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Field Testing of the Biocompetitive Exclusion Process for Control of Iron and Hydrogen Sulfides

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Abstract

This paper reports the results of several field tests of the ability of bacteria, indigenous to oil reservoirs, to reduce and eliminate hydrogen sulfide (H_2S) from the production stream. The effort was a logical progression from laboratory studies reported previously, to field testing under controlled conditions. The field testing ranged from production tanks to individual well treatments to large groups of wells. The treatment consists of providing small quantities of essential nutrients to denitrifying bacteria, which utilize the volatile fatty acids present in many oil reservoirs as a carbon source. These denitrifying bacteria in the reservoir compete in the microecosystem for the volatile fatty acids also required by the sulfate reducing bacteria. This process is called Biocompetitive Exclusion.

The field tests show the ability of the biocompetitive exclusion process to be a viable field treatment for the reduction and elimination of iron sulfide and hydrogen sulfide problems in producing oil wells. Different treatment practices, quantities, frequencies, and candidate selection were examined as part of this testing program. An attempt was made to quantify production increases resulting from the treatment. Recommendations are made to increase the effectiveness of the application of this process in a field environment. Treatment of wells with the Biocompetitive Exclusion Process was both a technical and an economic success.

Introduction

The classical interpretation of microbial enhanced oil recovery (MEOR) is to introduce a microorganism along with a food source to effect a positive change in the recovery mechanism of an oil reservoir. A common treatment is to clean up paraffin problems in producing wells[1]. More sophisticated processes take advantage of the microbe's ability to produce surfactants, acids, alcohols, and polymers to improve oil recovery[2]. In the biocompetitive exclusion process, bacteria already existing in the reservoir are stimulated to effect favorable changes in the production stream[3].

Sperl and Sperl[4] have shown that nutrients can be introduced into reservoir systems to stimulate indigenous microorganisms. This commonly occurs when reservoirs are flooded with water containing significant sulfates. This sulfate influx stimulates the indigenous sulfate reducing bacteria (SRB) population which metabolize the sulfate into hydrogen sulfide gas. The hydrogen sulfide then reacts with metallic compounds such as iron to form iron sulfide, apparent in many producing systems as a black scale soluble in hydrochloric acid. Iron sulfide scale often plugs flow paths in the reservoir, perforations, pump intakes, and tubulars, causing restricted production. In a similar manner, the introduction of nitrate salts as a nutrient to the denitrifying bacteria (DNB) population causes them to flourish and metabolize the sulfides out of the system, producing byproducts commonly used as agents for improved oil recovery.

Hitzman and Sper1[5] have recently discovered that volatile fatty acids (VFA), such as acetate, butyrate, formate, lactate and propionate, play a key role in the microecology of petroleum reservoirs. This is an important step in understanding reservoir microecology and effecting positive change using the biological system.

Volatile fatty acids have been found in many petroleum reservoirs. They act as a carbon source for microbial action. They are generally metabolized by sulfate reducing bacteria, such as *Desulfovibrio desulfuricans,* generating H_2S gas as a by_product. However, as Hitzman and Sperl reported, adding nitrate to waters containing VFA stimulates the growth of denitrifying bacteria, such as *Thiobacillus denitrificans.* These DNB are more voracious competitors for the VFA in the same environment as the SRB.

The process of H_2S elimination has been successfully tested in core floods and was also reported by Hitzman and Sperl. Six_inch Berea cores, with permeabilities of approximately 400 mD, were flooded both in the presence and absence of nitrates in an anaerobic environment. In the absence of nitrate, SRB concentration increased to 10' colonies per milliliter and sulfate concentration reduced to 0. Sulfide concentration increased, while propionate was totally consumed and acetate was decreased. In the presence of nitrate. the DNB became dominant, and depleted the VFA, and drastically decreased the sulfate reduction process.

Steamflood Test

The suppression of H_2S by a water soluble nitrate based nutrient formula in the laboratory needed to be verified and optimized under oilfield conditions. At the Naval Petroleum Reserve #3, the light oil steamflood had stimulated the SRB population in a halo area around the steam injection wells. A detailed description of the steamflood is given by Olsen, et al6 and Doll, et al7. This area was identified as a good proving ground, since the production facilities are being deteriorated by the sour oil and gas production, and the field is offered by the U. S. Department of Energy to public testing through the Rocky Mountain Oilfield Testing Center.

In May 1994, samples were taken from twenty Shannon formation producing wells and tested for the presence of indigenous bacteria. DNB were found in the samples. It was determined that it would be technically feasible to demonstrate the technology in this area.

It was initially planned to add the nitrate to stimulate the DNB through the steam injection system. and then its effect on reservoir microecology would be measured at the producing wells. A fluorescein dye tracer injection was planned to check the flow paths in the reservoir, and indicate which wells should be monitored closely for results.

