

Production Improvement from Increased Permeability Using Engineered Biochemical

Secondary Recovery Methodology in Marginal Wells of the East Texas Field

Final Report

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ABSTRACT

A combination of a regenerating biochemical mixture and an organic surfactant has been applied to wells in the East Texas Field with the goal of restoring permeability, reversing formation damage, mobilizing hydrocarbons, and ultimately increasing production. Initial work in task 1 was designed to open the perforations and remove blockages of scale, asphaltene, and other corrosion debris. This was accomplished on three wells that produce from the Woodbine, and was necessary to prepare the wells for more substantial future treatments. Secondly, in task 2, two wells were treated with much larger quantities of the biochemical mixture, e.g. 25 gallons, with a 2% KCl carrier solution that carried the active biochemical solution into the near wellbore area adjacent to producing reservoir. After a 7 to 10 day acclimation and reaction period, the wells were put back into production. The biochemical solution successfully broke down the scale, paraffin and other binders blocking permeability and released significant debris, which was immediately produced into the flow lines and separators. Oil production was clearly improved and the removed debris was a maintenance issue until the surface equipment could be modified. In task 3 the permeability restrictions in a cylindrical area of 10 to 20 feet from the wellbore within the reservoir were treated with the biochemical solution. Fluid was forced into the producing horizon using the hydraulic head of the well filled with 2 % KCl solution, allowed to acclimate, and then withdrawn by pumping. The chloride content of the produce water was measured and production of oil and water monitored. The most significant effect in improving permeability and removing scale and high molecular weight hydrocarbons was accomplished in the wellbore perforations and near wellbore treatments of tasks 1 and 2. The effect the deeper insertion of solution in task 3 had minimal impact on production. .

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1.0 INTRODUCTION

This research project has as its objectives: 1) the testing and evaluation of a method for increasing oil production by implementing innovative technology using a multi-dimensional biochemical secondary recovery treatment engineered to remove permeability impediments, e.g. paraffin, asphaltene, inorganic scale, iron corrosion, and mobilize residual frac gels, etc., accumulated over the 70 year production history of the East Texas Field. 2) To devise a protocol that has the significant environmental advancement that no petroleum based solvents or additives are required; consequently, permits, remediation and spill cleanup are avoided.

The project is using a regenerating biochemical produced by certain species of microbes i.e. Pseudomonas and related species to mitigate the aforementioned formation damage, thus restoring permeability and increasing recovery by reducing the surface tension of the oil in-place to the reservoir rock. The work is proceeding as three well-defined tasks. The initial task is to select prospective wells and use the biochemical treatment to open the perforations and clean up the wellbore, removing scale, paraffin, and other corrosion related residual material. The initial task is essential because debris and residual material mobilized by subsequent treatments in tasks 2 and 3 must be removed through the perforations, and thus obstructions within the perforations need to be removed. The second task is to clean outside the wellbore and break down the permeability barriers within the producing reservoir in the near well bore environment. The final task is to extend the biochemical suspension as far as is practical into the reservoir, either as an injection/withdrawal experiment, or as a well-to-well tracer test.

2.0 EXECUTIVE SUMMARY

A regenerating biochemical mixture and organic surfactant has been applied to wells in the East Texas Field with the goal of restoring permeability, reversing formation damage, mobilizing hydrocarbons, and ultimately increasing production. The biochemical solution is added to the well annulus by gravity feed, and the solution can be mixed at the well site. Three wells with known well bore characteristics and perforation depths were treated, and all three wells evidenced an improvement by either increased production volume or the pumping of sand, scale, and other debris with the produced water.

Operations are affected at least two ways by the mobilized debris, first the mobilized debris interferes with pump action and may require pump removal, and redressing, or secondly, scale and paraffin may be removed by the biochemical solutions exposing corrosion holes that were protected by the coatings of scale and paraffin. The use of cup-type tubing pumps significantly improves the capability of the pump to lift and discharge the mobilized debris with the produced fluid. The identification of weak or damaged tubing simply allows for proactive maintenance of tubing.

Two wells were selected for the more substantial biochemical treatment in task 2. The treatment consists of at least 25 gallons of the biochemical solution and 25 gallons of nutrient solution, and approximately 140 barrels of carrier 2% KCl water. Injection of fluid by pressure is not recommended in these wells; the physical integrity of many of these wells that are seventy years old is marginal so fluids are allowed to gravity drain. The volumes of fluid selected are

sufficient to send the active solution through the perforations and allow reaction on the outside of the wellbore and the face of the producing formation. The biochemical solution is transported in drums and added directly to the annulus of the well, and the 2% KCl solution is brought in by truck to the well site. Addition of the solution is rapid and the only time constraint is the delivery time for trucking. Wells are left shut-in for 7 to 10 days for the microbes to acclimate and react. Wells are then placed back into production. Well No. 9 was successfully improved: oil production increased from about 0.3 BOPD to 1.5 to 2.5 BOPD. Water production increased only slightly indicating that the treatment may be improving the oil-wet permeability more than the water wet permeability. Well No. 8 was also successfully treated evidenced by the increase in gas pressure and the increase in oil percent. This well does not produce a total fluid volume that is sufficient to remove the mobilized material and at present is still cleaning up.

In task 2, the quantity of material that was mobilized is significant. Flow lines, separators, and valves all become clogged with the debris and pressure actuated valves fail. A large gunbarrel performs effectively in separation of oil and water in the presence of the mobilized sediment and debris. By using a cup type tubing pump and gunbarrel the movement of debris ceases to be a problem.

Well No. 1 was selected for the reservoir clean-up test because: 1) it had already been treated with the perforation and near-field clean-up procedures of tasks 1 and 2, there was a bridge plug in the well directly below the perforations that allowed us to focus the fluid into one producing zone, and 3) the fluid level was low thus the entire column of fluid would provide the hydraulic head needed to force the solution as deeply as possible into the formation. Emplaced fluid was withdrawn with a pumping time of 48 hours, little debris was mobilized, and production

remained the same. This indicated that the solution did not effect a change in the permeability deeper into the formation, and further confirms that the greatest impact in production occurs when the near wellbore scale and high molecular weight hydrocarbons are removed.

3.0 EXPERIMENTAL

Task 1 - Application of the Biochemical Product (Well Bore Environment).

Wells in The East Texas Field are approximately 3300 feet in depth and production over the life of these wells has been from the main Woodbine sand and from lower sand stringers at the base of the Eagle Ford section. The wells in The East Texas Field may contain paraffin, asphaltene and scale inside the wellbore. It is therefore necessary to clean the immediate well bore area first.

Experimental Procedure: This treatment consisted of approximately 5 gallons of the biochemical product, 5 gallons of nutrient water, and 3 to 4 barrels of flush water. Samples of the produced water were collected prior to treatment for analysis of the existing microbial populations. The purpose of the initial microbial analysis was to determine if any species of *Pseudomonas* were present that would provide false indications of breakthrough in tracer test scheduled for task 3; none were identified. To the extent possible, care was taken not to introduce destructive microbes not already active, such as sulfate reducing bacteria; consequently, the flush water was either produced water from this lease, or purchased 2% KCl water. This treatment was designed to effect a cleanup of the immediate well bore environment, i.e. perforations, etc., by mobilizing/solubilizing the scale, rust, corrosion by-products, paraffin, and asphaltenes.

