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Solvent / Acid Blend Provides Economic Single Step Matrix Acidizing Success for Fines and Organic Damage Removal in Sandstone Reservoirs: A Niger - Delta Case Study

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Abstract

The formation of petroleum residue and deposits is a recurrent problem in low API gravity or heavy oil reservoirs and reservoirs with significant pressure and temperature fluctuations. It is also a challenge in fields where recent well interventions has pushed pipe dope into the perforations resulting in severe loss of native formation permeability and productivity.

This paper discusses the application of a unique solvent acid dispersion that offers one step stimulation of reservoirs damaged with both plugging solids and organic deposits. Conventional acid systems including the numerous patented HF – HCl and organic acid blends dissolve the plugging solids and cementitious materials but cannot stimulate sandstone reservoirs damaged with organic deposits or a combination of plugging solids, fines migration and organic deposits. In fact, the formation of acid induced sludge is common.

However, this acid - solvent blend dissolves asphaltene and paraffin deposits, prevents the formation of wax crystals and removes organic residue and inorganic materials simultaneously. A special surfactant train acts synergistically with the acid blend, prevents acid induced sludge and leaves the rock surfaces strongly water wet. Overall treatment efficiency was increased especially in gravel packed intervals by using a rotating jetting tool although success has also been recorded using the bullheading option. Recent experience has shown the acid blend is particularly suitable as a spearhead for injection wells. Optimum solvent loading for effective stimulation is between (10 – 20) percent depending on reservoir temperature, suspected damage mechanism and the severity of relative permeability effects.

Unique experience detailing standard lab / field practice and exceptional results for several wells in the Niger Delta is the focus of this paper. Wells treated with this unique blend either as spearhead for other specialty acid systems or as a one step treatment show dramatic and sustained productivity increases of between (50 – 150) % relative to initial well data. The system has been proven to be successful in most types of completion architecture. Key technical and economic performance indicators including skin factors, production rates, specific productivity indices, payback time and treatment cost indicate this low viscosity acid blend is both technically proficient and cost effective.

Introduction and Justification

The in-situ remediation of damage caused by organic material deposited in the near wellbore region from well construction and intervention operations i.e. from POBM's, pipe dope, e.t.c. And from the producing system itself (waxes, resins, and asphaltenes) has historically been tackled using either one or a combination of the following measures: Hot oil - water treatments, Hot water - solvent combination, Solvent - surfactant - dispersant trains and crystal modifiers.¹

The use of hot oil / water treatments is useful in the treatment of surface equipment clogged up with wax. Though these measures have attained a given degree of success even in reservoir stimulation applications, their continued usage has been proven to concentrate higher melting point carbon molecules in existing deposits, hereby making the resulting deposits more resistant to further heat treatments. This method has also been shown to cause significant formation damage by the way of negative relative permeability effects.

Solvents and solvent / surfactant / dispersant trains are excellent means of organic damage removal in the reservoir. However, the extent of their organic carrying abilities is limited by temperatures below the cloud point of the organic material / solvent combination. Large quantities of solvents are typically required i.e., 100 lbs. of xylene will just dissolve 6 lbs. of C₃₆ paraffin at 100°F.² However, the use of the proper combination of chemicals (determined by proper lab tests) can reduce treatment volumes and costs considerably. The use of crystal modifiers or pour point depressants provide a more effective means of preventing deposits in the reservoir but are usually cost prohibitive.

However, in the Niger Delta, organic deposition alone is rarely the sole cause of reservoir impairment. Often damage is as a

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result of a combination of organic and mineral scale deposition and plugging solids in the near wellbore region. For horizontal drainholes, the root cause of sub – optimal performance is the inefficient removal of the oil coated filter cake particles deposited often deliberately on the walls of the hole. Therefore a shallow characterization of the mechanism of impairment would encourage either the pumping of treatment recipes that will remove organic deposition or acids that will cause permanent damage to the system by producing sludge. Either way, reservoir skin stays or is worsened and treatment schedules become minor economic and technical disasters.

It is against this milieu that the development of a single – step solvent / acid dispersion became essential. This blend combines the dissolving powers of acid and solvent to remove both organic and inorganic material in one step. The blend is also compatible with other acid systems and is used as a preflush or mainflush in situations where organic damage belies a more severe form of reservoir impairment. These include plugging solids (requiring a HF based mainflush), scale deposition (an acid based mainflush with special scale inhibitor) and filter cake removal (requiring an enzyme based filter cake removal system).

Formation Damage Genesis

In this paper, formation damage mechanisms are viewed from 2 broad spectrums; the organic and inorganic. Organic sources of formation damage include the injection of pipe dope into a reservoir via bad completion and production practices. The formation of wax and asphaltene deposits due to shifts in the equilibrium of the hydrocarbon producing system (which may be internally or externally induced) and the coating of inorganic particulates with organic material in some types of filter cakes are also additional organic sources.

Inorganic sources of damage skin include a plugging solids - fines migration combination, scale precipitation in water injection systems and the CaCO_3 component of drill-in fluids used in drainholes. Because the proper characterization of these sources of impairment is absolutely necessary for efficient and in situ remediation, the factors that lead to this formation damage types will be briefly treated below:

Bad Completion Practices

Pipe dope is normally used in tubular make up operations during the completion module of well construction. It aids in the easy make up of tubing joints and helps ensure the integrity of each connection. Prior to commencement of injection in injection systems, it is imperative to wash the tubing with at least a solvent / surfactant combination. Sometimes, an acid pickle is also necessary. Sadly though, these simple precautions are overlooked very often, thus pushing the pipe dope into the perfs / near wellbore region. This blocks the reservoir's pore network and arterial passages leading to very poor injectivity. Consequently, the efficiency of the secondary recovery system is reduced considerably. The scenario painted above is very common in the Niger Delta and some of the case histories in this paper reflect this damage mechanism.

