manifold radial coreflood was performed to determine if the colloidal dispersion, aluminum citrate-polyacrylamide gel technology is stable to subsequent injection of an alkaline-surfactant-polymer solution is a situation where a difference in permeability exists between two cores. Prior testing in linear corefloods indicated that the colloidal dispersion gel was not stable to subsequent alkaline-surfactant-polymer injection. Radial common manifold dual core corefloods permit a gel system to be tested in a situation where once the gel is in place, the injected fluid has the opportunity to flow into the core with the least amount of gel initially. This is similar to an injection well that is perforated at multiple sand intervals, each with different permeability, with the sand layers separated by a vertical permeability barrier. Injected gel mixture was 400 mg/L HiVis 350 plus 20 mg/L Watercut 677N as Al^{+3}. The injected alkaline-surfactant-polymer solution was 0.885 wt% Na_2CO_3 plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A. Figures 5 and 6 depict resistance factor changes for the low and high permeability cores' corefloods. Residual resistance factors in the low permeability core, after gel injection and before alkaline-surfactant-polymer solution, indicated that gel was placed primarily near well bore. However, this is primarily due to the low

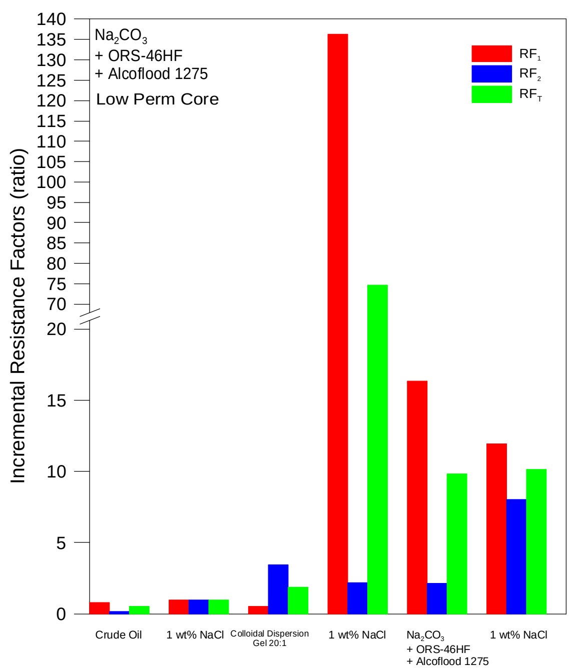

Figure 5 Low Permeability Core, Ending Resistance Factors for the Flowing Aluminum Citrate-Polyacrylamide Gel followed by Na_2CO_3-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

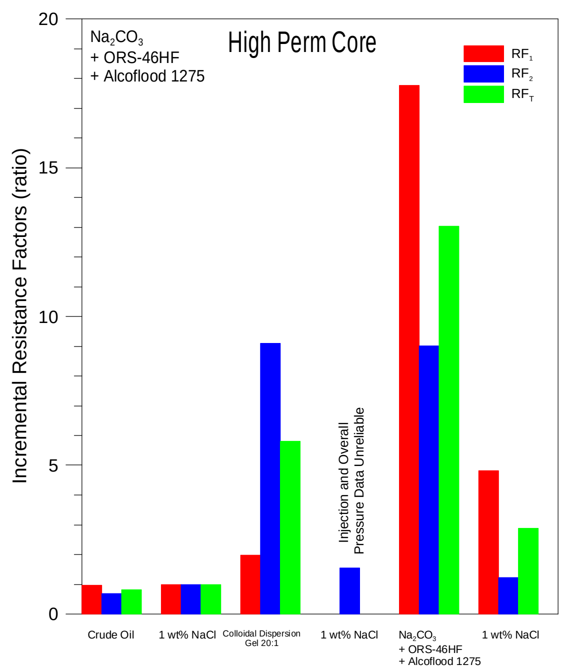

Figure 6 High Permeability Core, Ending Resistance Factors for the Flowing Aluminum Citrate-Polyacrylamide followed by Na_2CO_3-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_1(red), RF2(blue), RF_T(green)

volume of water injected into the core. Both core resistance factor distribution during gel placement suggest that gel was distributed through out the core.

A change in flow distribution due to aluminum citrate-polyacrylamide gel injection is shown in Figure 7. Initial flow is distributed with 90% or greater flowing through the high permeability core during crude oil, initial waterflood, and gel injection. Flow distribution was essentially equalized during the water flush subsequent to gel placement, indicating gel was diverting injected water from the high permeability core into the low permeability core. Injection of the alkaline-surfactant-polymer solution resulted in destruction of the gel and reversion of the flow distribution back to the original pattern.

