SELECTION, DESIGN, AND AUTOMATION OF CORROSION INHIBITOR TREATMENT IN ROD PUMPED WELLS

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INTRODUCTION

Experience developed in the Midcontinent Division of Exxon Co., U.S.A. indicates that well corrosion problems in rod pumped wells are directly related to the water cut of produced fluids. In general, severe corrosion problems as measured by excessive rod, pump and tubing failures, are predominant in wells that produce in excess of 30% water. Further, embrittlement and pitting resulting in reduced rod life and fatigue failures are accelerated by the presence of hydrogen sulfide in the produced fluids.

Corrosion in rod pumped wells is controlled by maintaining an inhibitor film on all wellbore equipment exposed to produced fluids. The film can be formed and maintained as a well is produced by maintaining an adequate concentration of inhibitor in the produced fluids. The film can also be created by a short contact time with fluids containing a high inhibitor concentration. The film thus formed can be allowed to dissipate using frequent retreatment to maintain protection.

Four methods are used to treat rod pumped wells with corrosion inhibitors: squeeze, batch flush, continuous injection, and circulation. The labor and material costs, investment, and treatment effectiveness vary with well characteristics for each method.

The purpose of this paper is to present information for selecting the "best" corrosion inhibition technique for a given set of well conditions. "Best" method is defined as the most economical when both well servicing costs and corrosion inhibition expense are considered. This paper also presents formulas and guidelines for design of an effective treatment once the appropriate inhibition technique has been selected.

The information presented is grouped in three main sections: (1) Selection of treatment methods; (2) Treatment design; and (3) Application of automatic chemical injectors.

TREATMENT METHODS

Any one of the corrosion control methods defined in the previous section can prove to be the most economical and effective method if selected carefully.

Squeeze Method

In the squeeze technique, a solution of inhibitor is injected into the completion interval. The well is then left shut-in for a period of time to permit adsorption of inhibitor on formation rock. Upon returning the well to production, the adsorbed inhibitor desorbs in the produced fluid and maintains an inhibitor film on the tubing and other subsurface equipment. The inhibitor and the solution concentration are selected to give optimum long-term protection. As the inhibitor desorbs, the concentration of inhibitor in the produced fluids declines. This concentration is monitored, and the well must be retreated when the inhibitor concentration is inadequate to protect well equipment.

The complexity and high expense of the treatment, plus the production lost during shut-in and while recovering injected fluids, usually limit economic applicability of the squeeze method in rod pumped wells to those wells completed with a packer.

Batch Flush

Batch flush treatments are made by dumping a mixture of a water-dispersible, oil-insoluble inhibitor in water into the annulus (the mixture consists of 2-5 gal. of inhibitor with 2-5 bbl fresh water). The inhibitor mixture falls through the oil column and enters the pump. The quantity of inhibitor is selected to provide a sufficient concentration in the produced fluids to form a protective film on the well equipment. The required frequency of treatment will vary from daily to monthly; however, weekly retreatment is adequate for most applications. Wells with a high pumping fluid level and/or high producing rate require a large flush treatment. The flush treatment is most economical in wells producing less than 50 BFPD and having a casing fluid level less than 700 ft above the pump.

Continuous Treatment

The continuous-type treatment is accomplished by continuously injecting a small quantity of inhibitor into the annulus with a portion of the produced fluid (a side-stream flush). The well is initially treated to establish a uniform protective inhibitor film by adding 3–5 gal. inhibitor to the annulus and circulating the well with all producing fluids to contact the well equipment with at least two passes of the inhibitor solution. After this initial treatment, inhibitor is injected continuously into the annulus to maintain the inhibitor concentration at 25-50 ppm in the produced fluids. The required inhibitor film by adding 3-5 gal. inhibitor to the produced fluids at a rate of 1-2 BPD.

Laboratory tests by Nestle[1] determined the relationship of corrosion rate to inhibitor concentration for both continuous and batch-type treatments. Also, Nestle's results showed that inhibitors added to the oil phase are not as effective as inhibitors which are mixed with both oil and water or water only. These test results support field experience which shows that inhibitors which are soluble or dispersible in water will result in more effective corrosion protection than when using oil-soluble inhibitors. Nestle's study also indicated that continuous addition of inhibitor at a rate of 25 to 50 ppm was not nearly as effective as a batch treatment resulting in inhibitor concentrations of 2000 ppm as shown by Fig. 1.

