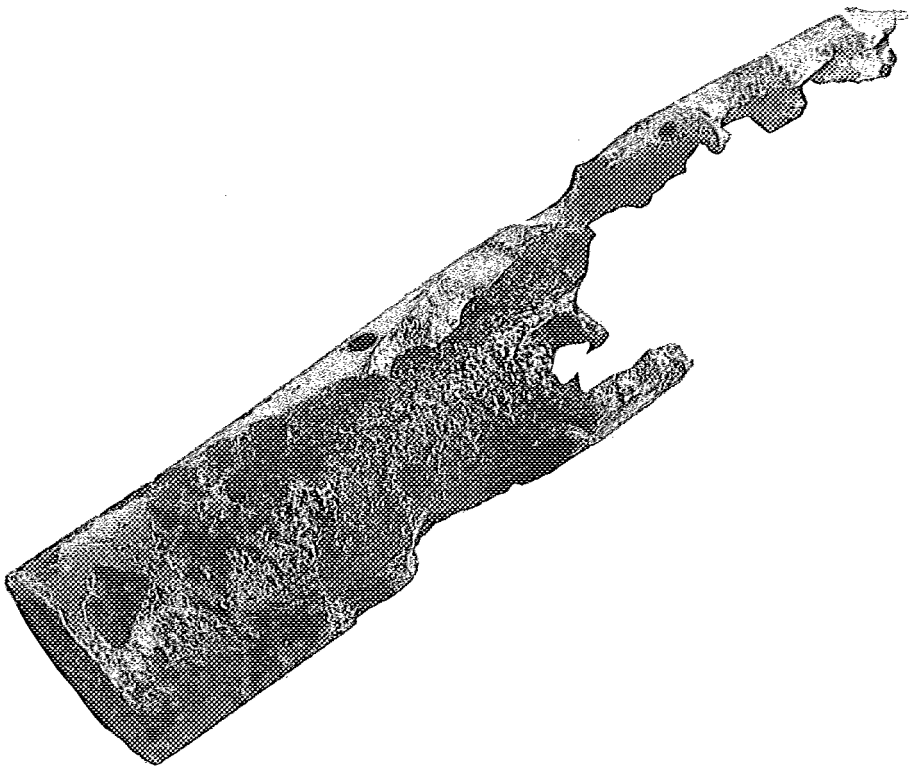
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CORROSION OF OIL- AND GAS-WELL EQUIPMENT

BOOK 2 OF THE VOCATIONAL TRAINING SERIES

SECOND EDITION, OCTOBER 1990



PRODUCTION DEPARTMENT

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Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, asbestosis, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) Health Standard for Asbestos, 29 *Code of Federal Regulations* Section 1910:1001; the U.S. Environmental Protection Agency's National Emission Standard for Hazardous Air Pollutants concerning Asbestos, 40 *Code of Federal Regulations* Sections 61.140 through 61.156; and the final rule by the U.S. Environmental Protection Agency (EPA), concerning phased banning of asbestos products, 40 CFR Part 763, published at 54 *Federal Register* 29460-29513 (July 12, 1989).

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FOREWORD

The practical value of corrosion countermeasures, no matter how perfect they may be in the theoretical or laboratory sense, depends upon certain knowledge and attitudes on the part of foremen, pumpers, well tenders, and individuals with related responsibilities. This book is directed at field operating personnel, in the hope that steady use will enhance the knowledge and attitudes mentioned, specifically:

Appreciation of the enormous cost of oilfield corrosion.

Ability to recognize early indications of corrosion.

Awareness of the importance of early reporting.

Desire to take effective part in the solution.

The book is not intended to produce technical experts. Therefore, it makes full use of the simplest possible terms and descriptions. The control measures it describes are only typical, and should not be automatically accepted as the best solution for any specific problem. The circumstances of corrosion vary widely, and technical advice should always be sought when causes are obscure, or cost or severity is high.

This second edition was prepared by an Ad Hoc Task Group with guidance and review by the API Production Department Executive Committee on Training and Development. It updates and supersedes the 1958 first edition. The first edition was developed in cooperation with the National Association of Corrosion Engineers (NACE), which later issued a separate publication: NACE TPC Publication No. 5, *Corrosion Control in Petroleum Production.* Personnel needing a more thorough understanding of corrosion technology may obtain that and other technical publications from: NACE, Box 218340, Houston, TX 77218.

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CHAPTER 1

GENERAL ASPECTS OF CORROSION

The useful life of oilfield equipment is often shortened as a result of corrosion. In the last several years great strides have been made in corrosion detection and remedies as applied to the oilfield. This book has been written to put this information in a form easy to use.

In simplified technical terms, corrosion has been defined as the destruction of a metal by either chemical or electrochemical reaction with its environment. Some general statements concerning corrosion rates can be briefly made.

1. Carbon steel will usually corrode faster than corrosion resistant alloys used in the oilfield. There are notable exceptions, such as the failure of strong alloy steels in H_2S systems.

2. The major corrodents encountered in the oilfield are carbon dioxide, hydrogen sulfide, organic acids, hydrochloric acid, and oxygen dissolved in water.

3. Films or scales at the interface between metal and corrodent influence corrosion rates. These films include corrosion products, mill scale, and corrosion inhibitors.

4. Environmental factors — such as chemical composition of water, temperature, and velocity — affect the rate of corrosion. In some cases, so-called natural inhibitors present in produced fluids greatly reduce corrosion rates.

5. Impressed voltages and stray electrical currents are often a source of serious corrosion damage.

6. Velocity of the flowing media plays an important role in erosion/corrosion. It exhibits mechanical wear effects at high velocities, particularly when the media contains solids in suspension.

Types of Corrosion

For practical considerations, corrosion in oil and gas well production can be classified into four main types, each of which will be discussed in a following chapter.

1. CO_2 corrosion is also referred to, and will be referenced in this book, as *Sweet Corrosion.* It occurs as a result of the presence of carbon dioxide. This type of corrosion occurs in both gas-condensate and oil production as well as in produced water handling systems.

2. H_2S corrosion is also referred to, and will be referenced in this book as, *Sour Corrosion.* It is designated as corrosion in oil and gas wells pro-

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ducing even trace quantities of hydrogen sulfide. These wells may also contain oxygen, carbon dioxide, or sulfate reducing bacteria.

3. *Oxygen corrosion* occurs wherever equipment is exposed to atmospheric oxygen. It occurs most frequently in offshore installations, brine handling and injection systems, and in shallow producing wells where air is allowed to enter the annular space. The presence of even trace amounts of oxygen in produced fluids containing CO_2 increases the corrosion rate by several orders of magnitude.

4. *Electrochemical corrosion* is designated as that occurring when corrosion currents can be readily measured or when corrosion can be mitigated by the application of current, such as in soil corrosion.

Economics of Corrosion Problem

The annual cost of corrosion and corrosion protection in the United States alone is estimated at approximately eight billion dollars per year. This figure was only for direct costs and no attempt was made to estimate indirect costs due to lost production, safety, and environmental factors. Furthermore, this figure did not take into consideration specific corrosion costs in oil and gas well production. Refinery and pipeline problems were the only aspects of the oil industry considered.

It has been demonstrated many times that where a costly corrosion problem is properly defined, mitigation procedures can usually be initiated with resultant savings to the industry. It should be cautioned that the establishment of a good, scientifically sound, corrosion-control program requires the expenditure of considerable effort by the corrosion expert and the field operating personnel.

We would all like to have a simple magical device which would miraculously cure all the troubles caused by corrosion, as well as every other phase of our lives. There is usually not a short-cut "cure all" treatment to prevent all corrosion problems.

Importance of Field Personnel in Corrosion-control Programs

Certain of the principles of corrosion and corrosion-control procedures have been worked out in corrosion research and engineering laboratories. However, it must be realized that the final success in the battle against corrosion rests on the shoulders of field operating personnel. Their responsibilities in this program can be briefly outlined.

1. *Recognition of the corrosion problem:* Field personnel are in the best position to recognize the onset of corrosion. They know when pulling cost and equipment maintenance costs begin to climb. They further have the opportunity to observe the condition of tubing, christmas trees, casing, pumps, etc., during routine maintenance and inspection.