First Procedure

On March 15, 1995, 45 barrels of water were injected into steam injection wells 72.3SX3 and 72.4SX3 to cool down the wells. There was 0.3 lbs. of fluorescein dye mixed with 30 barrels of water injected into 72.3SX3. Well 72.4SX3 was treated with 0.7 lbs. of fluorescein in 60 barrels of water. **Figure 1** shows the relative locations of these wells. Offset producers 72.5SX3, 73.2SX3, and 73.61SX3 were monitored every four to six hours for the appearance of tracer. After 48 hours, the sampling frequency was reduced to twice daily and continued until April 5, 1995. No sign of the tracer appeared in the wells being monitored.

From May 30 until June 2, 1995, 20 gallons of nutrient formula was injected into the steam injectors 72.3SX3 and 72.4SX3. Producing wells 72.5SX3, 73.2SX3. and 73.61SX3 were monitored for H_2S, nitrates, and oil production until July 20, 1995.

Results

Although variations in H_2S concentrations were seen, no significant changes to the existing trend could be established. No sign of nitrates appeared at the monitor wells. It was hypothesized that the tracer and nutrient formula were being precipitated or adsorbed in the reservoir. A voidage rate calculation shows poor balance between the injection and production rates of these wells, suggesting that they were not in direct communication.

Second Procedure

It was decided that a larger volume of nutrient formula was needed in order to see results. On August 28. 1995, another 15 barrels of nutrient solution was injected into 72.3SX3. Well 72.4SX3 received 15 barrels of nutrient and I kilogram of fluorescein dye. This time producing wells 72S3, 72.5SX3, 72.ISX3, 73.2SX3, 73.3SX3, 73.61SX3, and 82.ISX3 were monitored for fluorescein, H_2S content of casing head gas, and fluid production rates. On August 31. 1995 another 15 barrels of nutrient formula was added to each of the two injection wells.

Results

There were no positive indications of the fluorescein dye at any of the producers. Water samples were gathered during the first few days and analyzed for chemical and microbiological changes. No significant changes were noted.

The steam generator was down with mechanical problems from September 13 to October 11. 1995. This affected the total fluid and oil production rates and rendered the production data inconclusive.

There was a suppression of H_2S in Well 73.61SX3 from September 10 to September 20 from about 600 PPM to 200 PPM. Well 72.ISX3 dropped from 4500 to 2500 PPM during the period from September 21 to September 29. Well 72S3 also experienced an H_2S suppression from September 3 through September 15 from 1200 to 800 PPM. Figure 2 shows the H_2S concentrations in the casing head gas from each of the monitored producers.

It is theorized that the dye either precipitated out as the injection fluids cooled or were adsorbed by the formation clays at high temperature. Since the steam injection system is a relatively complex system, it was concluded that too many variables existed to effectively test the process.

Production Tank Test

After the lack of conclusive results experienced in the steamflood injection system test, the tact of the testing program was shifted from the injection system to the production system. It was decided to test the process in the surface equipment first. This testing environment bore the closest resemblance to a laboratory test that could be set up under field conditions. It would also minimize the number of variables that have been changed between the laboratory and the field.

Two parallel shipping tanks at the T.5.10 test satellite were chosen as the test site. T.5.10 gathers production from approximately 34 sour steamflood producers and has a test treater to measure producing rates from any of the associated producing wells. Produced fluid is then commingled with the effluent from the test treater and stored in a pair of tanks waiting on transfer to the tank battery for final separation. Here, one tank could be treated and shut in, while the other tank could still handle the production.

There is an equilibrium between the dissolved sulfides in the liquid phase and the free sulfide in the gaseous phase that allows the gaseous hydrogen sulfide concentration to be monitored as a delayed indicator of microbial activity in the liquid phase. The disadvantage of this method is that, in the short term, the equilibrium may not be complete. The gaseous phase H_2S concentration data was therefore reinforced with laboratory water analysis and microbial cultures to identify dissolved sulfides and iron concentrations, and bacterial populations.

Procedure

On October 17, 1995, the test was started. Ten barrels of nutrient formula was mixed with softened water and circulated in the chemical truck. The test tank was drained and isolated from everything but the production tank. The production and test tank were then equalized. The nutrient formula was pumped into the test tank. The test tank was then completely isolated from the production tank and scaled from the atmosphere. The test tank had 208 barrels of produced water in it with a high sulfate concentration. The hydrogen sulfide concentration in the atmosphere above the liquid was 600 PPM in the test tank and 1,025 PPM in the production tank. The system was left with the test tank shut in and the production tank handling the production fluids until October 21, 1995. Fluid samples were taken at the start and end of the test for laboratory analysis.