Well numbers 1, 5, 8, and 9 have been treated with the biochemical product to clean the immediate well bore environment. The product and flush were introduced down the casing side

of the well and the well was shut-in for at least 1 to 3 days. Subsequently, the wells were placed back on pump to remove the debris created by the treatment, and to observe any change in production because of the clean-up treatment...

Task 2.0 - Biochemical Squeeze Treatments (Production Stimulation).

The “biochemical squeeze” treatment is designed to force the biochemical slurry through the previously cleaned perforations to treat outside the well bore. The solution penetrates into the formation to liquefy blockages in the reservoir sands due to tar mats, and inorganic material adjacent to the well. The biochemical solution is also designed to reduce surface tension of the oil/rock matrix interface thus mobilizing more recoverable oil.

The optimum amount of the biochemical product, nutrient, and flush needed to deliver the product package to the formation is determined based on the fluid level, number of feet of perforations, and the volume of the annulus. The No. 8 and No. 9 wells were selected for the “squeeze treatments” principally because the locations and producing sands were well defined and part of the same sand interval. This also allows for a test of the lower stringer sands in two adjacent wells to determine whether this location is appropriate for the well-to-well test designed for the next task.

The optimum solution for the No. 8 well was 25 gallons of the biochemical solution, 20 gallons of nutrient, and 40 barrels of 2% KCl flush water also containing a 2% nutrient solution, and 140 barrels of a 2% KCl flush water.

The optimum solution for well No. 9 was 25 gallons of the biochemical solution, 20 gallons of the nutrient solution, 40 barrels of 2% KCl flush solution with 2% nutrient solution added, followed by 140 barrels of flush water. We installed a re-circulating loop on the wellhead to maximize mixing by sending the produced water down the annulus for at least 4 hours during the shut-in period.

The wells were shut-in for at least 7 to 10 days to allow the microbes to acclimate and begin to break down the paraffin, asphaltene, and tar mats. We then turned on the wells to evaluate the production and remove mobile debris.

Task 3.0 – Production Stimulation by Reservoir Clean-up

The production stimulation was conceptualized as preferably a two well test because of the close spacing of wells in the East Teas Field; addition of biochemical solution to one well and production in the adjacent well. Alternatively, an emplacement of the solution into the reservoir followed by withdrawal and monitoring would yield similar information. The former procedure was not selected because it became apparent that based on locations of perforations and separations of sand stringers that adjacent wells actually were not connected along continuous flow pathways. Well No. 1 was selected for the “injection”/production test and the produced fluid was monitored for effects of cleanup.

4.0 RESULTS AND DISCUSSION

The East Texas Field was discovered on October 5, 1930. This field is a classic stratigraphic trap comprising over 140,000 acres. Production is primarily oil with over 5-billion barrels of production to date. The Woodbine Formation includes the Lewisville and Dexter members these sands are the primary producing horizons within the field. These sands are in many places massive at the top with numerous stringer-like sands lower in the section. The energy that moves fluid within the formation comes from the active water drive and solution gas. More than 30,000 have been drilled in this field; which is a “giant” oil field even by today’s standards. Primary recovery under optimum conditions will be about 18% to 20% of the oil in place.

Based on our historical research of the East Texas Field, operators subjected these wells to virtually every type of production and stimulation treatment popular over the last 70 years. Many of these treatments resulted in significant formation damage i.e. asphaltene and paraffin precipitation in the pore throats thus reducing permeability, acid treatments causing inorganic materials such as iron sulfide to precipitate within the reservoir.

In addition, the rapid production and over-drilling could have caused paraffin and asphaltene to precipitate in larger quantities forming tar mats and creating major permeability barriers within the reservoir. Coning of water would also have occurred bringing dissolved inorganic material into the existing oil leg of the formation causing emulsion blocks and resulting in formation damage.

The regenerating biochemical solution used in this research project contains microbes, i.e. *Pseudomonas* and related species that reduce surface tension and mitigate some of the aforementioned formation damage, thus partially restoring permeability and increasing recovery. Certain species of *Pseudomonas* and related bacteria produce enzyme-based surfactants that reduce the interfacial tension of the oil to the rock grain causing the oil to become more mobile. Emulsion blocks are broken in much the same way with the enzyme-based surfactants causing surface tension reductions thus allowing oil and water to separate based on density. Since the bacteria are heterotrophic, they need external sources of carbon. *Pseudomonas* species remove carbon selectively from the higher molecular weight hydrocarbons i.e. paraffin and asphaltene thus breaking the larger molecules into smaller molecules and increasing solubility. Additional molecular changes have also been observed in the microcrystalline wax fraction that would increase the solubility of the high molecular weight hydrocarbon into the lighter hydrocarbon fraction. Plugging by organic solids such as iron sulfide can also be solved using a similar process. The bacteria need soluble forms of iron and sulfur for their intracellular processes; consequently, they produce enzymes and other biochemicals to resolubilize these inorganic compounds to make them bio-available.

In order to survive in the reservoir environment the microbes must be able to withstand high temperature and salinity. The species employed in this procedure are both thermophilic and halophilic. Since the bacteria are introduced into the reservoir environment with a nutrient package that contains nitrate, the species use nitrate as an electron receptor. *Pseudomonas* and related species used here are facultative, i.e. able to metabolize with or without oxygen. The selected bacteria with their nutrient package undergo logarithmic growth within 20 to 30 minutes

after being exposed to the nutrient. This rapid growth occurs after the bacteria are injected into the producing formation and helps the various species acclimate to the reservoir environment. An additional benefit of using facultative bacteria will be the scavenging of oxygen within the water phase of the reservoir. This scavenging of oxygen should help reduce corrosion.

Results of Task 1 Experimental Work. The cleanup of the wellbore environment was accomplished in four wells: Nos. 1, 5, 8 and 9 on the J. M. Finney lease in Rusk County, Texas

- The No. 1 well was producing at the rate of approximately 1.27 BOPD prior to the initial wellbore clean-up treatment. The treatment resulted in release of scale and debris that had two consequences: 1) there was too much material for the pump and it became clogged and eventually stuck, and 2) the biochemical material apparently removed scale and paraffin that was covering a hole in the tubing, and once removed, a tubing leak caused production to cease. When the pump was redressed and the failed tubing replaced, the production resumed at a slightly increased value of from 1.34 to 1.9 BOPD. Figure 1 is a photograph of the hole in the tubing that was revealed when the scale, corrosion and paraffin was removed by the biochemical treatment. This well is a candidate for a more substantial “squeeze” treatment in the future as discussed in Task 2.



Figure 1. Tubing leak that was discovered post-treatment in the Finney No. 1 well.