Core permeability changes during the aluminum citrate-polyacrylamide gel dual radial coreflood are summarized in Table 8.

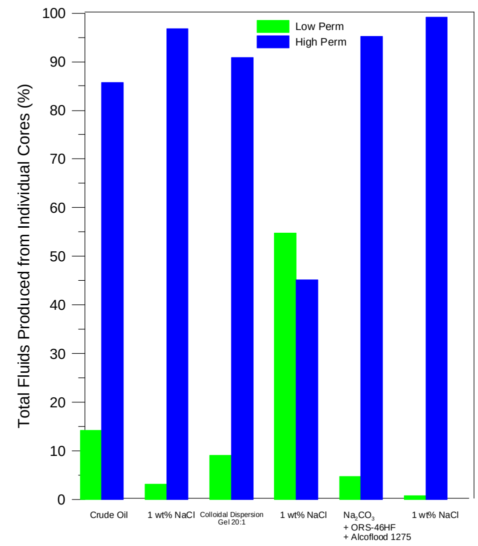

Figure 7 Flow Distribution between High and Low Permeability Cores, Dual Radial Coreflood, Aluminum Citrate-Polyacrylamide Gel, green is low permeability core and blue is high permeability core

Table 8

Berea Sandstone Physical Parameters
Common Manifold, Dual Radial Core
Aluminum Citrate-Polyacrylamide Gel Coreflood

	----------Permeability (md)----------		
	K_1	K_2	K_T
Na_2CO_3-ORS-46HF-Alcoflood 1275			
High Permeability Core – 22.1% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	651	566	622
Effective Perm to Oil at Immobile Water, K_{orw}	729	392	576
Effective Perm to Water at Residual Oil, K_{wro}	107	41	72
Post Gel Sequence, K_{wro}	---	---	---
Post ASP Solution, K_{wro}	22	33	25
Low Permeability Core – 17.5% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	55	49	53
Effective Perm to Oil at Immobile Water, K_{orw}	24	53	29
Effective Perm to Water at Residual Oil, K_{wro}	3	2	2
Post Gel Sequence, K_{wro}	---	---	---
Post ASP Solution, K_{wro}	0.3	0.2	0.2

Table 9 summarizes oil production of the aluminium citrate-polyacrylamide dual core radial coreflood.

Table 9
Oil Recovery of Common Manifold, Dual Radial Core
Aluminum Citrate-Polyacrylamide Gel Corefloods

	-------Cumulative Oil Recovery, % OOIP---------	
Injected Solution	High K - Core	Low K - Core
1.0 wt% NaCl - Waterflood	37.4	26.7
Gel Sequence and NaCl flush	40.0	28.4
ASP Solution and NaCl flush	65.3	28.6
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	2.6	1.7
Gel+ASP Incremental Recovery	27.9	1.7

Failure of the alkaline-surfactant-polymer solution to divert and flow through the low permeability core is evident with the poor oil recovery. In the high permeability core where chemical solution was injected, the alkaline-surfactant-polymer solution mobilized incremental oil.

Chromium Acetate-Polyacrylamide Gel Dual Individual Core, Common Manifold Radial Coreflood

A dual individual core, common manifold radial coreflood was performed to determine if the chromium acetate – polyacrylamide gel technology is stable to subsequent injection of an

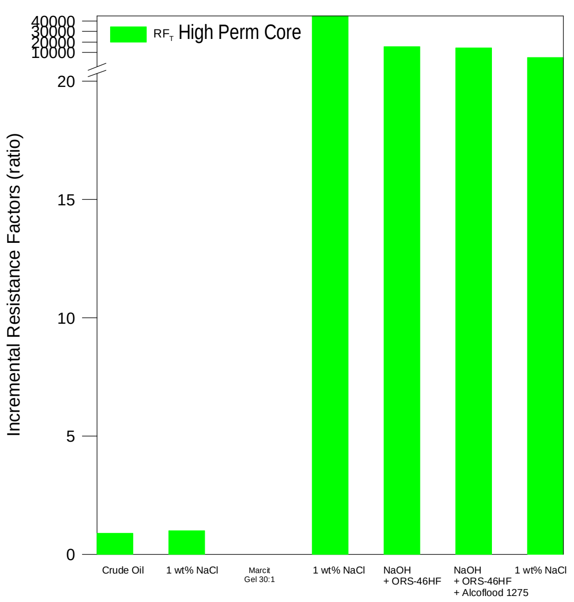

Figure 8 Low Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_T(green)