On November 6, 1995, the test was repeated without the addition of nutrient formula as a control run to eliminate the possibility of other mechanisms causing the observed effects during the static period. This test was concluded on November 11, 1995. Hydrogen sulfide concentrations were measured and fluid samples were taken as in the first test.

Results

The concentrations of H_2S in both tanks were monitored for five days. On October 19, the H_2S concentrations were 225 PPM in the test tank and 800 PPM in the production tank. On October 21, the concentrations were 150 PPM in the test tank and 1,225 PPM in the production tank. A consistent downward trend in the H_2S concentrations in the test tank was seen. This is contrasted to a consistently high level of H_2S concentrations in the production tank, and in the subsequent static control run. The H_2S concentrations in the gas on the production tanks are shown in **Figure 3.**

The laboratory analysis of water samples from the tank confirmed the indication that SRB activity had been suppressed and the DNB population stimulated. There was a complete elimination of dissolved sulfide in the test tank at the end of the test. In the control run, there was a slight increase in dissolved sulfide levels. SRB counts were reduced from 10' to 0 colonies per milliliter in the test tank. In the control run, they remained at 10' colonies per milliliter. Iron was reduced from 1.91 PPM at the start of the test to 0.23 PPM at the end. In the control run, iron remained at 1. 13 PPM. No significant change in DNB counts was noted. This data is summarized in **Table 1.**

Three Well Short Term Test

With the success of the biocompetitive exclusion process in the test production tank, the next level of complexity to test the process was in a producing well. Three candidate producing wells were chosen. 72S10, 68 ISX3 and 77S3. These wells are in the area surrounding the steamflood, and produce 140' F fluid with H_2S concentrations ranging from 700 to 2,800 PPM. The wells are approximately 300 ft. deep, with cased and perforated completions. Each well was hydraulically fractured in both the Upper and Lower Shannon zones. The wells are pumped with sucker rods on a time clock. Pumping fluid levels are in the perforated interval.

Procedure

From October 24 through November 2. 1995, the wells were tested four times for background H_2S levels on casing head gas. On Monday, November 13, water samples were taken from each of the test wells for baseline laboratorv analysis. Well 68-1SX3 and 72SIO were treated with one barrel of nutrient solution down the casing annulus. Well 77S3 produced more fluid and was treated with 13 bbls of nutrient formula to test the effects of a larger size treatment. The fluid in the wells was circulated for one hour by rerouting fluid pumped to the surface back down the casing annulus. The wells were then shut in for seven days. They were sampled for H_2S and water analysis after being returned to production. The wells were monitored through December 7 for H_2S populations increased from 0 to 102 colonies/ml. The levels of activity seen in this well substantiated the results from the previous well that smaller doses of the nutrient solution seemed to be more effective concentration in the casing head gas.

Results

As shown in Figure 4, Well 77S3 did not have a significant change in H_2S concentrations in the casing head gas. Laboratory analysis of produced water, as seen in **Table 2,** showed sulfate concentration increased and sulfides were reduced to zero following treatment.

SRB populations decreased from 102 colonies per milliliter to zero. DNB colonies increased from 10' to 103 colonies per milliliter. The VFA increased, as did the iron. It appeared from the laboratory data that the treatment was working, however production data and casing head H_2S concentrations did not reflect this microbial activity.

It should be noted that this well had considerably higher H_2S concentrations than did the other wells. It is possible that in this short duration test, the DNB were not able to become dominant in a large enough area surrounding the wellbore to establish an effective bioreactor. A longer test may be required to produce more conclusive effects.

The results of the treatment on 68 ISX3 are shown in **Figure 5.** There was a significant effect in this well. Hydrogen sulfide concentrations averaged about 750 PPM prior to the treatment. Immediately following the treatment, levels were dropped to 400 PPM, quickly recovering to 550 PPM during the monitoring period. Although production was seen to increase from 2 to 4 BOPD in the month following the test, it is not clear if this was a direct effect of the treatment.

Laboratory water analysis, as seen in **Table 3,** showed a decrease in the SRB population from 102 to 10' colonies/ml, while DNB populations increased from 0 to 10' colonies/ml. This microbial activity is substantiated by the sulfate levels, which increased from 18 to 553 PPM during the test and returned to zero following the test. This effect is due to the metabolism of sulfates by the sulfate reducing bacteria while they are active, and the suppression of this metabolism when DNB's are dominant. Iron levels also showed a significant increase during the test, then returned to pretest levels. Sulfide levels remained at zero for the entire test duration. The results from this well were very favorable, and indicated that the lower dosage level was more effective.

The best results were seen in Well 72S10, as shown in Figure 6. Pretest concentrations of H_2S in the casing head gas were reduced from 900 PPM to 300 PPM. Following the test they returned to 800 PPM.

