Corrosion of Oil and Gas Production Equipment

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INTRODUCTION

We in the "Oil Patch" are becoming more and more profit conscious -- we have to -- to survive. You will note I said more "profit" conscious; not more "cost" conscious. While both are important, there is an important difference. "Profit conscious" implies an awareness of the profit that is to be derived from a venture. "Cost conscious" implies an awareness of the cost of something and, by common usage, may even imply cost reduction and so-called "economy drives." We must be careful not to confuse cost cutting with profit improvement or false economies may be the result.

How is this related to corrosion and corrosion control? The economics of a corrosion problem are the controlling factors in most corrosion control work. Some use the term "corrosion cost control" rather than "corrosion mitigation." In any case, we must look at the overall picture and our goal should not be just reducing the cost of an item but should be increasing the profit from a project.

The details of accomplishing this goal will vary from company to company, depending on their own particular financial structure. Each company looks at its dollars a little differently and has a different approach to getting the maximum leverage from its dollars. These thoughts should be kept in mind as we discuss corrosion problems and corrosion control techniques.

This paper is a resume of internal corrosion and its control in the petroleum producing industry. It includes: (1) a brief review of some of the causes of corrosion and discusses some of the basics of corrosion control, (2) various types of equipment problems and their solutions, (3) corrosion problems in water systems, and (4) the importance of economics. We won't go into a lot of detail on any specific phase. For those who may want to dig a little deeper, however, a list of additional reading is included at the close of the paper.

DEFINITIONS

What is corrosion? Why does corrosion occur? How can we control corrosion?

What is Corrosion?

The widely-accepted definition sponsored by the Electrochemical Society of New York states: "Corrosion is the destruction of a metal by a chemical or electrochemical reaction with its environment." Corrosion is destruction. Why does it occur? Actually, corrosion is a process of nature. The metal is trying to return to its lowest level of energy. In the case of iron and steel, the lowest level of energy is iron ore: Iron Oxide -- Rust.

How Can We Control Corrosion?

We can't stop the natural process; we just slow it down; we control it. One corrosion expert says that when we spend money on corrosion control, we're just "buying time." And really, that is what we want to do: control corrosion to extend the useful and economic life of our equipment. How? There are several approaches. We said that corrosion is an electro-chemical process. Energy is flowing as ions and electrons. Therefore, we have an electrical circuit which consists of anodes, cathodes, electrolites and metallic paths. As with any electrical circuit, we can stop the current flow by interrupting the circuit. There are 3 basic methods of corrosion control (i.e. breaking the circuit): (1) use of protective barriers; (2) use of electrical circuitry, and (3) materials selection.

CORROSION CONTROL METHODS

In oil production, we see corrosion combated by all 3 methods of control:

1. Protective barriers show up as:
   a. Pipe coatings and linings.
   b. Paints and plastic films (in tanks and vessels).
   c. Inhibitors (more or less temporary barriers).
2. Electrical circuits are represented by cathodic protection in heater treaters and tanks.
3. Material selection is illustrated by:
   a. Metallurgical selection and specification (including resistant metals).
   b. The use of plastics and other inert materials of construction.
   c. Changing the properties of the fluids involved (such as neutralization of acids or removal of hydrogen sulfide from water).

Let's discuss these items a little further. What factors do we consider when we've decided that a corrosion problem exists? Obviously, the problem and the economic stakes must first be defined. Let's assume for the moment that we've defined the problem. What do we consider is the solution?

The economic and technical aspects of the various methods must be investigated as one item. They cannot be divorced. What is the most economical approach? It may be simply repair and/or replacement with like equipment. Maybe we need alloy metals? Inhibitors? Coatings? Plastics? and maybe combinations of these. You'll have to decide for yourself based on the stakes and the profit picture of the particular project. It may be a brand new installation or it may be that you're just trying to stretch the life of existing equipment.

As we look at the various technical solutions, what should we consider as we evaluate each approach? Let's review briefly the various methods of control and expand some of the important points.

