NEW TREATMENT IMPROVES CLEAN-UP OF HORIZONTAL / OPEN HOLE COMPLETIONS: A CASE HISTORY

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Abstract

This paper presents the results of a new treatment designed to improve the cleanup of horizontal/openhole completions. The wells evaluated in this study were drilled using either starch or cellulose polymers, xanthan polymer, and sized calcium carbonate or salt particulates. These clean "drill-in fluids" were introduced to minimize the damage to the wellbore when compared to that observed with conventional drilling fluids. Although used to minimize formation damage, testing and experience have shown that insufficient polymer degradation can significantly reduce flow capacity at the wellbore leading to reduced well productivity or injectivity. Acid treatments are typically applied in attempts to remove or "by-pass" the damage created by the filter cake. These acid treatments are often marginally successful, particularly when applied in extended length intervals.

Previous studies were conducted to develop laboratory procedures to better simulate and characterize the damage attributable to these "clean" drill-in fluids. Various chemical breaker systems were subsequently applied to evaluate the effectiveness of their relative filter-cake degradation capabilities.

Laboratory studies have demonstrated that drill-in fluid filter cake can be effectively removed through the application of a newly developed technique incorporating an enzyme-based polymer degradation system. The data show that through utilization of this new technology, smaller, less costly treatments can be used to treat entire openhole intervals to zero-skin potential with dramatically improved treatment efficiency. Much smaller, lower concentration acid treatments can then be effectively applied to stimulate the interval. Surveys following the field application of the new system have shown not only increased flow, but also flow throughout entire length openhole intervals.

Introduction and Statement of the Problem

The practice of drilling wells in horizontal or highly deviated configurations, as well as multilateral completions, has developed rapidly in recent times. The purpose of this activity is to contact more hydrocarbon-bearing payzone area within a single well in order to maximize productivity.[1] Such wellbores often penetrate thousands of feet of productive zone as opposed to the tens to hundreds of feet contacted in vertical well configurations.

The fluids, or muds, historically utilized in drilling applications for lubrication and cuttings transport typically contain high concentrations of clays such as bentonite. These are known to cause damage to the permeability of the near wellbore area due to leakoff and mudcake deposition on the face of the production zone. Thus, the formation damage can be related to both the filter cake and the filtrate that invades the productive zone. It is often necessary to apply stimulation treatments to these damaged intervals simply to bypass the drilling fluid damage. The recent development of new drilling techniques to maximize wellbore contact with the productive intervals has been complimented by the parallel development of drill-in fluids. The drill-in fluids are formulated to provide the functionality of drilling muds to drill through the productive zone while minimizing the associated wellbore damage experienced with drilling muds. The standard practice is to drill to the top of the payzone using the conventional muds and then switch to the cleaner drill-in fluids to drill through the pay.[2]

The drill-in fluids are typically comprised of either starch or cellulose polymers, xanthan polymer, and sized calcium carbonate or salt particulates. The starch or cellulose polymers provide viscosity for friction reduction and lubrication while the xanthan polymer enhances cutting transport capabilities. The particulates, which are removable, provide fluid loss control. Although drill-in fluids are inherently less damaging than the conventional drilling muds, relatively impermeable filter cakes are nonetheless still deposited on the borehole wall. Insufficient degradation of the filter cakes resulting from even these "clean" drill-in fluids can significantly impede flow capacity at the wellbore wall. This reduced flow capacity can result in significant reduction of the well productivity or injectivity. Formation damage from drilling fluid leaking off into the formation, as well as filter-cake impairment, must be eliminated to realize the full potential of horizontal completions.

A common approach to minimizing damage during the drilling of openhole horizontal wells is to use a brine-based drill-in fluid system with acid or water soluble weighting agents followed by the application of acid or an oxidative breaker system to dissolve filter-cake solids and polymers.[3] The typical wellbore treatment to remove damage due to the drill-in fluid filter cake consists of pumping 40 gallons of 15% hydrochloric acid per foot of interval. Alternative cleanup treatments utilizing a solutions of lithium hypochlorite or sodium hypochlorite have recently become popular.

Acids and oxidative solution washes appear to perform reasonably well in the laboratory environment where contact of the filter-cake damage with the reactive solution is easily achieved. However, previous testing has indicated that application of acids or oxidative solutions may not be effective for removing the damage in horizontal intervals.[4] Field experience has demonstrated that acids and oxidative solutions used to remove drill-in fluid filter cake have proven relatively ineffective based upon well performance. The problem is particularly evident when such treatments are applied in extended length openhole intervals. The primary problem is thought to be contact of the reactive solution with the drill-in fluid damage.