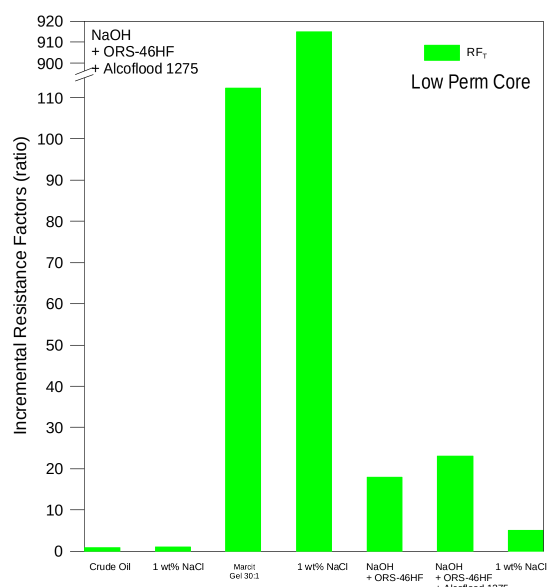

Figure 9 High Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_T(green)

alkaline-surfactant-polymer solution. Prior testing in linear corefloods indicated the chromium acetate-polyacrylamide was stable to subsequent alkaline-surfactant-polymer injection. Injected gel mixture was 7500 mg/L Watercut 204 plus 250 mg/L Watercut 684 as Cr^{+3}. Injected alkaline-surfactant-polymer solutions was 1.0 wt% NaOH plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A. Figures 8 and 9 depict resistance factor changes for the low and high permeability cores' corefloods. Chromium acetate-polyacrylamide gels reduced permeabilities significantly in both cores. Core permeability changes during the crhormium acetate-polyacrylamide gel dual radial coreflood are summarized in Table 10.

Table 10
Berea Sandstone Physical Parameters
Common Manifold, Dual Radial Core
Chromium Acetate-Polyacrylamide Gel Coreflood

	----------Permeability (md)----------		
	K_1	K_2	K_T
NaOH-ORS-46HF-Alcoflood 1275			
High Permeability Core – 22.0% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	502	535	435
Effective Perm to Oil at Immobile Water, K_{orw}	483	278	393
Effective Perm to Water at Residual Oil, K_{wro}	89	29	54
Post Gel Sequence, K_{wro}	---	---	---
Post ASP Solution, K_{wro}	---	---	0.1
Low Permeability Core – 19.1% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	26	70	33
Effective Perm to Oil at Immobile Water, K_{orw}	14	40	16
Effective Perm to Water at Residual Oil, K_{wro}	1	1	1
Post Gel Sequence, K_{wro}	---	---	---
Post ASP Solution, K_{wro}	0.3	0.3	0.3

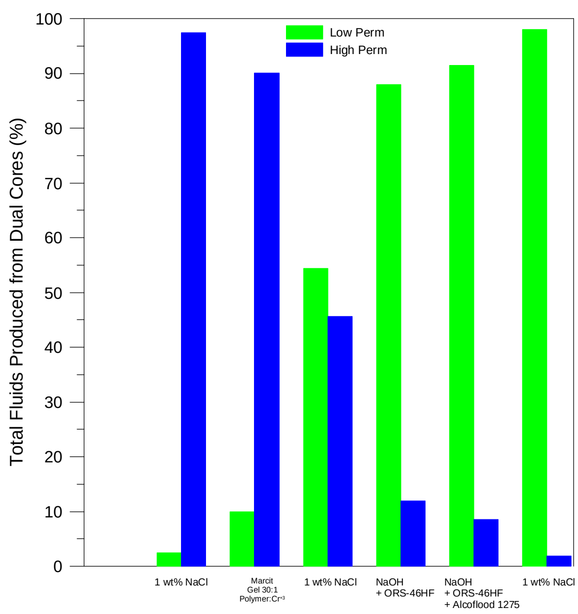

Figure 10 Flow Distribution between High and Low Permeability Cores, Dual Radial Coreflood, Chromium Acetate - Polyacrylamide Gel, green is low permeability and blue is high permeability

A change in flow distribution due to chromium acetate-polyacrylamide gel injection is shown in Figure 10. Initial flow is distributed with 90% or greater flowing through the high permeability core during crude oil, initial waterflood, and gel injection. Flow distribution was essentially equalized during the water flush subsequent gel placement, indicating gel was diverting injected water from the high permeability core into the low permeability core. Injection of the alkaline-surfactant-polymer solution resulted in even more diversion into the lower permeability core.

