PROCEDURES FOR EVALUATING CORROSION AND SELECTING TREATING METHODS FOR OIL WELLS

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INTRODUCTION

Of major importance in the efficient producing of oil is to minimize workover operations caused by wellbore equipment failures. The most frequent cause of such failures is corrosion due to the corrosivity of produced fluids. The rate of attack can increase markedly as water production increases. Unless such changes are quickly detected, corrosion-induced failures can occur before an effective inhibition program can be developed. This paper presents procedures for evaluating the corrosivity of well fluids and determining when the rate of attack changes. Also included are brief discussions on various treating procedures and how the producing characteristics of wells determine the selection of the treating method. While selection of the proper inhibitor is of equal importance in a corrosion control program, it is usually based on laboratory evaluations and is beyond the scope of this paper.

FACTORS GOVERNING OILWELL CORROSION

Most crude oils are noncorrosive and as long as well bore and surface equipment are in an oil-wet condition the producing system is protected. This condition will persist as long as oil remains the external phase of the produced liquids. The phase relationship between the oil and water will generally invert between a cut of 25-35% so that water becomes the continuous phase. With the inversion the wellbore equipment will change to a water-wet condition. The time required for equipment to become water-wet is a function of the tenacity and thickness of the oil film. However, once the phase inversion has occurred, eventually the system will become water-wet.

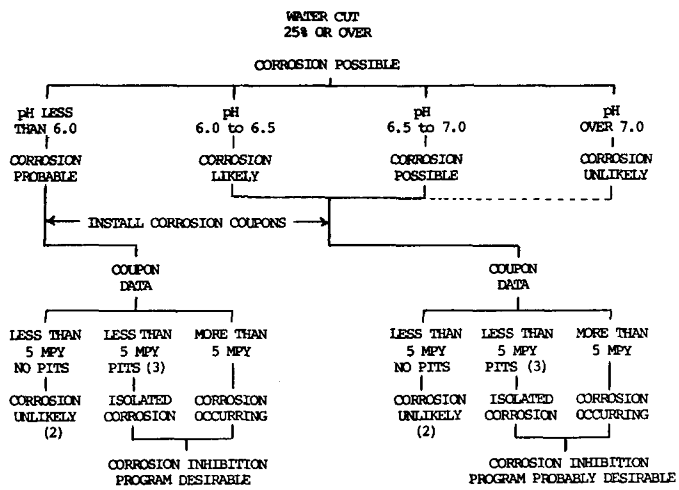
It would be suggested, that when the cut approaches 25%, analyses be reviewed or tests made to evaluate the potential corrosivity of the wells. In most producing areas, waters from the same formation will be roughly comparable as to corrosivity. Also where the produced gas contains either hydrogen sulfide and/or carbon dioxide it should be anticipated the produced water will be corrosive. The installation of corrosion coupons at this time is also highly desirable. If significant corrosion is occurring, the coupon will give an indication of severity. After a corrosion program has been started a comparison of "before" and "after" results are a measure of the treating effectiveness.

Figure 1 represents a step-wise procedure that can be followed in evaluating the corrosive possibilities in a well. As shown, with the produced waters having a pH of 6.0 or lower, serious corrosion is inevitable once the system becomes water-wet. If the pH ranges between 6.0 and 7.0, corrosion will also occur once water becomes the external phase; and inhibiting would be desirable when the attack is of the pitting type or over 5 MPY.

In using this approach it is imperative the pH measurements be on freshly produced samples as soon after being withdrawn from the system as practical. The order of magnitude rather than a high degree of precision is the principal requirement of this measurement; data obtained from pH paper is quite adequate. When samples are transported to a laboratory or stored for any significant time (1 or 2 days) the pH will not be representative. In cases where this type of measurement is the only one available and the pH is below 7.0, it would be suggested that the measurement be lowered by 1.0 in using Figure 1.

ECONOMIC EVALUATION OF CORROSION INHIBITION IN OILWELL PRODUCTION

When a study as discussed above or equipment



1. Corrosion occasionally occurs above a pH of 7.0. Where field experience indicates corrosion follow dashed line.
2. When equipment becomes water-wet corrosion will occur. Maintain a planned monitoring program.
3. Check systems for air entrainment. If air entrainment is found, eliminate and re-test.

Note: Phase relationship of water in oil will invert between 25-45% water. After inversion, equipment will be water-wet and corrosion may occur. The following is suggested as one procedure for early detection of corrosion.

