Patches on Our Oil Patch Pockets, or Corrosion Control in Petroleum Production

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INTRODUCTION

Patches on "oil patch" pockets have been becoming more important each year. There is no need to discuss the oil industry's problems of oversupply, cost cutting, belt tightening, etc., except to point out that never before in the industry's history have the economics of corrosion and corrosion control been so important. When the chips are down and when one is trying to get the maximum leverage from his operating and investment dollars, the care that he takes of his equipment, the design and construction of this equipment, and the life of this equipment become real dollars. Those who work in corrosion control and, yes, those who must live with corrosion and its control must exert every effort to become more proficient in our handling of these problems.

There are at the Short Course several other papers dealing with corrosion. However, they deal with specific problems and/or specific control measures applied to production equipment. This paper, however, attempts to "tie together" the various aspects of oil and gas production corrosion and reviews some of the problems and solutions of production corrosion along with some of the "tools of the trade." The author will try to illustrate with some specific examples from his experience and from information that he has been able to collect from others in the industry, through the National Association or Corrosion Engineers, etc.

To get started, one should go back to some definitions of corrosion and preventative measures and their effect on us in oil production. Atlantic's H. A. Stiff, in his University of Texas paper "Corrosion — the Holes in the Industry's Pocket" considers three different definitions:

1. The widely accepted definition sponsored by the Electro-Chemical Society of New York: "Corrosion is the destruction of a metal by a chemical or electro-chemical reaction with its environment."
2. A slightly different definition was proposed by a reservoir engineer: "Corrosion is a process of nature designed to increase the horizontal permeability of the casing."
3. Webster's American Dictionary, 1941 edition, states: "Corrosion is a process of being worn away as metals by rust, or morals by decay."

For this paper I believe that one can eliminate the "human" side. It is known that corrosion can be a serious problem in any industry and if often very serious in the "oil patch". As outlined in the Electro-Chemical Society definition that "destruction of a metal by a chemical or electro-chemical reaction . . .," corrosion is destruction. Actually, however, it is a natural act of the metal trying to return to its lowest level of energy, and in the case of iron and steel, the metal struction tries to return to its natural state: iron oxide (that is, iron ore). In oil production corrosion one sees chemical corrosion because of fluids handled and electro-chemical corrosion because of soils, dissimilar metals, "cell" action, etc. There are three basic methods of corrosion control (or of breaking the circuit, as it were): protective barriers, electrical circuit control, and control of materials. In oil production corrosion is combatted by all three methods of control:

1. Protective barriers
   a. Pipe coating, internal and external
   b. Paints and plastic films
   c. Inhibitors (more or less temporary coatings)
2. Electrical control as illustrated by cathodic protection of flowlines, well casing, vessels.
3. Material control by using resistant metal (such as copper) or alloys for pumps, valves, and special equipment by using plastics and inert materials of contruction or by changing the properties of the fluids involved (such as the neutralization of acids).

Corrosion takes its toll in all types of oil production equipment — from "the reservoir to the pipeline." And one finds casing corrosion, downhole equipment corrosion, wellhead and flowline corrosion, separation equipment corrosion, tankage corrosion, and corrosion in allied equipment, such as cooling systems, dehydrators, transfer pumps, and salt water disposal and water-flood equipment. Also, corrosion takes place at high pressure, low pressure, high temperature, and low temperature — inside equipment and outside equipment.

Fortunately, one usually does not have all forms of corrosion in all types of equipment in every well, in every field throughout its life, at least, not economically significant corrosion. Then when does corrosion become of economic significance? Corrosion becomes of economic significance when the costs because of corrosion exceed the costs of possible control and/or when hazards and safety may be involved.

How does one know? That is where engineers and corrosion control specialists come into play, for it is up to them to put together the story and evaluate each problem on its own merits. Sometimes corrosion and its costs are obvious; oftentimes they are hidden and difficult to define.