Acids and oxidizers are non-specific reactive species which will react with anything encountered which is oxidizable including tubular goods, hydrocarbons, and some formation components. Since the non-specific reactants begin spending upon contact with any oxidizable material, they are most likely at least partially spent prior to arrival at the damaged location. The uncontrolled action of the reactive solution to remove filter cake near the entrance of the open interval increases the permeability of that area resulting in preferential leakoff of the subsequent volumes of the solution. The problem is thus accentuated proportional to the distance of the damage from the entrance to the open section. In the situation of extended length openhole intervals this phenomena can pose extreme difficulties. Acids also tend to produce wormholes resulting in the generation of additional non-productive reaction area to divert the reactive solution away from the targeted damage.

Testing by Burnett[5] also indicated that the polymer coated carbonate particles used for weighting and fluid loss control can be resistant to acid attack and prevent complete removal of the filter cake. Additional concerns of using reactive acidic or oxidative cleanup treatments include the reactivity with tubulars which result in elevated iron concentrations injected into reservoir which can promote sludging problems.

Approach to Problem Resolution

Recently introduced technology utilizes polymer-linkage specific enzyme complexes to hydrolyze polymers to non-damaging fragments.[6] Enzymes are highly specialized proteins produced by cells of living organisms which have the ability to act as catalysts to promote specific reactions. Since, as a catalyst, the conformational structure of an enzyme is unchanged by the reaction it promotes, it can then initiate another, and so on. Thus, barring denaturization (damage to the enzyme by chemical, thermal, or mechanical means), the reactivity of an enzyme is essentially infinite.

Unlike acidic or oxidative processes, the new enzyme systems are not reactive with substances other than the targeted polymers. Therefore, many of the self-generating diversion problems experienced using acids or oxidative solutions are mitigated through the use of polymer-linkage specific enzymes. Corrosion of tubular goods as well as iron-promoted sludging are also avoided using this alternative technique of polymer degradation. Further, unlike acids or oxidative species, enzymes are inherently environmentally friendly. The new polymer- linkage specific enzyme technology has previously been incorporated into remedial treatments to remove residual polymeric damage resulting from stimulation and completion operations.[7,8,9]

A polymer-linkage specific enzyme-based system was developed to address the natural polymers commonly utilized in drill-in fluids. The enzyme system attacks the drill-in fluid filter-cake damage by degrading the polymer that acts as a glue holding the calcium carbonate or salt particulates together. After effective degradation of the polymer, the soluble weighting or bridging material can then be removed, ensuring even inflow into the wellbore.

The system was first evaluated for drill-in filter-cake removal as a single stage treatment and compared to the performance of the acid and oxidative solution treatments. However, it was known that the enzyme solution would have no effect on the non-polymeric particulates utilized in drill-in fluids for fluid loss control (calcium carbonate or sized salt). In many situations, it was thought that the particulates released from the filter cake after the polymeric degradation could be produced. In others, however, it is unlikely that the produced fluids could carry the particulates to the surface. Therefore, a two-stage treatment was also devised, with an initial stage of the enzyme solution followed by an acid stage to dissolve the particulates. The relative performance of the two-stage treatment was evaluated and compared to both the single stage acid, oxidative, and enzyme systems.

Laboratory Test Results

The laboratory techniques used in this study were previously developed to simulate and characterize the possible damage caused by drill-in fluids. A number of different test procedures were used to determine the effectiveness of the breaker systems in degrading the polymeric filter cake generated by the drill-in fluid. The laboratory procedures used in the evaluations were designed to simulate down hole conditions. These tests included the following:

1. Wellbore filter-cake removal.
2. Core flow/regain permeability testing.
3. Radial core flow cell testing.[10]
4. Modified API conductivity cell testing.[10]

Wellbore Filter-Cake Removal. A modified HTHP fluid loss cell was used to evaluate the filter-cake removal efficiency of the breaker systems. This apparatus was chosen because of the ability to closely approximate the downhole conditions. The formation face was simulated by placing an Aloxite or Berea disc of known permeability into the cell. The drill-in fluid breakers evaluated included polymer-linkage specific enzymes, 5% ammonium per-sulfate, 5% lithium hypochlorite, 6% sodium chlorite, and 3% hydrogen peroxide. The tests were performed at temperatures ranging from 120°F (49°C) to 220°F (104°C) using previously described procedures.[11]

Previous testing of drill-in fluids utilizing graded salt as the bridging or weighting material indicated the polymer specific enzymes will degrade the starch polymer from the point of contact in the wellbore out to the formation matrix. A subsequent flush with an undersaturated brine effectively dissolved the remaining salt particulates.[9]

Table 1 shows the results of Wellbore Filter-cake Removal Testing on drill-in fluids. The drill-in fluid used in Tests 1-6 of Table 1 consisted of 1.0 ppb XC polymer, 8.0 ppb starch polymer, 1.0 ppb caustic and 15.0 ppb calcium carbonate. The testing was conducted at 140°F with 500 md Berea core discs. The oxidative breakers provided cleanup efficiencies ranging from 13% for the 5% ammonium persulfate solution to 76% for the 5% lithium hypochlorite solutions. A positive indication for starch was observed post-test with each test using oxidizing solutions. The positive indication for starch indicates the presence of residual un-degraded starch. The polymer-linkage specific enzyme breaker system was observed to provide a 95% cleanup efficiency after a 24-hour shut-in. In a test reducing the shut-in time to 12 hours, an 85% efficiency was observed. A negative indication for starch was observed in both enzyme tests.