Table 11 summarizes oil production of the chromium acetate-polyacrylamide dual core radial coreflood.

Table 11
Oil Recovery of Common Manifold, Dual Radial Core
Chromium Acetate-Polyacrylamide Gel Coreflood

Injected Solution	High K - Core	Low K - Core
	-------Cumulative Oil Recovery, % OOIP---------	
1.0 wt% NaCl - Waterflood	35.2	25.1
Gel Sequence and NaCl flush	51.0	28.0
ASP Solution and NaCl flush	51.7	52.6
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	15.8	2.9
Gel+ASP Incremental Recovery	16.5	27.5

Alkaline-surfactant-polymer solution flow into the low permeability core recovered additional oil while the lack of flow into the high permeability core resulted in poor incremental oil.

Chromium Acetate-Polyacrylamide Gel Dual Stacked Core, Common Well Bore Stacked Radial Corefloods

A dual stacked core pair with a common well bore coreflood evaluated the stability of a chromium acetate-polyacrylamide gel to subsequent alkaline-surfactant-polymer injection. In this case, cross flow was possible. Injected gel mixture was 7500 mg/L Watercut 204 plus 250 mg/L Watercut 684 as Cr^{+3}. Injected alkaline-surfactant-polymer solution was 1.0 wt% NaOH

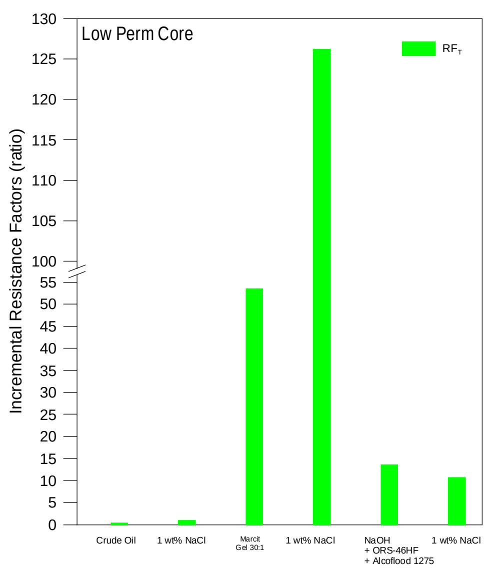

Figure 11 Low Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_T(green)

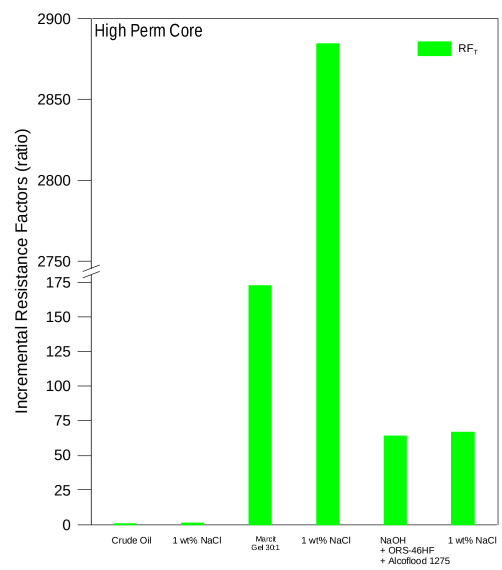

Figure 12 High Permeability Core, Ending Resistance Factors for the Rigid Chromium Acetate-Polyacrylamide Gel followed by NaOH-ORS-46HF-Alcoflood 1275, from left to right each set of histograms is RF_T(green

plus 0.06 wt% active ORS-46HF plus 1300 mg/L Alcoflood 1275A. Figures 11 and 12 depict resistance factor changes for the both core. As in the separate manifold, dual individual coreflood, chromium acetate-polyacrylamide gel reduced the permeability of each core and that permeability change persisted with subsequent alkaline-surfactant-polymer injection. Permeability changes for dual, stacked core chromium acetate-polyacrylamide coreflood are summarized in Table 12.

