CHEMICAL CORROSION AND ITS EFFECT ON FIBERGLASS SUCKER RODS

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ABSTRACT

Corrosive effect of chemicals on steel was the primary reason the oil industry began searching for an alternative material for sucker rods. This study is not a comprehensive study of chemical corrosion inhibitors, but it will discuss chemical corrosion and its effects on steel sucker rods and fiberglass sucker rods. Steel sucker rod replacement due to corrosion is one of the major costs of oil production. The author will show that water/CO2 and sour (H2S) gas has no obvious detrimental effect on a fiberglass rod body.

INTRODUCTION

Fiberglass has been an excellent tool for industry in general for several years. The petroleum industry has been using fiberglass tubulars and tanks very successfully, and it has long been established that fiberglass helps reduce failures caused by corrosion. Until recently, the industry had not been successful in designing a fiberglass sucker rod for use with beam pumping units, primarily due to extreme tensil requirements and problems caused by the cyclic loading of sucker rods.

The oil industry has been using steel in the manufacture of sucker rods for well over 80 years, but has had to deal with corrosion caused by hydrogen sulfide, carbon dioxide, oxygen and electrolysis, which are present in most producing oil wells. To overcome these problems, the oil industry has continually increased the size of the sucker rods under the assumption the "bigger is better." However, this attitude has created more problems, for the industry now has to deal with tensil and fatigue failures due to the weight of the sucker rods themselves. Also, because of the extreme weight of the larger diameter steel rods, the oil producers must use larger, more expensive pumping units to make the larger, more expensive sucker rods work.

THEORY

Corrosion, as discussed in this paper, means the destruction, degradation, or deterioration of material due to the reaction between the material and its environment by chemical or electro-chemical reaction.

The cost of replacement of corrosion damaged sucker rods is a multi-million dollar expense to oil producers in the United States. With decreasing reserves of metal ores and the energy resources needed to produce new material, the corrosion problem is now receiving its deserved attention. The petroleum production industry suffers some of the worst corrosion problems because of the very nature of oil production. Hydrogen sulfide (H2S) corrosion is very severe and appears in approximately half of all domestic oil wells. It is called sour corrosion and in addition to its detrimental effect on metal it is also a deadly menace, often called the "silent killer." Hydrogen sulfide is created by the same natural forces that form hydrocarbons and is likely to be present anywhere oil or natural gas is found. The fact that the gas has not been previously encountered in an area may indicate only that drilling has not reached the depth or location where the gas is present. The oil industry is drilling more and deeper wells and we are increasing our chances of finding it. H2S produces an odor which may smell slightly different to each individual. This odor can range from that of rotten eggs to a sweet smell. It causes a black iron-sulfide scale on metal and usually causes a smooth pitting on sucker rods. When contacting brittle steels, H2S can promote sulfide stress cracking which is usually associated with catastrophic failure of the steel.

Carbon dioxide (CO2) is plentiful on this planet, occurs in the atmosphere, and is present in most producing operaions. Because oil and water are not miscible, water-flooding leaves probably more than 50% of the oil in a reservoir trapped in rock pores. Carbon dioxide injected under pressure will mix with the oil and cut it from the rock. The continuing pressure of the injected CO2 or injected water, forces the mixture of oil and CO2 to a producing well, where the fluids are pumped to the surface. Oil production from CO2 enhanced recoveries totaled 75,000 barrels per day in 1980 from seventeen CO2 flood projects. Most major oil producing companies are considering carbon dioxide projects or are already involved in CO2 flooding.

Carbon dioxide in its natural dry state is not corrosive. However, when mixed with free water, it forms a weak acid (carbonic) which is capable of dissolving steel and destroying coatings. In some situations, carbon dioxide is perhaps the most feared corrodent of all. The pitting is sharp and deep and sometimes the pits are connected to give a "worm eaten" or grooved appearance.

Oxygen corrosion is the most common type of oil field corrosion. Oxygen has an affinity for iron and will combine readily with it to form iron oxide or rust. If oxygen is continuously supplied to the surface of steel, rusting will continue until all the steel present is converted to rust. The rate depends on temperature, erosion, corrosion film and electrolyte. The most important factor is the presence of water. Oxygen corrosion is recognized by its generally even-depth pitting.