Pipe Coating and Linings

There's a wide choice of internal pipe coatings and linings and the field is expanding. We have plastic coatings: both baked-on and air dry -- as thin films (5 to 10 mils thick) and thick films (15 to 25 mils thick). Cement linings have found wide acceptance in water handling applications. There are many hundreds of miles of coated and lined pipe in use today. They come in many formulations by a number of applicators. This brings up a point that is extremely important: know your applicator. In pipe coating as well as painting proper application is more than half the battle. An excellent coating material will fail with improper application and a poor material can give fair service when properly applied. The reputable manufacturers know the limits of their products -- consult with them. Draw up specifications to meet your needs and inspect to see that you get what you are paying for. Don't exceed temperature or service ratings on these plastic films. Handle the coated or lined materials carefully. Why buy plastic coatings or cement and plastic linings if you or your contractor's crews are going to mishandle the pipe?

Paints and Plastic Coatings

Paints and coatings for internal service in tanks and vessels fall in this same category as pipe coatings. Use the same intelligence in selection, specification, inspection and handling on these items. This brings up an important point: When discussing coatings we often get confused about coating life and success of coating jobs. One may be overheard to say, "Yes, we've used brand 'X' and it failed in 2 years;" but, someone else says, "Why, we've had that material in service for 5 years without a failure." What's the difference? Type of service? Area? Application? It might be any of these. You 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, when compiling data, people have trouble agreeing on what is meant by "coating failure". I believe you'll find the difference due to points of view -- a coating "fails" and a coating is a "failure" can be 2 different things. From the point of view of a coating expert, a coating fails when it first starts to break down or when the first pinhole breaks through. From a practical point of view, however, a coating is a "failure" when it doesn't do what it was designed to do. That is, if a coating system were applied to make a tank last 10 years and the tank lasts over 10 years, it may not matter that there are cracks and pinholes in the coating. From the user's standpoint, it is a success. My main point is to remind you that, as in many other things, when discussing coating be sure you are using the same meaning when using the same words.

Inhibitors

We said inhibitors are more or less temporary barriers or coatings. When we talk about coatings, we think of coating the metal to protect it from the fluid. Usually, however, when we talk about inhibitors, we talk about treating the fluids. This is not altogether correct and can be misleading. We are using the fluid as a means of applying the inhibitor film on the metal. The fluids are our carriers, our applicators, our paint brushes, as it were. But really, our aim is to get a coating of inhibitor on the metal. We don't have time to go into the many theories of "How do inhibitors work?" so let's assume they will work.

When designing an inhibition program, there are many variables which should be considered. Most can be grouped into 3 categories: (1) materials in the system, (2) materials added to the system, and (3) mechanics of application of the inhibitor. Unfortunately, these items are often considered as separate items, but to fit today's economics they need to be considered as interrelated variables. Let's look at each group:

Materials in the System. - These, of course, are our fluids: oil, gas, and water. Also, we should include the pipe or vessel; that is, the materials to be protected. Here we have the corrodants and the corroded parts. We have long recognized the differences in fluids, but only as we are getting into some of the new high pressure, high temperature situations have we considered the effects of an inhibitor on different steels and alloys. As we become more involved with water system corrosion, we're finding that the fluids involved may not be the same throughout the system.

Materials Added to the System. - Inhibitor selection has always been of concern. In recent years selection has become more important as such processes as displacement, squeeze, extended batches, etc. have made "film persistency" or "film life" very important. Again, with the upsurge of water injection systems with their corrosion problems we must consider the "Big Picture." What will the inhibitor do to the formation? What effect does inhibitor carry-over from produced water have on our injection? We haven't improved our profit picture if we stop corrosion but introduce other costly problems.

Mechanics of Inhibitor Application - Here we must consider not only how the chemical is applied (batch, squeeze, continuous) and what carrier or flush fluid is used (diesel oil, water, crude, etc.); but we must also consider the inplace mechanics: that is, from what fluid is the inhibitor filming (it may not be the same as the carrier)? What effects do system hydraulics have on the application? Are we getting the inhibitor where we think we are when we think we are? Is the inhibited fluid exposed to the steel long enough to allow proper filming? What are the effects of temperature and pressure at the new deeper depths? Are deposits preventing the inhibitor from reaching the metal surface? I'm becoming more convinced as time goes on that many so-called "inhibitor failures" are really "mechanical failures" and the inhibitor that was used, in the way it was used, just didn't get to the metal to build its film.