Table 12

Berea Sandstone Physical Parameters – Chromium Acetate-Polyacrylamide Dual Stacked, Same Well Bore Coreflood

	----------Permeability (md)----------		
	K_1	K_2	K_T
NaOH-ORS-46HF-Alcoflood 1275			
High Permeability Core – 22.5% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	850	400	628
Effective Perm to Oil at Immobile Water, K_{orw}	692	379	551
Effective Perm to Oil at Immobile Water, K_{orw} (after stacking core)	---	---	646
Effective Perm to Water at Residual Oil, K_{wro}	---	---	86
Post Gel Sequence, K_{wro}	---	---	0.03
Post ASP Solution, K_{wro}	---	---	1.3
Low Permeability Core – 18.5% Porosity			
Absolute Permeability to 1.0 wt% NaCl, K_{abs}	58	59	58
Effective Perm to Oil at Immobile Water, K_{orw}	41	50	41
Effective Perm to Oil at Immobile Water, K_{orw} (after stacking core)	---	---	51
Effective Perm to Water at Residual Oil, K_{wro}	---	---	3.1
Post Gel Sequence, K_{wro}	---	---	0.02
Post ASP Solution, K_{wro}	---	---	4.0

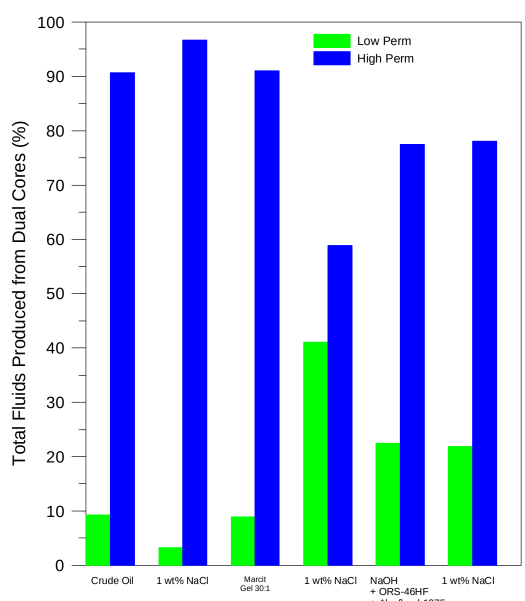

Figure 13 Flow Distribution between High and Low Permeability Cores, Dual Stacked Radial Coreflood, Chromium Acetate -Polyacrylamide Gel, green is low permeability and blue is high permeability

Change in flow distribution due to chromium acetate-polyacrylamide gel injection into the stacked radial core configuration is shown in Figure 13. Initial flow is distributed with 90% or greater flowing through the high permeability core during crude oil, initial waterflood, and gel injection. Flow distribution was essentially equalized during the water flush subsequent to gel placement, indicating gel was diverting injected water from the high permeability core into the low permeability core. Injection of the alkaline-surfactant-polymer solution resulted in some reversion of injected fluid back to the high permeability core with approximately half of the diverted injection volume being maintained.

Oil recoveries from the chromium acetate-polyacrylamide gel stacked radial flood are summarized in Table 13. A significant volume of incremental oil was produced during gel injection from the high permeability core but not the low permeability core. Alkaline-surfactant-polymer injection produced a significant volume of incremental oil from both core as well. It is possible that a fraction of the oil mobilized from the low permeability core was produced by the high permeability core in all injection stages due to vertical communication.

Table 13
Oil Recovery of Chromium Acetate -- Polyacrylamide Gel
Dual Stacked, Same Well Bore Radial Coreflood

	-------Cumulative Oil Recovery, % OOIP---------	
Injected Solution	High K - Core	Low K - Core
1.0 wt% NaCl - Waterflood	56.7	5.4
Gel Sequence and NaCl flush	76.0	7.4
ASP Solution and NaCl flush	83.1	20.8
	-------Incremental Oil Recovery, % OOIP---------	
Gel Incremental Oil Recovery	19.3	3.0
Gel+ASP Incremental Recovery	26.4	13.4

Conclusions

1. Aluminum citrate-polyacrylamide gels are not stable to subsequent injection of an alkaline-surfactant-polymer solution.

2. Chromium-polyacrylamide gels are stable to injection of an alkaline-surfactant-polymer solution.

3. Prior gel sequence injection did not reduce the total oil recovered by a waterflood plus alkaline-surfactant-polymer solution.

4. Gel injection followed by alkaline-surfactant-polymer injection will improve oil recovery by diverting alkaline-surfactant-polymer solution into lower permeability rock.

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2. Smith, J.E., Liu, H., and Guo, Z.D.: “Laboratory Studies of In-Depth Colloidal Dispersion Gel Technology for Daqing Oil Field,” SPE 62610, presented at the 2000 SPE/AAPG Western regional Meeting held in Long Beach, CA, 19-23 June 2000.

3. Pitts, M., Qi, J., and Wilson, D.: Semi-annual Technical Progress Report, Coupling the Alkaline-Surfactant-Polymer Technology and the Gelation Technology to Maximize Oil Production, April 1, 2004 to September 30, 2004, submitted to the Department of Energy, Award Number De-FC26-03NT15411.