Wax / Asphaltene Deposits

Naturally occurring hydrocarbons in the earth's crust contain varying amounts of certain molecules called waxes and asphaltenes. When the thermodynamic conditions in the reservoirs change, organic solids are precipitated. Asphaltene flocculation and wax crystallization are the two major mechanisms by which organic deposition takes place from crude oil. Paraffin deposition may result from both natural causes (temperature drops e.t.c.) and well intervention operations (water / gas injection, acid jobs with cold fluids, e.t.c.). It is particularly instructive to know that productivity loss in gas condensate reservoirs when pressure near the wellbore reaches the dew point is not only due to relative permeability effects, but also probably due to the formation of wax crystals.³

Asphaltenes are high molecular weight, complex aromatic ring structures containing O, N, S and heavy metals. They give crude their color. They adsorb on clay surfaces and are usually precipitated by the presence of incompatible liquids in the system. They glue wax molecules together and form sludge with acid treatments. Waxes and asphaltenes are usually deposited together. This is probably the reason why waxes are difficult to re-dissolve in the same fluid even after original formation temperatures are restored.

Apart from externally induced processes, the twin mechanisms of biodegradation and evaporative fractionation could have been responsible for wax / asphaltene deposition tendencies in some Niger Delta reservoirs. Gas and light hydrocarbons could separate from a lightly biodegraded oil system, migrate into another reservoir and leave behind lower gravity fractionated oil that varies slightly in composition and is enriched in $\text{C}_{17} - \text{n} - \text{paraffins}$.⁴

Filter Cake from POBM / SOBM

Drill – in fluids used in the drilling of horizontal intervals are composed of base fluid (synthetic / base oil, water or brine), polymers, bridging agents and other components necessary for the attainment of the required fluid properties. Calcium carbonate particulates often form excellent bridging agents that stick to the formation face as filter cake. These particles are often bounded together by the polymer / base oil in the drill – in fluid. Ideally, this filter cake is supposed to slough off the formation face after the application of a drawdown of circa 50 psi during production. However, in reality this is not the case (as confirmed from MPLT's).⁵ Thus, the filter cake deposited becomes a veritable source of reservoir impairment. To remedy this impairment, procedures have been developed incorporating an enzyme based clean up system (to degrade the polymers) and an acid – solvent dispersion (to react with the oil coated calcium carbonate particles).

Well Completion Types

The completion architecture of the candidate wells is varied. From stand alone screens to expandable sand screens and horizontal open hole gravel packs, the acid blend due to its low viscosity is easily conveyed to the treatment interval either by high rate pumping (bullheading) or by using coiled tubing. The completion architecture sometimes determines the choice of placement technique especially in gravel packs

where hydraulic energy from a rotating jetting tool may be needed to optimise the chemical action of the acid blend.

Description of the Niger Delta

The Niger Delta Province has only one identified hydrocarbon system called the Akata – Agbada Petroleum system. This hydrocarbon system is situated in the Gulf of Guinea and has an area of about 300,000 km², a sediment volume of 500,000km³ and a sediment thickness of over 10 km in the basin depocenter.⁶ The delta formed at the site of a rift triple junction related to the opening of the Southern Atlantic starting in the late Jurassic and continuing into the Cretaceous. The primary source rock is the marine – shale facies of the delta called the upper Akata formation with possible contribution from the interbedded marine shale of the lowermost Agbada formation. Most of the sands consist of several sequences of shale and sandstone, mostly medium to poorly consolidated sands depending on depth. The sandstones are fine to medium quartz, poorly to moderately sorted; smectite, kaolinite and illite clays with feldspathic and carbonate scale materials. Many reservoirs are overpressured. Primary production is from gas expansion, though a great number of reservoirs have strong aquifer support. Common oil production problems include water coning, unconsolidated sands, high GOR's and wax deposition.⁶

Crude Oil Composition: The Niger Delta

There is a very high degree of variability in the physiochemical properties of reservoir crudes in the Niger Delta. The API gravity range of crude from this basin is between (16 – 50)° API with lighter crudes having a greenish – brown color.⁶ Crudes in this prolific province are either non-biodegraded or moderately biodegraded. The non – biodegraded crude type are light paraffinic based waxy oils with a wax content of up to 20% the biodegraded type are low API gravity naphthenic oils. Biodegradation and washing / fractionation are 2 factors that lead to the formation of wax prone heavy crudes in the basin.

Table 1 – Crude oil properties in the Niger delta

Property	Range	Comments
API gravity	16 - 50	56% Niger delta crudes have an API gravity of between (30-40)°API < 15% of Niger delta crudes have API gravity < 25
Sulfur	(0.1 – 0.3)%	Low sulfur content
Associated gas / gas cap	Low CO ₂ / N ₂ , No H ₂ S	Natural gas from Niger delta crudes is usually sweet and free from acidic gases like CO ₂ and H ₂ S.