When selecting inhibitors for a specific application, all these items must be taken into account, since the relationships of each to the other is extremely important. Folks often wonder why we don't have more "pat answers" to inhibition problems. For those who have been in this field 15 years or less, inhibitors are just part of the oil patch like rods, tubing, electric logs, etc. Actually, the entire science of inhibition as we know it today is only about 15 years old. The first organic inhibitors were used in the late 1940's. We've come a long way since then and we still have a long way to go. We know from experience some things work; now we need to find out more about why and how they work so we can improve the success of our inhibition programs.

Let's sum this up by defining a successful inhibitor program as the one which achieves the maximum dollar savings per inhibition dollar spent. The inhibition dollar includes the cost of chemicals, equipment and labor required for the inhibitor program. The successful inhibition program is achieved as the result of careful selection of the proper chemical, to combat the corrosion in the environment, using the most practical mechanical application.

Electrical Circuit Control

In production operations, electrical control usually involves either cathodic protection or electrical isolation. Cathodic protection has proved very successful for heater treaters and water handling vessels. Basically, this involves impressing an electrical current onto the structure, which overcomes the "corrosion potential." The external current may be the result of galvanic action; for example, magnesium anodes coupled to steel for protection of the steel. Another source of protecting current could be a rectifier.

Cathodic protection is one of the best-documented forms of corrosion control. It has long been applied to the exterior of structures. Sir Humphrey Davy cathodically protected His Majesty's Ships in the early 1800's. Pipeliners have been using cathodic protection for many years. As with all forms of corrosion control, the design of cathodic protection systems is very important. Over-protection, changing conditions, improper maintenance due to design problems all contribute to problems and failures and must be considered when developing a cathodic protection system.

Electrical isolation is important in "breaking the circuit" between 2 structures and can often pay for its use many times over. The most common circuit interrupters are insulated flanges and insulated unions. These insulators have been used by many to isolate flowlines from well casing and vessels. They are also used to separate dissimilar metals, such as the isolation of bronze or brass meters from steel lines and fittings, and more recently, the isolation of bronze water injection wellhead assemblies from steel tubing.

Metallurgy

As we said when discussing inhibitors, you just can't talk about corrosion without considering the materials being corroded. Metallurgy is extremely important because it involves the properties of these materials. As we've mentioned, iron and steel are trying to return to their lowest levels of energy. What can we do to slow down this process? How can we design our material to best fit the environment? Do we need alloys? Should we change to non-ferrous metals? In reality, all these things are done. You should put as much effort into metal selection as you put into other corrosion control considerations.

Hydrogen sulfide has been one of our main causes of headaches; not only from the removal of metal standpoint but also, and perhaps more importantly, from the standpoint of cracking and embrittlement. We don't have time to delve deeply into this so let's just hit the high spots. High strength steels have an inherent tendency to crack. Hydrogen and hydrogen sulfide aggravate this tendency. Alloying elements which tend to make the steel more corrosion resistant may also increase the susceptibility to cracking. Hardness of the metal is a rough guide to the cracking tendency. The harder the material, the more likely it is to crack under given conditions. From the practical standpoint, the industry has generally gone to as soft a steel as strength requirements allow and then controlled the metal loss with inhibitors and coatings.

The uniformity of the steel is another important metallurgical consideration. Most oil country tubular goods are now fully normalized, i. e. heat treated after manufacture to assure a uniform metallurgical structure throughout the tube. We still occasionally see the so called "ring worm" corrosion near the upset where the pipe was not properly treated after upsetting. The use of "thin walled" pipe for surface lines has brought up similar problems. This pipe is manufactured by rolling a sheet of metal into a tube and welding the edges together. If the weld seam is not normalized, the weld area becomes very susceptible to corrosive attack. The welding process causes changes in the metallurgical structure. Although the chemical composition of the metal is unchanged, the differences in the crystal structure in different areas cause the same corrosion current flow we see with dissimilar metals.