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2. *Record keeping:* Many times the real costs of corrosion are not apparent without up-to-date and accurate records kept specifically for corrosion-control purposes. Certainly the costs and effectiveness of corrosion-control measures can never be ascertained without good records. These records can be kept and evaluated only by field personnel.

3. *Carrying out control procedures:* No matter how well a control system is designed, it is of no value unless it is carefully, regularly, and diligently applied to oilfield equipment.

The experienced corrosion person is always available to assist in the solution of field problems, but is usually in no position to carry out these solutions. This person can help in the selection of the most appropriate corrosion mitigation technique which may include: inhibition; metallurgy; coatings; and cathodic protection. The remainder of this book has been written as a guide to assist the field operator in: *1*, understanding the corrosion problem; *2*, evaluating the severity of the problem; and *3*, choosing and applying proper control procedures.

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CHAPTER 2

SWEET CORROSION

Until recent years, the term "sour crude" was used by production personnel to designate corrosive fluid, and the term "sweet crude" designated noncorrosive fluid. Inasmuch as many of the wells that were previously considered noncorrosive because of the absence of hydrogen sulfide have become corrosive, this distinction has lost most of its accepted meaning. Sweet corrosion, as used here, can be defined as corrosion occurring in oil or gas wells where no iron sulfide corrosion product and no odor of H_2S occurs. Some sweet wells do contain very low concentrations of sulfides.

Controlling corrosion in gas-condensate wells was one of the most pressing problems before the industry several years ago. Expensive workover jobs, damage to the reservoir, and danger to operating personnel all contributed to make this a serious problem. Chemical inhibitors, coatings, and special metal alloys have all been used to combat this problem.

Corrosion in sweet oil wells usually becomes serious after the wells have produced for some years, and is associated with high salt water production. Oil wells usually become corrosive when water production reaches 40 to 50 percent of the total fluid. It is estimated that thousands of gas lift wells will become corrosive and could cost the industry millions of dollars per year in corrosion damage.

DESCRIPTION OF DAMAGE

Chemistry of Reaction

Corrosion in gas-condensate wells is attributed to carbon dioxide and organic acids. Carbon dioxide (CO_2) is noncorrosive in the absence of liquid water. When water is present, CO_2 dissolves and forms carbonic acid.

$$\underset{\text{Carbon dioxide}}{CO_2} + \underset{\text{Water}}{H_2O} \longrightarrow \underset{\text{Carbonic acid}}{H_2CO_3}$$

This carbonic acid causes a reduction in pH of the water which makes it quite corrosive to steel.

$$\underset{\text{Iron}}{Fe} + \underset{\text{Carbonic acid}}{H_2CO_3} \longrightarrow \underset{\substack{\text{Iron carbonate} \\ \text{Corrosion product}}}{FeCO_3}$$

In addition to the acidity produced by carbon dioxide, low molecular-weight organic acids, such as acetic acid, contribute to the corrosion. These acids are seldom considered the primary cause of sweet corrosion.

In general, the preceding statements apply to both oil and gas wells.

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However, there is one minor exception. Corrosion has been experienced in some high-pressure, Louisiana Gulf Coast flowing sweet oil wells that produce very little water. This corrosion has been associated with a porous scale deposition containing both chlorides and sulfates. A photograph of typical scales responsible for this type of corrosion is shown in Figure 1. The condition of the pipe after removing the scale and the extent of pitting is shown.

Because carbon dioxide plays such a prominent role in sweet corrosion, some of the factors governing its behavior should be considered. The important factors governing the solubility of carbon dioxide are pressure, temperature, and composition of the water. Pressure increases the solubility (Fig. 2), reducing the temperature decreases the solubility (Fig. 3), and many dissolved minerals may buffer the water (prevent pH reduction). In a gas-condensate well, with almost no dissolved minerals and at relatively high temperatures, pressure is the controlling factor influencing carbon dioxide solubility. In fact, the partial pressure of carbon dioxide can be used as a yardstick to predict corrosiveness of gas-condensate wells.

The partial pressure of carbon dioxide can be determined by the formula:

$$\text{Partial pressure} = \text{total pressure} \times \text{percent carbon dioxide.}$$

For example, in a well with a *bottom-hole pressure* of 3,500 psi and gas containing 2 percent CO_2:

$$\text{Partial pressure} = 3{,}500 \times 0.02 = 70 \text{ psi at the bottom of the well.}$$

Using the partial pressure of carbon dioxide as a yardstick to predict corrosion, the following relationship has been found:

1. A partial pressure above 30 psi usually indicates a corrosive condition.
2. A partial pressure between 3 and 30 psi may indicate a corrosive condition.
3. A partial pressure below 3 psi is considered non-corrosive.

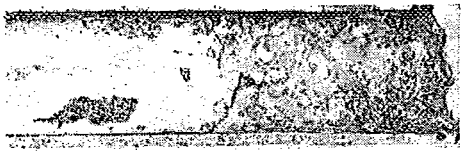
The salt water usually produced by a sweet oil well contains dissolved minerals and the foregoing relationship does not always apply. However, corrosion is most often encountered where the carbon dioxide content is high. As a first approximation, the partial pressure of carbon dioxide is useful in predicting corrosivity of sweet oil wells. In Fig. 4, the solubility of CO_2 in a typical sweet well has been calculated.

Gas-condensate Wells

Corrosion in the tubing of gas-condensate wells usually takes the form of deep pitting, as shown in Fig. 5. The tubing is attacked in sharp, well-defined pits that may penetrate the wall completely in a relatively short