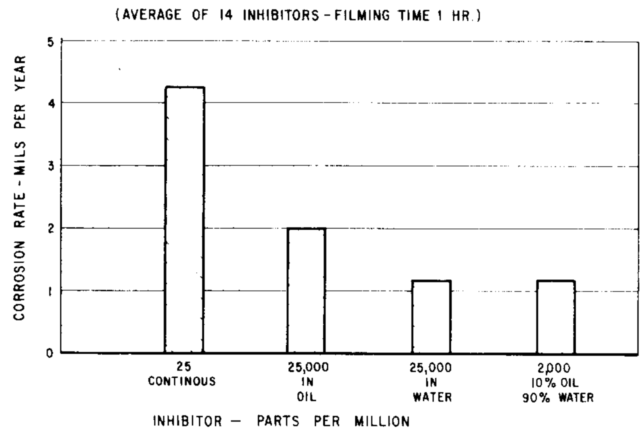

FIG. 1 – RELATION OF CORROSION RATE TO INHIBITOR CONCENTRATION

The continuous-type treatment does not provide as effective corrosion control as batch treatments and should be used only when the corrosion rates are low and producing rate or pumping fluid level necessitates prohibitively large batch treatments.

Circulation Method

In the circulation method, the produced fluids are mixed with sufficient inhibitor and diverted into the annulus to obtain a concentration in the return fluid that will provide the protective film. Production is delayed during the circulation treatment. To initiate treatment by this method, the film is established by injecting a slug of inhibitor (3-5 gal.) into the casing-tubing annulus and circulating the well until the inhibitor slug is returned to the annulus a second time. This insures that the well equipment is contacted twice with well fluids containing a high inhibitor concentration. For optimum economic use of this method, it is necessary to keep inhibitor volume and delayed production volume to a minimum.

Subsequent periodic treatments utilize only sufficient inhibitor to repair damage to the protective film with a one-pass circulation. The circulation method provides the most effective corrosion control, and can be used economically except where one-pass circulation volumes require large quantities of inhibitor and long circulation time with corresponding large volumes of delayed production. Treatment by circulation will be the most economic for all wells which have pumping fluid levels less than 2000 ft above the pump in a large-volume annulus and fluid production in excess of 50 BPD.

SELECTION OF TREATING METHOD

The general comments on selection of the best method for treating a rod pumped well with corrosion inhibitor are reduced to a handy form in the chart shown in Fig. 2. The chart relates pumping fluid levels and production rate to an optimum treating method and generally applies to wells producing 30% or more water. The circulation method of treatment proved to be adaptable to the majority of wells in our operations.

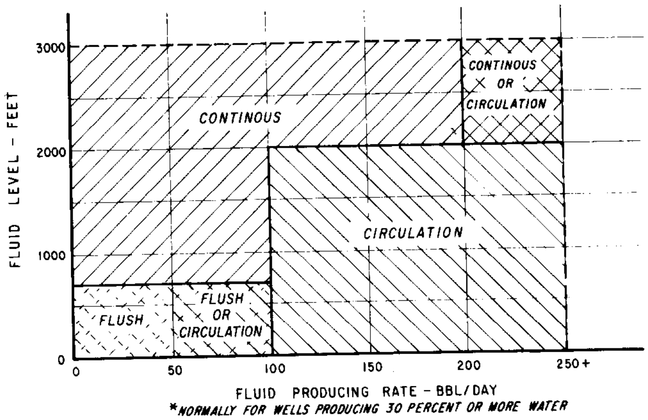

FIG. 2 — CHART* FOR SELECTION OF CORROSION INHIBITION METHOD IN ROD PUMPED WELLS

TREATMENT DESIGNS

Once the corrosion treating method is selected, the treatment must then be "designed." Unfortunately, the "design" in some cases must be based on experience instead of fully recorded data. Most of the time, an adequate design of corrosion treatment can be made with knowledge of industry practices tempered with local experience.

Squeeze Treatment

In general, design of a squeeze treatment involves calculating the quantity of inhibitor required to yield an average concentration of 20 ppm in the water that will be produced during the life of the treatment, which is usually three to six months. This inhibitor volume is then diluted with lease crude or diesel oil in a ratio of about 4 bbl of inhibitor to 25 bbl diluent. The adsorption capacity of the formation is determined and is then employed to calculate the pore volume of formation which must be contacted to deposit the desired quantity of inhibitor. The diluent oil with approximately 1/2% inhibitor is used as after-flush to cause the concentrated inhibitor solution to contact the required volume of rock. Many formations contain clays which irreversibly adsorb inhibitor. The adsorption capacity of the clays is usually satisfied with the first treatment by using an excess of inhibitor. Subsequent treatments are made using the normal volume of inhibitor.

Effective squeeze treatment requires that the inhibitor solution and after-flush be injected below formation fracture pressure, and that the well be shut-in for 24 hours to permit adsorption.

As indicated, the design requires selecting the inhibitor and solution plus knowledge of the adsorptive capacity of the producing formation. Not all formations have adsorptive-desorptive characteristics which permit effective squeeze treatment. For example, sandstone formations, in general, have much better characteristics than limestone or dolomite.