The use of dissimilar metals can present many problems in some of our equipment. Each metal and each alloy of each metal have a different electrochemical potential. When metals with unlike potentials are coupled together in the proper environment, electrical current flows; corrosion takes place, metal is lost. We do this on purpose when we couple magnesium to steel and sacrifice the magnesium to protect the steel. Yet we don't want to sacrifice one pump part to protect another.

Plastics

Oil field plastic materials have certainly been in the news the last few years. We see salesmen with new materials every day. As a group, the plastics look very promising. While their use in the field is still somewhat limited, these limits are being raised every year.

Plastics, as they appear in oil country tubular goods, can generally be divided into 2 categories: thermo-plastic and thermo-setting. The thermo-plastics soften and can be shaped or re-formed at temperatures above their softening point. In manufacturing, these plastics are melted and extruded through dies to make the pipe. The properties of the resultant pipe are as dependent on the extrusion as on the resin (or plastic) used. Again -- know your extruder. All PVC (poly vinyl chloride) pipe isn't the same; or all ABS (Acrylonitrile Butadiene Styrene); or all polyethylene, etc. The temperature and pressure limits of these materials are very important as is the chemical resistance of some of the newer materials. Check your supplier and make sure the pipe you are considering has been sufficiently tested and used in your environments. At least one material on today's market is highly susceptible to damage from mineral acids. In other words, don't try to acidize through this pipe -- at least, not very often.

The thermo-setting plastics require heat to set the plastic. The heat used in manufacturing may be from external sources such as ovens, or it may be from the heat of reaction as the components polymerize. The setting of these plastics is irreversible, reheating will not soften the plastic. Too much heat will simply destroy the material. The thermosetting resins used in plastic pipe are usually used for glass reinforced pipe. The glass fibers act as reinforcement to give the physical properties to the pipe. Generally speaking, the reinforced pipe is stronger, more temperature-resistant and has higher pressure ratings than the extruded thermo-plastics. The reinforced pipe is also more expensive.

Probably the biggest problem facing the plastic pipe industry is the establishment of the limits for their use. Unfortunately, the properties of plastics change with time. We've been used to testing metals on a short term basis. However, this procedure doesn't apply to plastics. The ratings of these materials must, therefore, include allowances for aging. The industry has come a long way and most reputable manufacturers, although realists in their ratings, cannot judge the life expectancy for your environment. So don't let an over-eager salesman talk you into over-rating his product for your use unless you can assign a realistic risk. By the same token, make sure that you have given your supplier the complete store of your application. Don't overlook such things as temperature or pressure fluctuations, peak capacities (not average flow) etc. In other words, work together and engineer the application.

Plastics have their place and can be used to improve your profit picture when the installation is properly designed, installed and used within the limits of the material.

Another inert material quite common in low pressure water gathering and distribution systems is cement asbestos pipe. Don't overlook this material just because it has been around a long time.

Fluid Properties Control

We've just about exhausted the methods of control that we listed a while back except the item of changing the properties of the fluids involved in our system: i.e. changing the corrodant. While this hasn't been too common in most producing applications, it is becoming more common in some auxiliary operations. We see pH control in some water injection systems, and in cooling towers and other "plant" type equipment. pH control is also used in glycol dehydrators where the glycol reboiler systems have given problems.

Acid gases are sometimes removed from injection waters. Originally, air was used to degasify the water but in most of our applications, the oxygen from the air created more problems than the acid gases. Several installations of inert gas scrubbers to remove acid gases have been reported in West Texas. Oxygen can also be removed by scrubbing with inert or natural gas. Oxygen is becoming a more apparent problem as the number of water injection systems increases. Sodium sulfite and some other chemicals can be used to scavenge oxygen from water. Of course, usually the most practical way to avoid trouble from oxygen is to keep it out. But that is easier said than done.

When the fluid is primarily gas, we can often dehydrate it to remove water vapors.

