

Field Guide for Investigating Internal Corrosion of Pipelines

Richard Eckert



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Richard Eckert

**NACE International
The Corrosion Society**
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Houston, Texas 77084

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Foreword

Field Guide for Investigating Internal Corrosion of Pipelines by Richard Eckert is an extremely well-written volume devoted to procedures for determining the cause of corrosion inside gas pipelines. The volume is unique in that it provides a thorough treatment of the subject, with overview for the experienced corrosion engineer and detailed methodology for the technician. The volume addresses persistent misconceptions about microbiologically influenced corrosion (MIC), e.g., that detection of specific types of microorganisms means that MIC has taken place and that pits produced by microorganisms can be identified/differentiated by morphology. The author references U.S. government and state regulations, in addition to NACE International and ASTM standards. In describing the protocol for conducting a corrosion investigation, the author uses the analogy of a crime scene investigation, including an approach for collecting evidence under ideal and compromised situations, the significance of circumstantial evidence, a sequence of analyses to optimize data collection, sample size, supplies and procedures, as well as details about sample storage and shipment. Mr. Eckert has provided valuable checklists to structure a corrosion investigation and to assist in data interpretation and report preparation. Mr. Eckert anticipates questions and answers them in a concise, authoritative manner that reflects his 20-year experience with internal pipeline corrosion. His approach to the subject of internal pipeline corrosion is sometimes humorous, sometimes philosophical, but always informative.

Brenda Little

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About the Author



Richard Eckert is Senior Metallurgist at Kiefner & Associates, Inc. in Columbus, Ohio, where he specializes in internal corrosion monitoring and mitigation. He holds a B.S. degree in engineering metallurgy from Western Michigan University.

During his career, Mr. Eckert worked in the Laboratory Services divisions of ANR Pipeline, Coastal and El Paso, where his focus was pipeline failure analysis and corrosion investigation. He has been involved with microbial corrosion research for many years and helped develop an innovative approach for detecting biotic pit initiation. He served on the GRI MIC task group from 1989–98.

Mr. Eckert is presently chairman of NACE Task Groups on Internal MIC of Pipelines and the first Internal Corrosion Training Course to be offered by NACE. He is also involved in industry efforts to establish procedures for Internal Corrosion Direct Assessment (ICDA).

He has published in *Oil and Gas Journal*, *Pipeline and Gas Industry*, and several NACE conference proceedings.

Introduction

Corrosion Detectives

Books about corrosion often include a “rogue’s gallery” of photographs showing the various manifestations of corrosion. Usually, the caption of each image identifies the form of corrosion shown: CO₂ corrosion, microbiologically influenced corrosion (MIC), and so on. Instinctively, readers tend to compare their own corroded specimen with that in a photograph and based on the physical likeness between the two, deduce why the corrosion occurred. The underlying assumption is that if the corrosion of a specimen looks similar to the picture in a book, then the mechanism behind it must be the same. However, is this a valid assumption?

The short answer is no. Although physical appearance is important, corrosion morphology by itself is generally insufficient evidence for distinguishing among corrosion mechanisms.¹ While many would like to believe that the various causes of corrosion can be “fingerprinted” by their appearance or morphology, the truth is that more evidence is usually required to make a correct and technically sound diagnosis. In any investigation, the physical appearance of corrosion must be considered in light of other facts about the corrosive environment.

Therefore, how does one make a valid assessment of what caused the corrosion in their particular case? An investigative process that can be used to make a sound diagnosis of what caused the corrosion in any given situation is what this field guide is about.

All corrosion is the result of a material interacting with a certain environment. This interaction can be described in terms of

chemistry, electrochemistry, microbiology, metallurgy, and numerous physical conditions such as temperature and flow velocity. Inadequate consideration may be given to these factors, however, when physical appearance is used as the primary means of distinguishing the corrosion mechanism. Additional information about the operating environment may appear to be unnecessary once a cursory conclusion is at hand. While there is certainly value in learning from previous case histories of corrosion and from the physical effects of corrosion observed on similar materials, a competent corrosion investigator needs to gather all the facts about the environment in which the corroded material was exposed before reaching a conclusion. Looking only at the “victim” of the corrosion “crime” does not provide adequate evidence to develop a conclusion that will hold up in court. Consider the following example.

A police detective pulls up to a crime scene, jumps from the car, takes one look at the unfortunate victim and proclaims to the crowd, “I know who did it!”

Onlookers and fellow officers are impressed. This guy must be one sharp detective if he can solve the crime just by looking at the victim. However, in reality, just how astute is this detective?