Batch Flush

Treatment of a well by the batch flush method requires the use of 1-2 gal. inhibitor flushed down the annulus with 1/2 bbl of water per 1000 ft of depth to the pump. The use of this treatment procedure normally results in exposure of well equipment to an inhibitor concentration of at least 1000 ppm in the produced fluid for 1 hour or longer. A comparison of inhibitor concentrations in a well treated by both batch flush and circulation methods is shown by Fig. 3. This data is typical of that

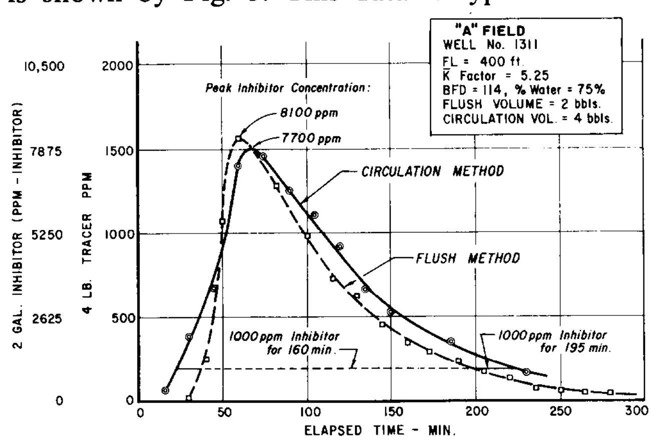

FIG. 3—TRACER TEST DATA ON A LOW VOLUME, LOW FLUID LEVEL WELL TREATED BY THE CIRCULATION & FLUSH METHODS

obtained from tests in five wells and shows that ample treatment is obtained by either procedure. The flush technique of treatment is most adaptable for wells producing 100 BFPD or less, and for wells with fluid level of 700 ft or less. Wells producing 50 BFPD or less can be best treated by the flush method. Wells being pumped-off in this category would have practically no fluid level above the pump.

The tracer tests were made using a highly water soluble chemical to simulate the concentration of the water-soluble or water-dispersible inhibitor. The concentration of chemical in the circulation or flush treatment of a well was correlated to represent the amount of corrosion inhibitor when it is circulated or flushed.

Inhibitor volume and treatment frequency required for adequate inhibition are dependent upon the corrosivity of the well. For wells where corrosion is not severe, initial treatment volumes and frequency should be equivalent to a minimum of 25 ppm in the fluid production between treatments. (One gal. inhibitor per 1000 bbl produced fluids). Each treatment should use at least 1 gal. of inhibitor with no more than two weeks between treatments. These criteria should provide downhole inhibitor concentrations of 1000 ppm, or preferably greater, for a period of an hour or longer with each treatment.

If a flush treatment designed according to the criteria above does not satisfactorily inhibit corrosion, ideally the time interval between treatments should be reduced; if this is not practical, the inhibitor volume should be increased.

Continuous Injection

The design for treatment of a well by continuous injection consists of calculating the quantity of inhibitor required to provide a concentration of 25-50 ppm in the produced fluids. The treatment is performed by injecting inhibitor into the annulus at the required rate along with a side-stream flush of 1-2 bbl of produced fluid per day. As stated earlier, the well should be initially treated by adding 3-5 gal. inhibitor to the annulus and circulating the well until the inhibitor makes two passes by the wellbore equipment to establish a uniform protective film.

Circulation Method

Effective treatment by the circulation technique requires that the well equipment be exposed to a high concentration of inhibitor for one hour or longer. Tests data by Larrison[2] shows that exposure of equipment to inhibitor concentrations of 1000 ppm for a period of two hours will establish an effective inhibitor film. Refer to Fig. 4. Further, the data shows that a ten-minute exposure time at lower concentrations results in a drastic reduction in protection. Based on the data from these tests and the results of Nestle's experimental work shown in Fig. 1, it is concluded that effective treatment by the circulation method must provide downhole inhibitor concentrations of 1000 ppm for a period of at least one hour. The frequency of treatment should be based on well corrosivity and filming persistency. A guideline for selection of treatment frequency is determined from the time interval required to produce 1000 bbl of fluid.

A test program was conducted to determine the volume of inhibitor and volume of circulated fluid required to provide the optimum corrosion inhibitor treatment. The design technique presented here for the circulation treatment of wells is based on results of the study. All the equations were developed from results of the tracer tests and a mathematical derivation from a circulation model of a well. To simplify the characteristics of the model, certain assumptions were made: (1) reservoir pressure remains constant during circulation; (2) formation fluid influx is a linear function of pressure drawdown in a well; (3) the well has a single casing and tubing size; (4) the pumping rate of the well remains constant throughout the time of circulation; and (5) once circulation is completed, the pump will

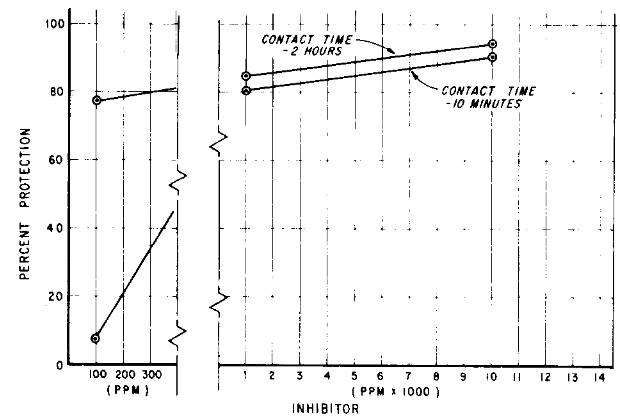

FIG. 4 — RELATION OF INHIBITOR CONCENTRATION AND FILMING-TIME TO PERCENT CORROSION PROTECTION

produce at capacity until the fluid level in the casing is restored to the level before circulation.