Superior corrosion resistance is the primary reason for the development of the fiberglass sucker rod and today this corrosion resistance is still one of the main reasons for using fiberglass rods. Other advantages include its lighter weight, its strength-to-weight ratio and its elasticity, but the author will restrict this discussion to corrosion resistance.

For the past twenty years the industry has been compiling data about corrosive resistant fiberglass in use with petroleum products. Most oil producers agree that fiberglass is a totally non-corrosive material. However, fiberglass rods which have been proven successful, are constructed with metal end-fittings which are still susceptible to corrosion. The bottom portion of the rod string is necessarily metal and must be protected from the corrosive environment. It is also necessary to protect the tubing and the downhole pump. For these reasons an adequate chemical program should be maintained.

Normally, corrosion requires water in contact with the steel surface. Corrosion inhibitors are made up of materials which are attracted to, and attach to, the steel surfaces. These materials also attract oil and result in an inhibitor-oil film forming on the steel, thus keeping the water away. Inhibitor molecules are continuously leaving the steel surface leaving it unprotected. It is necessary to add more inhibitor to replace the molecules which have been removed from the surface. The corrosion inhibitors commonly used in the oil producing industry can protect from all kinds of corrosion except oxygen. Oxygen molecules can attach to the surface of steel in spite of the inhibitor-oil film and set up corrosion cells.

A typical fiberglass rod string design consists of fiberglass rods in the top portion and steel rods in the bottom portion of the string. Steel rods on the bottom of the rod string are not attacked by corrosion as severely as when the rod string is 100% steel. Metallurgists with major oil companies have worked with fiberglass rod manufacturers devoting many hours of study to this phenomenon. No definite explanation has been agreed upon, but several theories have been offered.

1. Corrosion inhibitors do not have an affinity to fiberglass and does not coat the rod body. This means a reduced amount of inhibitor is required to adequately treat a well. The real advantage is the extra inhibitor in the

system will be used to replace the molecules which have left the steel surface unprotected.

2. It is easier to treat wells with low fluid levels than to treat wells with high fluid levels. In many instances, fiberglass rods can produce more fluid with the existing equipment, thus reducing the fluid level in a well. This allows the operator to provide a better inhibitor program and reduce the frequency of corrosion failures.

3. There are two things necessary for corrosion of steel sucker rods; an electrolyte and an electrical path. Since most producing oil wells contain salt water, we must assume that most oil wells have the electrolyte necessary for corrosion to attack. An electrial path can be present within a non-homogeneous metal and corrosion will occur, however, the most severe electro-chemical corrosion will occur when two dissimilar metals are present in an electrolyte, and a current is introduced into the system. There is a theory based on the Hysteresis Effect that needs to be investigated. The proponents of this theory conclude that the steel sucker rod string oscillating through the earth's magnetic field, will generate a current which moves through the electrolyte between the rod string and the tubing. This theory was tested by attaching a voltameter between the polished rod and the casing, and measuring current while the pumping unit oscillated the rod string. The current flow stops when the pumping unit stops. This same test conducted on a well with fiberglass rods will not measure any current because fiberglass is a totally non-conductive material. Since there is no current introduced into the system, the severity of the electro-chemical corrosion is reduced.

Of these three theories, the author feels theory 1 and theory 2 are more feasible than theory 3.

A 67% fiberglass rod string was installed in a 4,447 foot test well in March 1981. This well was chosen because of the severe corrosion experienced by the steel sucker rods used just prior to this test. After 14 months this report was filed. "...the glass rod is uneffected by the corrosion. We have performed an analysis along with (another testing company) on the rod to determine if it had lost any of its properties. All test data from (this) well and others show that the fiberglass has actually increased in its properties. It has retained its tensil strength and increased in compressive shear and flexural shear strengths. This was not totally unexpected as the process for building the rod does leave some molecules of catalyst and resin that have not cross-linked. Time and work causes these molecules to post cure or finish their cross-link which increases the properties of the rod. We do not at this time know how long this reaction continues. The analysis of this rod compares with rods in other wells that were in (use) for shorter time periods. Current data indicates that post curing occurs thirty to sixty days after installation, depending on down-hole temperatures."