The One Step Process

A process focussed on the removal of acid soluble / organic sources of reservoir impairment simultaneously. It may also include the one step removal and inhibition of scales. This process is not a substitute for HF acid treatments. Infact, unique synergy is achieved if it is used in consonance with HF based acid systems (if the predominant damage mechanism is fines migration) and with other acid blends designed to reverse specific mechanisms of skin damage.

Primary areas of acid – solvent blend application include:

- Wax crystallization / asphaltene flocculation prone reservoirs.
- Reservoirs damaged with pipe dope and its clones.
- Reservoirs with emulsion / fluid incompatibility problems.
- Reservoirs with a HCl soluble fines plugging problem.
- Waxed – up completions / tubulars.
- One or a combination of the above challenges.

Description of the Acid – Solvent Blend

This system is a unique blend of hydrochloric acid, an aromatic solvent, mutual solvent, a foaming agent, dispersant, corrosion inhibitor and surfactant.⁷ The concentration of acid is dependent on the amount of acid soluble compounds suspected to be bridging on the formation face. This concentration is typically between (7.5 – 15)%. Likewise, the percentage volume of aromatic solvent relative to total system volume is dependent on the severity of the impairment. This system combines the synergistic effect of all the different additives to form a dispersion capable of stimulating reservoirs damaged with emulsions, organic and inorganic material whilst leaving both the reservoir and metal surfaces water wet – a condition ideal for hydrocarbon production. A fines migration additive prevents formation deconsolidation after acidizing though this additive is unnecessary for tubing wash applications. Since the presence of iron compounds tends to cause asphaltene flocculation in some crude oils, an iron sequestrant is added to eliminate this possibility. The blend has both static and dynamic compatibility with both crude oil and other acid systems. This has made it a very useful system in the treatment schedules of intervals with complex damage mechanisms.

Acid – Solvent Blend – How it works

- It strips oil coated particles of organic material, exposes acid soluble material to acid penetration.
- Resolves emulsions in the near wellbore region with its unique suite of surfactants and eliminates incompatibility between the acid and crude oil.
- Acts like the standard HCl preflush to a HF – HV mainflush in non – HF sensitive reservoirs.
- In reservoirs with strong scale / wax formation tendencies, the blend acts to remove both organic and acid soluble material in one step.
- It acts as a mainflush removing CaCO₃ particles from polymers degraded by enzyme treatments.
- Foaming the acid sometimes tends to minimize acid volumes, achieve deeper penetration in long horizontal intervals and gravel packed completions.

Candidate Selection

The candidate selection criteria for well stimulation using existing acid systems is also applicable for the acid – solvent blend. These include WIQI < 0.5, BS&W < 60%, PI < 10 (obtained from BHP surveys / Nodal Analysis) and PI decrease > 30%. The reservoir must also have adequate reserves to justify the cost of stimulation. A thorough analysis of the production history is imperative to show whether the

reservoir has a wettability or an emulsion block problem as a side effect of organic deposition. High water cut wells have a tendency to produce fines, scales and organic deposits (from flocculation of asphaltene molecules). For new completions, the type of drilling mud used aids in the selection of proper candidates for this acid blend. A look must also be taken at the crude oil composition. A low API gravity reservoir is also most often prone to organic deposition and thus might be a good candidate depending on other parameters related to candidate selection. The key-determining factor in successful candidate selection is to conduct a deep investigation considering all facets of the construction and intervention operations carried out on the well.

Treatment Design

The treatment schedule is dependent primarily on the suspected form of impairment. The main focus of the design was to propose a formulation that removes suspected impairment and can effect true stimulation. It also sets in clear detail the optimum sequence of wireline, CT and pumping operations. Effectively, the design covers the entire chain of events from fluid recipe selection to job execution and evaluation.

The main forms of impairment considered in this paper include those from:

- a) Organic and HCl soluble materials
- b) Organic, HCl / HCl - HF soluble and scaly materials
- c) Organic, Polymer and HCl soluble materials

Treatment Schedules

Organic and HCl soluble materials – For reservoirs damaged with HCl soluble plugging material coated with organic compounds, a single stage flush of the acid – solvent blend is the norm. Depending on the severity of damage and the desired radial penetration, the loading of the acid blend is calculated. A loading of 50 gals / ft is not uncommon.

The acid – solvent blend strips the oil coated acid soluble molecules of the organic matter, hereby exposing them to react with HCl. The entire treatment fluid train is displaced into the reservoir with either tubing or coiled tubing content of brine depending on placement technique (bullheading or CT). Pump rates are typically between 1 to 5 bpm @ MSP. The acid is sometimes foamed to enhance acid penetration and flow back.

Organic, HCl / HCl - HF soluble and scaly materials – The acid – solvent blend performs the same functions as outlined above in addition to it being a preflush for a sandstone acid or phosphonic acid complex mainflush. This complex removes and inhibits scale compounds by the process of sequestration and complexation.^{8,9} The lack of fluoride ions in the chemical make – up of this complex eliminates the risk of the formation of insoluble precipitates and helps stimulate HF sensitive reservoirs. The phosphonic complex adsorbs on the faces of the reservoir matrix and this stunts scale crystal growth and propagation. It also has the added value of leaving the reservoir in a strongly water wet condition. However, the pumping sequence can be changed with the acid solvent blend

serving as mainflush. This of course will be dependent on the pre – dominant mechanism of reservoir impairment.