The drill-in fluid used in Tests 7-9 of Table 2 consisted of 0.75 ppb XC polymer, 3.0 ppb polyanionic cellulose, 0.25 ppb caustic, 0.25 ppb soda ash and 12.0 ppb calcium carbonate. The testing was conducted at 220°F with 800 md Aloxite discs. A 30% cleanup efficiency was observed with the lithium hypochlorite solution. The polymer-linkage specific enzyme system was observed to provide a 95% cleanup efficiency with a 12-hour shut-in. A second test using a 10 ppg NaCl carrier fluid instead of the 2% KCl used in other tests was observed to clean up to 91% in 24 hours. Additional testing indicates that compatibility problems are not encountered when the system comes in contact with crude oil.

Core Flow Testing. A core permeameter was utilized to evaluate returned permeability under dynamic conditions at 140°F. The core flow tests were performed using Middle Eastern carbonate plugs consisting predominately of dolomite with small amounts of calcite, anhydrite and quartz. The cores were loaded into a hydrostatic holder and allowed to thermally equilibrate overnight. The cores were then flushed with a refined mineral oil to establish an irreducible water saturation. The drill-in fluid used to generate the filter cake consisted of seawater, sodium chloride, 1.0 ppb XC polymer, 8.0 ppb starch polymer, 1.0 ppb caustic (pH 9.0) and 15.0 ppb calcium carbonate. Testing was performed to evaluate returned permeability with the 15% hydrochloric acid, with the polymer-linkage specific enzyme system and, a two-stage treatment with the enzyme system followed by 15% HCl.

The first test was designed to evaluate the effect an acid treatment alone had on a filter cake built on this Middle Eastern carbonate core. A refined mineral oil blend was used to define the initial oil permeability. A filter cake was built on the upstream coreface using the drill-in fluid described above. The subsequent high injection direction pressures confirmed that the filter cake remained on the coreface and was not permeable at the pressures used. The drill-in fluid was displaced from the flowlines, followed by a short interval of 15% HCl pumped across the upstream annulus to ensure acid contact with the filter cake. The 15% HCl acid was then pumped against the filter cake to simulate a wellbore acid treatment. The initial acid treatment caused endface plugging, so a small amount of acid was again flushed across the coreface, after which, the acid pumping against the filter cake resumed. The second crosshead flush yielded an improvement in flow through the core. The improvement was due to the evolution of a very large wormhole through the core. The wormhole grew to the hydrostatic sleeve, which quickly ruptured. A graphical representation of the test, shown in Figure 1, illustrates that 57.3% of the initial permeability was regained by the application of 15% HCl to remove the drill-in fluid filter cake.

The second test was conducted to evaluate the performance of the polymer-linkage specific enzyme applied independently to remove the drill-in fluid damage. A baseline permeability was established and then, a filter cake was built on the injection coreface using the drill-in fluid described above. The enzyme treatment was flushed across the coreface and shut in for 16 hours. Oil pumped in the injection direction following the enzyme treatment revealed the filter cake to be partially permeable, indicating the enzyme had degraded the starch polymer in the drill-in fluid. Final permeability in the production direction approached 80% of the original value. This test is shown graphically in Figure 2. Following the test, the core was removed and visually examined for the presence of starch. Although calcium carbonate was found on the core, iodine testing indicated there was no starch remaining in the filter cake.

The third treatment was designed to evaluate the combination of an enzyme to degrade the polymer followed by an acid treatment to remove the remaining calcium carbonate. Following determination of the baseline permeability and filter-cake building, the core was treated with the enzyme as described for the previous test. The injection direction permeability was improved but still limited by the remaining thick calcium carbonate filter cake. A 15% HCl solution was pumped across the coreface for five minutes then, one pore volume injected through the core. Differential pressure in the injection direction immediately began to drop as the acid broke through the core. Production-direction permeability approached the value obtained in the initial stage. Examination of the core following the test revealed very little filter cake remaining on the coreface. The graphical results of the combination treatment test are shown in Figure 3.