Laboratory water analyses are shown in **Table 4.** Sulfate concentrations increased from 177 to 338 PPM, while sulfide concentrations decreased from 35 to 0 PPM. An increase in VFA from 8 to 25 PPM was noted, as was an increase in iron concentration from 1.2 to 29 PPM. SRB populations decreased from 105 to 104 colonies per milliliter, while DNB

Single Well Extended Test

Since the effects of the biocompetitive exclusion process in 72SIO and 68 ISXIO were positive. the next phase of testing was planned to evaluate the effects of long term treatment in a single well. Well 72SIO was selected for this extended treatment based on the robust microbial activity in the short term test. Since a reduction in dosage from 13 barrels to I barrel resulted in a substantial positive increase, the effect of an even lower dosage level would also be investigated.

Procedure

Treatments were conducted twice per week at a dosage level of one gallon of nutrient formula per treatment. The well was shut in just prior to treatment and nutrient formula was simply poured down the casing annulus. The well was immediately put back on pump. Treatments on Well 72SIO were started on January 22. 1996 and continued twice a week until April 8, 1996. Monitoring continued until May 29, 1996.

Results

At the start of the treatments on January 22. 1996. the H_2S concentration in the gas being vented from the casing head was 600 PPM. In about a week, levels were seen to start decreasing. By one month following the start of treatment, H_2S levels were suppressed, with only occasional readings of 10 PPM until April 24, 1996. about two weeks following the last treatment. These results arc shown on Figure 6. This sulfide depression effect is interpreted to be the result of dominant DNB populations being established.

Laboratorv

Laboratory analyses were done on water samples collected twice per week. Selected samples of this laboratory analysis are shown in **Table 5.** The laboratorv analyses showed an increase in sulfates from 250 PPM in December to 318 PPM by mid February. The levels of sulfate staved on the upper 200's through the beginning of April when the treatments were discontinued. This is a result of the suppressed SRB population's inability to metabolize the sulfates in the system.

Dissolved sulfide started out in the 18 to 25 PPM range at the beginning of the test. Somewhat lower readings were observed throughout the treating period. with a final decrease to 0 observed near the end of the test. After treating, sulfides increased to the 30 PPM range. Although total suppression was not observed during the treating period, the sulfides may have been carried in to the well

from deeper in the reservoir with insufficient time to react in the near_wellbore area. Higher nutrient formula treatment volumes may be required to decrease the reaction time.

At the start of treatment, iron levels were in the I PPM range. During the treatment period, levels as high as 4.29 PPM were detected. Following the treatment period iron levels again decreased to below I PPM. This is interpreted to be the result of cleanup of iron sulfide scale by the DNB population.

Population counts of three consortia were also monitored during the treatment. These include the SRB's. the DNB's, and the general aerobic bacteria population. No change in SRB populations were noted through the span of the test, with levels averaging 10' colonies per milliliter. DNB populations increased dramatically from 102 colonies per milliliter before the test to 10' colonies/milliliter by the end of the test. After the test they returned to 10' colonies per milliliter. General aerobic bacteria populations remained unchanged at 106 colonies per milliliter.

Ten Well Extended Test

Although the test in 72SIO was successful in demonstrating the potential for H_2S sweetening. there was no conclusive data to evaluate the effect of the biocompetitive exclusion process on oil production. In order to further evaluate the treatment for H_2S suppression and evaluate the ability of the treatment to increase oil production rates, another test was planned. This test would be done in a larger number of wells in order to lend statistical strength to the test results. A requirement of this test was that all of these wells should be in a common test satellite, so that they could be batch tested simultaneously.

Well Selection

In order to avoid the interference from steam injection rate changes that invalidated the production results in a previous test, an area of the field was selected that had been steam flooded in the past and had H_2S production. but was no longer affected by active injection. It was preferred that the wells produce into a common production facility so they could be batch tested frequently. An area in the central part of Section 10 at the Teapot Dome field fit these criteria. An additional consideration for well selection was the smoothness of the well's production decline curve. This would help to eliminate as much noise as possible, and allow quantification of smaller percentage changes in the production caused by the microbes. The selected wells along with their pretest production rates, temperatures, and H_2S concentrations in the casing head gas are shown in **Table 6.**

Test Design

The ten wells selected for the test produced into a common test satellite called T_5_10. The satellite was dedicated to testing the ten wells as a group for three days per week. Treatments were conducted on all ten wells on Mondays and Thursdays. On Tuesdays the produced fluid was sampled from the commingled fluid at the test satellite for laboratorv testing. Each well was checked daily to make sure that it was pumping properly. If maintenance was required. it was performed immediately to minimize the effect on production. A baseline test was started on June 1. 1996. The wells were tested for three days per week. Particular attention was paid to well performance and any mechanical well problems were worked out during the first week. By June 17, 1996 the system was considered to be steady_state and treatments were started.