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(a) Typical Scale Formation



(b) Appearance of Pipe after Removal of Scale

Fig. 1 — Tubing Corrosion from Wells with Very Low Water Content

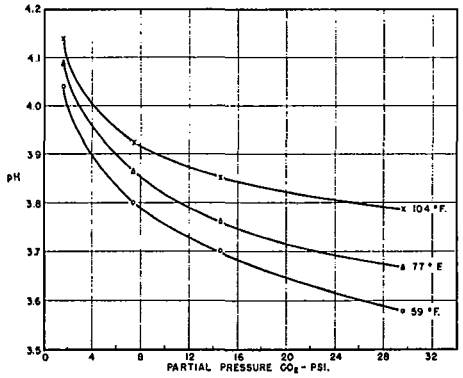


Fig. 2 — Effect of CO_2 Partial Pressure on pH of Condensate Water

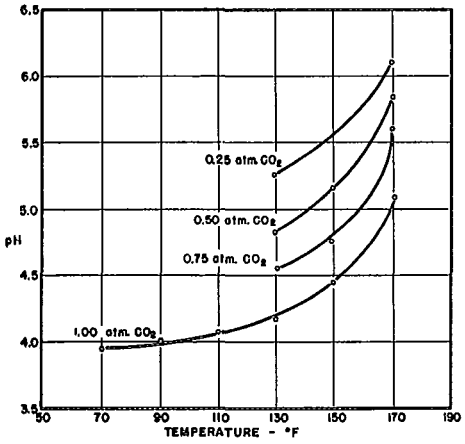


Fig. 3 — Effect of Temperature on pH

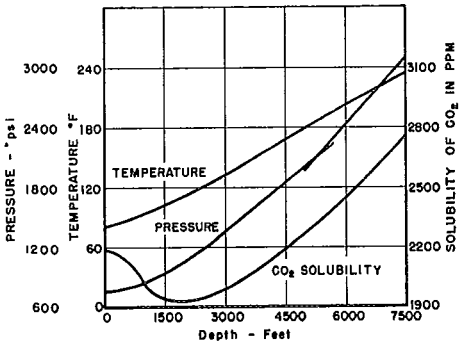


Fig. 4 — Solubility of CO_2 at Various Depths of a Typical Oil Well

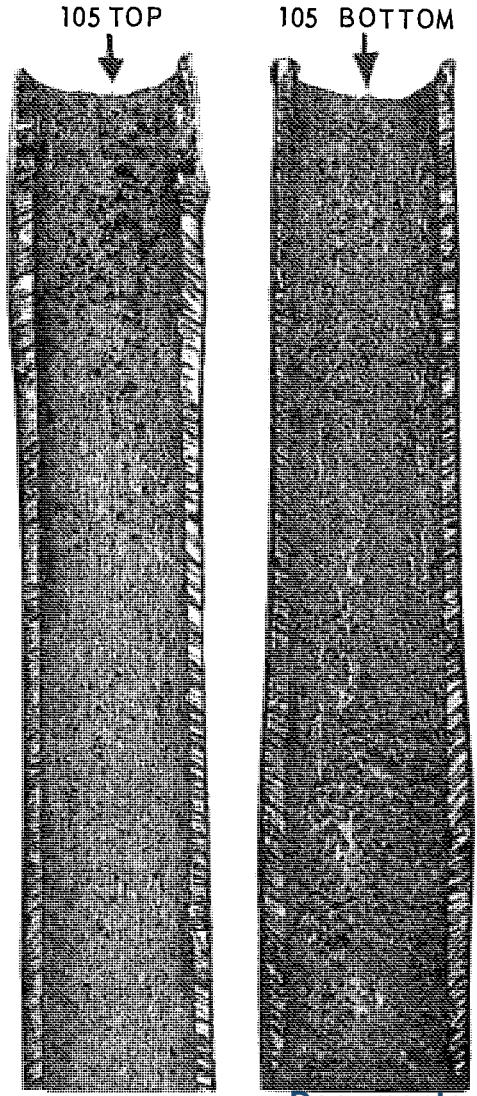


Fig. 5 — Gas-condensate Well Tubing — Severe Pitting

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period of time. This pitting is caused by acidic gases dissolved in droplets of water condensed on the tubing wall. Tubing below the point of condensation may be relatively free of corrosion damage.

Another type of corrosion sometimes found in the tubing of gas-condensate wells is known as "ringworm" corrosion. As the term implies, the corrosion occurs in a ring a few inches from the upset, as shown in Fig. 6. This corrosion may take the form of very smooth corrosion or severe pitting near the upset. The cause of "ringworm" corrosion has been traced to the upsetting process. The heat required in upsetting causes the heated end to have a different grain structure from the rest of the pipe. A transition zone in grain structure near the upset runout is usually susceptible to corrosion. This condition can be overcome by fully normalizing the tubing after upsetting. Normalizing is a heat treatment that gives uniformity to grain structure. Ringworm corrosion is a common problem with J-55 tubing. Other tubings such as N-80, L-80, and P-110 are normalized to prevent this phenomenon.

Another type of corrosion damage is commonly called "sand-cutting" or erosion. Although sand-cutting does sometimes occur as a purely mechanical action, the damage usually seen is a combination of corrosion *and* erosion. This type of damage is illustrated in Fig. 7 to 10, incl. Damage of this type usually is found near a restriction (such as a choke) where velocities and turbulence are higher than normal. Corrosion products that normally stifle the corrosion reaction are removed and corrosion continues unabated. Erosion/corrosion also occurs where the flow is disrupted such as tee's and short radius ell's. A solution for this type of problem is the utilization of a tee with a bull plug in the running end. As would be expected, damage of this type is most prevalent in the wellhead fittings, but experience has proven that velocity also has considerable effect on corrosion in the tubing. In one field, it was shown that increasing the gas velocity 3.7 times increases the corrosion rate 5 times.

Sweet Oil Wells

Corrosion damage to sucker rods in sweet oil wells may take the form of severe pitting, as shown in Fig. 11 to 13, incl.; or the damage may be in the form of fine cracks that are not so obvious, as shown in Fig. 14. In many areas, pin-and-coupling failures are a major source of trouble (Fig. 15 to 20, incl.). Fig. 21 and 22 show body corrosion-erosion of a coupling and alloy rod.

Damage to the tubing in pumping wells may take the form of pitting, rod wear, or a combination of the two. Pitting of the tubing in sweet oil wells (Fig. 23 and 24) is similar to that in gas-condensate wells. Failures attributed to rod wear are usually the result of both rod wear and corrosion (Fig. 25 and 26). The sucker rod rubs the tubing and removes corrosion products that could stifle the corrosion reaction, thus allowing cor-

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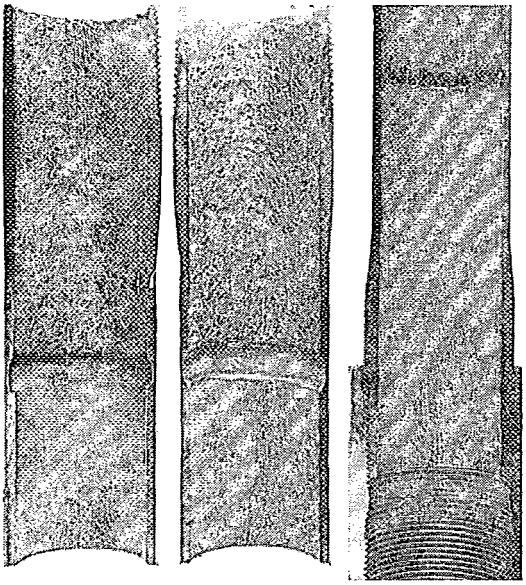


Fig. 6 — Ring-worm Corrosion

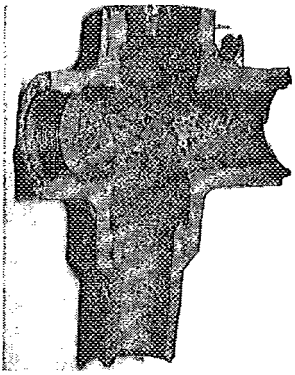


Fig. 7 — Corrosion-Erosion of Cross-over Tee

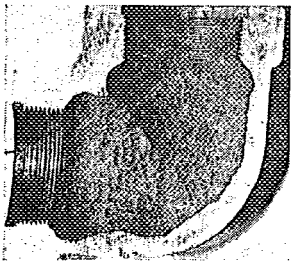
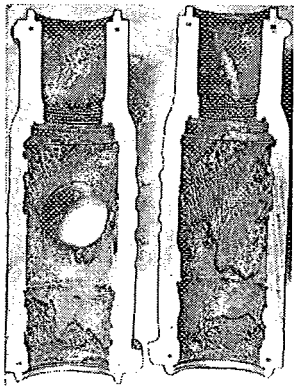


Fig. 8 (left) — Corrosion-Erosion of Ell

Fig. 9 (right) — Corrosion-Erosion of Choke Body



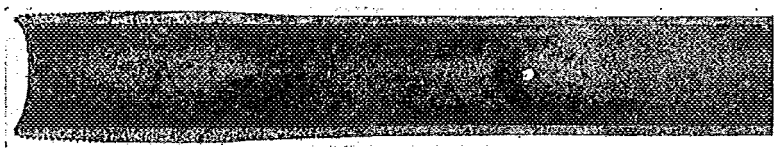


Fig. 10 — Corrosion-Erosion of Tubing Wall Opposite Tubing Perforation

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rosion to proceed. The first external evidence of this condition is a split or crack in the tubing wall. The special problem of pump corrosion and wear is discussed in Part 3 of Appendix.

Probably the most serious sweet-oil corrosion problem is in gas lift wells. These wells are usually deep, with high bottom hole pressures and correspondingly high partial pressure of carbon dioxide. They also are usually high water producers. This problem is often accelerated by the injected gas lift gas which may contain small amounts of oxygen. A severely corroded gas lift valve equalizer tube is pictured in Fig. 27. The gas lift problem is doubly severe because it is difficult to get chemical treatments down the annulus and below the gas lift valves. This problem will be discussed in more detail under treating techniques.

METHODS OF EVALUATING THE PROBLEM

A number of tests have been devised to detect corrosion and to determine its severity. The ultimate goal of this work is to be able to predict corrosion before severe damage occurs. By use of all the techniques described below, a reasonable prediction of severity of corrosion can be made.

Iron Content

Analysis of produced water to determine the *iron content* is a useful means of predicting corrosion. However, there are a number of factors that should be considered when using this method of determination. The iron content of water from a gas-condensate well has more significance than the iron content of water from a sweet oil well. This is to be expected, because there is usually very little bottom water to contribute impurities.