Radial Flow Cell Testing. To better simulate an actual wellbore configuration, a series of large radial flow cell tests were conducted at an independent laboratory. A 2-in. thick, 5-in. O.D. Berea disk with a 1.25-in. I.D. center hole was used as the simulated wellbore. The tests were run at a confining stress and test temperature of 1,000 psi and 200°F using previously described procedures.[10] Two tests were performed to compare the effectiveness of a two stage enzyme/acid treatment against an acid treatment alone. The same drill-in fluid used in the core flow testing was used in the following tests.

The baseline permeability stabilized at 565 md during the first test. Following the mud squeeze, the permeability was measured at 235 md indicating that without any treatment 42% of the original permeability would be recovered. After flowing the enzyme treatment and shut-in period of 16 hours, the permeability had increased to 485 md or 86% of the baseline value. Following a 15% HCl treatment to remove the remaining calcium carbonate, the permeability was observed to have increased to 580 md or a 103% retained value. The Berea cores used in these tests were not pre-acidized possibly accounting for the slight amount of stimulation.

Baseline permeability of the core used in the acid only test stabilized at 240 md. Following the mud squeeze, the permeability was measured to be 76 md or 32% of the original permeability. After a 15% HCl acid wash and 30-minute soak, the permeability stabilized at 143 md or 59% of the original permeability. The results of the radial flow cell tests, shown graphically in Figures 4 and 5, illustrate that the treatment with the enzyme followed by the acid soak significantly outperformed the treatment in which only acid was used.

Modified API Conductivity Cell Testing. Additional testing was conducted at an independent laboratory using a modified API conductivity cell with one piston and core slab replaced with a clear piston. Spacers were used to maintain a gap between the wellbore side of the core and the clear piston. As in the radial cell evaluations, two tests were conducted to compare the benefits of a staged enzyme system/acid treatment to an acid treatment alone. The tests were performed 120°F (49°C), also using previously described procedures.[11]

The results of the modified API conductivity cell tests are shown graphically in Figures 6 and 7. The initial permeability in the first test stabilized at 89 md. Following the mud squeeze, the permeability was measured at 48 md indicating that 54% of the original permeability was recovered by flowing brine through the core. After the enzyme treatment wash and 16-hour shut-in time at 120°F, the permeability climbed to 58 md or 65% regained permeability. The acid wash and soak removed the remaining calcium carbonate and produced a final permeability of 86 md or 97% regain of the initial permeability. In the second test, the initial permeability stabilized at 102 md. The permeability after the mud squeeze dropped to 31 md, 30% of the initial value. Following the acid wash and 30-minute soak, the permeability leveled out at 45 md. Without the benefit of the enzyme treatment, only 44% of the initial permeability was recovered.

Case Histories

The new technique for removing the damage caused by drill-in fluids has been successfully evaluated on two horizontal injection wells in the Middle East. Both wells were first treated with the enzyme breaker followed by an acid wash to remove the calcium carbonate. The offset wells in each case were treated only with a 15% HCl acid.

The first well had a measured depth of 12,700 ft with a 4,080- ft, 6.125-in. horizontal openhole interval and a bottomhole temperature of 211°F. The well was drilled using a clean "drill-in fluid" consisting of cellulose polymer and calcium carbonate. The enzyme treatment system consisted of the cellulose-linkage specific enzyme in 2% KCl along with a surfactant. 149 bbls of the enzyme treatment were needed to fill the open hole. An additional 60 bbls were mixed to account for pit volume and excess. The treatment was pumped at 1.5 BPM through 2-in. coil tubing. Following a 12-hour shut-in period, the well was opened and began accepting 3,361 BWPD. The acid treatment consisted of 15% HCl at 40 gallons per foot to remove the calcium carbonate. The injection rate increased to over 20,000 BWPD and continued improving over several days to stabilize at 33,300 BWPD. Two production surveys indicated the entire interval was accepting fluid. An offset well was drilled to a depth of 12,000 ft with a 6.125-inch horizontal openhole interval of 4,070 ft. The bottomhole temperature in this well was 200°F. The same drill-in fluid was used, and it was treated without the enzyme step, using only 15% HCl at 40 gallons per foot. The initial injection rate was 13,000 BWPD, and production logs indicated there was no injection below 10,900 ft. The well treated with the combined enzyme system/acid treatment improved injectivity by 256% when compared to the offset well.