FIG. 1—GENERAL PROCEDURE FOR ANALYZING OILWELL CORROSION

failures have established that corrosion is occurring, the instituting of a corrosion inhibition should be evaluated. The principal function of such a program is to reduce well equipment repair costs while maintaining maximum allowable production. The cost of an inhibitor program is an additional operating expense that must be more than offset by the reduction in well equipment repairs due to corrosion to warrant a treating program.

The type of study will vary with each field and its particular problems. The following example illustrates one approach that can be used. The data is from a field test program.

Case History

Field: Gulf Coast, piercement dome type, producing from multiple steeply dipping sands

Wells: Initially produce only minor amounts of water and are noncorrosive. As water-cut increases to between 25-35% the phases invert and the wellbore equipment becomes water-wet and serious corrosion develops. Also many of the wells are crooked so that rod, rodbox, and tubing wear is a serious problem. Some wells offshore in shallow water.

Corrosivity: Sweet (CO_2), Surface Samples pH - ±6.8, Calculated pH at pump - ±6.5. Coupon Data - NonCorrosive Wells - Less than 5 MPY - No Pits
Coupon Data - Corrosive Wells - Over 75 MPY - Severe Pitting

TABLE 1—SUMMARY OF SERVICE WORK ON 18 WELLS DESIGNATED NONCORROSIVE

Avg. No. Jobs/Mo.	Avg. No. Rod Jobs/Mo.	Est. Cost Rod Jobs/Mo.	Avg. No. Tbg. Jobs/Mo.	Est. Cost Tbg. Jobs/Mo.	Tot. Est. Cost/Mo.
4.3	1.6	$375	2.8	$1035	$1410

TABLE 2—SUMMARY OF SERVICE WORK ON 13 WELLS DESIGNATED HIGHLY CORROSIVE

Avg. No. Jobs/Mo.	Avg. No. Rod Jobs/Mo.	Est. Cost Rod Jobs/Mo.	Avg. No. Tbg. Jobs/Mo.	Est. Cost Tbg. Jobs/Mo.	Tot. Est. Cost/Mo.
13.6	7.9	$1885	5.7	$2110	$3965

It is obvious from Tables 1 and 2 that a significant reduction in service work charges should be possible with an effective corrosion inhibiting program. While a number of wells were under treatment at the time of the study, the service records on these wells were not significantly different from those not under treatment. This suggested either the wrong inhibitor or treating program was being used. A series of laboratory tests were run using field fluids to evaluate and select a suitable inhibitor. During the same period the producing characteristics of the wells were reviewed to establish the most effective treating procedure. This study indicated, in general, that wells with high fluid levels were experiencing the most serious corrosion and it was unlikely that the type inhibitor program used in these wells would effectively film the rods and tubing.

On the basis of this study, a pilot program was started on the 13 wells indicated as highly corrosive, (Table 2). The chemicals selected were based on the laboratory tests. The treating procedures selected for trial were weekly batching with a weighted inhibitor and weekly batching with an oil-soluble type. With the later inhibitor the batch was circulated and parked in the annulus. The treating rate was 25 ppm based on total produced fluids.

Figure 2 illustrates the excellent response obtained with the program. The transition period was the time required to place all wells on the new treatment and reflects failures that were imminent when the program was instituted.

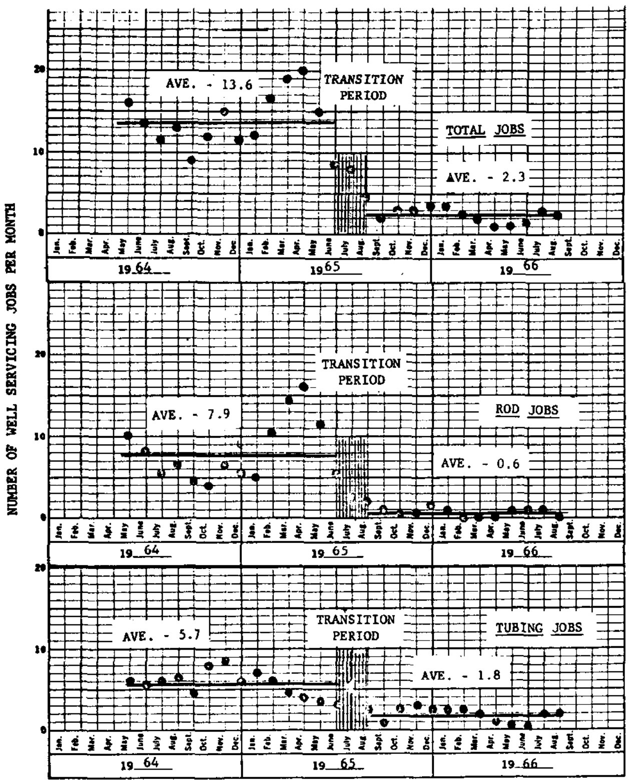


FIG. 2—SERVICING RECORD ON THIRTEEN WELLS INCORPORATED IN PROGRAM FROM START OF STUDY (DATA PLOTTED ON BI-MONTHLY BASIS)

The reduction in well equipment repair cost covered by the period of the figure (Fig. 2) is shown in Table 3.