Each well was treated with one gallon of nutrient formula down the casing annulus while pumping. No shut_in period was observed. The wells were pumping with a fluid level in the perforations. Some of the wells with low production rates were pumping on a time clock. The treatments were continued until August 1. 1996. Production rate tests continued for two more weeks after treatment stopped.

Results

The results from the ten wells did not show any conclusive evidence of production increases due to the nutrient formula treatments. The results are shown in Figure 7. Although a slight increase may be interpreted after July 20. the data is statistically insignificant. Further complicating the interpretation was the fact that a new pair of steam injection wells was drilled in the area and put on line on August 1.

Although the desired production results could still not be quantified during the allotted test period, the data associated with bacteriology was very good. A steady decline in average H_2S readings can be seen. A varied response to suppression of H_2S in the casing head gas was obtained on individual wells. Wells 53_16SX10, 54_51SXI0, and 63_2SX10 experienced excellent suppression. Wells 53_ISXIO, 63_ISXIO. 63_4SX10, and 63_64SXIO experienced some suppression. Wells 53_62SX10, 63_3SX10, and 63_31SXIO did not experience any significant suppression. To investigate the effect of a treatment procedure change. wells 53_ISXIO and 63_

3SX10 were treated again on August 19. 1996. This time the treatment procedure included a one hour shut_in after treating. The H_2S levels on 53_1SX10 1 SX 10 kvcrc dropped from 900 PPM to 1 PPM. Well 63_3SX10 experienced a drop from 1000 PPM to 400 PPM.

Laboratory water analyses arc shown in **Table 7.** Only selected samples before the treatment and after treatment response are represented in the table. DNB populations increased from pretest levels of 10' colonies per milliliter to more than 106 colonies per milliliter by mid July. returning to 10' colonies per milliliter by mid August.

SRB populations were 10" colonies per milliliter before the test and remained fairly constant through the end of the test. In retrospect this is considered to be an effect related to the test setup. The ten wells at T_5_10 involved in this test represent about a third of the total wells at the test satellite. The ten test wells were batch tested from Monday through Thursday, and fluid sampling was conducted at the test manifold on Tuesdays. Additional SRB's may have been picked up through the flow lines from the remainder of the wells being tested during the other half of the week.

Sulfide concentrations were 0 in every sample that was analyzed during the ten well test period. This again may be caused by the test setup. In previous tests, water samples were collected at the wellhead. In this test. the samples were collected at the test satellite after traveling through a lengthy flow line system. These flow lines are uncoated steel, and may have consumed the dissolved sulfide in the formation of iron sulfide scale.

Sulfate concentrations increased from 46 PPM to 91 PPM during the treatment, then returned to pretest levels two weeks after the treatment was discontinued. Iron levels also increased from pretest levels of 13 PPM to 39 PPM just prior to the end of the treatment, before dropping back to pretest levels one week after treatment was discontinued. VFA increased from 5 PPM to 12 PPM during treatment and returned to 8 PPM following treatment.

The treatments that were most successful in reducing H_2S were done in wells with lower oil production, lower water production, lower H_2S concentrations, and lower temperatures. The average successful well produced 1.2 BOPD. 3.6 BWPD, had pretest casing head H_2S concentrations of 400 PPM, and an average produced fluid temperature of 61'F. The average poor response well had a production rate of 3.4 BOPD, 17.9 BWPD, and initial H_2S levels of 833 PPM, with a produced fluid temperature of 94'F. These statistics all point to a problem with overloading of the bioreactor in the near wellbore area. Higher treating volumes and/or longer shut_in times would be required to set up a functional bioreactor and successfully treat these wells.

In order to quantify production increases due to the biocompetitive exclusion process, test times longer than 6 weeks would be required. The existing test data show that the desired microbial activity can be fostered in the near wellbore area of the reservoir. and that increases in iron production can be measured. Given sufficient time, this should result in a gradual increase in production as iron sulfide scale is cleaned up and perforations, pump intakes, and reservoir flow paths are unplugged.

Treatment Economics

The treatments discussed in this paper are simple to perform and very economical. The nutrient formula can be obtained commercially for approximately $10 per gallon. The treatment was simply poured down the casing annulus of the well. In some cases, a short shut_in time is used to increase effectiveness. For the low volume wells used in this study, treatment frequencies of twice weekly were effective. In the higher volume wells, higher treatment volumes or more frequent treatments may be appropriate. For wells with significant pressure on the casing head. a pump may be required to treat the well. Treatment costs should range from $ 100 to $500 per month on most wells.