When a line leak develops because of a corroded hole, it is obvious that something should be done. When a rod string parts and is pitted and worn looking, it is also fairly obvious; or when the bottom corrodes out of a tank and fills the firewall with oil, it is also obvious — but is it? If the equipment is new, yes; but that pipe or those rods or that tank may have been in service for ten years, twenty years, or more — maybe the most economical thing to do is to repair or replace the equipment. But will it last another ten years, twenty years? How long would it have lasted with some minor expenditure for corrosion control? When during the equipment's life should corrosion control be applied? That last can be the principle problem.

However since many companies are just beginning to keep detailed records of certain types of failure, and costs are often hard to pin down, the repair cost is usually only part of the story and oftentimes a minor part since downtime, lost and/or deferred production, damages, etc., cannot always be easily assigned a dollar figure, but still may be very costly to the company. One operator in a recent report stated that his company broke down costs due to corrosion in Kansas sour production into the following categories:

Direct Costs	Indirect Costs
Inhibition	Damage Claims
Casing Repair	Decreased Safety Factors
Rod and Tubing Replacement	Lost and/or Deferred Production
Miscellaneous Expenses	Lower Salvage Values
	Losses because of Iron Sulphide Formation: pumps stuck, emulsions harder to break, increased paraffin deposition, plugged salt water disposal wells

As one can imagine, the indirect costs often exceed the direct.

To achieve overall corrosion control, the engineer or corrosion specialist has to devote time to two aspects or categories: remedial (after a failure to prevent future failures) and predictive (to prevent the first failure). The former is usually more obvious — leaks have a way of making themselves known. But the latter is often much harder, since each field, and sometimes each well, presents different conditions which may change during the field's life.

When trying to prevent future corrosion after failures have occurred, or in evaluating a corrosion control program, all available data must be considered — failure records, cost data, fluid studies, coupon evaluations, caliper surveys, and many others. These are the tools of the corrosion specialist, and it is at this point that field men play an important part in the corrosion control picture. The field man — foreman, gangpusher, pumper, roustabout, field engineer, or whoever — is the man who was there and is the man who knows the equipment. He may not know why something happened, but he does know what happened, and when it happened and how; and it is his information that can be invaluable in analyzing a problem.

It should be stressed here that anytime one is around a failure or makes equipment inspections, he should remember what he sees and report it whenever possible, even when formal report forms, etc. are not used. He may be the only person in his company who knows that the hole in the line was from the inside out, or that the pump was stuck with sand, or scale, which might have caused the rod break, or that the coating had been chipped off the tank a few months before, or even that the rectifier was hooked up backward, or that because of circumstances (mud, high water, work schedule, etc.) a well did not receive chemical treatment, or that a vessel had scale in it with corrosion pits under the scale, and on and on . . . These may sound elementary and even foolish, but just such information as this can make or break the solution to a corrosion problem.

But the author has talked enough about generalities; he will now look at some types of production equipment and what can be done.

EQUIPMENT CORROSION

It was said that in oil production one can have corrosion problems from the reservoir to the pipeline, so one should look at these problems — starting in the ground.

Casing Corrosion

The corrosion of oil well casing has become a costly item in many areas. Both internal corrosion (caused by well fluids) and external corrosion (caused by soil, etc.) can cause casing leaks.

Internal corrosion has been fairly successfully combatted by the use of inhibitors. And regular corrosion inhibitors have been very successful where the problems have been due to corrosive liquids.

In a stripper field in Northeast Texas, the use of a "standard" corrosion inhibitor batched down the annulus has been fairly successful in stopping severe internal casing corrosion.

Further, dehydration of lift gas has materially reduced internal casing corrosion in some gas lift wells where the injected gas was very corrosive and saturated with moisture.

Also in some sour gas areas where the corrosion attack is in the vapor space in the casing-tubing annulus, vapor phase inhibitors such as ammonia are being used.

And, internal casing corrosion can oftentimes be detected and control measures evaluated by inspection of the exterior of tubing in the well. Caliper surveys may be used to determine the extent of damage and the success of a treating program.

External casing corrosion is, however, an "animal of a different color." There just is no good way of looking down outside the pipe to check its condition. One is usually in trouble before he knows it — he has a hole in the casing and a repair job before he even realizes that he has a problem.