TABLE 3—SUMMARY OF SERVICE WORK ON 13 WELLS DESIGNATED HIGHLY CORROSIVE

Avg. No. Jobs/Mo.	Avg. No. Rod Jobs/Mo.	Est. Cost Rod Jobs/Mo.	Avg. No. Tbg. Jobs/Mo.	Est. Cost Tbg. Jobs/Mo.	Tot. Est. Cost/Mo.
		BEFORE PROGRAM			
13.6	7.9	$1885	5.7	$2110	$3965
		AFTER PROGRAM			
2.3	0.6	$140	1.8	$665	$805

On planning the program it had not been anticipated that there would be a significant improvement in the incidence of tubing failures which were primarily associated with crooked-hole problems. The marked improvement is believed due to the tenacity and oiliness of the inhibitor establishing a lubricating film between the mating surfaces of the rod string and tubing.

As soon as the success of the program had been established the procedure was applied to all wells in the operation; even those wells listed originally as noncorrosive were included, based on the reduction that could be anticipated on tubing jobs which were the major expense item.

The results obtained on all wells are shown in Figure 3 and summarized in Table 4. The table also summarizes the cost reduction effected per year. This does not include the increase in revenue obtained by maintaining the wells on production. This program has now been is effect for eight years with continuing success. It is estimated the total savings over this period would be in excess of $300,000.

TABLE 4—SUMMARY OF WELL SERVICE WORK FOR 46 WELLS EVENTUALLY INCORPORATED IN PROGRAM THROUGH AUGUST 1965

Avg. No. Jobs/Mo.	Avg. No. Rod Jobs/Mo.	Est. Cost Rod Jobs/Mo.	Avg. No. Tbg. Jobs/Mo.	Est. Cost Tbg. Jobs/Mo.	Tot. Est. Cost/Mo.
		BEFORE PROGRAM			
24.1	13.7	$3220	10.4	$3850	$7070
		AFTER PROGRAM			
6.9	2.8	$660	4.2	$1555	$2215

1.	Cost Reduction per Month on Well Service Charges	— $ 4,755
2.	Treating Cost per Month for 48 Wells ($25/Mo.)	—$ 1,200
3.	Net Cost Reduction per Month	—$ 3,555
4.	Net Reduction in Service Charges per Year	—$42,660
5.	Service Charge Reduction per Well Year	—$ 890

The program (Table 4) was completed a number of years ago. On the basis of its success the same approach was used in a larger Permian Basin field. Initially the program was directed to 23 problem wells. Rod breaks were reduced from 14.3 to 2.3 and pump changes from 4.6 to 2.3 per month.

This program, in addition to corrosion, included scaling studies and equipment inspection and repair and procedures. The study was completed in 1970 and procedures were expanded to the entire producing area of over 700 wells. Studies are now in progress in other producing areas with similar improvements anticipated.

CORROSION INHIBITION TREATING PROCEDURES FOR OIL WELLS

The two principal requirements for a successful corrosion control are selecting a suitable inhibitor and using a treating method that assures the filming of the producing equipment.

While selection of the inhibitor is beyond the scope of this paper it is essential that the laboratory evaluations simulate as closely as practical the wellbore fluid relationships to be