We haven't talked about one source of trouble that from time to time gets lots of publicity: bacteria. When hydrogen sulfide generated by bacteria creates corrosion problems in an otherwise sweet system, bactericides have proved very effective. Many of our waters are already sour and unless the bacteria cause well plugging problems, it is often more economical just to live with them. As with everything else we've said, it is hard to generalize about the effects of bacteria. You've got to look at your own project, its problems and your company's economics.

EQUIPMENT PROBLEMS

We have talked in general about corrosion problems and the methods of corrosion control. Let's talk about specific examples of what can happen to various items of equipment. We'll begin in the hole and work from there, as we review some of the problems and corrosion control applications.

Internal Casing Corrosion (casing-tubing annulus)

Unpackered wells - Corrosion problems are due to well fluids below the fluid level and to corrosive gases in the vapor space above.

1. Fluid corrosion may be controlled by "standard" inhibitors flushed down the annulus. Atlantic has done this successfully in some N. E. Texas rod pumping wells for the last 10 years.
2. Vapor space corrosion has caused problems in many sour areas. Moisture from the gas condenses on the casing walls. Acid gases dissolve in the water drops and set up corrosion cells. Vapor phase corrosion controls have included: Ammonia injection to neutralize the acids; vapor phase amines to neutralize and film; and inhibited oil flushes to provide an inhibited oil film.

Packered wells - Corrosion problems occur with muds and with synthetic brines used as packer fluids. The present attempts at solution include redesign of fluid systems and/or use of inhibitors. Our present knowledge may be far from adequate as the inhole conditions of temperature and pressure become more severe.

Monitoring -- Caliper surveys are about the only way to evaluate the extent of corrosion and the success of remedial measures. The ultimate evaluation, of course, is the elimination of casing leaks caused by internal corrosion.

Tubing and Downhole Equipment Corrosion

Although the corrosion of subsurface equipment probably represents our industry's most costly corrosion, the problem was one of the first recognized. Much of our past effort has been aimed at the control of producing well problems.

Gas Condensate Wells -- In general, the highest pressure producing wells are gas condensate wells. Here the corrosion problem is often severe. Failures can be extremely hazardous and costly.

1. Coatings are often used. The baked-on coatings are the most widely used because they usually have higher temperature tolerance and greater chemical resistance than air dried coatings.
2. Inhibitors are applied in several ways.
   a. Stick inhibitors are still used profitably for some applications; however, the need of frequent treatment and mechanical problems have limited their use in recent years.
   b. Small batches of liquid inhibitors may be lubricated into the tubing several ways. The well is then shut in to allow the liquid to fall to bottom.
   c. Large batches of inhibitor in a carrier fluid are often pumped into the well. The batch may be large enough to fill the entire tubing as in the "tubing displacement" or only part of the tubing as in the "yo-yo" or "multiple-pass." The filming time is increased in the latter methods by repeating a cycle of: shut in (inhibited mix to bottom); flow (mix to wellhead), shut in, etc.
   d. The "inhibitor squeeze" was developed a few years ago. A high concentration of inhibitor in a carrier liquid is pumped into the formation. The main advantage has been lower over-all treating costs due to infrequent treatments (3 to 12 months between treatments). In many cases, the squeeze has provided more effective inhibition than other methods. The first squeeze on a well may be short-lived because it has to "clean up" the equipment. Never evaluate the program on less than 2 squeezes.
3. High strength and alloy tubing is used only occasionally because of cracking problems. Particularly where hydrogen sulfide is involved (even in trace quantities). Alloy tubing has actually cracked and failed while being run.

Flowing Oil Wells - Generally, flowing oil wells have given less trouble than other producing wells. This is probably due to the crude's ability to wet the steel and to natural inhibitors in the crude. Usually corrosion starts as water production increases and by then, the well is being artificially lifted. Where flowing wells have presented problems, corrosion is combated by coatings and/or inhibitors.