The second case history also involved Middle Eastern horizontal injection wells. The test well (Well 1 in Table 3) was drilled to a TVD of 9,220 ft. The horizontal section was 2,500 ft, completed with a 7-in. liner. The bottomhole temperature in this well was 220°F. The "drill-in fluid" used while drilling through the horizontal section consisted of seawater, sodium chloride, 1.5 ppb XC polymer, 8.0 ppb starch polymer, caustic (to pH 9.25) and 15.0 ppb calcium carbonate. The well was treated with a starch-linkage specific enzyme solution followed by an acid treatment through coil tubing to dissolve solids and stimulate the formation. Two other wells in the field were also completed as horizontal injection wells. Well 2 was drilled to a TVD of 9,300 ft with a horizontal length of 2,310 ft and completed as an 8.5-in. open hole. This well was treated by bull-heading 15% HCl acid. Well 3 was drilled to a TVD of 9,248 ft with a horizontal length of 3,350 ft and completed with a 7.0-in. liner. Well 3 was treated pumping 15% HCl acid through coil tubing in order to achieve better distribution along the wellbore.

An analysis comparing the ratio of barrels of water injected per KH (md-ft) accounting for available productive footage and the average permeability is shown in Table 3. Well 1, treated with the enzyme to remove the polymer damage and acid to dissolve the solids and stimulate the formation, shows a final normalized injectivity ratio of 17.52. This value fell between the values of the other two wells. However, when analyzed with respect to permeability, an excellent result is observed with an injection of 6 20 B WPD/md-ft. This indicates that the dual treatment had removed both the polymer and solids damage.

Well 2 had been shut in for 12 weeks before being treated with acid. Since coil tubing could not be run to bottom, it was treated by bull-heading 15% HCl. While the final normalized injection index was relatively low at 11.43, which would be expected due to poor acid distribution, the well appears to perform better under available permeability analysis where the result was 5.11 BWPD/md-ft.

After being shut in for six weeks, Well 3 was treated by pumping 15% HCl through coil tubing. This well showed significant improvement between initial injectivity (prior to extended shut-in) and injectivity after acidizing based on a normalized injectivity index of 23.13. However, the injectivity relative to available permeability was a poor 3.77 BWPD/md-ft and may be indicative of relatively poor efficiency of the acid in cleaning up polymer filter cake and solids related damage.

There were no PLT logs run on these wells to evaluate the injection profiles. However, using formation capacity to measure the well's ability to receive fluid, it is clear that the combination treatment of enzymes to degrade the polymer and acid to dissolve the solids was a success.

Treatment Engineering Considerations

Successful application of the enzyme-based cleanup system is an interdependent balance between the chemistry of the fluids and the engineering involved to achieve proper placement of the fluid.

The enzyme complex must be selected to attack the specific polymeric components of the drill-in fluid in the bottomhole environment. For example, if polyanionic cellulose is the predominant component of the drill-in fluid, a cellulose-linkage specific enzyme capable of performing at bottomhole conditions would be necessary. The necessary shut-in time to allow degradation of the polymer by the enzyme is primarily dependent upon the enzyme concentration used and the bottomhole temperature. Pre-treatment laboratory testing conducted with the actual drill-in fluid at reservoir conditions will establish the shut-in time needed. Recommended shut-in times of 12 to 24 hours are typical.

Proper placement of the treatment is critical to the success. The enzyme solution must contact the polymeric damage in order to initiate degradation and removal of the filter cake. Application through coil tubing should be considered in all extended openhole applications. The most preferred method is to run coil tubing with a jetting nozzle to the bottom and load the hole as the tubing is reversed out. Foaming of the enzyme solution should be considered in high permeability situations to maintain the solution in the hole as long as possible.

The application of an acid wash following the enzyme treatment has been demonstrated to be beneficial for dissolution of the particulates. However, the use of the typical 15% HCl at 40 gallons per foot is believed to be unnecessary for particulate removal. The strength and volume needed to remove the solids will be dependent upon the amount of solids to be dissolved. Note, however, that the intention is to remove the particulates remaining in the hole and thus, 10 to 20 gallons per foot of 5.0 to 7.5% HCl is considered to be reasonable.

Conclusions

The "clean" drill-in fluids can cause significant damage to the wellbore permeability. Conventional oxidative solution or acid washes are often inadequate for removal of drill-in fluid filter-cake damage to achieve maximized well productivity.

A new polymer specific enzyme system for enhancing removal of drill-in fluid filter-cake damage has been developed and evaluated. The specific reactivity of the enzyme system minimizes placement problems associated with the use of non-specific reactive fluids. The new enzyme system provides for specific polymeric damage removal without causing damage to the formation or tubular goods. The new enzyme system is environmentally friendly.

Laboratory evaluations have shown that the new enzyme system can provide significantly improved wellbore damage cleanup relative to the conventional acid or oxidative solution cleanup systems. The use of the enzyme system to degrade to polymer followed by an acid wash to remove the particulates was observed to be most effective for removal of drill-in filter-cake damage.