If fines migration is an issue along with scale and organic deposition, it is imperative that HF is represented in the chemical make – up of the mainflush. The acid – solvent is used in place of the standard HCl preflush with the added function of removing organic deposition. The HF acid system also contains a phosphonic acid complex, which aids in the deeper penetration of the HF (due to sequential hydrolysis of H^+), reduces the spending of HF on clays and manages effectively the risk of the formation of insoluble precipitates. This retarded HF acid has an extended dissolving capacity which after moving the fines from the near wellbore region, continues dissolving the fines with time and hence retarding subsequent fines deposition in this critical area.^{10,11}

Organic, Polymer and HCl soluble materials – A polymer specific enzyme based treatment is used as preflush to degrade the polymeric constituents of filter cake deposited on the walls of horizontal drainholes. This ensures the oil coated $CaCO_3$ particles are susceptible to the acid – solvent blend. This patented polymer – linkage specific enzyme complexes to hydrolyze polymers (starch, xanthan, e.t.c) to non – damaging fragments.^{12,13} Unlike oxidative / acid systems, this enzyme based system will not react with other substances other than the targeted polymers. Lab tests indicate that the regained permeability achievable with the enzyme / acid blend system in that sequence is greater than if either system was used independently.¹⁴ The enzyme system is non – hazardous and does not undergo chemical or structural changes during the reactions they initiate. Typical turnover numbers for these enzymes are in excess of one million, which indicates that more than one million linkages of polymer substrate can be cleaved per minute. The key to successful treatment design for this kind of impairment is to conduct laboratory analysis to determine the acid strength, solvent volume, enzyme / acid system soak time and the use of the appropriate placement mechanism. In the case histories treated in this paper, the placement method for this particular kind of impairment has been coiled tubing.

Laboratory Analysis

For any identified mechanism of impairment, the recommended laboratory recipe is rigorously tested to confirm compatibility and suitability for actual field operations. Such tests are carried out under strict quality control, as the degree of success in the field would depend on the efficiency of lab work. In this paper, procedures for determining both static and dynamic compatibility between the acid blend and a sample of reservoir crude are discussed. A unique procedure involving the laboratory simulation of the impairment process in POBM filter cakes is analyzed.

Static Compatibility tests – Outlined below is the procedure for performing a static compatibility test between acid blend and formation fluid.

1. Collect a sample of formation fluid (do not centrifuge)
2. Pour 50 ml of acid blend into a 100 ml cylinder and 50 ml of formation fluid into a 400 ml beaker

3. Pour 50 ml of acid blend into the 400-ml beaker containing the crude oil mixture.
4. Stir the acid blend and crude oil mixture in the lab mixer at high speed in order to form an emulsion and pour the resulting mixture into a 100-ml cylinder with stopper.
5. Place cylinder in a water bath at 70 deg C and record the column heights of the test acid and oil after 30 seconds, (1, 3, 5, 10, 30 and 60) minutes.
6. Pour a mixture of acid blend and crude oil mixture in the following ratios; 10:90, 30:70, 40:60, 60:40, 70:30 and 90:10 into the 100-ml cylinder with stopper.
7. For each of the mixtures in step 6, repeat steps 4 and 5.

The results are presented in Table A – 1. The vigorous agitation produced an unstable emulsion, which disappeared before the end of the test. The increasing height of the acid blend and decreasing interface column height support this assertion. If serious incompatibilities and the formation of stable emulsions was observed, the addition of anti – emulsion agents in greater concentrations would be considered. See Appendix C to observe a 46.5: 48.5 ratio of the acid blend / crude oil mixture. The percentage breakout is $(2 * 46.5 / (46.5 + 48.5)) = 97.9 \%$. In addition to recording the degree of aqueous phase break out, parameters such as volume of sediment layer, preferential wetting of solids, quality of interface (fluid, viscous, e.t.c.) and whether oil adheres to the sides of the cylinder in the aqueous layer must be taken into consideration. Ideally, no fines should be present in the oil phase and the fines in the aqueous phase should be water – wet.

Dynamic Compatibility tests – Outlined below is the procedure for performing a dynamic compatibility test between acid blend and formation fluid.

1. Collect a sample of the formation fluid and centrifuge for 10 minutes.
2. Extract the oil portion of the separated fluids.
3. With the extracted oil from the sample, run a rheology test and record the 600rpm, 300rpm, 200rpm and 100rpm readings.
4. With the acid test sample containing the required additives, run a rheology test and record the 600rpm, 300rpm, 200rpm, 100rpm readings.
5. Form a mixture of the test acid and the extracted oil sample in the ratio of 75:25, 50:50, and 25:75. Run a rheology test in each case, recording the 600rpm, 300rpm, 200rpm, 100rpm readings respectively.
6. Using the 600rpm and 300rpm readings as shown in Table A-2, the corresponding values of n, k, SR and SS in each test case can be determined.
7. Make non-linear Cartesian plots of all the test cases on the same graph sheet with Shear Stress (SS) on the vertical axis and the Shear Rate (SR) on the horizontal axis. Join the plot points for each test case starting from the X-Y origin using French curve if necessary (Figures B-1/B-2).

The shear stress versus shear rate curves of the different acid blend / crude oil mixtures must fall in between those of 100% acid blend and 100% crude, otherwise the mixture might form

stable micro – emulsions even though it may not be physically visible.

Laboratory simulation of the effectiveness of an Enzyme breaker system / acid – solvent blend on Polymeric filter cake clean up – The synergistic effect of combining both systems as outlined above is starkly displayed in results from this test.