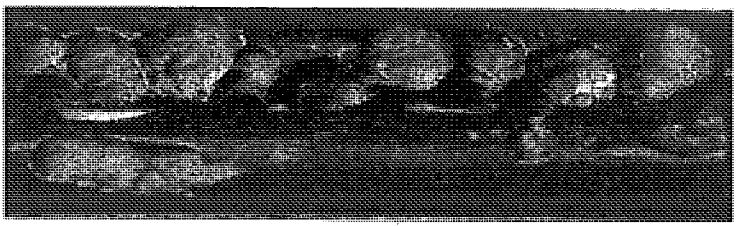


Fig. 11 — Severe Pitting of Sucker Rods

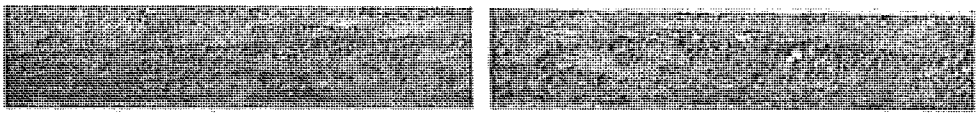


Fig. 12 — Severe Pitting of Sucker Rods

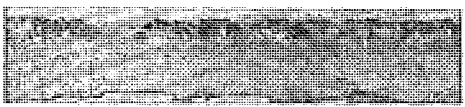


Fig. 13 — Sweet Pitting with Corrosion-Erosion

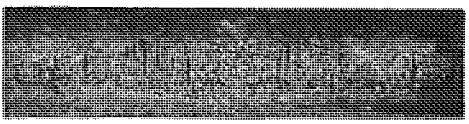


Fig. 14 — Corrosion-fatigue Cracks with no Visible Pitting

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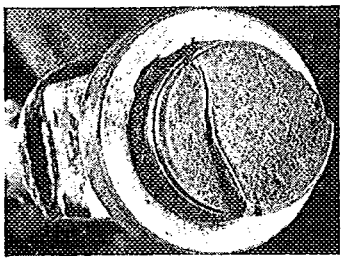


Fig. 15

Pin Break

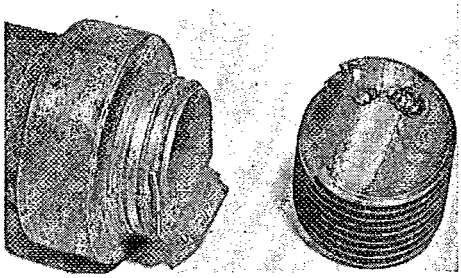


Fig. 16

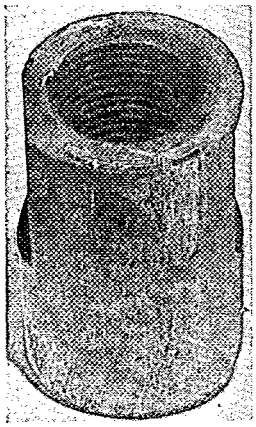
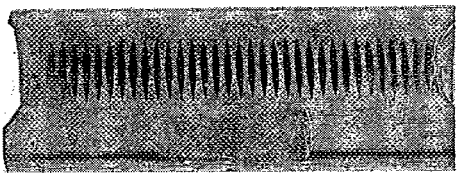


Fig. 17 (left) — Coupling-thread Break



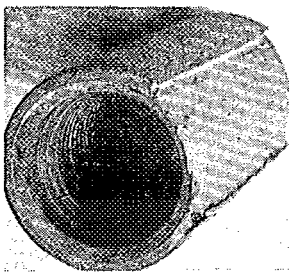


Fig. 18 (above) — Corrosion Wear of Coupling

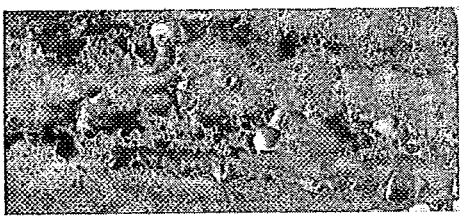


Fig. 19 — Severe Corrosion of Coupling

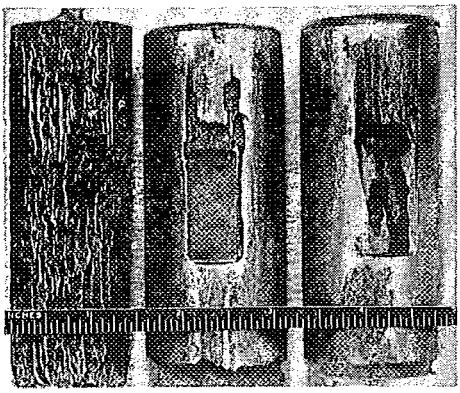


Fig. 19a — Corrosion of Alloy Coupling in Sweet Condensate Well

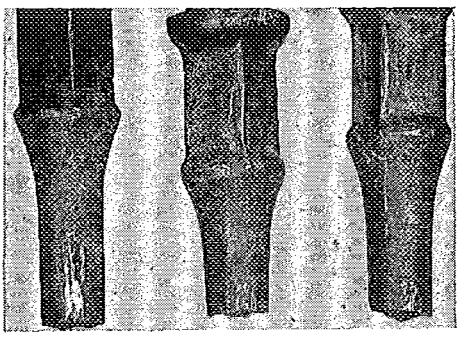


Fig. 20 — Upset Breaks



Fig. 21 — Corrosion-Erosion of Coupling



Fig. 22 — Corrosion-Erosion of Alloy Rod

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Though the iron content of condensate waters varies widely, a survey by the NGAA gave an average of 310 ppm* for corrosive wells and 125 ppm for noncorrosive wells. In practice, many corrosive wells have as little as 100 ppm iron. It has been possible to reduce iron content of corrosive wells to as low as 10 to 25 ppm by effective inhibition. In oil wells, iron content of corrosive wells may range from 5 ppm up to several hundred parts per million where large concentrations of iron are present in formation water.

The occasional failure of iron counts to correlate with corrosion failures can best be explained by considering the types of attack. If the corrosion is a uniform metal removal, the iron count can be high but the damage to equipment relatively small. On the other hand, if the corrosion damage results in deep pits, the iron count may be low but the damage severe. Also, the amount of water produced has considerable bearing on the interpretation of iron-content data. Obviously 5 ppm iron in 1,000 bbl of water represents far more corrosion than 50 ppm in 10 bbl of water. To reduce

*Parts per million

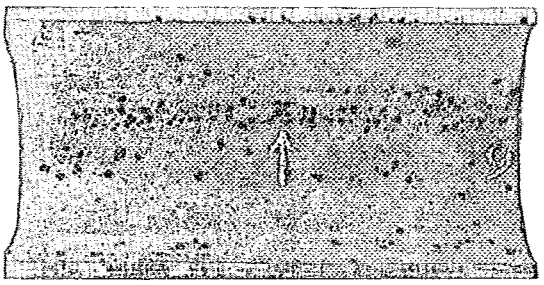


Fig. 23

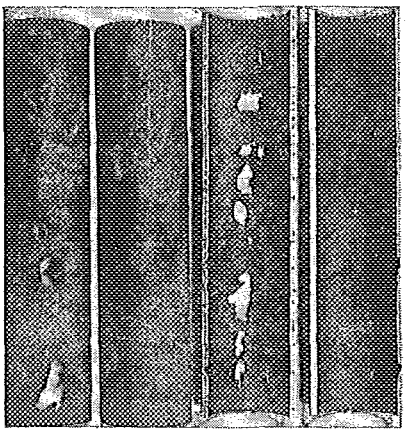


Fig. 24

Severe Pitting of Tubing in Sweet Oil Wells

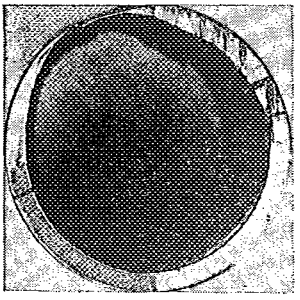
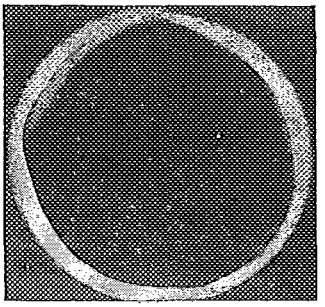


Fig. 25 (left) — Corrosion Wear of Tubing

Wear all on one side—protective scale intact on other.