Case history evaluations demonstrate that the polymer-linkage specific enzyme treatment can be a very effective tool for removal of drill-in fluid filter-cake damage. Field application of the system in horizontal injection wells was observed to provide results superior to those achieved in offset wells treated conventionally with acid.

The maximizing of wellbore permeability by effective removal of the drill-in fluid damage has far reaching implications, particularly in extended length completions. Improved wellbore permeability provides the potential for maximized productivity from a given well. The maximized ability to transmit fluids through the wellbore yields much improved recovery economics through more rapid recovery as well as the potential for fewer wells to achieve reservoir drainage. With respect to injection wells, there is the obvious potential to handle more injection through a single well but also, the potential for improved sweep efficiency due to better distribution of the injection which leads to improved recovery of valuable reserves.

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SI Metric Conversion Factors

bbl	x 1.589 873	E-01	= m^3
ft	x 3.048*	E-01	= m
gal	x 3.785 412	E-03	= m^3
in.	x 2.54*	E+00	= cm
lbm	x 4.535 924	E-01	=kg
md	x 9.869 233	E-04	= μm^2
psi	x 6.894 757	E+00	= kPa
°F	(°F-32)/1.8		= °C

Table 1
Wellbore Filter-Cake Removal

Test	1	2	3	4	5	6
Disc	Berea	Berea	Berea	Berea	Berea	Berea
Permeability	500 md	500 md	500 md	500 md	500 md	500 md
Mud Type	Starch	Starch	Starch	Starch	Starch	Starch
Breaker	$(NH_4)_2S_2O_8$	H_2O_2	Enzyme	Enzyme	LiOCl	NaOCl
Carrier Fluid	2% KCl	2% KCl	2% KCl	2% KCl	2% KCl	2% KCl
Temperature	140°F	140°°F	140°F	140°F	140°F	140°F
Initial Flow (300 cc)	12.25 secs	11.37 secs	11.22 secs	11.48 secs	12.06 secs	11.61 secs
Shut-In Time	24 hrs	24 hrs	12 hrs	24 hrs	24 hrs	24 hrs
Test for Starch	Pos	Pos	Neg	Neg	Pos	Pos
Final Flow (300 cc)	92.0 secs	17.22 secs	13.22 secs	12.21 secs	15.87 secs	18.43 secs
Cleanup Efficiency	13%	66%	85%	94%	76%	63%

Table 2
Wellbore Filter-Cake Removal

Test	7	8	9
Disc	Aloxite	Aloxite	Aloxite
Permeability	800 md	800 md	800 md
Mud Type	Cellulose	Cellulose	Cellulose
Breaker	Enzyme	LiOCl	Enzyme
Carrier Fluid	2% KCl	2% KCl	10.0 ppg NaCl
Temperature	220°F	220°F	220°F
Initial Flow (300 cc)	12.59 secs	12.32 secs	12.26 secs
Shut-In Time	12 hrs	12 hrs	18 hrs
Test for Starch	N/A	N/A	N/A
Final Flow (300 cc)	13.28 secs	40.44 secs	13.42 secs
Cleanup Efficiency	95%	30%	91%

Table 3
Injection Well Results and Analysis of Injectivity Index

Well No.	Status	Rate BWPD	Press. psi	Index	Normalized Injection	Aver. Perm. (md)	Productive Footage (ft)	KH (md-ft)	Inject. BWPD/ md-ft
1	At Completion	288	2074	0.14	-	0.53	920	488	0.59
	After Enzyme	864	1274	0.68	4.88				1.77
	After Acid	3024	1242	2.43	17.52				6.20
2	Before Shut-In	576	1674	0.34	-	0.74	1260	932	0.62
	Before Acid	3312	2041	1.62	4.72				3.55
	After Acid	4765	1211	3.93	11.43				5.11
3	Before Shut-In	288	1673	0.17	-	1.1	1150	1265	0.23
	Before Acid	4320	2010	2.15	12.49				3.42
	After Acid	4766	1197	3.98	23.13				3.77