- We treated the No. 5 well with the biochemical solution to open the perforation with no resultant change. Records for this well are sparse and a subsequent search of archived records at the Texas Railroad Commission revealed that this well was apparently never worked over by the original operator, Hunt Oil Company; and as a result if the well was not deepened, then no liner was installed, and no sections perforated. It appears this well is still producing as an “open hole” completion; consequently, if this were the case a small clean-up treatment would not be sufficient to impact production from a large exposed open section of the Woodbine formation. No further work will be done on this well.
- The No. 8 well has always produced a small amount of total fluid and it was assumed that it has a substantial permeability block. Prior to treatment, the total volume produced was in the range of 10 to 25 barrels of fluid a day with oil production approximately 0.3 to 0.5 BOPD. Post-treatment production was essentially the same with no detectable difference and it was

concluded that the permeability restrictions were not in the perforations, but formation damage. This well became a candidate for the more substantial treatment as discussed under Task 2.

- The number 9 well was producing at a rate of 0.3 BOPD accompanied by 50 to 75 BWPD, depending on the fluid level in the well. The lower quantities of water production occur when the fluid level in the well is low only a few feet above the pump. Following the treatment, the production rate initially rapidly increased, and the produced fluid contained evidence of the effect of bacteria breaking down the binding organics material and scale e.g. debris and clumps of organic rich sand. The tubing pump was not able to remove adequately the mobilized material; consequently, the pump filled with debris. Because of the additional resistance to the pump action, the sucker rods parted. It appeared that the treatment was successful, and subsequently it was decided that this well would be a candidate for a more substantial biochemical treatment when the pump was cleaned, and the parted rods replaced. This well is further discussed under Task 2.

Results of Task 2 Experimental Work. The objective of this task was to mobilize permeability blocking material such as scale, paraffin, tar, iron sulfide, etc. located both outside the wellbore and in the formation itself. To accomplish this, the perforations were first opened with a small biochemical treatment as discussed in Task 1. Subsequently a large treatment was done consisting of 25 gallons of the biochemical mixture, 20 gallons of nutrient solution, 40 barrels of 2% KCl solution, 5 additional gallons of biochemical solution, and a carrier solution of 140 barrels of 2% KCl solution. The volume was predetermined to be sufficient to move the biochemical solution more than 10 feet into the reservoir sand to mobilize the target material in the reservoir near the wellbore. The solution was added without complication and allowed to

acclimate and react for at least a week before pumping resumed. Both well No. 8 and No. 9 were treated similarly, but the response was different from each well.

Well number 9 was drilled in 1931 to a depth of 3709 feet below land surface then cased to the top of the Woodbine sand at 3605 foot depth; the Woodbine reservoir sands were produced as an open-hole completion. In the 1970's Hunt Oil Company, who operated this lease, deepened the wells about 200 feet to install a liner and test the lower Woodbine stringers about 100 feet deeper than the top of the main Woodbine sand, as did most other operators in the East Texas Field. By the 1970s, the recompleted wells could be logged with borehole geophysical tools not available when the wells were drilled in the 1930's, and by installing the liner through the Woodbine reservoir, the zones with the most prospective sands were perforated and tested. Figures 2 and 3 are photographs of the No. 8 and No. 9 locations, and Figures 4 and 5 are logs of the wells illustrating the intervals that were perforated for production in the 1970s.



Figure 2. Finney No. 8 location in the East Texas Field, Rusk County, Texas.



Figure 3. Finney No. 9 location in the East Texas Field, Rusk County, Texas.

Finney No. 9

Elev. 496'

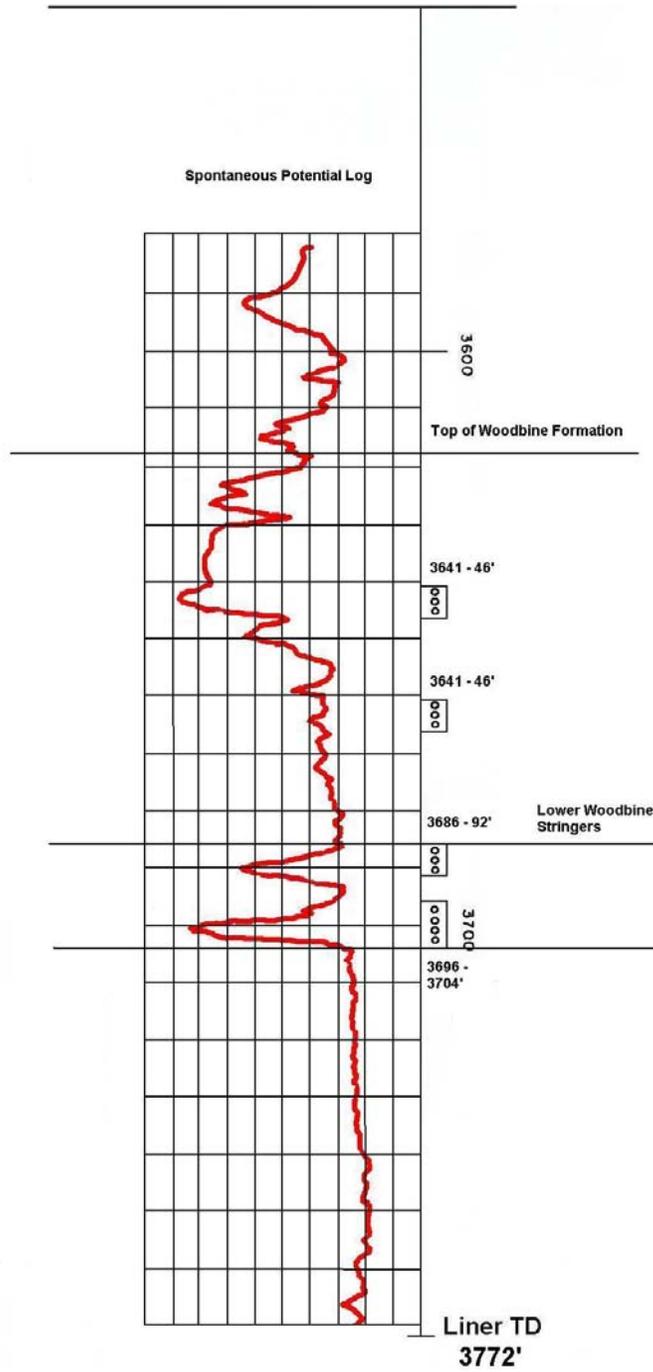


Figure 4. No. 9 well diagram with Spontaneous Potential log and well perforations indicated.