The first step in the design procedure is to determine the effect of the height of the casing fluid above the pump on the circulation volumes. The following two formulas are used to calculate the optimum circulation volumes. The equation that results in the larger volume will control the design of the circulation treatment.

$$V_c = 0.001\ (H_p\text{-}FL) \qquad (1)$$

A graphical solution of Eq. (1) to determine circulation volume for low fluid wells is given by Fig. 5

$$V_c = A_{ct}\ (FL\text{-}500) \qquad (2)$$

A graphical solution of Eq. (2) to determine circulation volume for high fluid level wells is given in Fig. 6

V_c = optimum volume of produced fluid to circulate (bbl)
H_p = depth of the pump (ft)
FL = casing fluid level above the pump (ft)
A_{ct} = capacity of the casing-tubing annulus (bbl/ft)

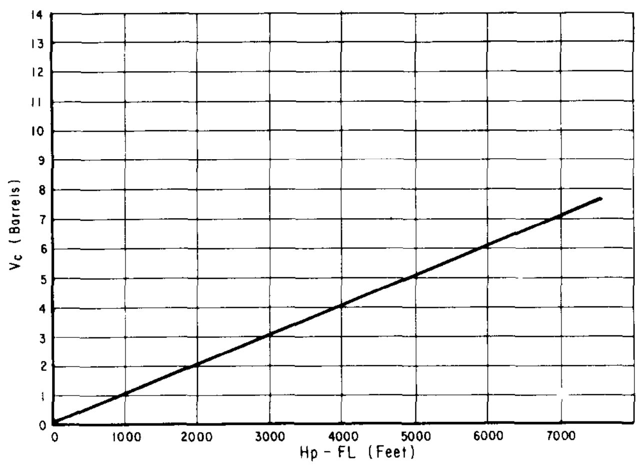

FIG. 5 -GRAPHICAL SOLUTION OF EQUATION 1 TO DETERMINE CIRCULATION VOLUME FOR LOW FLUID LEVEL WELLS

If Eq. (1) is found to control the optimum volume to circulate, the well is considered a "low fluid level" well. In general, these wells will have excess pumping capacity, and little or no production delay will result from circulating a volume equal to the optimum volume. Since Eq. (1) controls the volume to circulate in a low fluid level well, Eq. (3) will be the only equation required to calculate the inhibitor volume.

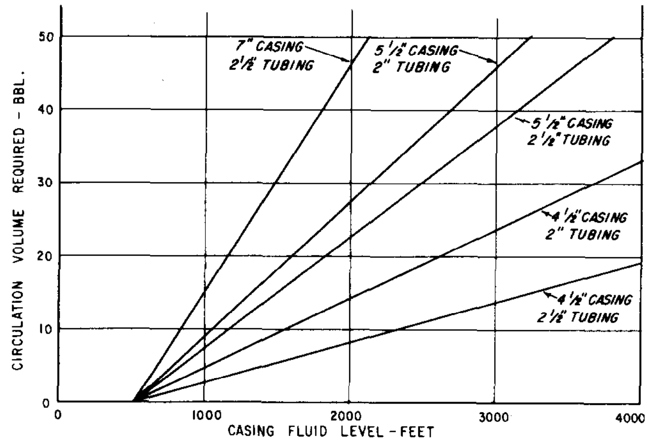

FIG. 6 -GRAPHICAL SOLUTION OF EQUATION 2 TO DETERMINE CIRCULATION VOLUME FOR HIGH FLUID LEVEL WELLS

$$V_{inh} = \frac{P_W}{37.5} \qquad (3)$$

Where:

V_{inh} = volume of inhibitor (gal.)
P_W = percent water in produced fluids

Where Eq. (2) controls the optimum volume of circulation, the design procedure becomes more complex. First, the well must be capable of pumping the optimum volume before the circulated inhibitor has fallen to the pump suction level; and second, production delay may be associated with wells controlled by Eq. (2). Therefore, an estimation of this delay must be made to determine the economic loss due to circulating the optimum volume. (Production delay occurs when the pump is routinely operating at capacity, such that increased fluid levels during treatment will not cause significant increased production when the well is first returned to production).