1. Assemble cell with disk at the bottom; condition the HPHT cell to BHT (150°F) and mix up to 400mls of Enzyme breaker sample.
2. Fill the cell with 150mls of 2% KCL (prepared from clean or filtered water).
3. Open the top and bottom valves of the cell and let the brine flow due to the small hydrostatic of the brine in the cell.
4. Record the time for 100mls of 2% KCL solution to pass through the cell, T_1
5. Remove the cell, and fill with 150mls of drilling fluid (mud).
6. Close the top of the cell and attach the nitrogen manifold. Set the nitrogen pressure to 100psi.
7. Open the top and bottom valve in sequence and record the fluid loss at 1, 4, 9, 16, 25, 36 minutes.
8. Bleed off pressure, remove the cell and extract excess drilling fluid from the cell leaving the filter cake intact (See Appendix C).
9. Open the cell, invert the disk to simulate a production scenario, fill the cell with 150mls brine and place back in the heating jacket.
10. Allow the brine to flow as in (3) above. Record the flow time, T_3
11. Remove the cell, and extract excess brine.
12. Add the treatment fluid (enzyme breaker) to the cell, pressurise to 100psi.
13. **Allow fluid loss of 1ml to ensure effective enzyme coverage and dissolution of dried disk filtered drill in fluid.** Shut-in cell for 16hrs or overnight.
14. After shut-in time, bleed of pressure and extract excess treatment fluid from the cell.
15. Visually inspect the disk for the presence of filter cake, gently rinse disk surface with clean water to remove any remaining carbonate materials or drilling solids (See Appendix C).
16. Invert the disk to simulate a production scenario. Fill the cell with 150mls of 2%KCL
17. Allow the brine to flow as in (3) above. Record the time, T_5 to collect 100mls of the brine.
18. Prepare Acid – solvent blend (containing 90% of 7.5%HCl and 10% Solvent). Fill the cell with the acid blend and soak for 30min.
19. Remove the cell, extract the acid and fill with 2% KCL brine. Let the brine flow as in (3) above. Record the time to collect 100mls of brine, T_7
20. Repeat step 5 to 8 to form another filter cake.
21. Prepare the acid blend (containing 90% of 7.5 % HCl and 10% Solvent). Fill the cell with acid – solvent blend and soak for 30min.

22. Remove the cell, extract the acid and fill with 2% KCl brine. Let the brine flow as in (3) above. Record the time to collect 100mls of brine, T_{10} .

Analysis – Analyzing the data from Table A – 3, it is seen that the permeability of the Aloxite disc has been reduced by about 98%. The effectiveness of the enzyme breaker alone in reversing the effect of the drilling fluid is $(T_1/T_3) * 100 = 27.7\%$. For the acid – blend system alone, the efficiency was about $(T_1/T_{10}) * 100 = 71.6\%$. However, for a combination of the enzyme breaker and the acid blend, the efficiency was about $(T_1/T_7) * 100 = 92.2\%$. The laboratory results were proven by field data as presented in the case histories accompanying this paper.

Case Histories

Case One

The well was drilled and completed as a single tubing string across 2 sets of perforations in an IGP. The 30 feet upper zone is closed behind sleeve and the 125 feet lower zone can be accessed through the 3.5" tubing with a deviation of 48 degrees through the perforations. The reservoir was damaged with salt pills used as lost circulation material during drilling. Several acid jobs had been executed on this interval with no success. However, a detailed examination of the damage mechanism indicated that previous well interventions had pushed pipe dope into the near wellbore region. The effect of this was to coat the plugging materials in the perforations with organic matter hereby rendering the particles impervious to conventional acid systems.

The acid – solvent train (11 bbls of aromatic solvent, 99bbls of 15% HCl) was conveyed to the lower zone via a CT deployed rotating jetting tool for effective diversion, penetration and uniform coverage of the entire interval. A foamed acid treatment was then bullheaded into the upper zone through an open SSD. The entire system was displaced into the reservoir with filtered seawater (2475 psi @ 6.8 bpm). The pressure fell to 35 psi when the acid contacted the reservoir. The effect of the treatment was to increase productivity from the interval from 1600 bopd to 4275 bopd with 1% BS&W, WHP = 570 psi. The key advantage displayed here was the unique synergy between the treatment train and the CT deployed rotating jetting tool.

Case Two

A 260 feet horizontal water injection well was drilled with SOBM (weighted with CaCO_3). The mud is essentially some sort of oil based starch polymer fluid system used to minimize the associated wellbore damage experienced with conventional drilling mud (See Appendix C). It was expected that water injection would push the CaCO_3 particles away from the near wellbore region during the injection process. However, this was not achievable as the oil in the mud coated the carbonate particles and rendered them impervious to an aqueous based system. The damage mechanism necessitated the spotting of 10% HCl across the screens to dissolve the plugging material. The acid wash was lifted out of hole prior to the the enzyme treatment in order to ensure pH conditions in the near wellbore region do not denature the enzymes. The acid wash was

followed by 40 bbls of the polymer degrading enzyme system with a soak time of 6 hours . The final treatment stage was 40 bbls of foamed acid – solvent blend deployed with CT. The soak time for the acid solvent blend was 30 minutes.

Well tests conducted after the entire treatment schedule suggest the interval is receiving fluid with a low skin factor. The key determining factor aiding treatment efficiency was the combination of the enzyme system and the acid – solvent blend to remove impairment due to the SOBM filter cake.