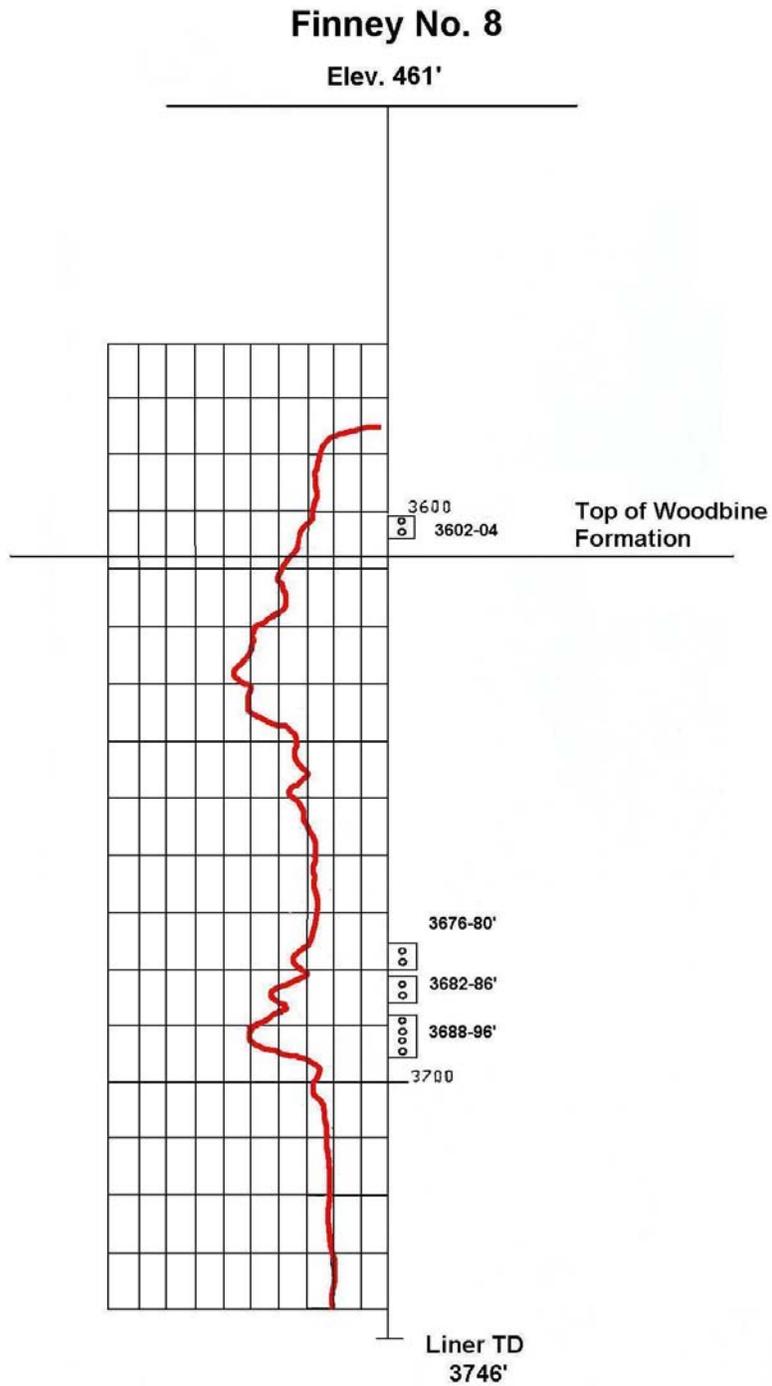


Figure 5. No. 8 well diagram with Spontaneous Potential log and well perforations indicated.

The No. 9 well was producing 0.3 BOPD prior to treatment as indicated in Figure 6. The initial cleanup treatment was performed in mid-September followed by a 3-day shut-in period. When the well was turned on it pumped fluid and debris immediately, indicating that the microbes had been successful in breaking down material that was affecting the perforations and allowing the material to be mobilized. Within 48 hours, however the rods parted in this well and pumping ceased. It is our preliminary assessment based on observation of the mechanical behavior of the treated wells, that the biochemical treatment creates several circumstances that exacerbate the failure rate of the rods and tubing. First, the released debris enters the pump, adds resistance, and creates a higher density suspension; thus, this added strain on the rods can result in rod failure. Secondly, the mobilized debris enters the pump and creates drag, restricts the valve action, and restricts the movement of the traveling valves requiring pump cleaning. Thirdly, the biochemical solution removes scale and paraffin that may be masking corrosion holes and rod-cut gouges in the tubing, thus allowing the tubing to leak and short-circuits fluid production. The biochemical solution is effective in mobilizing the debris and the operator must be prepared to repair mechanical consequences in the production system.

The rods were repaired in the number 9 well and the “squeeze” treatment of Task 2, as discussed above, was done in October to place the active biochemical solutions into the formation. The solutions were allowed to acclimate and react for at least seven days. When the well was repaired, and returned to production at the end of October, the produced fluid was again heavily laden with organic rich sand particles and debris released in the treatment. The total fluid produced was slightly greater than before the treatment, but the significant change was in the oil production (Figure 6). Production increased from a pre-treatment rate of 0.3 BOPD to a range

from 1.5 to 2.5 BOPD, with a significant increase in the gas pressure in the well. The permeability to oil and gas was improved substantially, and permeability to water only slightly.