Artificial Lift Wells

1. Gas Lift -- Corrosion problems may be caused by lift gas or by produced fluids.
   a. When lift gas is corrosive: inhibitors may be atomized into the gas and/or the gas may be dehydrated (dehydration was very effective in controlling severe corrosion in an East Texas lift gas which contained about 2% carbon dioxide, 1 to 2% oxygen and traces of H_2S.)
   b. When produced fluids are corrosive, a combination of protection may be used. Gas lift valves may be made of resistant metals. Tubing may be coated. Inhibitors may be used. The inhibitor squeeze has been reported to be very successful.
2. Hydraulic Pumping -- Often, corrosive fluids are involved. Inhibitors in the power oil are used to reduce inhole troubles.
3. Rod Pumping -- Corrosion in rod pumping wells may show up in the pump, the rod string, the tubing or all three.
   a. Pump corrosion can often be traced to dissimilar metals. Unfortunately, all pump manufacturers and all pump repair shops do not worry about matching materials for maximum corrosion resistance. We've all seen plunger or pull rod sections severely attacked when adjacent parts were in excellent condition. One part was being sacrificed to protect the other. Material selection is important. Inhibition has allowed the selection of cheaper materials in some areas.
   b. Rod failures are most economically controlled by a combination of effects. The use of carbon manganese rods (standard mild steel rods) with inhibition has proved more profitable than the use of alloy rods. As we discussed, the alloy steel may be more resistant to metal loss, but it is more subject to cracking than the softer, cheaper steel. No inhibitor film is perfect. Pinpoint attack occurs at holidays in the film. The alloy rod cracks and fails because the tiny pits act as stress raisers. The cheaper rod doesn't crack under these conditions.
   c. Tubing problems in rod pumping wells are usually associated with "rod wear." Rod wear, as generally observed, is a combination of wear and corrosion. The "wear" keeps bright areas exposed for corrosion attack. Eliminate the corrosion and you've eliminated the problem. Inhibitors have been very effective in controlling wear-corrosion.
   d. Many methods are used to apply inhibitors on rod pumping wells.
      1. Daily, weekly, or monthly batch treatments are most common and very successful. Small quantities of inhibitor are flushed down the casing-tubing annulus.
      2. Since pumper labor is not as available as it once was, companies are trying other methods of applying inhibitors. Contract treating using "treater trucks" is increasingly popular. Various methods of unattended inhibitor addition and circulation are being tried. Several approaches to try to extend the time between treatments have been used: "Circulate and park" came in a few years ago; "Extended Period Batch Treatment" (EPBT) has come out of Western Kansas recently.

Surface Piping

1. Internal flowline corrosion is generally controlled by carryover of inhibitor from the well.
2. Coatings and plastic pipe, particularly the latter, are showing up in many places. However, corrosion control is usually not the primary justification.
3. Internal inplace coating is popular in some areas. This is usually not successful for corrosion control because of problems of cleaning, surface preparation, and application. However, internal in-place coating has been used to get a few more years' life out of a severely corroded system.

Separation Equipment Corrosion

Corrosion in gas-oil separators is usually minor.

Most separation equipment corrosion occurs where oil and water are being separated; i.e., treaters, heaters, free water knockouts, gunbarrels, etc. Cathodic protection, coatings, and resistant materials are most widely used methods of control.

Cathodic Protection. - The electrification of leases throughout the industry has enabled many companies to make cathodic protection of heater treaters a common practice. Treaters should be purchased with anode connections, but anodes are installed only when and if protection is justified. Rectifier-anode systems are considered more practical than sacrificial anodes by most companies.

Coatings. - Treater emulsion sections are often coated. Varying success has been reported for coated fire tubes. Epoxy-fiberglass patches and linings have become common in many areas to repair and extend the life of corroded vessels.

Resistant Materials. - Wooden gunbarrels are still a common sight in many sour areas.

Tankage Corrosion

Corrosion of lease tanks has not been severe in many areas; however, in many others it has been quite severe. As we centralize facilities and utilize LACT units, we no longer have "lease storage" but have "surge tanks." We don't have the storage capacity or the number of tanks we once had. Tank failures due to corrosion may cost us several days' production as well as expensive repairs. Most problems occur on the underside of the deck where moisture collects and/or on the bottom and bottom few inches of the sides where BS&W collect. Corrosion control efforts have included: resistant materials, coatings and cathodic protection.