Examples of the validity of Eq. (1) are shown by the results of tests on two wells plotted in Fig. 7. Solving Eq. (1) for Well No. 1311 at Field A shows the volume of circulated fluid needed is approximately 4 bbl. A similar calculation for Well No. 72 at Field C shows the volume to be circulated is 7 bbl. The tracer test results given by Fig. 7 for these wells when 4 and 8 bbl of fluid were circulated, show that inhibitor concentrations in excess of 1000 ppm for longer than one hour were obtained. These results show that Eq. (1) gives a reasonable estimate of the volume of circulated fluid required for an

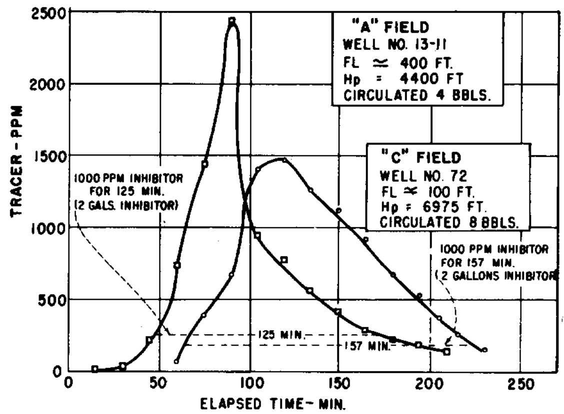

FIG. 7—TRACER TEST DATA ON LOW FLUID LEVEL WELL SHOWING VALIDITY OF EQUATION 1

adequate corrosion inhibitor treatment in a well.

Figure 8 presents the results of a tracer test performed on a well in Field B. For this well, the fluid level was found to be between 2000-2500 ft above the pump. The optimum volume of circulated fluid given by Eq. (2) is found to be 47-62 bbl. Notice that test results for 60 bbl of circulated fluid show that the treatment associated with 2 gal. of inhibitor is adequate.

The following two approximate equations are suggested to determine an upper and lower limit in estimating the maximum effective circulation time. A more exact equation to estimate the time for the inhibitor to fall to pump suction (maximum effective circulation time) was derived in the calculations for the mathematical model.

$$(\text{Lower limit})\ T_{max} = \frac{FL}{V_d + \dfrac{Q_d}{1440\ A_{ct}}} + \frac{H_p - FL}{V_g} \qquad (4)$$

$$(\text{Upper limit})\ T_{max} = \frac{5760}{Q_d} + \frac{FL}{V_d} + \frac{H_p - FL}{V_g} \qquad (5)$$

Where:

- T_{max} = maximum effective circulation time (min)
- Q_d = well fluid production (BPD)
- V_d = inhibitor fall velocity in oil (use 12 fps)
- V_g = inhibitor fall velocity in gas (use 150 fps)

To prevent needless delayed production, the volume of circulated fluid should never be allowed to exceed the volume V_{max} associated with the maximum circulation time. V_{max} is given by the following equation:

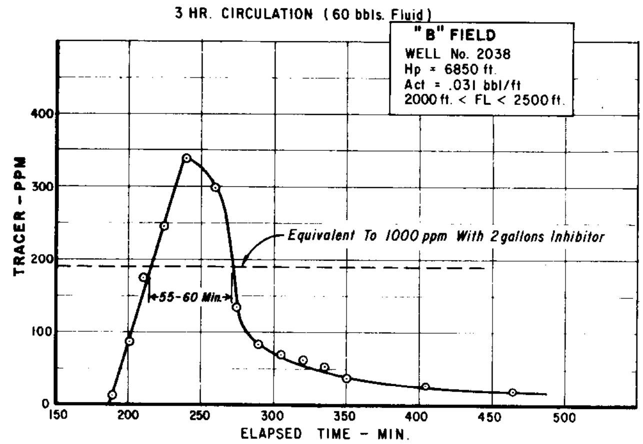

FIG. 8—TRACER TEST DATA ON HIGH FLUID LEVEL WELL SHOWING VALIDITY OF EQUATION 2

$$V_{max} = \frac{Q_d}{1440} T_{max} \qquad (6)$$

An equation derived for estimating the production delayed in the circulation of a well in simplified form is suggested for design by hand calculation:

$$V_{delay} = V_{act} - A_{ct}\,(FL_{SI} - FL)\left(1 - \frac{Q_d}{Q_{cap}}\right) \qquad (7)$$

Where:

- V_{delay} = volume of delayed production (bbl)
- V_{act} = volume of fluid chosen to be circulated (bbl)
- FL_{SI} = shut-in fluid level above the pump (ft)
- FL = casing fluid height above the pump (ft)
- Q_{cap} = pumping capacity of the well equipment (BPD)
- Q_d = well fluid production (BPD)
- A_{ct} = capacity of casing-tubing annulus (bbl/ft)

To obtain the simplified form of Eq. (7), it is necessary to consider that the ability of the well to store circulated fluid is solely a function of the volume in the casing-tubing annulus which is available for fluid build-up during circulation; i.e., $A_{ct}\,(FL_{SI}\text{-}FL)$. Further, it is necessary to assume that the ability of the well to produce the stored fluid can be expressed uniquely in terms of well pumping efficiency (Q_d/Q_{cap}). These assumptions are obvious simplifications of a fairly complex mechanism; however, the formula provides a very close estimate of the production delays found in the test study.