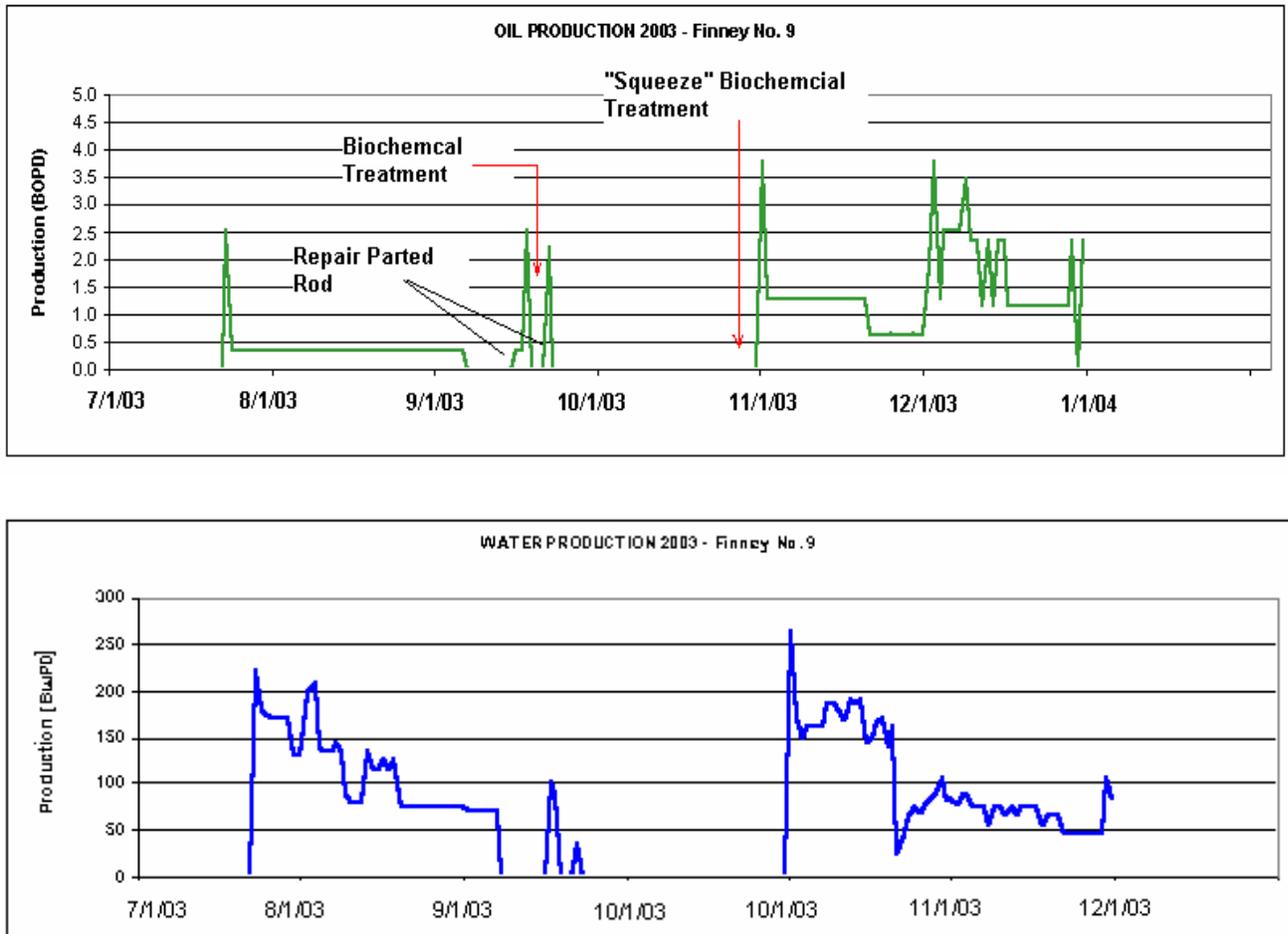


Figure 6. Production history for oil and water in No. 9 well before and after treatment.

The treatment for the No. 8 well has been only partially successful, but we are continuing the testing. The Spontaneous Potential log depicted in Figure 4 indicates that the lower Woodbine sand is not as well developed in the No. 8 well as it is in the No. 9 well. The squeeze treatment

initially increased fluid flow, and the flush production was primarily oil and gas with significant clumps of debris released from the perforations. The gas pressure was significantly increased; for example, most of the Woodbine wells have no measurable positive pressure, and after treatment the pressure is at least for a while between 10 to 35 psi and produced fluid is exceptionally gassy. It appears that this well does not produce sufficient total fluid to clean out all the released sand, scale, and other debris, so production for the well continues to be less than 35 barrels of gassy total fluid with an oil fraction of from 1 to 2 percent. Additional treatments may be performed, but the immediate issue is the removal of released debris.

Secondary Effects. Valuable insight was gained during the testing periods that will be useful in this project and to other operators in the future. The most difficult issue to cope with is the physical handling of the released well and formation debris. The objective is to mobilize this material and improve permeability but physical removal requires a strategy. Figures 7 and 8 are photographs of the material produced from both the Finney No. 8 and No. 9 wells. The particles are primarily very fine sand what appears to be dense black hard iron sulfide and asphaltene grains, all of which tends to clump and coagulate once produced. Further analyses will be conducted on this and similar material in the future, so that we can characterize the composition.

This debris was produced in such a large quantify that eventually the pumps were clogged, the flow lines were partially obstructed, and sediment could be seen coming out of the “stuffing box” at the well head. The 3-phase separator on this lease is a horizontal design with gas actuated dump valves for both the oil and water legs (Figure 9). The separator holds approximately 20 barrels of total fluid, and by December, the separator was more than 50 percent



Figure 7. Photograph of debris pumped from wells after treatment.



Figure 8. Photograph of pumped debris as closer view.

full of sediment, the dump valves were stuck open and sediment was distributed throughout the flow lines. After many episodes of disassembling the separator and cleaning the valves, followed by refilling with produced debris, it was determined that the use of a 3-phase separator was not the optimum method for separating oil. The maintenance required in cleaning the lines, pumps, and equipment, is both expensive and time consuming. Additionally, a further significant consequence occurs after the valves to the water discharge line become plugged with debris then the separator diverts water flow to the oil tanks, filling the oil tanks with produced water and sediment.

The lease was completely down for most of December and January as attempts were made to clean the production system. The remedy for the problematic maintenance of this debris is to produce into a gunbarrel separation system, which uses gravity feed, does not rely on any gas actuated valves, has 3 inch flow lines rather than 2 inch lines, and has a capacity five times as great as the three-phase separator. The current arrangement of the gunbarrel and oil tank is depicted in Figure 10. No additional problems have been encountered regarding the inability to handle the produced debris, and additional treatment and testing is continuing.



Figure 9. Photograph of 3-phase separator initially used in production.



Figure 10. Photograph of Gunbarrel now used for separation to avoid debris removal issues.

Results of Task 3 Experimental Work. The objective of this task was to mobilize permeability blocking material such as scale, paraffin, tar, iron sulfide, etc. located outside the wellbore and in the formation between wells. The conceptual model was that in addition to permeability barriers such as paraffin and scale build-up on the perforations and in the adjacent reservoir rock that similar barriers occur within the sandstone reservoir. These barriers would be located more than a few feet away from the well and such barriers would exist because of the increase in water fraction, and the temperature and pressure drop that has occurred over the decades of production. Spot additions of the biochemical solutions would not reach this material and a more invasive procedure would be required.

The preferable approach was a well to well movement of solution and with the close well spacing in the East Texas Field this could be accomplished by filling one well with the biochemical mixture creating a significant hydraulic head, and then pumping the adjacent wells until breakthrough occurred. Virtually no records are available for these old wells but the standard procedure was to leave the Woodbine sandstone as an open hole completion.

During the course of the project, we located personnel at Hunt Petroleum, the original Operator of this lease in the 1930s that had archived some of the original re-completion records for this lease. We discovered that even though there are many continuous sand zones that would be useful for the intra-well test, each well had been deepened and recompleted in a slightly deeper sand zone and the Woodbine sands of greatest interest are behind the liner. Detailed evaluation of these sands led us to the conclusion that no adjacent wells were completed in the same sand stringer and thus a well-to-well flow connection was of low probability. As discussed in the

Semi-annual Report an alternative had already been proposed in the event of difficulties with a well-to-well test. The alternative was to conduct an “injection”/withdrawal test with sufficient volume and residence time to react with any permeability blocking material on the order of tens of feet from the wellbore into the reservoir. This test was conducted as follows.

Injection/Withdrawal Experiment. The well selected for the injection withdrawal test was Well No. 1 (Fig. 11), the easternmost well on the lease. This well was logged by Schlumberger using the Reservoir Saturation Tool computer log suite and substantial oil is indicated as remaining in the main Woodbine sand (Fig. 11). This zone is perforated in three sand stringers from 3587-90’, 3597-3600’, and 3607-3612’ represents the zones that would have been produced for the longest period of time. In addition, this well has a bridge plug directly below these perforations isolating them from the deeper liner and additional perforations. This allowed us to focus more of the solution into a smaller zone providing deeper penetration into the reservoir.