Case Three

A 1500 feet long horizontal oil producer was drilled with oil based mud containing polymers and calcium carbonate particulates. An HzOHGP was installed across the drainhole section. The CaCO_3 bridging materials was supposed to flow back out of the well during production. A brief description of the recommended treatment schedule included displacing the horizontal section to nitrified brine, placing 167 bbls of polymer degrading enzyme system across the drainhole (soak time of 6 hours) and finally jetting the screens and near wellbore region with 184 bbls of foamed 7.5% acid – solvent blend.

Post treatment results indicate well is producing with a low skin of 5.95, flow rate of 10,700 bopd on bean 64/64". Reservoir energy for this well is supposed to be supplemented by water injection but the efficiency of the injection system is poor due to surface facility constraints.

Case Four

This gas injection well was occupies a central crestal position in the XX reservoir. The XX reservoir consists of loose and poorly cemented sandstones underlain by shale / sand sequence. During the over – balanced perforation of the interval, particles from the completion fluid flushed the near wellbore region. Also, pipe dope applied to the pin ends was suspected to have been injected into the reservoir leading to very poor injectivity.

20 bbls of the acid – solvent blend was used to pickle the tubing. This treatment was displaced out of hole by calcium chloride brine. This was followed with 10 bbls of the acid blend at a pump rate of 0.7 bpm to remove oily and acid soluble deposits (with backside closed). After a 15-minute soak time, 50 bbls of a phosphonic acid complex was pumped mainly to inhibit formation of scales.

Post treatment well tests indicate well is injecting at a skin factor of – 0.0724 and a PI of 31.3463. The injection profile has also been affected by gas availability.

Case Five

Severe impairment attributed to organic and scale deposition characterized the vertical water injector, resulting in a drop in water injection from a peak of 14,500 bwpd to 4718 bwpd at 2250-psi injection pressure. The treatment of this well with a phosphonic acid preflush and the acid – solvent blend mainflush not only restored the peak injection rate prior to the treatment in April, 2003 but also offered a huge increase in water injection rate. Post-treatment injection was 32,400 bwpd / 2000 psi compared to the pre-treatment rate of 2000 bwpd / 2000 psi established from the injectivity tests. The well was

kicked-off after the stimulation at 17,496 bwpd / 2165 psi and it is still injecting almost one year after treatment.

The choice of placement technique over the 30-ft completion interval was bullheading (pumping at high fluid rate was critical to treatment success), comprising a treatment schedule of 62 bbls of the acid – solvent blend, 62 bbls of the phosphonic acid complex and 62 bbls of 5% HCl acid overflush. Better results could have been obtained if the treatment was diverted using a foam pad stage.

Case Six

This well was drilled in 1974 and completed as an oil producer and later in 1987 re-completed as a gas injector in an interval having 37-ft of perforations. The mineral components of the reservoir are basically 69.1% halite (NaCl), 19.1% siderite (FeCO_3), 5.3% quartz (SiO_2), 0.5% calcite (CaCO_3) and 6.0% barite (BaSO_4).

During the injection life of this well, various problems had characterized the well; salt / bacteria growing in the tubing from the gas condensate, top sediments increasing due to sand and rust, growth at the bottomhole with appearance of a 'black-thick gum-like' substance. It was suspected that the damage due to drilling operations and plugging of the perforation tunnels by rust and oil particles from the injection network are among the causes of the impairment skin in this interval. Also, formation of wax from gas injection systems has also been proven and may have been a factor in this scenario. Previous treatments with other acid and cushion of brine formulations slightly improved injectivity.

A coiled tubing intervention with rotating jetting tool was carried out with an excellent response in injection rates.

25 bbls of the acid - solvent was used to pickle the injection tubing and wash the perforations (removal of organic deposits and acid soluble materials). 60 bbls of Phosphonic acid complex was bullheaded to stimulate the formation (removal and inhibition of scale) and 100 bbls of 3% NH_4Cl containing mutual solvents used to displace the acid system into the formation. The gas injection rate improved from 5 to 21 mm scf/day, offering a 4 - fold increment. This well is currently injecting at an average of 18.3-mm scf/day / 3435 psi on 100% choke size eight months after the treatment.

Case Seven

This well was drilled and completed as oil producer in 1972 and later in 1993 re-completed as gas injector in an interval of 34-ft perforations. The damage mechanism seen in this well is similar to that of the case six well.

A coiled tubing intervention with a rotating jetting tool was carried out with an improvement in injection rates.

25 bbls of acid – solvent blend was used to pickle the injection tubing and wash the perforations (removal of organic and acid soluble deposits). 60 bbls of phosphonic acid complex was injected through coil tubing to stimulate the formation (removal and inhibition of scale) and 100 bbls of 3% NH_4Cl containing mutual solvents used to displace the acid system out of coil tubing and into the formation. The gas injection rate improved from 2 to 16.5 mm scf/day, giving an 8 - fold increment. The well is currently injecting at an average of 12.1-mm scf/day / 3446 psi on 100% choke size eight months after the treatment.

Case Eight

This well was drilled and completed in January 2004. During the process of drilling, gel – like material used as lost circulation material seriously impaired the reservoir. Also, pipe dope used on the pin ends of completion tubing was injected into the reservoir during the completion / perforating process.