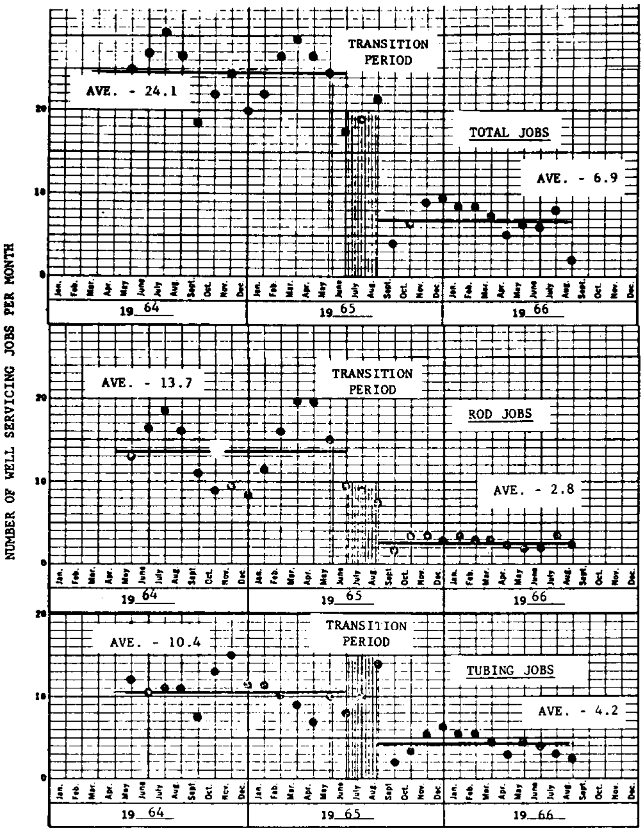


FIG. 3—SERVICING RECORD ON ALL WELLS (46) EVENTUALLY INCORPORATED IN PROGRAM (DATA PLOTTED ON BI-MONTHLY BASIS)

encountered in treating. While it is desirable to select a single type of inhibitor and treating method for the entire field, this may not always be possible. As noted in the field program discussed, the producing characteristics of the wells varied widely. The optimum program for this field required two different chemicals and treating methods.

Another factor frequently overlooked in corrosion inhibition programs is the changes that occur in the producing characteristics of the wells during primary depletion or in secondary recovery periods. Chemicals and treating methods that give good protection during the period when water-cuts are relatively low (25-40%) are frequently inadequate when large volumes of water are produced. It is highly desirable to begin a systematic monitoring program at the same time an inhibition program is started. This, in addition to establishing the success of the program, will usually indicate when a change in chemicals or application method is necessary.

One condition that is frequently overlooked in oilwell corrosion programs is the possibility of air entering the system. Occasionally, wells are maintained in a pumped-off condition with the annulus open. In the later stages of depletion, with high water-cuts and no significant gas, air can contaminate a system through the open annulus. Other sources of air are the polished rod, stuffing box, and valve packings on the well side of the flow line check valves. In this presentation, it is presumed that the systems are air-tight and all corrosion is from the produced fluids.

Figure 4 shows typical well type completions, producing characteristics and types of treatment that may be suitable. The figure is intended primarily for conventional flowing or sucker rod-pumped wells, with the tubing set at or above the producing interval and where there is some open hole below the bottom of the producing zone. While the conditions shown are typical of the majority of wells there are other installations that require special consideration. Examples of these are dual and gravel-packed completions, fluid and centrifugally-pumped, and gas lift wells. Also, there are other types of chemicals not considered in the figure, i.e. stick or encapsulated. The following briefly discusses the treating procedures contained on the chart.

Note: The section entitled "Corrosion Inhibition Treating for Oil Wells" discusses the following table and the limitations and precautions required for certain conditions. While a number of the types of treatments are suitable for all the completion types the chemicals applied will vary with the type of fluids and the relative volumes of oil and water.

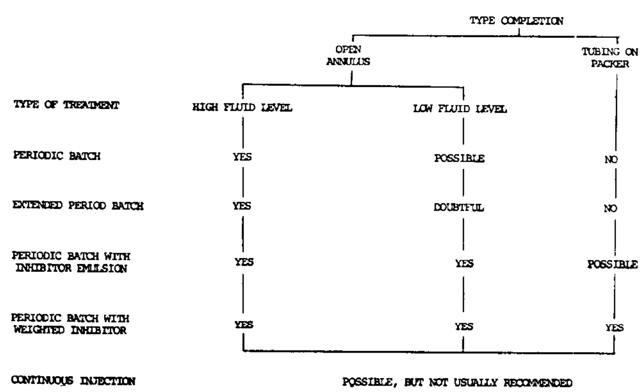


FIG. 4—TREATING PROCEDURES FOR TYPCIAL OIL WELL COMPLETIONS

Periodic Batch

This is the simplest and quickest procedure and the one most operators would prefer to use in wells with open annuli. The occasional failures with this treatment in high fluid level wells can generally be attributed to either improper selection of inhibitor or not conditioning the well when treating is started. Conditioning consists of batching sufficient inhibitor to establish the required treating level in all the oil in the annulus and then circulating the well. This will establish an initial film and mix the inhibitor with the annulus fluids so as to assure a uniform feed-back during production.