Well No. 1 was treated with the biochemical solution under Task 1 to clean up the perforations and well bore as discussed in Task I, and production increased from 1.27 to 1.9 BOPD accompanied with the production of substantial scale and debris released as the solution removed high molecular weight material. By September of 2003, the settled production for the No. 1 well was 1.2 BOPD and 75 BWPD at which time the well developed a leak in the tubing and was shut in for repair. The failed tubing and worn rods were replaced on the 19th of March 2005 and the well resumed pumping. The “injection”/withdrawal test occurred over a seven-day period from the 16th to the 23rd of April. The biochemical solution was added at this point and allowed react in the formation for approximately six days then

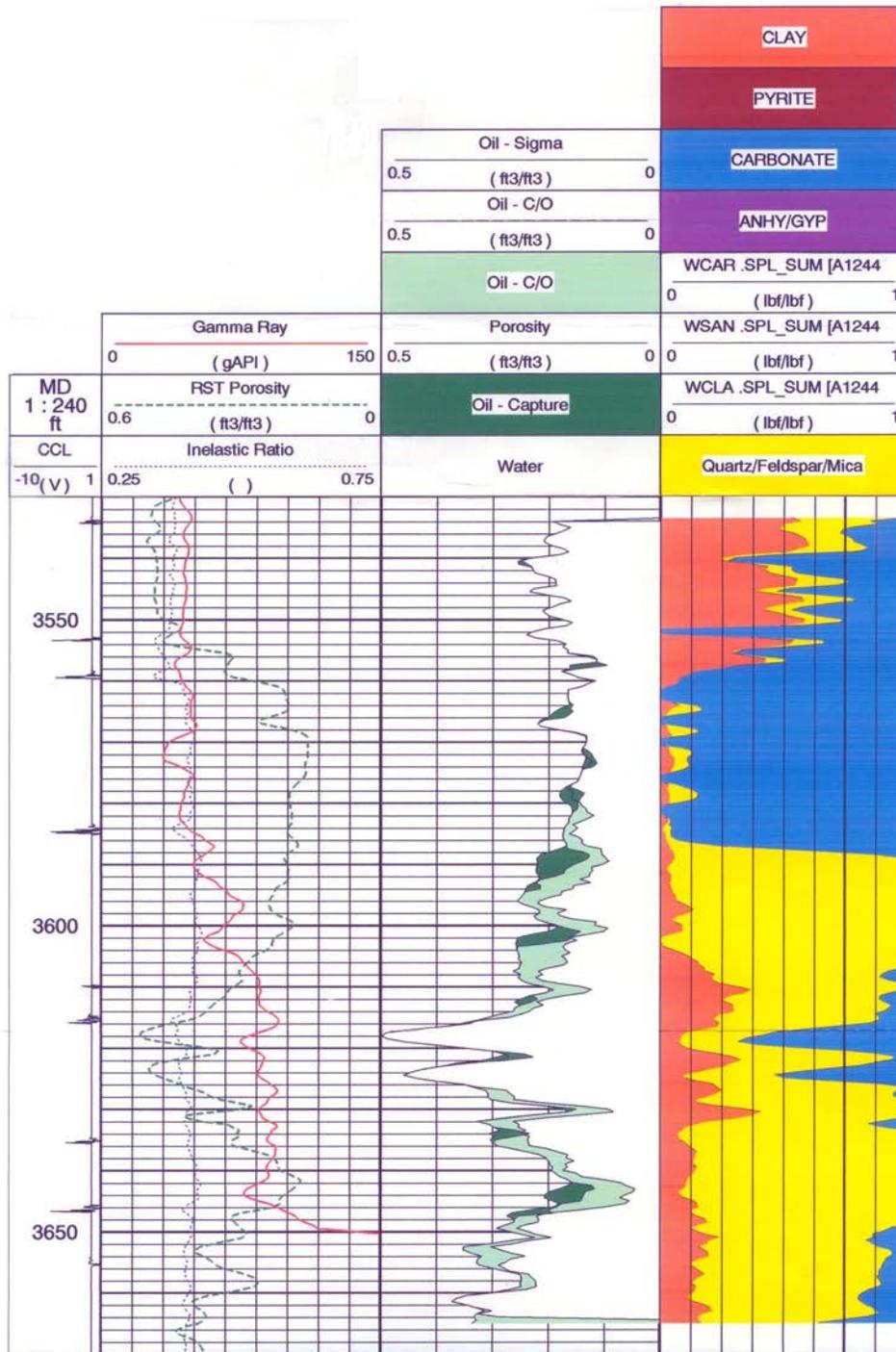


Figure 11. Schlumberger computer Reservoir Saturation Tool log for the No. 1 well.

pumping was initiated on the 23rd of April. Figure 12 depicts the production before and after the addition of the biochemical solution and the 2% KCl flush.

Procedure.

Objective: To flood a cylinder of the Woodbine Reservoir for 10 to 20 feet in radius from the well bore. Using the following data:

Production Casing – 7”, from surface to 3508’ depth.

Liner - 5” from 3508’ to a bridge plug at 3630’ depth

Tubing – 2 7/8” OD

Rods – 3/4” OD

Perforations – 3587-90’; 3597-3600’; 3608-3612’ total of 11’

Average porosity – 20%

Total volume of fluid required to fill the borehole and penetrate the formation approximately 20 feet, assuming about 50% mixing and allowing for stringers and other permeability blockages, was about 200 barrels.

The well was treated first with the biochemical solution, followed by 200 barrels of flush water.

The biochemical solution mixture is:

30 gallons of the biochemical product (Paragone)

30 gallons on nutrient solution

The flush solution is 2% KCl solution with 8 oz. per barrel of a nutrient solution.