Resistant Materials

a. Wooden tanks are found in many sour areas; however, in general they are more expensive than externally coated steel. Since vapor recovery become an important item in our profit improvement programs, tanks are acting as low pressure vessels and metal tanks are preferred.
b. Aluminum top rings and decks are used by some operators in sour areas.

Coatings. - Probably the most widely used method of protecting tankage. Oftentimes only the problem areas are coated. It is extremely difficult to get a good coating job on bolted tanks, so most coated tanks are welded.

Cathodic Protection. - Magnesium anodes have been used in a few instances to protect tank bottoms. In such case, a few inches of water must be maintained to establish a path for current flow.

Auxiliary Equipment Corrosion

There are many other types of equipment on our lease which have corrosion problems. Time and space limitations prevent our covering such things as: transfer pumps, heat exchangers, flow-line heaters, cooling towers, compressers, meters, etc. However, the same solutions we've been discussing apply to these items. Just don't overlook them as you plan your profit improvement program.

Water System Corrosion

The one further classification I want to discuss is water handling system corrosion.

General - Waterflooding is rapidly expanding. Salt water disposal systems are becoming mandatory in most states. With this increase in water handling, we have increasing corrosion problems. Various types of equipment are involved and various waters may exist in the same system. Therefore, the problems and control methods are not necessarily the same throughout a system.

Prediction of corrosion problems and costs are difficult. There is no adequate way to technically predict time and chance factors for the over-all solution of handling the numerous waters the industry is required to handle. Current practices include: (1) Assume no corrosion -- close our eyes and go ahead, (2) Assume severe corrosion -- overdesign and "gold plate" the system, (3) try to predict, based on empirical research for the specific system (possibly, even with a pilot) and then tailor our system. The latter, though expensive technically, generally yields the highest profit.

Component Parts - To better understand the whole system we need to look at each component and some of the corrosion control methods being used in typical waterfloods.

1. Water Source
   This can be supply well water, surface waters, produced waters, or mixtures of these. The method of lift is an important variable for supply wells.
   a. Gas lift wells may have coated tubing and corrosion resistant valves. Inhibitor may be introduced into the lift gas stream. At least one operator has reported success using the inhibitor squeeze.
   b. Rod pumping wells can be handled more or less conventionally with inhibitors designed for water system use.
   c. Downhole centrifugals (both shaft driven and submerged motor) present several special problems.
      1. Pump parts are often alloys, their cases may be resistant materials or can be plastic coated.
      2. Shafts and cable sheaths may be alloy steels or alloys such as monel.
      3. Inhibitors may be added down the annulus in batches or continuously. It also is important to protect the inside of the casing from the perforations up to the pump intake. In such cases, a macaroni string is run to the perforations to serve as an inhibitor inductor pipe.
   d. The casing-tubing annulus of supply wells should be gas blanketed, if at all possible, to prevent entry of air (oxygen). As we get further into water system corrosion, it becomes apparent that dissolved oxygen plays a very important role in water system corrosion even at very low concentrations.
2. Water Gathering System
   This pipeline from source to plant is usually low pressure or gravity.
   a. Cement Asbestos pipe, a number of the plastic pipes, and plastic coated or cement lined steel are all quite common.

b. If inhibitors are used in the supply well, they can be expected to protect the gathering system.

3. Water Plant

A plant may be simply a holding tank with controls to a pump; or it may be a rather involved water treating plant with many types of equipment. Here waters are mixed and here properties may be changed. Several methods of corrosion control are used;

a. Coatings in vessels and tanks.
b. Gas blankets on vessels (to exclude oxygen).
c. Cathodic protection, both sacrificial anode and rectifier systems in tanks, filters, etc.
d. Degasification to strip hydrogen sulfide or oxygen.
e. Scavengers--to remove oxygen.

4. Injection Pumps

Pumps are usually located at the water plant, but may be at each injection well. Material selection is very important.

a. Centrifugal pumps may be internally coated. High speed, high pressure centrifugals may be made of resistant metals such as stainless steel.
b. Plunger and piston pumps for corrosive service often have aluminum bronze fluid ends, with alloy or ceramic plungers.
c. Don't depend on inhibitor carry-through to protect injection pumps. The high velocities and corrosive conditions make it highly unlikely that an inhibitor film could be maintained.