The application of this treatment in low fluid level wells depends on the fluid level maintained in the annulus. The method would not be recommended in wells that pump-off. It would be estimated that a fluid level of at least 150 feet should be maintained. In placing the treatment in operation in these wells it would be recommended the initial treatment be immediately displaced into the tubing and a second batch of inhibitor be placed in the well.

Extended Period Batch Treatment

This treating method has been used successfully in high fluid level wells. The procedure consists of calculating the total volume of inhibitor required for a three-six month period and batching the quantity into the annulus. The annulus oil is circulated several times to thoroughly mix the inhibitor in the oil and then parked in the annulus. Where wells have been on a successful treating program the circulation may not be required. Also when the extended batch is replaced, circulation will not be required. However, the well should be re-treated and circulated with any workover requiring pulling of the tubing.

Periodic Batch With Inhibitor Emulsion

This treatment can be used with both low and high-level wells and with wells set on packers. Of particular importance with this procedure is selection of the inhibitor. In general, the method consists of creating a semipermanent emulsion with inhibitor and water, dumping the mixture into the tubing or annulus, and closing the well in for a sufficient time for the mixture to fall to the well bottom. The ability of the method to effectively inhibit is contingent upon the emulsion being sufficiently stable to remain dispersed until the mixture has reached bottom. At the same time the emulsion must be of a semipermanent nature that will allow the inhibitor to slowly coalesce and enter the oil column. Testing of the inhibitor and mixing water is mandatory for applying this system. As a "rule of thumb" the mixture should remain relatively stable for a minimum of four hours. Some inhibitors can also form too stable an emulsion so that the chemical does not have an opportunity to film the equipment.

Batch with Weighted Inhbitor

In these chemicals the inhibitor is chemically coupled to a weighting agent.

Various densities of inhibitor are available to assure the inhibitor will fall through either the oil or water encountered in the annulus or tubing. The combination of water and temperature in the well causes the inhibitor to disassociate and enter the production column filming the wellbore equipment as it is produced. The weighted inhibitors have frequently been applied successfully where other types of treatments have been ineffective. The type of production, i.e. sweet or sour, must be considered in selecting the chemical. Certain of the weighting agents are not suitable in sour operations. The weighted inhibitors should be considered where other methods have been ineffective.

Continuous Injection

With proper equipment and well conditioning, continuous injection is practical in all cases and in some instances the most effective; but it is not generally used for oil wells. This is primarily due to inconvenience, time, and expense. Injection pumps must be maintained, injection rates checked, and reservoirs filled. With the low injection rates normally required, plugging of jets and lines is a continual source of annoyance. It would be recommended only as a last resort.

RULES OF THUMB ON OILWELL CORROSION

These are generalities that can be used in a preliminary evaluation of the possibility of corrosion in a specific oil well or field; and treating conditions that can be considered when no other information is available. Where specific test data or other information contradicts these, the "rules" should be disregarded.

1. In wells producing less than 25% water, the equipment will be oil-wet and corrosion would not be anticipated.
2. In wells producing between 25-45% water, the equipment may be either oil or water-wet and the possibility of corrosion depends on the corrosivity of the water.
3. In wells producing over 45% water, the equipment will be water-wet and corrosivity will depend on the corrosivity of the water.
4. When the equipment is water-wet and the pH is between 6.5 and 7.0, mild corrosion is probable; but unless it is a pitting-type attack, frequent equipment failure would not be expected.
5. When the equipment is water-wet and the pH is between 6.0 and 6.5, significant corrosion is occurring and further tests are required to determine how serious the attack may be.
6. When the equipment is water-wet and the pH is below 6.0, serious corrosion is occurring and an inhibition program should be started.
7. When equipment inspection or coupon data indicates a pitting-type attack, the corrosion should be considered serious regardless of MPY; and an inhibition program should be started.
8. Where applicable, an oil-soluble, water-dispersible inhibitor should be used.
9. Where applicable, the periodic batch-treating procedure should be preferred.
10. A treating rate of 10-15 ppm should be used for mild corrosio
11. A treating rate of 15-25 ppm should be used for moderate corrosion.
12. A treating rate of 25 ppm plus should be used for serious corrosion.
13. Initial treating should be on a weekly basis and extended as monitoring data indicates.

ACKNOWLEDGMENT

The field data in this presentation is from a nonpublished NACE paper by R.D. Shelton and C.E. Walker who conducted the investigation.