Considerable analyses have been performed in an effort to understand why the 4620 steel made into fiberglass sucker rod end-fittings does not corrode as rapidly as it normally does in steel sucker rods. Metallurgists have proposed the "bearing quality" 4620 steel used in the end-fittings is a more corrosive resistant material than normal quality 4620 steel. This idea, coupled with the reduction of stress (as a result of a lighter weight rod string) and the reduction of electrolysis, is a strong argument for the reason why fiberglass sucker rods are more corrosive resistant than steel sucker rods.

Regardless of the reason, oil producers are reporting fewer rod parts with fiberglass rod strings than with steel rod strings in the same well. (SEE TABLES 1 THROUGH 5)

A major oil company requested an independent engineering firm, specializing in oilfield corrosion, to test a fiberglass sucker rod after it had been used in a producing oil well for one year. The test proceedures included these ten steps:

1. Make preliminary measurements of the sucker rod diameter prior to test.

2. Fill test chamber 1/3 with 5% NaCl brine, 1/3 with 50% toluene/50% kerosene and pressure up the remaining 1/3 with a gas mixture consisting of 1% H_2S, 49% CO_2 and 50% CH_4 to a pressure of 2000 psi.

3. Heat test chamber to 180 degrees F and hold at that temperature for 24 hours.

4. Drain test chamber and pressure up to 2,000 psi with CO_2.

5. Heat test chamber to 180 degrees F and hold at that temperature for 24 hours.

6. Release pressure from test chamber and repeat steps 2 through 5 an additional two times for a total of three complete cycles.

7. Make subsequent measurements of the sucker rod diameter to check for swelling.

8. Cut rod transversely to check for fluid penetration.

9. Conduct a tensile test between the rod and pin end connection, increasing the tensile load until failure occurs.

10. Report any visual observations which might be significant to the test.

DISCUSSION

Two samples of fiberglass sucker rods were submitted by (major oil company) for evaluation in a simulated water/CO2 alternating system (WAG) with sour gas present.

One pin end section was used in the simulated WAG system test and the other pin end was not tested. Approximately six inches had to be cut from the fiberglass end of one section to enable it to fit into the pressurized test chamber.

After completion of the simulated WAG system test, a tensil test was conducted on both the WAG tested pin end section and the untested pin end section to determine the effects of the WAG environment on the bonded joint and the fiberglass rod.

The pin end WAG tested section withstood an ultimate load of 35,400 lb. after test. The tensile test had to be stopped at 35,400 lb. because the fiberglass rod crushed and slipped in the clamps attaching it to the tensil test apparatus. There was no measurable movement of the fiberglass rod in the bonded joint.

The pin end section which had not been tested in the WAG system, withstood an ultimate load of 36,300 lb. The tensile test had to be stopped at 36,300 lb. due to slippage of the fiberglass rod in the clamp attaching it to the tensil test apparatus. Again, there was no measurable movement of the fiberglass rod in the bonded joint.

After completion of the tensil test, the WAG tested section was cut longtitudinally so it could be examined cross-sectionally. There was no evidence of wicking or leaching of the environment into the fiberglass rod. The only visual change was a slight discoloration (darkening) of the surface of the fiberglass rod. The slightly darker surface is attributed to exposure to a sour (H_2S) environment which deposited a film of iron sulfide on the surface of the rod. Cleaning the surface of the fiberglass rod with a liquid detergent and hot water removed the dark (FeS) film.

CONCLUSION

The simulated WAG system environment had no obvious detrimental effect on the fiberglass rod or the adhesive used to bond the fiberglass rod to the metal pin end section of the sucker rod.

CONCLUSION

This author feels there must be additional test made and additional time given for empirical data to be assembled before any conclusion can be reached as to why fiberglass sucker rods are less susceptible to corrosion, but there is enough documented evidence to assume that fiberglass sucker rods are the best equipment to use in corrosive environments.

NOTE

The following tables are results of tests reported by oil producers using fiberglass sucker rods. The information has not been documented by the author, however the information is a consensus of test results reported by users of fiberglass sucker rods.

TABLE 1
TEST WELL NUMBER L31

This well had fiberglass rods installed in February 1979. Corrosion and a low bottom hole pressure made it impossible to pump this well from 6400 feet with the pumping unit at this location. Prior to installing the fiberglass rods, the steel rods were parting three times per year. No rod parts since the installation of the fiberglass rods.