To test the validity of Eq. (7), refer to the well test

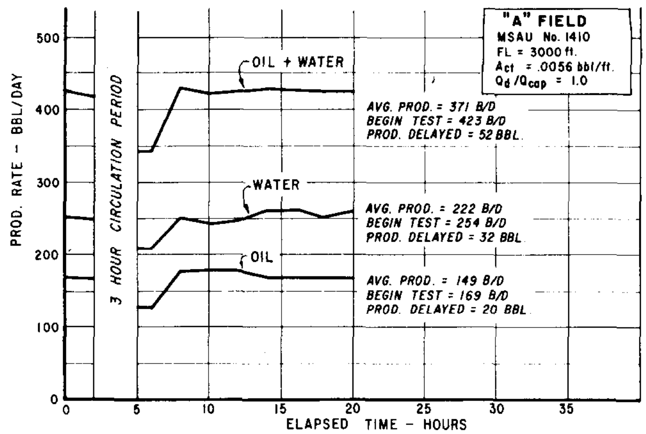

FIG. 9—EFFECT OF CIRCULATION ON PRODUCTION DELAY IN A WELL WITH LIMITED ANNULAR STORAGE AND PUMP CAPACITY

data presented by Figs. 9 and 10. Figure 9 illustrates the effect of circulation on a well with a limited capacity to store circulated fluid and no capacity to produce fluid at an accelerated rate following circulation. Equation (7) would predict that the volume of production delayed would be equal to the volume of fluid circulated. In fact, both the one-hour and three-hour circulation tests show that daily production was reduced by the volume of fluid circulated.

Figure 10 presents the test results for a well with a high capacity to both store and produce circulated fluids. The low pumping fluid level combined with a liberal annular area results in a storage capacity which exceeds the volume of fluid circulated. Further, the pumping efficiency indicates that this

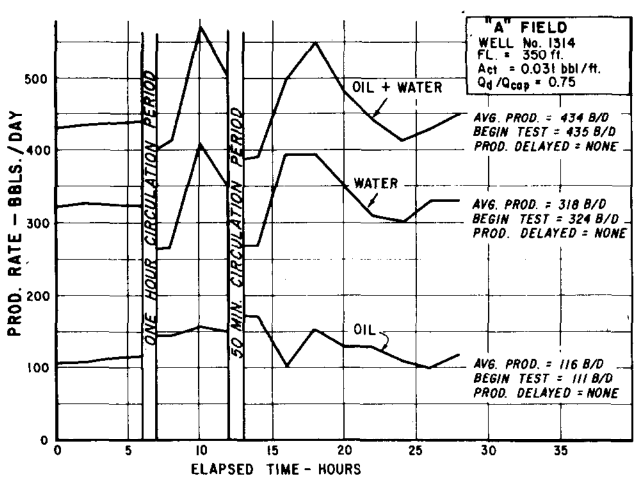

FIG. 10—EFFECT OF CIRCULATION ON PRODUCTION DELAY IN A WELL WITH AMPLE ANNULAR STORAGE AND PUMP CAPACITY

well should have a capacity to produce the stored volume in addition to normal production following circulation. Solution of Eq. (7) for this well yeilds a negative result indicating the well's capacity to store and produce fluid exceeds the volume actually circulated. Therefore, the equation would predict no delayed production and, in fact, little or no delayed production was observed.

If the optimum volume of fluid can be circulated within the maximum effective circulation time (T_{max}) and the volume of production delay, if any, is not excessive, Eq. (3) may again be used to calculate the volume of inhibitor required. However, when the optimum circulation volume (V_c) exceeds the maximum effective volume (V_{max}) or the volume of delayed production is excessive, the following formula should be used to determine inhibitor volume.

$$V_{inh} = \frac{P_W}{37.5}\left(\frac{FL}{500} - \frac{V_{act}}{500\,A_{ct}}\right) \tag{8}$$

Once the circulation and an inhibitor volume have been determined, a proper treatment frequency must be selected. As a guideline, the treatment interval should be equal to the number of days necessary for the well to produce 1000 bbl of fluid or two weeks whichever is less. If this design proves ineffective, the time between treatments should be reduced.

The following is an example of using the foregoing equations in designing a circulation treatment.

Given a well with the following characteristics:

Q_d = 300 BPD
Q_{cap} = 400 BPD
P_W = 50%
FL = 1000 ft
FL_{SI} = 3000 ft
H_p = 4000 ft
Casing Size = 5-1/2 in.
Tubing Size = 2 in.
A_{ct} = 0.0178 bbl/ft

Corrosion History: Four jobs in 12 months for $2500

1. Determine whether Eq. (1) or (2) will control design of circulation treatment.

   (Eq. 1) V_c = 3 bbl
   (Eq. 2) V_c = 8.9 bbl (largest - therefore, Eq.(2) controls)

2. Since Eq. (2) controls, estimate maximum effective circulation time (T_{max}).
   (Eq. 4) (Lower limit) $T_{max} = 62.2$ min
   (Eq. 5) (Upper limit) $T_{max} = 122.5$ min
   Determine T_{max} by averaging values obtained by Eqs. (4) and (5). Then
   $T_{max} = 92.3$ min
3. Calculate maximum effective circulation volume (V_{max})
   (Eq. 6) $V_{max} = 19.2$ bbl
   Since $V_c < V_{max}$, let $V_{act} = V_c = 9$ bbl
4. Estimate volume of production delayed (V_{delay})
   (Eq. 7) $V_{delay} = 0$ bbl fluid
5. Calculate volume of inhibitor required (V_{inh})
   (Eq. 8) $V_{inh} = 1.3$ gal. inhibitor
6. Select treatment interval based on time to produce 1000 bbl fluid.