The savings that can be realized from the treatment can vary greatly, In some cases, sour production is simply tolerated and nothing is spent on maintaining equipment. In this case. the benefit is the increased safety of working around the produced fluid and the longer life of the existing equipment. In some cases. biocides and corrosion inhibitors are used to extend equipment life. Hydrochloric acid treatments are often used to clean up iron sulfide scale and can produce deadly H_2S gas during the treatment. The costs of such programs can easily reach $ 1 .000 per month. If water disposal systems are required to handle sour produced water. the maintenance costs will increase even further as the pumps, filtration systems. injection lines, and injection wells arc attacked by sulfide scale and corrosion.

Conclusions

1. Biocompetitive exclusion is an effective process for treating H_2S and iron sulfide scale in production wells. When optimized to the individual well, it is capable of reversing the reservoir microecology and completely eliminating H_2S from the production stream.
2. Treatments must be tailored to individual wells to achieve optimum results. Different artificial lift methods. fluid production rates, and reservoir properties will affect microbial activity in the near wellbore area. A one hour shutin period following treatment successfully lowered H_2S levels in two wells with poor response to treatment while pumping.
3. The time required to eliminate H_2S production is in the week to month time frame. Individual wells may vary based on their production characteristics and the degree of nutrient formula treatment optimization required.
4. The treatments arc simple and economical to administer. Significant cost savings can be realized over conventional treatments with biocides, corrosion inhibitors. and hydrochloric acid.
5. Treatment of sour production wells with the biocompetitive exclusion process will clean up iron sulfide scale, and increase the life of production system components.
   The Process has the potential of increasing production from wells with significant damage.

6. Treatment of sour wells with the biocompetitive exclusion process can improve the safety of handling well fluids and performing well servicing operations.

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SI Metric Conversion Factors

°F	(°F-32) / 1.8 = °C
gal x 3.785 412	E - 03 = m^3
ft x 3.049 006*	E - 02 = in
in x 2.54*	E+ 01 = mm
in^3 x 1.639 673*	E+ 01 = ml
lbm x 4.535 924	E - 01 = kg
bbl x 1.589 873	E – 01 = m^3

*Conversion factor is exact

Tables

Tables

TABLE 1 Test Tank Laboratory Results		
	Before	**After**
Date	10/18/95	10/24/95
VFA	81 PPM	76 PPM
SO_4	83 PPM	98 PPM
S=	0.2 PPM	0 PPM
H_2S	600 PPM	100 PPM
Fe	1.91 PPM	0.23 PPM
pH	7.2	7.4
Salinity	<3%	<3%
SRB	10^3 colonies/ml	0 colonies/ml
DNB	10^1 colonies/ml	10^1 colonies/ml
GAB	10^4 colonies/ml	10^1 colonies/ml

TABLE 2 77S3 Laboratory Results		
	Before	**After**
Date	11/14/95	11/20/95
VFA	48 PPM	59 PPM
SO_4	9 PPM	38 PPM
S=	7 PPM	0 PPM
H_2S	2600 PPM	2600 PPM
Fe	0.79 PPM	2.81 PPM
pH	7.6	7.0
SRB	10^2 colonies/ml	0 colonies/ml
DNB	10^2 colonies/ml	10^2 colonies/ml
GAB	10^2 colonies/ml	10^2 colonies/ml

TABLE 3 68-1SX3 Laboratory Results		
	Before	**After**
Date	11/14/95	11/20/95
VFA	0 PPM	8 PPM
SO_4	18 PPM	553 PPM
S=	0 PPM	0 PPM
H_2S	650 PPM	450 PPM
Fe	15.23 PPM	28.65 PPM
pH	7.1	7.3
Salinity	0.09%	0.09%
SRB	10^5 colonies/ml	10^4 colonies/ml
DNB	0 colonies/ml	10^1 colonies/ml
GAB	10^3 colonies/ml	0 colonies/ml

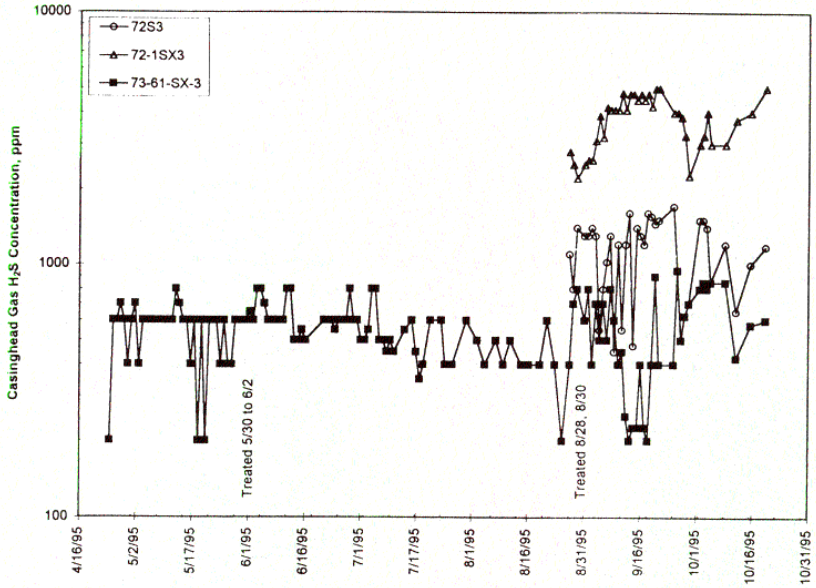

Figure 2. Steamflood Test Results (Casinghead H_2S Concentrations)