Fig. 26 (right) — Corrosion Wear of Tubing

Wear has been severe at several points.



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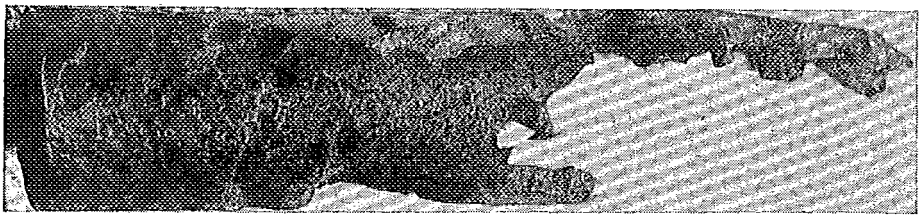


Fig. 27 — Equalizer Tube from a Gas-lift Valve

iron content to a comparative basis, the iron content is converted to pounds of iron being removed per day. In this instance, iron losses can be readily determined using the nomograph in Fig. 28. For example: With a ruler, draw a line from 5 ppm in Col. 1 to 1,000 bbl per day in Col. 3. This line intersects the middle column at 1.8 lb of iron removed per day. The principal value of iron analysis is not in predicting extent of corrosion, but in determining changes in corrosivity. For example, iron analyses are useful in showing increased corrosivity as water production increases, or for evaluating the effectiveness of inhibitors. Such data are shown in Fig. 29, which has been plotted from data for the North McCollum Field.

Iron-content data is no better than the technique used in obtaining and analyzing the sample and the analytical procedure. In all cases, samples should be taken from representative flowing fluids and not stagnant systems. Samples taken at the well head are usually superior to all others. In any case, the loss of iron can represent general or pitting corrosion. It is important to establish the extent to which variations in iron counts relate to corrosion rates in your field.

Corrosion Test Coupons

The corrosion test plate or "coupon" is another tool used to evaluate corrosion. The coupon is a small specimen of metal, usually low-carbon steel, which is exposed to the well fluids for 2- to 4-week periods. The loss in weight is used as a measure of corrosion and is reported as "mils per year" (mpy) penetration. This method of evaluation assumes that the corrosion is uniform, which may not be true because the loss in weight may be caused by pitting. The visual appearance and maximum pit depth of the coupon is usually reported along with the weight loss. The calculation of corrosion rates from coupon weight loss data is made according to the following equation:

$$\text{mpy} = \frac{\text{weight of metal removed (grams)} \times 1{,}000}{\underset{\text{(g/cc)}}{\text{specific gravity of metal}} \times \underset{\text{(cc/cu in.)}}{16.387} \times \underset{\text{(sq in.)}}{\text{area}} \times \underset{\text{(days/365)}}{\text{years}}}$$

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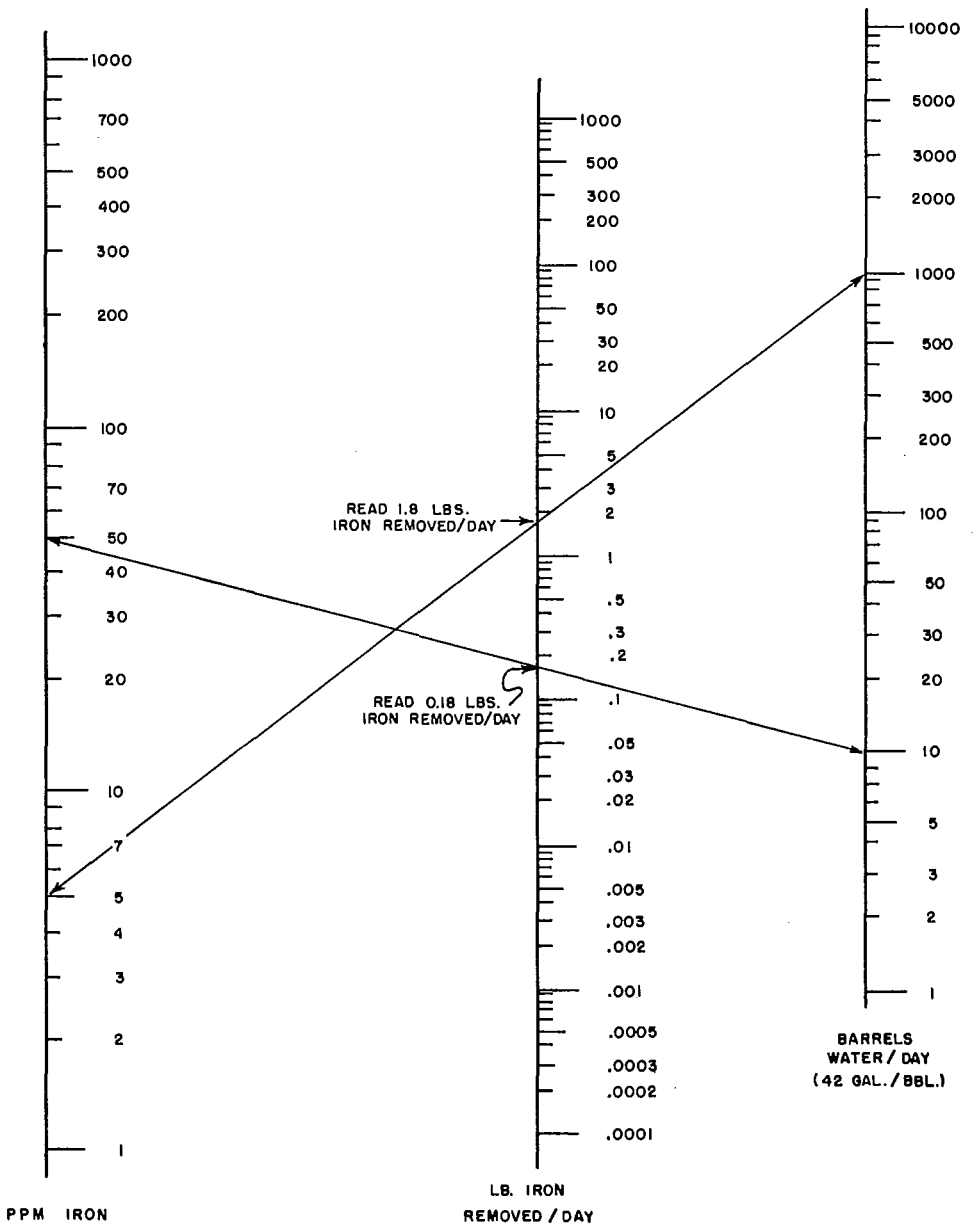


Fig. 28 — Iron-loss Nomograph

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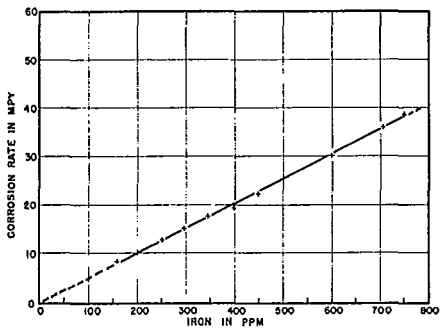


Fig. 29 — Correlation of Iron Content and Coupon Corrosion Rate for North McCollum Field