External casing corrosion has shown up in many areas throughout the "oil country." In some cases the corrosion takes place over several hundred ft of pipe; in other cases only a few ft may be affected. Sometimes the corrosive attack will be general; that is, the entire area of the pipe will be more or less uniformly corroded. Or many times only small areas will be attacked. In any case, however, a hole is a hole, and expensive repairs are required.

For many years, about all that could be done was to repair the damage. Several preventative measures were tried, but most had to be done when the well was drilled. However, as casing corrosion became a bigger problem, several operators experimented with cathodic protection for casing corrosion control. There have been many problems to be overcome; and, like many other subjects in which technology is relatively new, there may be disagreement among the experts about the details of application. However, where economics dictate, cathodic protection has and is being used to stop or at least slow down corrosion of that important oil field structure — oil string casing.

Downhole Equipment Corrosion

The corrosion of "downhole" or "inhole" equipment in an oil and gas well probably represents the production industry's most costly corrosion. Since there are many types of wells which produce several types of fluids at various pressures and temperature, here again there are separate although similar problems and solutions. One may have a well making fluids that are sweet or sour; a well may be flowing at several thousand lb pressure, or one may be artificially lifting by rod pump or other means; a well may be producing gas distillate or may be pumping mostly salt water with only a small percentage of oil. In all cases, however, there may be costly corrosion which can be economically prevented or at least decreased.

Inhibition and coatings are the two methods of protection which have been used most widely to protect downhole equipment. The use of alloy tubular goods has not caught on in most areas, mainly because of certain technical limitations and costs.

To briefly recap inhibition, most inhibitors used in oil production today are the so-called "organic film-forming inhibitors." There are many of these compounds which have varying properties and which are made by a wide selection of manufacturers. However, as with many of today's sciences, the last several years have seen many changes in inhibition technology, both in the chemicals themselves and in methods of application. The industry is advancing; it has been only a short time since it was the custom to "treat" continuously in most inhibitor applications (that is, a small amount of inhibitor was injected at all times). Then the industry progressed to "batch" treatments of various sizes, but still they were applied rather frequently. In introducing the "batch" there are several methods: pumps, various types lubricators, sticks, etc. But today one sees an increasing use of the inhibitor "squeeze" treatments (in which inhibitor is pumped into the formation) which may be performed several months apart and, in many cases, which are giving better protection than did previous methods of application. Of course, the "batch" treatment in which relatively small volumes of inhibitor are introduced into the well at regular intervals (daily, every other day, or weekly) has not been eliminated.

Batch treatment seems particularly applicable in rod pumping wells; and, as pumper work loads have increased and individual wells get less attention, there is a tendency toward unattended inhibitor application. Many experimental systems are being developed to automatically introduce the chemicals and flush fluids, and in many instances this "timed routine" may lead to better corrosion control than was practical under old methods of applications.

When discussing inhibitor selections, there are many variables which should be considered. Most can be pretty well grouped into three categories: (1) materials in the system (2) materials added to the system and (3) mechanics of application of the inhibitor. These categories have often been considered as separate items, but to fit today's economics they need to be considered as interrelated variables.

1. Materials in the system. These of course, are the produced fluids oil, gas and water, but the group should also include the pipe or vessel, or material to be protected. Here one has the corrodant and the corroded part. The difference in fluids have long been recognized, but only as some of the new high pressure, high temperature situations have been developing have the effects of an inhibitor on different steels and alloys been considered.
2. Materials added to the system. Inhibitor selection has always been of concern, but it has become much more important in recent years as such processes as displacement and squeeze have made "film-persistancy" or "film life" very important.
3. Mechanics of inhibitor application. Here one must consider not only how is the chemical applied, (batch, squeeze, continuous) and what carrier or flush fluid is used (diesel oil, water crude, etc.), but one must also consider the inplace mechanics; that is, from what fluid is the inhibitor filming (it may not be the same as the carrier) and what effects do inhole hydraulics have on the application? Is one getting the inhibitor where he thinks he is when he thinks he is? Is the inhibited fluid exposed to the steel sufficiently long to allow proper filming? What are the effects of temperature, and pressure at the new deep depths?