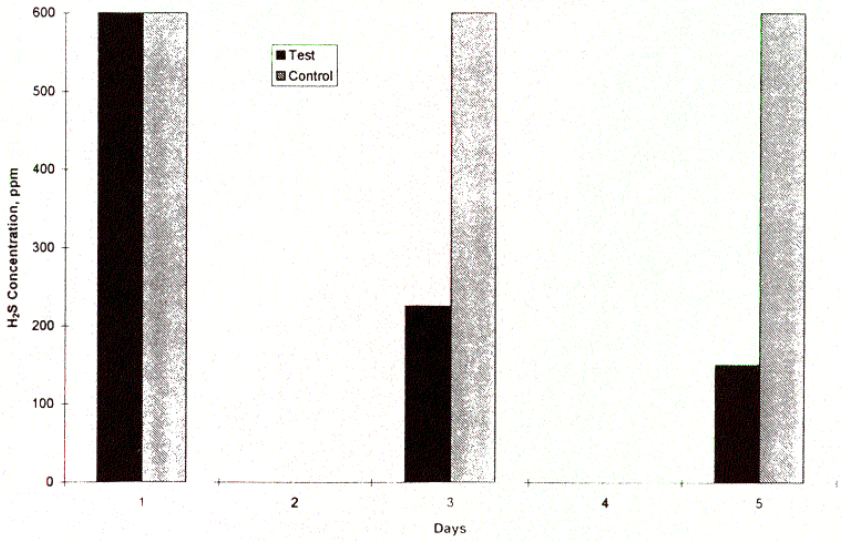

Figure 3. Production Tank Test Results

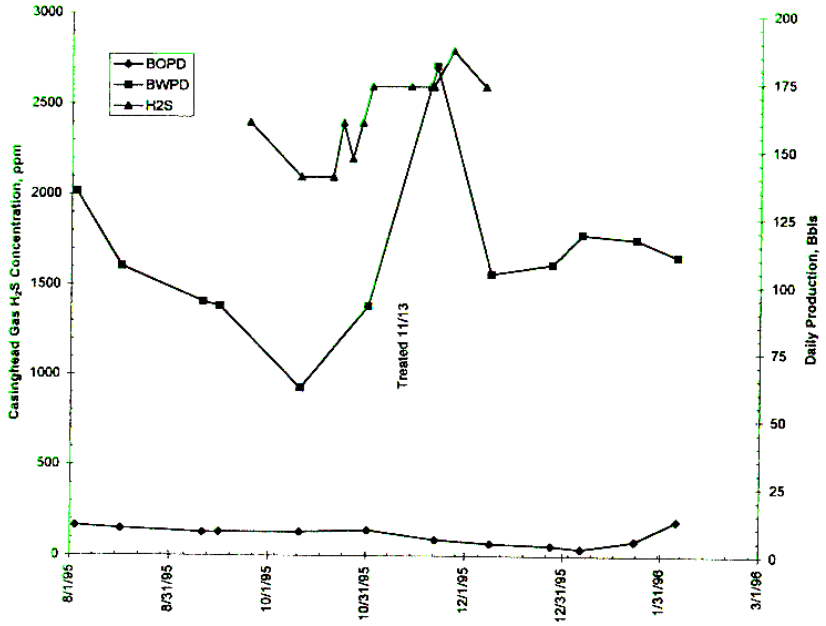

Figure 4. Well 77S3 Treatment Results

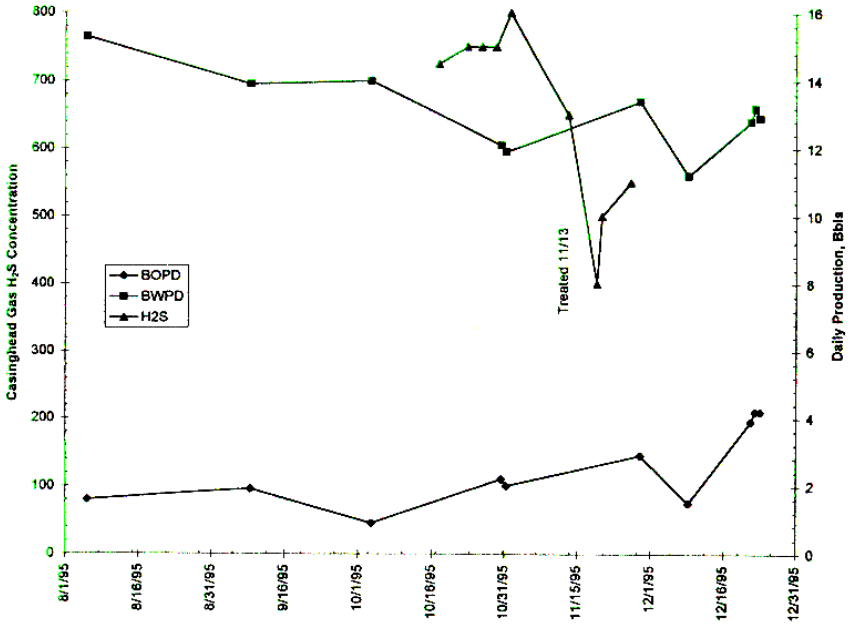