   Treatment interval = 3.3 days
   (approximately twice each week)

Design Summary: Treat well *twice a week* with 1.25 gal. inhibitor and circulate *9 bbl* fluid.

ECONOMIC JUSTIFICATION OF AUTOMATIC CHEMICAL INJECTORS

Currently, there are over 300 automatic chemical injectors installed in the Midcontinent Division of Exxon Co., U.S.A. Comparison of the estimated cost of application of corrosion inhibition by manual and automatic methods in a rod pumped well is illustrated in Table 1. This analysis shows that the cost of inhibition either by manual or automatic flush or circulation methods is about the same when the treatments are made at frequency of once per week. When wells are to be treated two or more times per week, use of the automatic injectors provides a labor savings of $250 to $500 per well-year. This savings alone will pay out the total cost of the chemical injectors in approximately one to three years.

The cost advantage of using automatic chemical injectors was determined by comparing the well servicing costs before and after installation of automatic chemical injectors in 79 wells where about one year of data was available before and after installation. All wells were being treated manually before installing the injectors. The data showed that the projected annual well servicing cost was reduced

TABLE 1 – OPERATING COST OF CORROSION INHIBITION BY METHODS IN A ROD PUMPED WELL

Treating Method	Investment[a] $	Treatment Frequency	Treatment Gals.	Cost/Treatment Labor	Cost/Treatment Chemical	Cost/Year	Automatic Injectors Savings Per Year Over Manual $
Flush - Manual	-	1/wk	1	$3.25	$1.50	$247	
- Automatic	900	1/wk	1	3.70[a]	1.70	281	-34
Circulation - Manual	-	1/wk	1	3.10	1.70	250	
- Automatic with chemical pump	650	1/wk	1	2.75[a]	1.70	231	+19
- Automatic without chemical pump	750	1/wk	1	3.15[a]	1.70	252	-2
Flush - Manual	-	2/wk	1	3.25	1.50	494	
- Automatic	900	2/wk	1	1.85[a]	1.70	281	+213
Circulation - Manual	-	2/wk	1	3.10	1.70	500	
- Automatic with chemical pump	650	2/wk	1	1.37[a]	1.70	231	+269
- Automatic without chemical pump	750	2/wk	1	1.57[a]	1.70	252	+248
Flush - Manual	-	3/wk	1	3.25	1.50	731	
- Automatic	900	3/wk	1	1.23[a]	1.70	281	+450
Circulation - Manual	-	3/wk	1	3.10	1.70	750	
- Automatic with chemical pump	650	3/wk	1	0.92[a]	1.70	231	+519
- Automatic without chemical pump	750	3/wk	1	1.05[a]	1.70	252	+498

[a]Investment for chemical injector depreciated in 5 years.

by \$86,000, or 41% for an average annual saving per well of \$1090. Payout of the injectors have been approximately 7 months when considering the labor savings and the reduction in average servicing costs.

DESIGN OF AUTOMATIC CHEMICAL INJECTORS

Automatic chemical injectors have been in use for several years and were initially designed to apply corrosion treatment by both the circulation and batch flush technique. The use of these injectors permits the application of chemical treatment so that the volume of chemical, frequency of treatment and circulation time can be selected to meet the requirements of each well. This also reduces the chance that a treatment will be missed or delayed.

For automation of chemical treatment by the circulation technique, two types of automatic chemical injectors are used in our area. One type, as shown in Fig. 11, consists of a beam chemical pump to inject the chemical into a chemical collection pot. The top of the pot is connected to the flowline through a three-way valve and the bottom is connected by a gooseneck line to the casing annulus. The gooseneck has a vacuum breaker connected to the top of the pot to permit injected chemicals entering the pot to displace fluid into the annulus.