5. Water Distribution System (or injection lines). This set of pipelines may differ from the gathering system in several ways. The injection system is often high pressure; the lines are longer; the layout more complex; and the water may be a mixture or may have been treated at the plant.

a. Plastic coated and cement lined pipe is frequently used.
b. Fiberglass reinforced plastic pipe is just moving into this usage as their pressure ratings are increased. Thermoplastics are being used in low pressure systems.
c. Inhibitors can be effective, either from inhibition of the supply well on from inhibitor injected at the water plant.

6. Water Injection Wells

Injection wells have the same basic problems as the distribution system, except it may be easier to rig up to pull pipe from a well than to redo a buried injection line. Wells may be singles, conventional duals or multistring completions.

a. Coatings and linings are common for tubular goods.
b. Fiberglass plastic pipe shows some promise.
c. Alloys and special materials are used for wellheads, packers and valves.
d. Inhibition may be used. If you have a dual well, a conventional dual with inhibition may be more profitable than coated dual strings.

The "Big Picture" - Whether you're talking about a new installation or an old system; whether waterflood or salt water disposal, you need to look at the complete project, its problems and its profit picture. We've covered a lot of items and ideas and it may seem confusing and complicated. However, when you look at your specific cases you'll find a pattern and it will make sense. Look at the options -- compare your profits by using various options. Use your methods of economic analysis and an interest rate realistic with your company's fiscal experience and select your corrosion control method. Look at each project in light of its own merits. Remember that conditions, technology and economics change.

Until recently most of us considered the inhibition of large volume water systems impractical -- too costly. We felt that coatings, linings, and resistant materials were the only answer. Currently, however, we're having to change our minds. Newer materials, newer application techniques, revisions in test procedures, and the changing economic picture are demanding a revision of out thinking. In many cases when the differential economics of the project are considered, inhibitors look very promising. Don't misunderstand. Coatings, linings, plastics, etc. are here to stay. There is a place for all methods of corrosion control. Match the most profitable method to your project.

Examples - As a brief example of some of our experience, our group recently looked at 2 flood projects of about the same size (30,000--40,000 BWPD) -- one in West Texas and the other in Oklahoma. After an economic-technical analysis we recommended that: (1) The West Texas flood be installed with coatings, linings, and resistant materials throughout, and (2) the Oklahoma flood be installed essentially unprotected (bare tubular goods, provisions for cathodic protection in the vessels, and corrosion resistant trim on the injection pumps). The corrosion rate will be monitored in the Oklahoma Flood and if corrosion becomes an economic problem, inhibitors will be used for corrosion control (if the economics of that time are still favorable). We also have an extensive 30,000 BWPD flood that has been inhibited since it was installed about a year ago.

We haven't time for details, but the over-all profit picture said go one way on one system, another on the second and still another on the third. The economic balance includes the value of money, the timing for spending money, the cost of failures (with and without corrosion control), the costs of various combinations of control, and the chance factors for success of control for each option. Chance factors are an important part of your economic analysis. The tendency is to start a corrosion control program and forget it; but no corrosion control is perfect. There will be failures and repair costs regardless of what you do. Your goal is to balance the variables to achieve the most profit from the project.

Summary - To sum up water system corrosion control, all I'm saying is: Look at the "Big Picture," make sure your corrosion control system is compatible with the rest of the project and then be "profit conscious."

CONCLUSION

We said at the start that we wanted to review corrosion problems and control in the producing industry. We've recapped the basic methods of corrosion control; we've discussed some of the specific problems and solutions as applied to various items of equipment; we've discussed water system corrosion control from the standpoint of the "big picture." In summary:

1. Corrosion is an economic problem.
2. Corrosion control is a method of profit improvement.

3. The details of profit improvement will vary with the specific problem and with each company.

It follows then that team work at all levels in a company is required to prevent corrosion from gobbling up your profits. Management has its responsibilities -- engineering has its responsibilities -- the men in the field have theirs -- and they all must work as a team to achieve their goal of pofitable operation.

"Corrosion Control Takes Teamwork"

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