Figure 5. 68-1SX3 Treatment Results

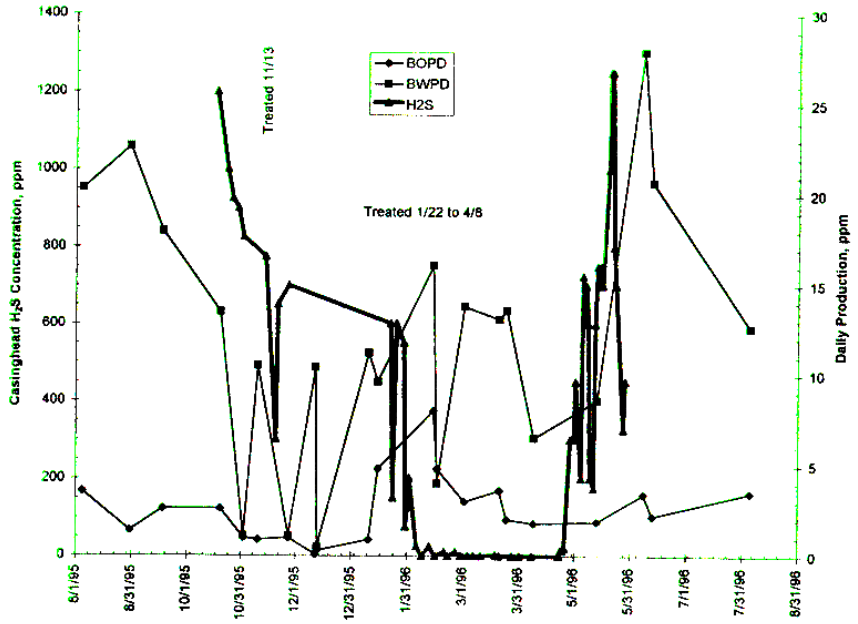

Figure 6. Well 72S10 Treatment Results

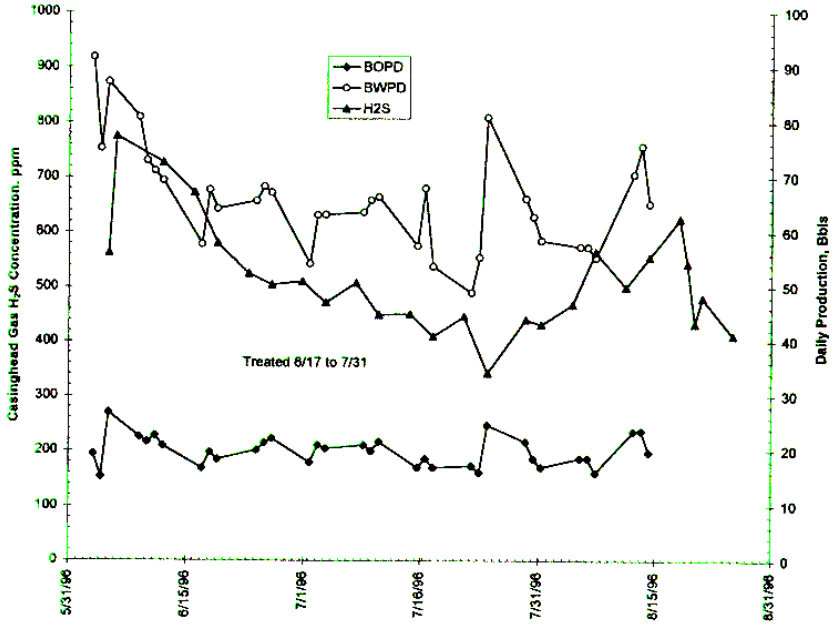

Figure 7. Ten Well Test Results