The second design system, shown by Fig. 12, consists of two electrically actuated three-way valves, a chemical pot, and an air eliminator. One valve is connected to the flowline and the other is connected to the casing and the chemical drum. Both valves are connected to the chemical collection pot. Before circulation begins, a predetermined volume of inhibitor flows by gravity from an elevated chemical drum to the chemical pot. When circulation begins, the produced well fluids move the inhibitor from the pot into the casing-tubing annulus. Once the circulation cycle is completed, the

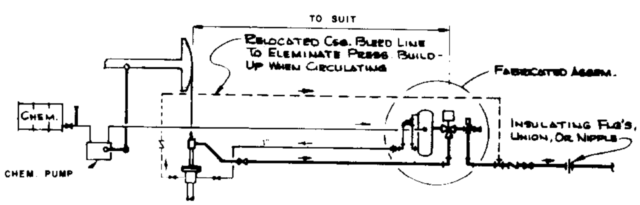

FIG. 11 — AUTOMATIC CHEMICAL INJECTOR WITH BEAM CHEMICAL PUMP

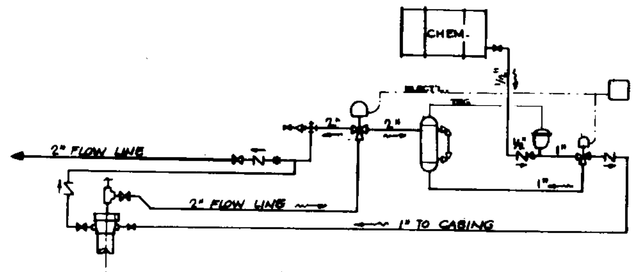

FIG. 12—AUTOMATIC CHEMICAL INJECTOR WITH AIR ELIMINATOR

air eliminator bleeds pressure from the pot so that inhibitor can gravitate from the chemical drum to the chemical pot. The height setting of the air eliminator relative to the chemical pot determines the volume of chemical that accumulates in the pot for each treatment.

For treatment of wells normally treated with pump truck type flush method, the automatic flush chemical injector was developed. A schematic of this system is shown by Fig. 13. In the operation of this unit, produced fluid from the well flows through a 250-gal. horizontal separator vessel placed such that approximately 5 bbl of produced water accumulates up to the flowline level. The accumulated water is used to flush the chemical from the chemical pot down the casing annulus. The flush cycle begins automatically when the timer signals the two-way valve to close flow from the chemical drum to the chemical pot and open flow from the pot to the casing to allow flow from the separator vessel to the chemical pot.

INSTALLATION OF AUTOMATIC CHEMICAL INJECTORS

All three automatic chemical injectors shown in Figs. 11, 12, and 13 are shop-fabricated, and purchased as a single unit. Therefore, installation of these devices at the wellsite is a fairly simple job

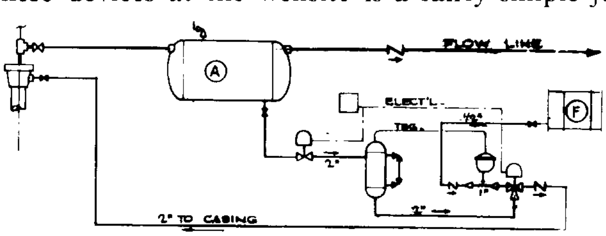

FIG. 13 – AUTOMATIC FLUSH CHEMICAL INJECTOR

requiring a minimum amount of field labor. However, to insure proper operation of these units, the following installation guidelines should be observed.

It is important to install the automated equipment in the flowline at a point at least 20 ft away from the wellhead and at least 10 ft from access roads. The minimum distances recommended should provide adequate accessibility to both the injector and the wellsite and adequate protection of the injection equipment.

If the produced fluid is diverted to the annulus with no provision to vent gas build-up, the annulus pressure will increase due to redistribution and separation of the gas in the annulus. Pressure build-up can cause premature failure of stuffing boxes and increased production delays. Pressure build-up tests taken during the period of circulation have indicated pressure increases in excess of 190 psi where chemical injectors have been installed without a bypass line. Experience has indicated that this pressure increase during circulation has resulted in accelerating stuffing box failures. In the one field it was noted that the additional pressure due to circulation without a bypass line resulted in significant reduction in daily well production several days following a circulation treatment. With the automatic circulation injectors, Figs. 11 and 12, installation of a one-inch bleed line from the casing to the flowline downstream of the automatic injector will prevent this pressure build-up. The bleed line should be installed opposite the circulation line at the wellhead to insure that inhibitor injected into the annulus does not enter the bleed line.

Automatic flush unit shown in Fig. 13 does not require the installation of a bleed line to the casing. During the automated flush treatment, the flowline is always open to production and as a consequence there is no pressure build-up associated with this treatment technique.

CONCLUSIONS

1. The most economic method for controlling corrosion in a specific rod pumped well producing 30% or more water can be selected using Fig. 2.
2. The circulation method is the most economic method for controlling corrosion in most wells in the Midcontinent Division of Exxon Co., U.S.A.
3. Contact of well equipment for one hour with a solution containing 1000 ppm inhibitor will form an adequate protective film.
4. The optimum circulation treatment can be designed using methods presented in this report.
5 Automatic chemical injectors will reduce the cost of corrosion in wells using batch treating methods, especially where treatment frequency is more than once per week.
6. Additional circulation test work is needed to refine formulas developed. Tagging of chemical with radioactive tracer such as tritium should be considered.

REFERENCES

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