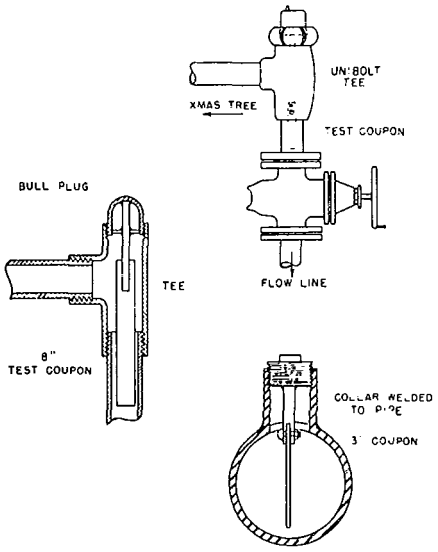


Fig. 30 — Typical Wellhead Coupon Installations

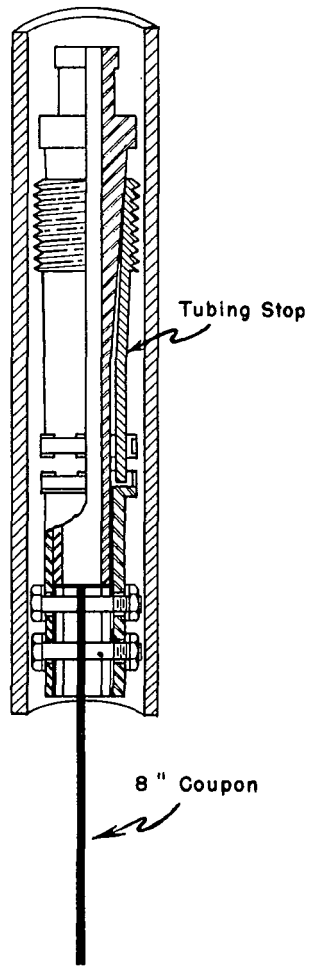


Fig. 31 — Wireline-operated Tubing Stop Adapted as Downhole Coupon Holder

For a $^1/_{16}$ in. × 1-in. × 8-in. mild steel coupon:

$$\text{mpy} = \frac{\text{weight loss (grams)} \times 365 \times 1{,}000}{\text{days} \times 7.86 \times 16.387 \times 16.6}$$

$$= \frac{\text{weight loss (grams)} \times 365{,}000}{\text{days} \times 2{,}138.08}$$

$$\text{mpy} = \frac{\text{weight loss (grams)} \times 166}{\text{days}}$$

Typical wellhead coupon installations are shown in Fig. 30. In all cases, coupons should be electrically insulated from the wellheads or flowline by use of non-metallic holders.

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One obvious limitation of coupons is that they indicate the corrosion rate only at the point of exposure. A number of operators have used subsurface installations to obtain rates at various depths. This technique has proven to be valuable for special studies, but is too expensive for routine use. A downhole coupon installation which can be run using standard wireline equipment is as shown in Fig. 31. Typical data obtained using surface and downhole coupons are illustrated in Fig. 32.

Scale and paraffin depositions on the coupon can produce erroneous indications. These factors should be considered when evaluating a coupon survey. Also the fact that the corrosion rate indicated by the coupon is a relative figure, because corrosion may be affected by a combination of pressure, temperature and velocity, and it is very difficult to assure coupon placement in an exactly similar environment. Other factors affecting coupon results include: *1*, Coupon steel generally is not manufactured from the material in which it is being placed; *2*, If the metals are identical, the coupon is in the middle of the flow stream and may be damaged due to erosion; *3*, The coupon will be located in one phase of the production stream and may remain oil wet and therefore uncorroded.

Equipment Inspection

Caliper surveys are widely used as an index of corrosion. Within the limitations of the tool, the survey is a direct measurement of the damage that has occurred in the subsurface equipment. The tool, as shown in Fig. 33, consists of a number of peripheral feelers which bear against the inner surface of the pipe. The feelers actuate a stylus that records the greatest

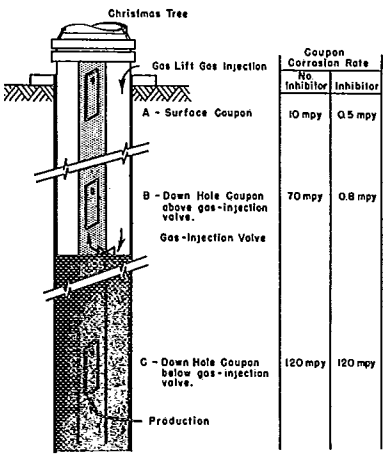


Fig. 32 — Coupon Installation in Well Produced by Gas-lift

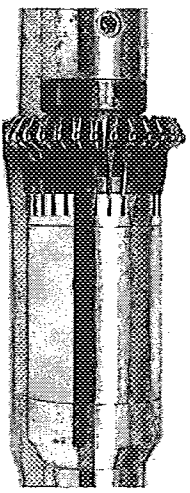


Fig. 33 — Feelers of Tubing Caliper

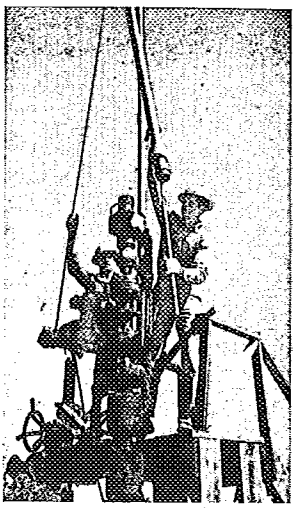


Fig. 33a — Lubrication of Tubing Caliper into High-pressure Well

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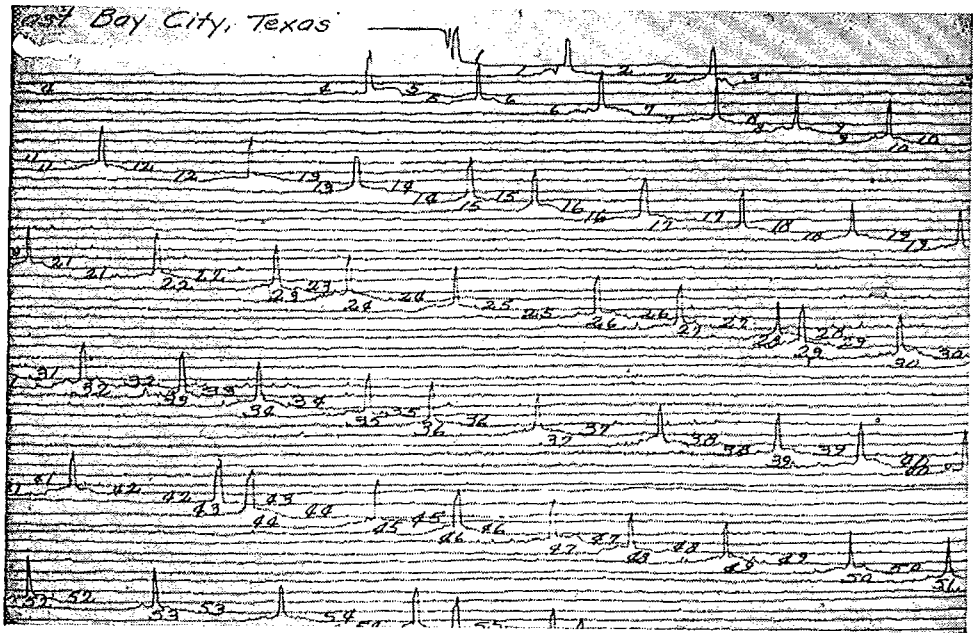


Fig. 34 — Caliper Survey Showing Corrosion in Early Stages

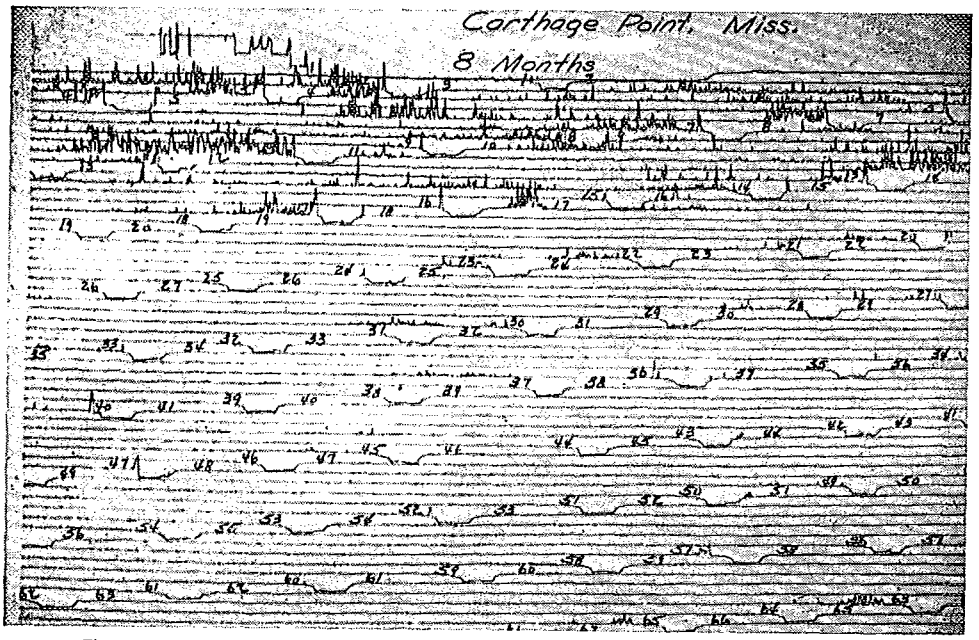


Fig. 35 — Caliper Survey Showing Severe Only above Zone of Water Condensation in Condensate Well