When selecting inhibitors to use, all these items must be taken into account, since the relationships of each to the others is important. For instance, just because an inhibitor was effective in a particular well when it was used for batch treatment does not mean that this is the best material to use for a squeeze treatment, etc. One must therefore use all tools at his disposal for inhibitor selection. Many new inhibitors tests are constantly being developed, and one hears much about laboratory procedures.

The so-called "wheel test" in which coupons are rotated in bottles of produced fluids containing various inhibitors under various temperature conditions is used to check inhibitor effectiveness or film life for a given project. If one is ever asked to provide samples for such tests, he should remember that the fluids used in this work should be as fresh as possible for many fluids "age" and "weather" and change their properties even in closed containers. Also, delays in handling and shipping of samples can often affect results.

The importance of these laboratory evaluations has increased tremendously in the last few years. When the "daily batch" or at least frequent batch treaments were used, most manufacturers had one or more inhibitor formulations which would do a good job. Since inhibitor was added frequently in such cases, the film persistancy was of secondary importance. However, now that treating frequencies are measured in months instead of days, with inhibitor squeezes and tubing displacements, film persistancy becomes a controlling factor in inhibitor selection. One, therefore, relies more and more on laboratory data to help him select inhibitors. The author will grant that a) lab testing cannot approach field testing, b) that lab tests do not equal field conditions, c) that variations in lab technique can cause variations in test results, d) that as many manufacturers will say, "Tell me what test you're using, and I'll send you an inhibitor to pass it," e) and that one may occasionally miss a good inhibitor because of test procedures. However, these tests are the current guides. So one must use them . . . but they must be used cautiously. They could direct one to a chemical or to an application variation that would extend the treating frequency from three months to six months. Then corrosion control cost is cut in half.

Obviously, there are many variations to these approaches. But to sum up, one can say that a successful inhibition program is the result of careful selection of the proper chemical, chosen to combat, by using the most practical mechanical application, the corrosion in the environment. A successful inhibition program is by definition the one which achieves the maximum dollar savings per inhibition dollar spent.

Oftentimes, one finds that the most economical control is a combination of effects. This fact has proved quite true in rod pumping corrosion control. For example, in several fields, "mixed" string rod tests have been run to determine what sucker rod "grade" (or type steel) is best suited for the application. The results of these tests run over a period of years have usually indicated that the cheaper carbon-manganese steel rods ("standard" mild steel rods) with chemical inhibition have been equal to or better than the most expensive alloy rods with inhibition. The alloy rods may have shown a better service life than did the carbon-manganese rod before inhibition, but they too were failing without inhibitor protection. These events are apparently tied in with the properties of the various steels; that is, a high alloy steel may be more resistant to corrosive attack, but it is more subject to cracking than is a softer, cheaper steel. Thus, since no inhibitor is perfect and since pinhole attack may occur even with inhibition, the high alloy rod cracks and fails with pinhole pitting while the cheaper rod does not. So one has an example of economically combatting corrosion by the use of inhibitors and selection of materials.

It is this same "cracking" tendency of alloys that has given hard, brittle high alloy steels a bad reputation in many high pressure services (especially where hydrogen sulfide is present).

The tendency today for tubular goods for high pressure wells seems to be the selection of the "softest" grade of steel that will meet the strength requirements, and then the protection of this steel with a coating of plactic or inhibitors, or both. In critical applications, such as offshore, many companies are coating their tubing and are then chemically treating for insurance and to control holidays, etc., just as pipeliners coat, wrap, and insulate, then apply cathodic protection.

As has been indicated, the use of coated tubing has found application in many cases in high pressure oil and gas wells. However, because the "wearing" action of the rods on the tubing which tends to remove the coating, it is not, of course, particularly applicable for corrosion control in rod pumping installations.

In other forms of artificial lift, such as hydraulic pumping, inhibitors introduced into the power oil stream have proved very effective.