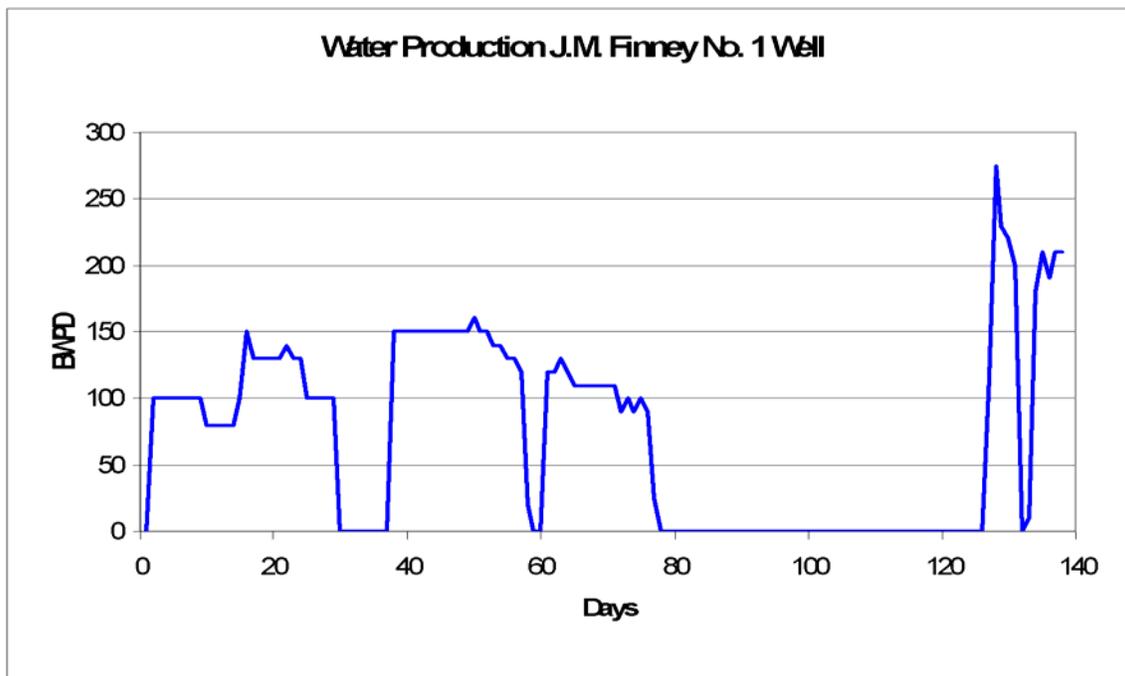
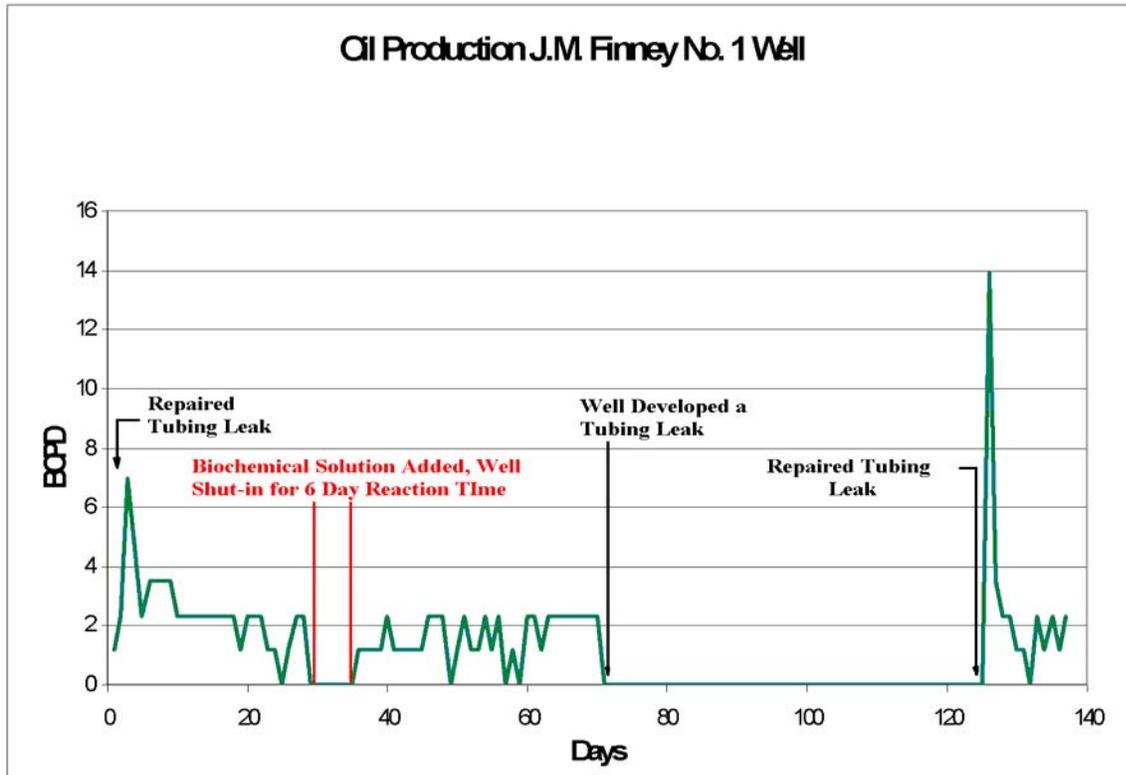
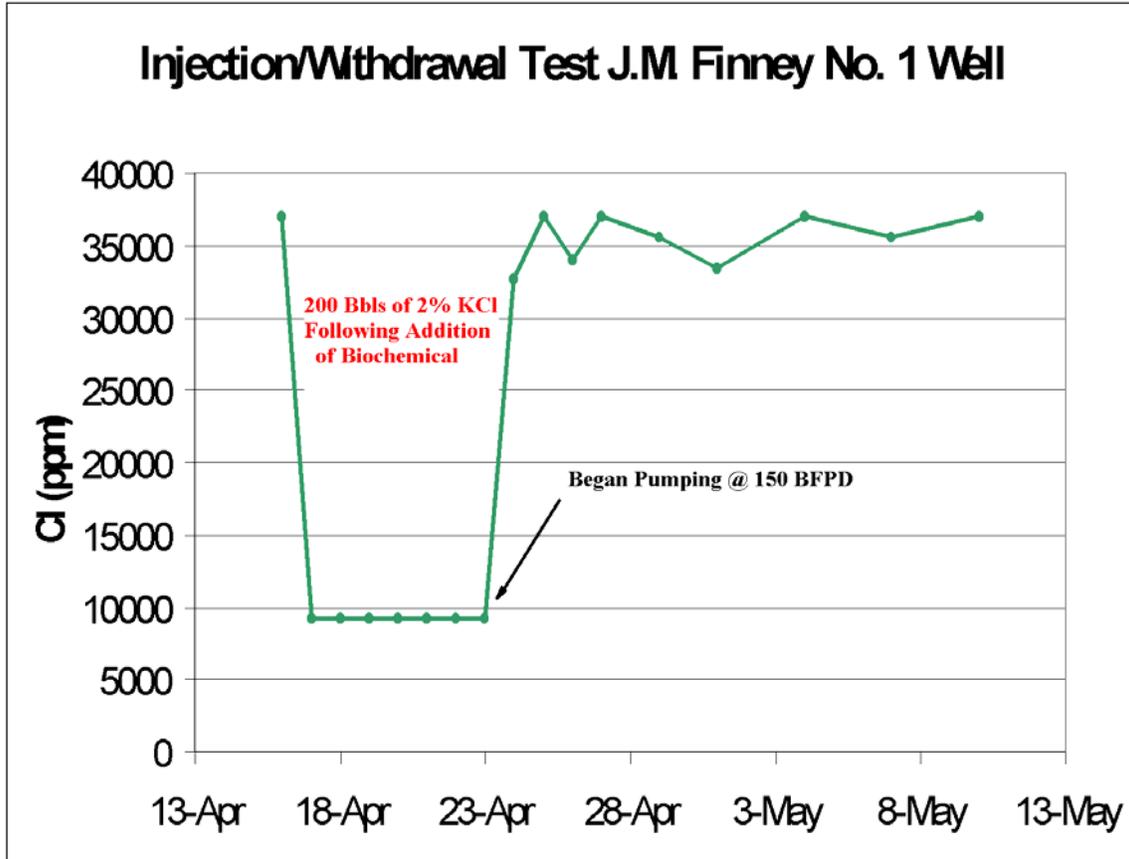


Figure 12. Oil and water production graphs for the No. 1 for the test 3 test.

The flush solution was allowed to enter the formation with gravity flow because the fluid level of the Woodbine is only a few hundred feet above the perforations. The microbes were allowed to acclimate and react with the scale and paraffin, etc., in the formation for approximately six days after which time the No. 1 well was placed back on production. Figure 12 illustrates the production rates for this time.