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pit depth at the location of the feelers. The possibility of the feelers missing some pits or only partly entering other pits must be considered. Also, scale or corrosion products can mask the true condition of the pipe. Usually, a consideration of pit depth and general condition of the pipe is a better approach than using a literal pit-by-pit interpretation. Caliper surveys are most valuable when they can be compared to a known condition (e.g., an earlier survey in the same well or new tubing). Several typical surveys are shown in Fig. 34 to 37, incl.

The use of caliper surveys in coated tubing is considered a poor practice. The feelers are hard metal and bear against the pipe with considerable force. Damage to the coating usually occurs at the end of the joint as the feelers spring out into the collar.

There is a real danger in running calipers in corrosive wells which will not subsequently be treated with inhibitors. Caliper feelers remove protective scales and allow corrosion to occur in the feeler tracks. A photograph of such a phenomenon is shown in Fig. 38 and 39.

The benefits obtained from a visual *equipment inspection* should not be overlooked. This procedure is most applicable to surface equipment and may indicate that a corrosive condition exists before equipment failures occur. This type of evaluation is especially useful in gas-condensate wells where corrosion is aggravated by turbulence. If coupon and iron-analysis data indicate corrosion, inspection of the equipment should be made.

Accurate records of equipment failures cannot be over-stressed as a means of evaluating a corrosion problem. If accurate records have been kept, many times a pattern of corrosion can be discovered before individual failures are sufficiently outstanding to indicate that a problem exists.

CONTROL MEASURES

Design and Operating Techniques

Design and operating techniques can be used to combat corrosion in two ways. The original design can be chosen: *1*, to reduce the severity of corrosion; and *2*, to allow mitigation procedures to be easily applied if corrosion appears in a well. Selection of tubing to reduce corrosion caused by high flow rates, designing the christmas tree and surface flow lines to reduce turbulence, and designing rod strings are all applications of this principle. Sometimes the water-oil ratio can be reduced by squeezing off water-bearing formations. Poor or questionable operating techniques can be the difference between success or failure of a mitigation program.

Corrosion Inhibitors

Corrosion inhibitors are used extensively in both oil and gas wells to reduce corrosion damage to subsurface equipment. Most of the inhibitors used in the oilfield are of the so-called "polar organic" type. All of the

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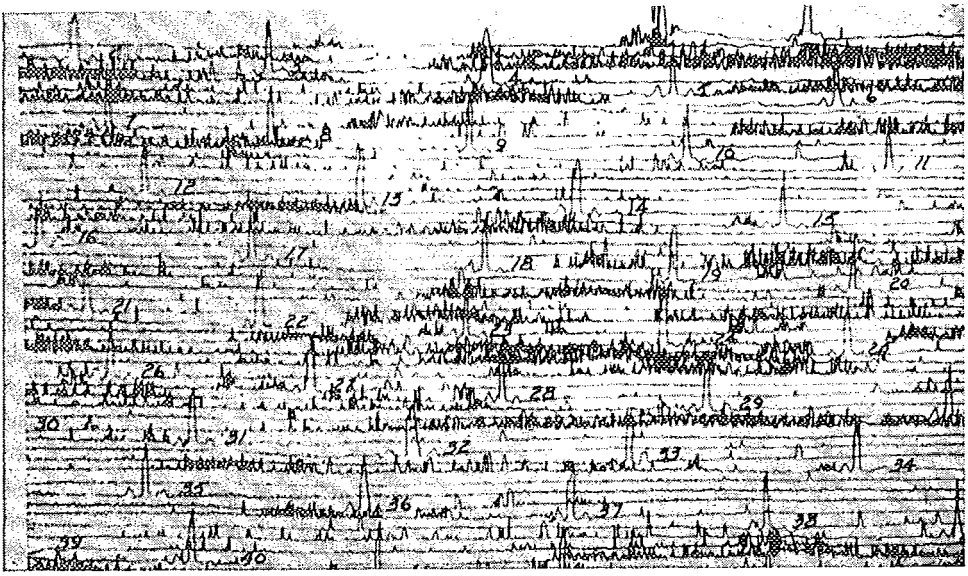


Fig. 36 — Caliper Survey Showing Severe General Corrosion

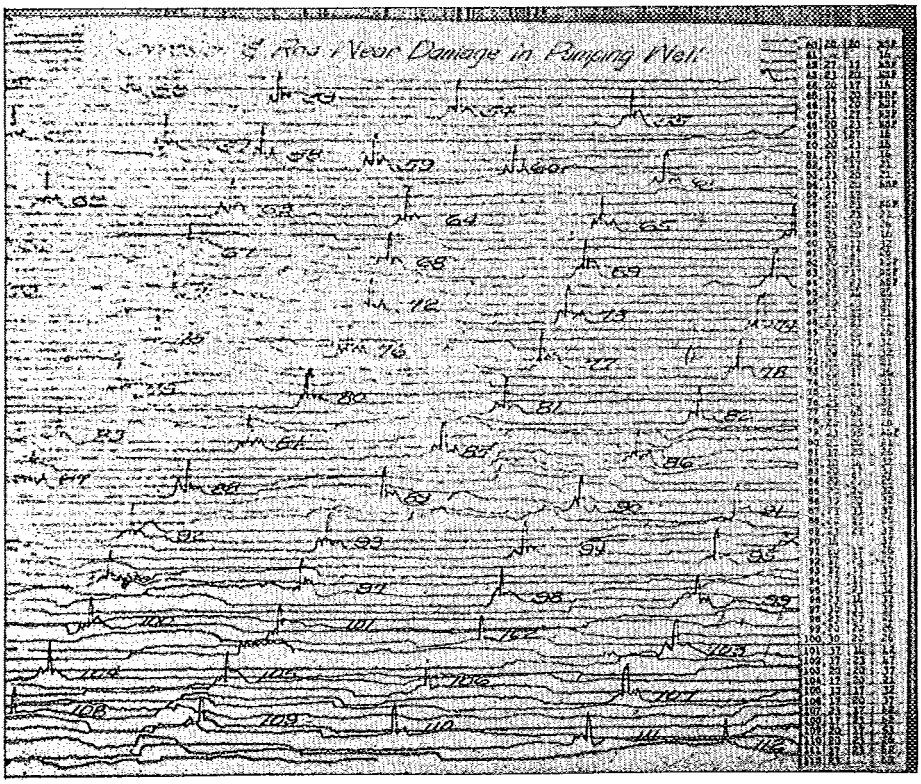


Fig. 37 — Caliper Survey Showing Erratic Pattern of Corrosion and Rod-wear Damage in Pumping Well

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major inhibitor suppliers now can furnish effective inhibitors for the prevention of sweet corrosion as encountered in most fields. The major factors to be considered are the selection of the proper inhibitor and application procedure.

Wells, either flowing or pumping, completed without a packer are usually treated by dumping the chemical down the annulus so that it drops to the well bottom and enters the tubing with produced fluids (Fig. 40). The chemical is sometimes flushed down with the produced fluids. In some situations it has been most successful to use oil soluble inhibitors; in other cases, water soluble inhibitors. It is important to select the best inhibitor or evaluate the type of inhibitor for a given well. Inhibitor screening methods have been developed that are accurate and field proven. These methods are known as linear polarization and potentidyne. They have proven to be more accurate than the wheel test.