About 21 bbls of the acid – solvent blend (@ 21 gals / foot of perms) was pumped across the 50 feet perforation interval. The acid was deployed using 1.25" CT.

Post treatment results show the well tested @ 4044 bopd of 37.8 degree API gravity crude on bean 32 / 64" and zero BS&W. This production rate is well above estimated well potential implying true stimulation and removal of existing impairment.

Conclusions

1. Reservoirs with complex damage mechanisms have been successfully stimulated.
2. Damage caused by poor tubular clean up practices especially in injection wells has been reversed.
3. Field results show that both organic and inorganic deposits can be removed simultaneously by combining various acid systems.
4. A combination of the blend and a coiled tubing rotating jetting tool offers an exciting alternative for the stimulation of damaged gravel packed wells.
5. Laboratory tests to confirm compatibility of treatment / reservoir fluids in both static and dynamic conditions is critical to treatment success.
6. Laboratory simulation of the impairment processes and the removal of it indicate the efficacy of the treatment schedules described in this paper.
7. The removal of skin, scale and organic slime in one step is a distinct and exciting possibility. The critical factor here is to ensure compatibility between the acid – solvent blend and the scale removal / inhibiting agent

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Nomenclature

API	=	American Petroleum Institute
BHP	=	Bottom Hole Pressure
Bpm	=	barrel per minute

BS&W	=	Basic sediments and water
C ₁₇ ⁺	=	Organic molecule with more than 17 carbon Atoms
C ₃₆	=	Organic molecule with 36 carbon atoms
CaCO ₃	=	Calcium carbonate
CO ₂	=	Carbon dioxide
CT	=	Coil Tubing
Gals	=	gallons
H ⁺	=	Hydrogen ion
H ₂ S	=	Hydrogen Sulphide
HCl	=	Hydrochloric acid
HF	=	Hydrofluoric acid
HV	=	Phosphonic acid complex
H ₂ OHP	=	Horizontal Open Hole Gravel pack
IGP	=	Internal Gravel Pack
KCl	=	Potassium chloride
lbs	=	Pounds
ml	=	Milliliters
MMscf	=	Million standard cubic feet
MPLT	=	Memory Production Logging tool
MSP	=	Maximum Surface Pressure
N ₂	=	Nitrogen gas
NH ₄ Cl	=	Ammonium chloride
O ₂	=	Oxygen gas
PI	=	Productivity Index
POBM	=	Pseudo oil based mud
psi	=	Pounds per square inch
rpm	=	revolutions per minute
S	=	Sulphur
SOBM	=	Synthetic oil based mud
WHP	=	Well head pressure
WQI	=	Well Inflow Quality Indicator

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SI Metric Conversion Factors

cp x 1.0*	E-03	=	Pa.s
ft x 3.048*	E-01	=	m
⁰ F: (°F – 32) / 1.8		=	⁰ C
gal x 3.785 412	E-03	=	m ³
lbm x 4.535 924	E-01	=	kg
psi x 6.894 757	E+00	=	kPa
sack x 4.535 924	E+01	=	kg
bbl x 1.589 874	E-01	=	m ³
inch x 2.54*	E+00	=	cm
⁰ API: 141.5 / (131.5 + ⁰ API)		=	g / cm ³

*Conversion factor is exact.

Appendix A – Tables

Table A – 1 : Static Compatibility Tests – Results

TIME (MINS)	Column Heights (ml)													
	10:90		30:70		40:60		50:50		60:40		70:30		90:10	
	ASB	CS	ASB	CS	ASB	CS	ASB	CS	ASB	CS	ASB	CS	ASB	CS
0.5	0	100	0	100	2	95	3	93	4	96	3	97	100	0
1.0	0	100	0	100	4	93	6	91	7	93	6	94	100	0
3.0	1	99	5	95	12	85	21	74	23	77	20	80	98	2
5.0	1	99	11	89	23	74	44	51	42	58	40	60	95	5
10	5	95	24	76	34	63	45.5	49.5	60	40	70	30	90.5	9.5
30	11	89	31	69	40	57	46.5	48.5	61	39	71	29	90	10
60	17	83	32	68	41	56	46.5	48.5	61.5	38.5	71	29	90	10

ASB = Acid – Solvent Blend ; CS = Crude sample

Table A – 2 : Dynamic Compatibility Tests – Results

SAMPLE	DIAL READING			
	100rpm	200rpm	300rpm	600rpm
100% Crude : 0% Acid	33	64	93	181
75% Crude : 25% Acid	14	21	29	55
50% Crude : 50% Acid	7	11	14	22
25% Crude : 75% Acid	4	7	8	13
0% Crude : 100% Acid	2	2	3	5

Table A – 3 : Lab Simulation of Polymeric Filter Cake Cleanup – Results

Date:			Disk Type: Aloxite		Mud Type: SOBM		Bottom Hole Temp.: 150°F					
Stage	Fluid type	Qty. mls	Press. psi.	Shut-in time Hr:min	Fluid loss (for mud)						Flown qty.	Flow time. min:sec
					1min	4min	9min	16min	25min	36min		
1	2% KCl	150	14.8								100	1:23 = T ₁
2	Mud	150	100	0:30								36:00
3	2% KCl	150	14.8			1	5	9	12	45	75	60:00 = T ₃
4	Mud zyme	100	100	16:00								
5	2% KCl	150	14.8								100	6:00 = T ₅
6	ASB	100	100	0:30								
7	2% KCl	150	14.8								100	1:30 = T ₇
8	Mud	150	100	0:30	4	4.2	5.3	5.6	5.8	6	6	36:00
9	ASB	100	100	0:30								
10	2% KCl	150	14.8								100	1:56 = T ₁₀