PRODUCTION	STEEL	FIBERGLASS
BOPD	130	164
BWPD	119	160

TABLE 2
TEST WELL NUMBER C724

This well was pumping from 6450 feet. Corrosion, gas interference and low producing bottom hole pressure caused the rods to part 6 times a year.

Glass rods enabled the production to be maintained while stopping the rod parts. Since the glass rods were installed in June 1980, one pin break in the 7/8" steel rods has occurred. The rod string consists of 33% 7/8" steel rods below 67% glass rods pumping from 6100 feet. Future plans for this well are to lower the pump to 6450 feet to lessen gas interference. Design predictions show the unit and rod string will not be over-stressed.

PRODUCTION	STEEL	FIBERGLASS
BOPD	138	251
BWPD	16	27

TABLE 3
TEST WELL NUMBER C216

With a conventional steel rod string this well was parting 3 times per year.

A combination of corrosion, gas, and low PBHP caused the load range on the steel rods to exceed the recommended limits.

Since the 65% glass rod string was installed in May 1981, no parts have occurred, while production has increased 30 BOPD and 15 BWPD.

PRODUCTION	STEEL	FIBERGLASS
BOPD	50	80
BWPD	50	65

TABLE 4
TEST WELL NUMBER 79-8

Fiberglass rods were installed in August, 1981. This well is pumping from a depth of 6700 feet and has a PBHP of 800 psi. The pumping unit is a Lufkin 320. It was determined that to pump this well at present production rates, either the rod string or pumping unit would have to be overstressed if steel rods were continued to be used.

By installing the fiberglass rods, the production rate could be maintained without over-stressing the glass rod string or gear reducer.

No rod parts have occurred to date since the glass rods were installed. Prior to this, the steel rods were parting 5 times per year, even after new steel rods were installed.

PRODUCTION	STEEL	FIBERGLASS
BOPD	150	171
BWPD	18	45

TABLE 5
TEST WELL NUMBER WFL 1

During March, 1975, a corrosion inhibition program was initiated in the subject field, with the subject well at that time producing an average of 3 BOPD and 260 BWPD. During the prior 19 months the well had accumulated 16 rod parts and 4 tubing leaks, with 11 of the rod parts being corrosion related body breaks. As part of a field wide program, this well was placed on a weekly batch treating schedule with an oil soluble corrosion inhibitor. By June, 1976 (15 months later), seven additional body breaks had accumulated.

The corrosion chemical was then changed to a water soluble corrosion inhibitor. The batch treating schedule was continued.

By February, 1977, four additional body breaks had occurred. At this point the corrosion chemical program was modified to include treatment by formation squeezing. The subject well was squeezed using two drums of water soluble corrosion inhibitor mixed with 20 barrels of produced water, and overflushed with 200 barrels of produced water.

In May, 1977, the well had accumulated its third body break since February. By this time, it had become obvious that corrosion was not the only producing problem. A dynamometer was run to survey the loading of the surface pumping equipment. The pumping unit gear box was 86%, structure was 59%, rods were 93% and prime mover was 111%.

The producing reservoir is a prolific water drive carbonate, which requires high fluid producing rates to be economical. As producing rates climb, so does the required loading on all producing equipment. This is the reason why the producing equipment on the subject well was so highly loaded. This well was recommended for fiberglass rods in August, 1977. Actual installation occurred in May, 1978. During the 9-1/2 month interim, the well experienced four body breaks.

Two years had passed since initiation of a field wide chemical program when the fiberglass rod string was installed. During this period of changing chemicals, treatment volumes, proceedures and equipment the frequency of corrosion related rod parts had not diminished. The average frequency of failures for the two year period was one body break every 1.8 months. A highly loaded pumping system and a corrosive environment were the conditions that prompted the introduction of fiberglass sucker rods.

In July, 1978, a follow-up dynamometer survey was run to analyze pumping conditions after 14 months of fiberglass service. The subject well was now producing 330 BFPD as compared to 263 BFPD before installation. Peak torque on the gear box was 62%, structure 32%, rod loading 40% and prime mover 64%.

At the time of this report, 3-1/2 years have elapsed since installation of the original fiberglass rod string in this well. This original fiberglass rod string is still in operation in the well, and has experienced no rod body parts.

(Author's note: The original fiberglass rods are still operating today and there have been no rod parts.)