In gas lift wells there is a special problem of getting the inhibitor to drop below the operating gas lift valves. This results in protection of only that portion of the tubing above the lowest operating valve (Fig. 41).

Wells with the annulus packed off present an entirely different problem. Inhibitor cannot be injected into the annular space (Fig. 42). Methods that have been used for chemical protection in this type of completion include:

1. *Batch Method.* Alternative batch treating methods include pump and shut-in, pump and displace, and atomization. The choice of the method should be based on individual well characteristics.

2. *Continuous Injection Method.* There are four different methods available to perform this type of inhibition.

   a. *Continuous Injection Method.* One of the latest developments and preferred methods is injecting filtered inhibitor through a small diameter stainless or inconel encapsulated or bare tubing (Fig. 43) that is attached to the outside of the tubing string and is tied into the tubing string near the packer.

   b. *Gas Lift Injection.* Injection through a gas lift mandrel. The inhibitor is generally atomized into the gas that is utilized for gas lift. The inhibitor then travels through the annulus and enters the tubing string at the point of the mandrel (Fig. 41).

   c. *Treater Strings.* An extra string of tubing is run inside of the production tubing (Fig. 44) or as a separate dual string (Fig. 45). Inhibitor is injected into the annulus between the two tubing strings or down one of the dual strings and production is through the other string.

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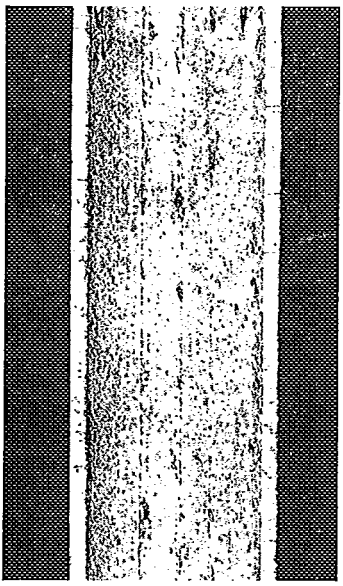


Fig. 38 — Corrosion in Caliper Feeler Tracks of Uninhibited Well

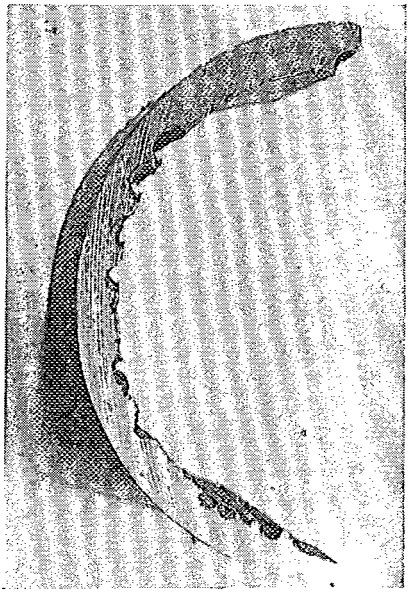


Fig. 39 — End View of Caliper Track Corrosion

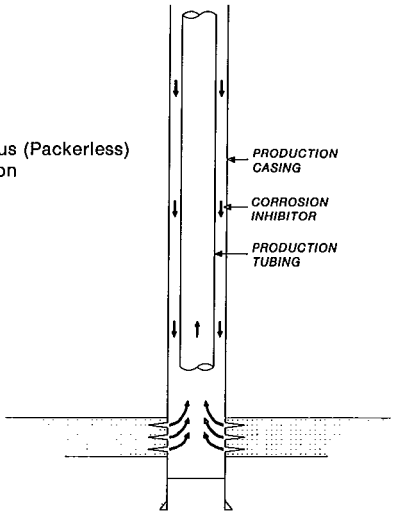


Fig. 40 — Open Annulus (Packerless) Completion

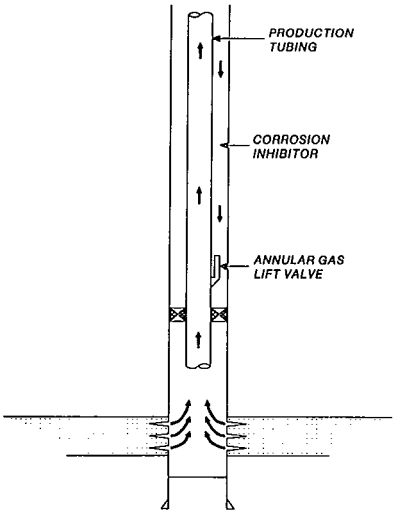


Fig. 41 — Annular Gas-lift Valve Completion

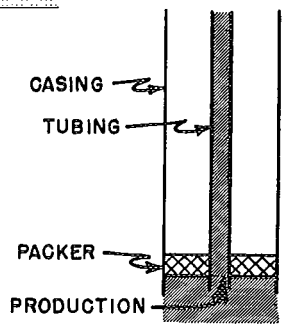


Fig. 42 — Packed-off Well

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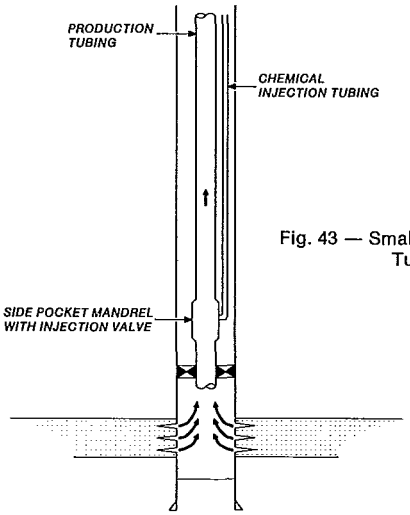


Fig. 43 — Small Diameter Chemical Injection Tubing Completion

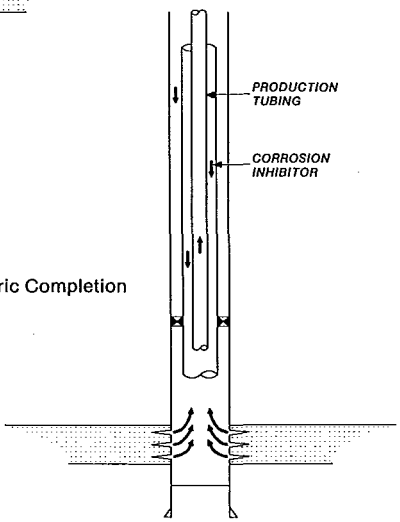


Fig. 44 — Concentric Completion

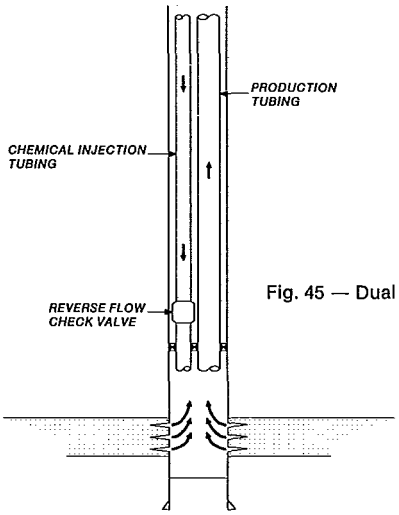


Fig. 45 — Dual Completion

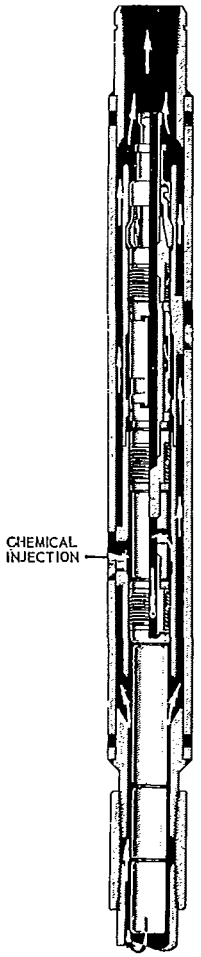


Fig. 46 — Bottom-hole — Bypass Chemical Injection Valve

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