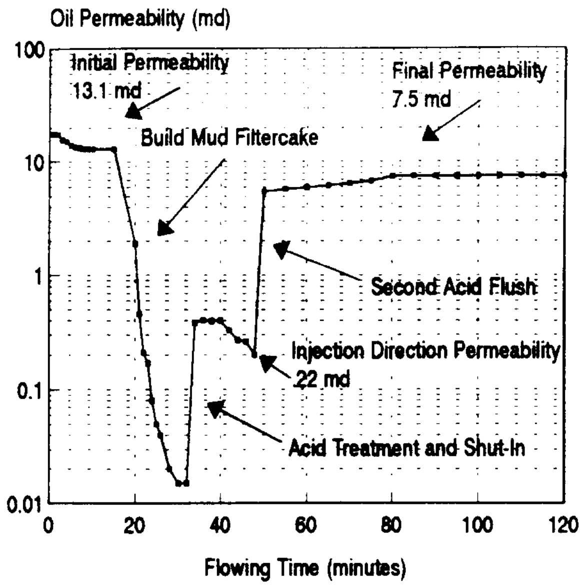

Figure 1 - Acid Treatment Only

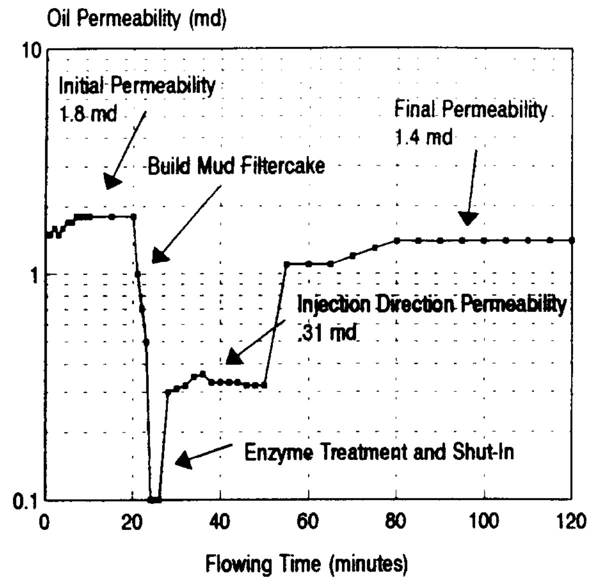

Figure 2 - Enzyme Treatment Only

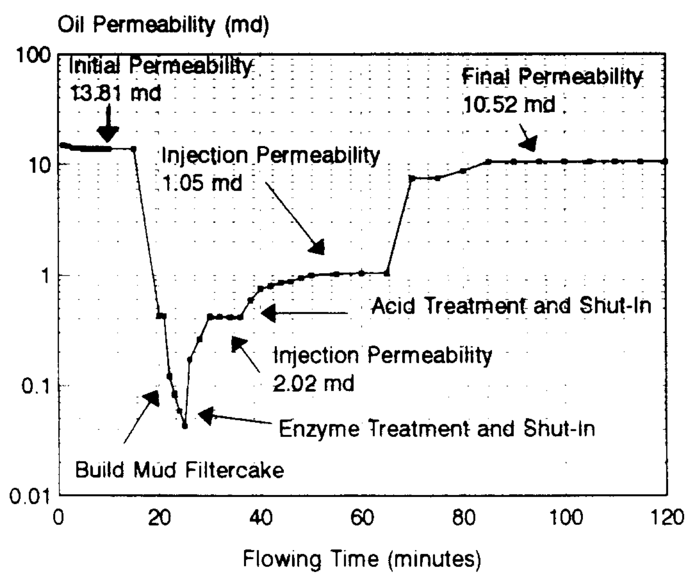

Figure 3 - Enzyme/Acid Treatment

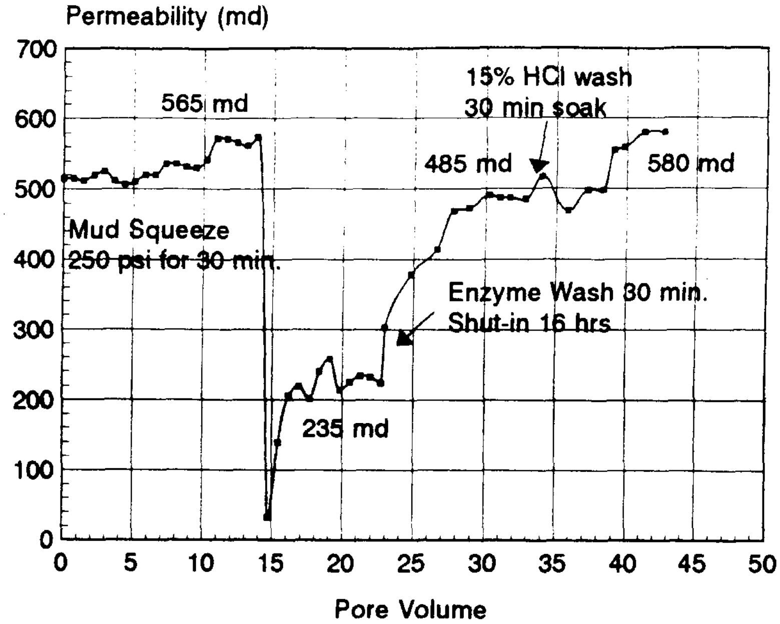

Figure 4 - Effect of Enzyme/Acid on Mud Damaged Berea Sandstone in Radial Cell