In gas lift production several methods of corrosion protection have been used. When the corrosion problem has been in the annular space — that is, the attack has been on the interior of the casing and/or the exterior of the tubing — the removal of water from the gas by dehydration has proved effective. Although there have been some installations where inhibitors have been "atomized" into the gas stream in cases where corrosion has been severe, the most successful method of combatting tubing interior corrosion in gas lift wells, has been the inhibitor squeeze.

Although, as I mentioned, the corrosion of tubing and inhole pumping equipment has been the most costly to oil production, it is also the problem that was first recognized and has been most often successfully controlled.

Surface Lines (Flowline Corrosion)

In following the order of discussing corrosion from the reservoir to the pipeline, the author is now on "top" of the ground. Here one has the surface lines or flowlines. Since in most cases in oil production one deals with short lines of small diameter, "repair and replacement" are the "normal" procedure of corrosion control. In many cases, however, severe flowline corrosion has been seen, and the pipeline techniques of coating and/or cathodic protection are used. Further, in some cases where long life or pressures are involved, the flowlines may be coated and insulated when installed with provisions for cathodic protection when and if it is required.

Separation Equipment Corrosion

After the fluids leave the flowline they may be processed through a variety of types of separation equipment. The type equipment used largely depends on the fluids being handled. In most oil field applications corrosion is usually found in water handling equipment — gunbarrels, heater-treaters, and free water knockouts — in which the oil and water are separated. In the case of separation tanks or gunbarrels, the use of wooden vessels is very common in corrosive areas. But when metal equipment must be used and where corrosion has presented a problem, coatings and cathodic protection seem to be the most economical answer. And in vessels or portions of vessels in which primarily oil field salt water is handled, cathodic protection has been successful. Both magnesium anode systems and rectifier systems are used.

Within the last five years there has been an upturn in the use of cathodic protection in the free water and firetube sections of heater-treaters. In fact, in the East Texas Field numerous cases have been reported and the most successful applications have been rectifier systems. Of course, installations vary from operator to operator; however, most installations are designed with 3-5 graphite anodes with the circuits designed to impress 10 milliamps per sq ft, and, depending upon the type of rectifier purchased and the details of installation, the cost of installing these units varies from $250 to $500 per treater, and for more than five years, some operators have been using "mail-order house" battery chargers as their rectifiers at an initial cost of less than $30 per charger.

Here again in the evaluation of whether or not to apply cathodic protection to a treater, many factors must be considered. On the one hand, the payout might be the elimination of repair costs; on the other, the tendency might be to install protection at "day one" when the treater is new, so that when the lease is abandoned the treater would be "like new." The importance of such factors will vary with each company and with their consideration of their economics.

Tankage Corrosion

After the oil has been separated, it, of course, goes to tankage to be stored for the "pipelines." Field tank corrosion can be very costly in some areas, i.e., sour gas areas are historically rough on tankage. In many such areas one sees wooden tankage used throughout a field, while, in other areas for the protection of metal tankage, coatings have been the usual answer with cathodic protection applied in some instances.

There are two main areas of internal attack in lease tankage — the underside of the deck (or roof) and the bottom of the tank and a few in. up the sides at the bottom.

Deck corrosion is caused when the condensation of moisture from the gases dissolves acid gases (hydrogen sulfide and carbon dioxide) and oxygen, and, thus, set up corrosion cells. The coating of the vapor space has proved very effective in combatting this attack, and in some areas aluminum decks have been used to prevent deck corrosion.

The corrosion at the bottom of the tanks is usually caused when bottom sediments and water collect in various spots on the bottom and set up corrosion concentration cells. In the bottom area coatings have been used to protect the steel from corrosion, while some operators (as well as some "pipeliners") have also used cathodic protection to protect these areas. In these cases they maintain, in the bottom of the tank, a few in. of salt water to provide a continuous path for current flow.

Quite frequently an entire tank is not coated; rather, the vapor space, the bottom, and up about 18 in. on the sides will be coated since these are the "problem areas."

At this point two items should be reviewed:

1. The application of the coating is a large part of the story. In other words, an inferior material properly applied can out-perform the very best material improperly applied. Surface preparation is of utmost importance, especially when coating "used" equipment. Whenever possible, the author likes to specify a "white metal" sand blast. Of course, one cannot always afford or get it, but it is a goal for which to strive.