To further monitor the recovery of the injected flush, samples were collected for a two-week period following the resumption of pumping; the pumping rate was approximately 150 barrels of fluid per day and assuming essentially plug flow the bulk of the treatment solution should have been withdrawn within a few days. Samples were collected at the wellhead of the No. 1 well and analyzed for chloride concentration. The flush water with the biochemical solution had a chloride concentration of 9,220 ppm, the pre-treatment produced water concentration was 37,000 ppm, and the post-treatment produced water back to initial values within two days (Fig. 13).

The effectiveness of the biochemical solution in dispersing scale and high molecular weight hydrocarbons was clearly observed in earlier treatments of the perforations and near well bore as discussed in the earlier experiments. The evidence was mobilized sand, clay, scale particles coated with bound organic material in such quantities that pumps, flowlines, etc. were impacted. This was not the case in the “injection”/withdrawal test. Some particulate material was observed but not of sufficient quantity to impact production in any way.



The rate of both water and oil production was not changed by a statistically significant amount. The treatment did not negatively affect production by changing the oil percentage or increasing water entry. The increase in both oil and water production observed when the tubing was repaired at day 125 is not the result of the treatment but the result of refurbishing the pump. The interpretation of these results suggests to us that one of more of the following circumstances exists:

- 1) the material blocking permeability in the perforations and near the wellbore is not present at large distances for the well,
- 2) where present in the reservoir the flow path of fluid easily bypasses this material,

- 3) this material requires longer reaction time to mobilize, or
- 4) the interstitial velocity of fluid at large distances from the wellbore is too slow to mobilize the decomposed material and it remains in the interstices.

The results observed for the wells of this lease represent only a limited test of the effectiveness of the biochemical solution in removing permeability blocking and restricting material. Each well and even different sections of the same productive reservoir will have unique quantities of scale and paraffin. On this lease, the most effective treatment was near the wellbore however, the long-term impact is difficult to evaluate because of mechanical problems inherent in these old wells with severely deviated boreholes. The difficulty in maintaining continuous pumping with the extreme wear on the tubing is a significant technical challenge in its own right.

Other locations in the East Texas Field are now being evaluated by other operators using this same biochemical solution provided by MICRO-TES. In locations where the wells have less deviation, the production increases from this treatment are quite significant. This project was for small-scale test one lease and this was accomplished. One of us (MICRO-TES) is continuing the application of this process on other leases and has had significant success on a lease a few miles north of this lease producing from the same reservoir. The results have just been announced in a news release from X-Change Corporation (www.biz.yahoo.com/bw/050216/166046_1.html)

“X-Change Corporation director Robert Barbee announced plans to treat one the company's Snoddy wells in the East Texas Oil Field this week with Micro-TES' PARAGONE product. PARAGONE solubilizes paraffin and asphaltene in formations, well bores, pumps, flow lines, heater treaters and storage tanks. The product reduces or eliminates emulsion, BS&W, corrosion, scale, hydrogen sulfide and oil carry over. PARAGONE releases drilling fluid, frac gels, polymers and soap from the formation. It increases API gravity, oil production, gas production and water injection rates. Treatments with the product have resulted in significant savings for operators when compared to the cost of chemical treatments.

Recent PARAGONE treatments in three other X-Change Corporation wells have resulted in significant yield increases, pushing daily production levels by as much as ten-fold. Since initial treatment, the wells have settled down to respectable four-fold increases over previous flow rates.”

5.0 CONCLUSIONS

Summary of Results from Task 1

- The addition of the engineered biochemical solution is easily added to the well by gravity feed down the annulus, and for the initial well clean-up phase, the solution can be mixed at the well site.
- Solutions are comprised of 5 gallons of the biochemical mixture, 5 gallons of nutrient solution, and 3 barrels of either lease water or 2% KCl solution. The biochemical solution should be allowed to acclimate and react for 24 to 72 hours, and then the well can be placed on production.
- Three wells with known well bore characteristics and perforation depths were treated and all three wells evidenced an improvement by either increased production volume or the pumping of sand, scale, and other debris with the produced water.
- Operations are affected at least two ways by the mobilized debris, 1) because it interferes with pump action and requires pump removal, and redressing or 2) the removal of scale and paraffin exposes corrosion holes that were protected by the coatings of scale and paraffin.
- The use of cup-type tubing pumps significantly improves the capability of the pump to lift and discharge the mobilized debris with the produced fluid. The identification of weak or damaged tubing simply allows for proactive maintenance of tubing.

Summary of Results from Task 2

- Two wells have been selected for the more substantial biochemical treatment in task 2. The treatment consists of at least 25 gallons of the biochemical solution and 25 gallons of nutrient solution, and approximately 140 barrels of carrier 2% KCl water.
- The biochemical solution is transported in drums and added directly to the annulus of the well, and the 2% KCl solution is brought in by truck to the well site. Addition of the solution is rapid and the only time constraint is the delivery time for trucking. Wells are left shut-in for 7 to 10 days for the microbes to acclimate and react. Wells are then placed back into production.
- Well No. 9 was successfully improved with oil production increased from about 0.3 BOPD to 1.5 to 2.5 BOPD. Water production increased only slightly indicating that the treatment may be improving the oil-wet permeability more than the water wet permeability.
- Well No. 8 was also successfully treated evidenced by the increase in gas pressure and the increase in oil percent. This well does not produce a total fluid volume that is sufficient to remove the mobilized material and at present is still cleaning up.
- Significant lessons have been learned that will benefit other operators in the future. The quantity of material that is mobilized is significant. Flow lines, separators, and valves all become clogged with the debris and pressure actuated valves fail. A 3-phase separator is not recommended; rather a large gunbarrel works far more effectively in separation of oil and water in the presence of the mobilized sediment and debris. By using a cup type tubing pump and gunbarrel the movement of debris ceases to be a problem.

Summary of Results from Task 3

- The No. 1 well was selected for the more insertion of the biochemical treatment as much a 20 feet into the producing reservoir to treat the high molecular weight hydrocarbons. Fluid is not pressure injected because of the age of these wells and uncertainty of well integrity when pressurized.
- The wellbore is first spotted with 25 gallons of the biochemical solution and 25 gallons of nutrient solution, and then the well is filled with a carrier 2% KCl water carrier solution. The fluid level of this well is low and thus the hydraulic head was able to force the reacting solution at least 20 feet into the selected portions of the reservoir.
- The well was shut-in for 7 days allowing the solution to react and acclimate. Production was then initiated at 150 BFPD; chloride concentration, oil and water percentages were monitored for two weeks.
- The biochemical solution was withdrawn within 48 hours and the production was restored to essentially the same pre-treatment levels. It is concluded that the impact of the permeability blocking material within the reservoir are either not easily accessed or not significantly affecting production.

- The most significant production improvements are observed when the immediate wellbore area is treated. The effects of deeper reservoir treatment are not significant based on this limited testing.
- This procedure is now being used by other operators on nearby leases with notable success and with wells that are less deviated and have fewer mechanical complications the long term success should be significant.

6.0 REFERENCES

No journal or technical references were cited in this report.