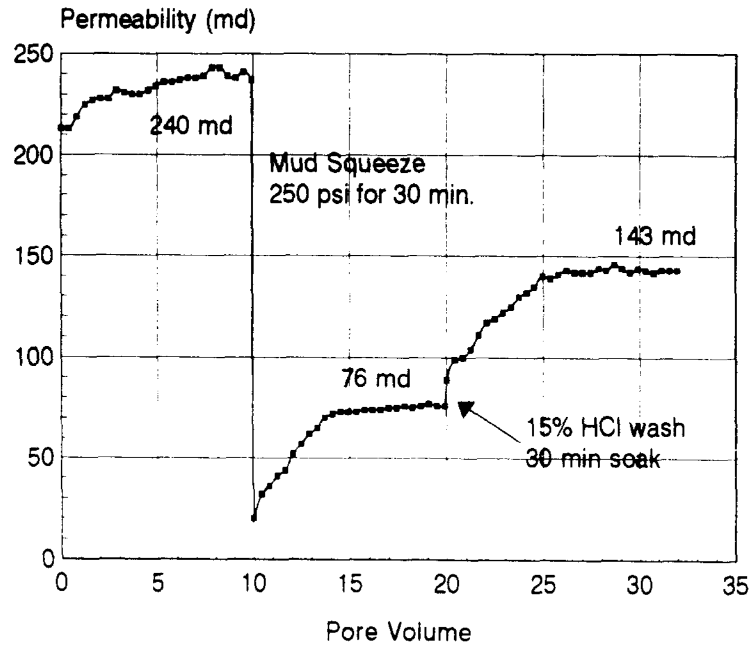

Figure 5 - Effect of 15% HCl Acid on Mud Damaged Berea Sandstone in Radial Cell

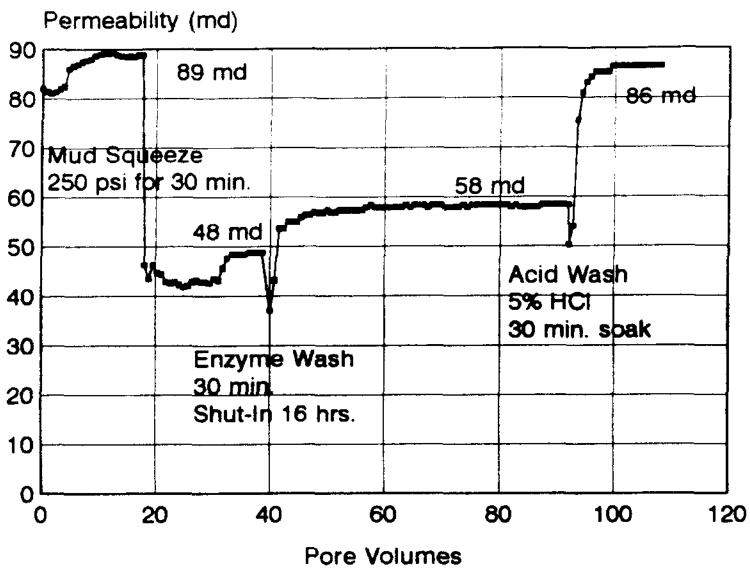

Figure 6 - Effect of Enzyme Treatment on Mud Damaged Berea Sandstone in API Cell

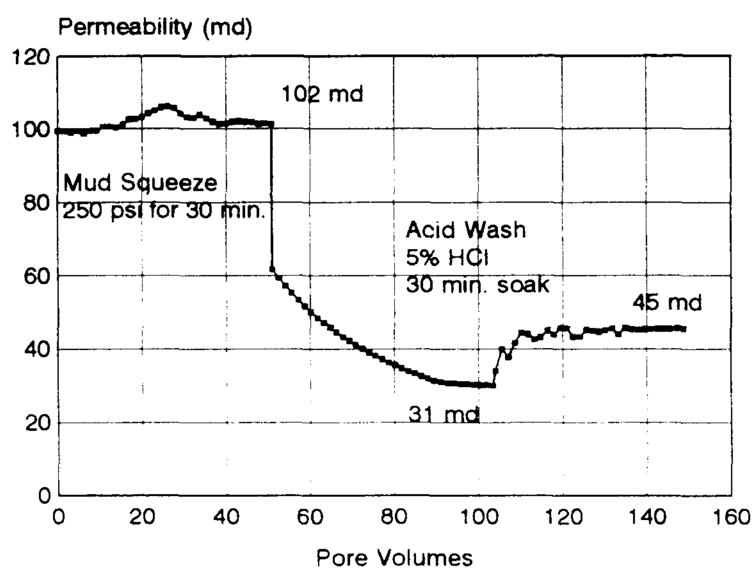

Figure 7 - Effect of 5% HCl Treatment on Mud Damaged Berea Sandstone in API Cell