2. One must know his coating contractor and whenever possible have on the job a trained inspector who will be able to tell just what happened and when and why it occured and will it tend to keep the contractor "on the ball." Most contractors are reliable, honorable people, but they are people; Besides most of them like to have a company man around to approve their work; and after all, inspectors have been traditionally used on pipeline work.

As an example of proper application, inspection and follow through, the author of this paper recently had to rebuild a tank that had been internally coated with a coal-tar-epoxy coating. The author had an opportunity to inspect the sheets that had been cut out of the tank, and, except in areas that had actually burned, the coating was not damaged and could not easily be chipped off. Even where the plates were cut with the cutting torch, the coating was missing only in the area of the cut; 3/8 in. away, a knife could not chip the coating. Granted that the system was not designed for this "service," but the incident really illustrated the tenacity of today's coatings properly applied under proper supervision.

When discussing coatings one often becomes confused about coating life and success of coating jobs. One man may be overheard to say, "Yes, we've used brand 'X' and it failed in two years;" but, someone else says, "Why, we've had that material in service for five years without a failure." What is the difference? Is it because of type of service or area or application? It might be any of these. But one can also hear the same talk about a coating in the same type of service, same area, etc. It may then be a matter of definition. Often times when compiling data, people have trouble agreeing on "what is meant by coating failure." One will, thus, find the difference due to points of view. When a "coating fails" and when a "coating is a failure" can be two different situations. From the point of a coating expert, a coating fails when it first starts to break down, or when the first pinhole breaks through. From a practical "oil patch" point of view, however, a "coating is a failure" when it does not do what it was designed to do. That is, if a coating system was applied to make a tank last ten years and if the tank lasts past the ten years, it may not matter that there are cracks and pinholes in the coating; from the user's standpoint, it is a success. All the foregoing means is that, as in many other areas, when discussing coating one must be sure that he is always using the words in the same connotation as do others in the same discussion.

Auxiliary Equipment Corrosion

Now that the oil is at the point where it is ready to be turned over to the pipeline, one should take a moment to look around. There are many types of equipment used in oil and gas production which are, one might say, "auxiliary" to the areas that have been discussed. For example, there are salt water disposal and water flood equipment which are major categories in themselves. Or there are many transfer pumps, circulation pumps, and compressors with their problems, while many places find heat exchangers (both for heating and cooling) which have corrosion problems. And there are many others, any of which could have papers all their own. However, there are a few items that might be of interest:

1. In salt water service: Resistant materials (plastics, cement - asbestos pipe, etc.), various coatings and linings and cathodic protection are commonly used to prevent corrosion.
2. In valves, controls, and pumps: Alloys, non ferrous metals (such as brass), ceramics, and plastics for linings and parts are very common. Coatings are often used in centrifugal pumps.
3. In "air free" (closed) heating and cooling water systems: Common soluble oil "radiator" inhibitors (such as one uses in his car) have proved very effective.
4. On the glycol side of glycol dehydrators: pH control (that is in effect neutralization and/or buffering of acids) is proving effective.
5. In both flowline and salt water service: Plastic pipe is becoming more common. As the properties of plastic pipe and fittings have improved, and as the cost has been decreased, it has become more and more competitive with steel in many applications.
6. In many water flood disposal systems: Recently the new so-called "light weight" pipe is appearing. The pipe is being internally coated (plastic or cement) and externally coated or taped for complete corrosion protection. This pipe may be welded, or "rolled groove" couplings or the newer "bell and spigot adhesive" coupling methods may be used for joining the pipe to give a continuous corrosion resistant surface.

Thus is completed a trip through the oil patch and a discussion of some of the ways by which one can apply patches to the holes in his pockets. Many things have been left unsaid, and many others have been hinted at; but all can benefit from this paper if it is remembered that (1) corrosion is a costly item which can be economically controlled by proper application of corrosion control techniques, and (2) corrosion control is a team effort with the men in the field, the corrosion engineer, and management all working together to get the greatest return from their company's dollar.

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