Appendix B – Figures

Figure B – 1 : Dynamic Compatibility Tests : Plots of Shear Stress vs Shear Strain values for various ratios of oil / acid samples (Oil Sample 1)

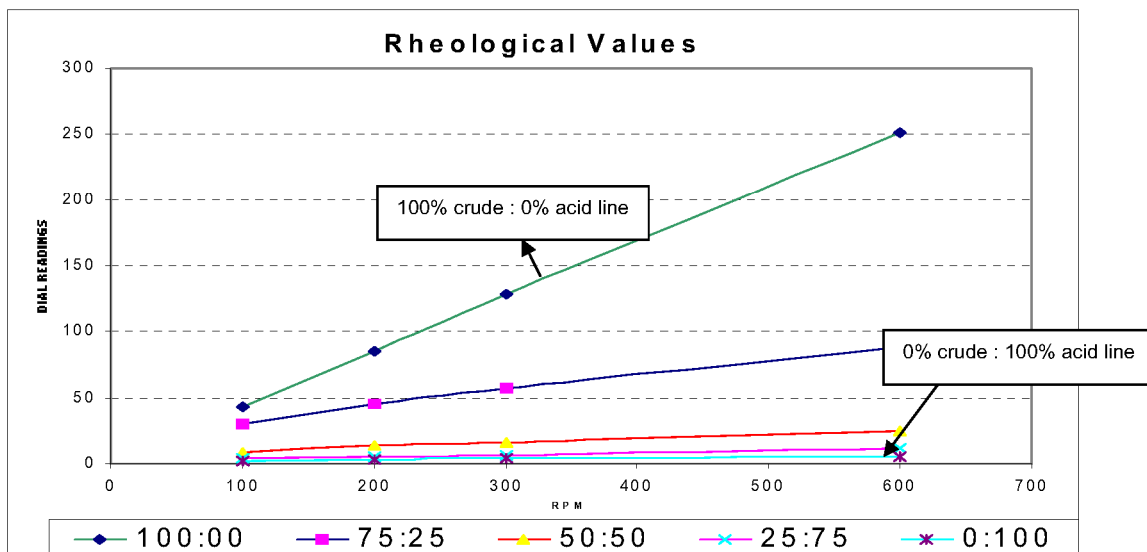
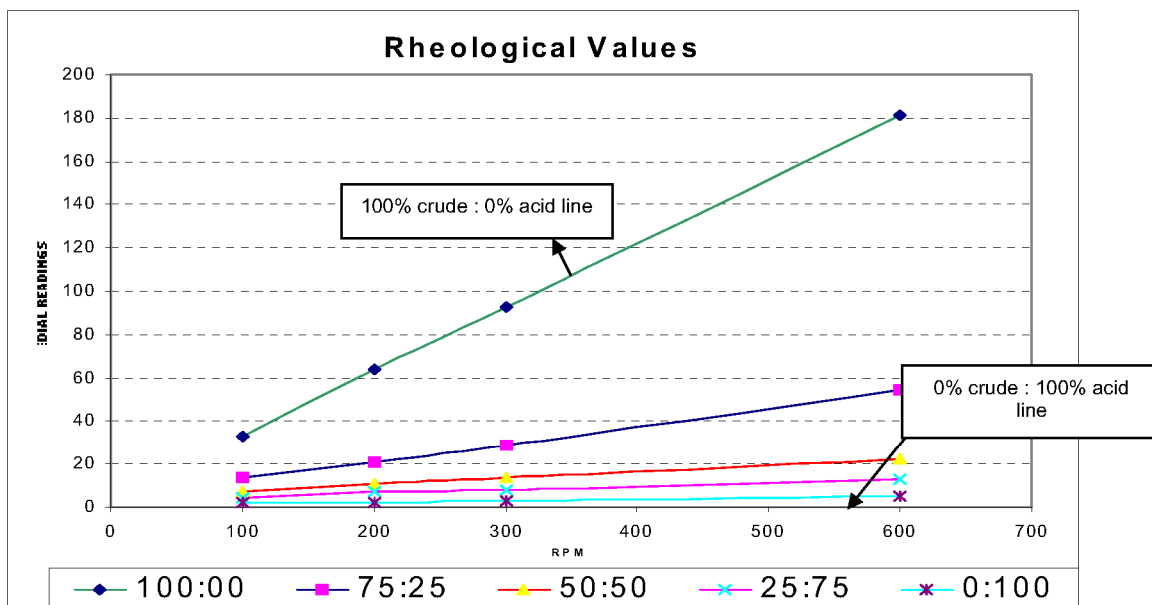


Figure B – 2 : Dynamic Compatibility Tests : Plots of Shear Stress vs Shear Strain values for various ratios of oil / acid samples (Oil Sample 2)



Appendix C – Pictorial Descriptions

Acid – Solvent Blend



Unique Compatibility between acid, solvent and surfactant train.

Polymeric Filter Cake on Aloxite Disc – Before Treatment



Damaged Permeability = 0.02 (original permeability)

Static Compatibility Tests



97.9 % break out

Polymeric Filter Cake on Aloxite Disc – After Treatment



Regained Permeability = 0.92 (original permeability)

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