In this case, our detective observed that a large, heavy safe had been dropped onto the victim from the 10th floor of a nearby apartment building. In all of the safe-dropping cases ever investigated by our detective, the spouse of the victim was always the perpetrator. Our detective also has several case histories that show pictures of safes that have been dropped on unwitting husbands by their wives. Therefore, the detective concludes that the victim’s wife must have done it and he believes the case is solved.

Only after the victim has been extricated from beneath the safe does our detective read the back of the victim’s work jacket: “ACME Safe Movers, Inc.—We Make Every Move a Safe Move.” Thus, by jumping to a conclusion before obtaining all of the facts, our ace detective appears foolish.

While we might witness a scene like this in a bad movie, it is unlikely that we would in real life. Why? Because a good detective would never pronounce “whodunit” before carefully collecting and objectively analyzing all of the evidence.

Good detectives do not let their experience with previous cases cloud their judgment about the current investigation. Good detectives gather as many facts as possible before making a conclusion. Good detectives try to understand what conditions led up to the final crime scene. Good detectives don't jump to conclusions.

In order to do a good job investigating internal corrosion of pipelines, you too will need to be a good detective.

This book will equip internal corrosion detectives like you with the tools and procedures metallurgists and corrosion engineers use for analyzing the cause of internal corrosion in pipelines. Instead of providing numerous photographs of corrosion for visual comparison, this guide will help you collect the information needed to identify the environment responsible for causing the internal corrosion. By investigating the environment responsible for the corrosion, you will then be able to "fingerprint" the culprit in your corrosion situation better than ever before. It may take more time and effort, but this will pay off in the end.

Finally, remember that in conducting these investigations, it is more important to be objective and thorough than to arrive at a conclusion shortly after showing up at the crime scene. Keep this fact in mind as you conduct your field investigation and you will be off to a good start, regardless of your experience or background in corrosion investigation. If pressed for an answer before you have all the facts, you can simply say, "We have some suspects but we are still collecting evidence."

Human anatomy suggests that hearing and seeing are twice as important as speaking, especially to a good investigator. Listening and observing for facts is a skill that corrosion investigators should strive to cultivate. As an old pipeliner once reckoned, "Better to be silent and suspected foolish, than to open your mouth and confirm it."

Purpose of This Guide

Management of internal corrosion in pipelines can be divided into three main areas: detecting the corrosion, determining the cause of the corrosion, and mitigating (controlling) corrosion. This book, being a field guide for investigating internal corrosion, is directed toward the second area, determining the cause. While finding internal corrosion (via in-line inspection tools or "smart pigs") is certainly important in managing pipeline safety and integrity, the root cause of the corrosion

must also be determined in order to know how to treat or prevent it in the future. Detecting internal corrosion and treating internal corrosion are very significant and extensive issues beyond what could be adequately covered in this field guide. Therefore, this guide will only address how to investigate the cause of internal corrosion once it has been detected by visual inspection or nondestructive examination. Although the focus is on internal corrosion, the principles of investigation given in this book can be readily applied to external corrosion as well, as long as the effects of cathodic protection and coatings are considered.

As the title implies, this book is also meant to be used in the field by pipeline technicians and corrosion personnel to guide their efforts to determine and document why the internal corrosion has occurred. Of course, one does not become proficient at something by attempting to read a “how-to” book while in the middle of a crisis; planning and advance preparation are necessary. Thus, in Chapter 2, advance planning and training are addressed. Once key personnel are equipped and trained in corrosion investigation, this book can serve as a useful reference while working in the field.

Finally, the importance of internal corrosion investigation and the priority it should warrant are points worthy of mentioning here. Often in the course of maintaining the functionality of a pipeline system, understanding the reason why something happened is less imperative than keeping things flowing in the right direction. While the business of safely transporting gas and liquids is indeed the bottom line, maintaining long-term system integrity and regulatory compliance are fast becoming priorities for many operators. Understanding why internal corrosion has occurred is essential to controlling future corrosion problems and prioritizing future inspection/remediation efforts. Proper analysis of internal corrosion conditions in a pipeline feeds valuable information into the Direct Assessment process now being instituted in pipelines across the United States. The value of technically sound internal corrosion investigation should not be underestimated.

How to Use This Guide

To get the greatest benefit from this guide, first scan through the contents to become familiar with where things are located. Chapters 2 and

3 are designed to help you prepare to conduct corrosion investigations through advance planning and training on how to look for evidence. In Chapter 4, detailed procedures on how to conduct the field investigation are presented. It is essential to have read this chapter before going out and attempting to conduct a corrosion investigation. Chapter 5 discusses the benefits of laboratory analysis of the corrosion, and lists some common types of testing that can be performed. Finally, Chapter 6 offers some help in putting all the evidence together so that a conclusion can be drawn. Additional technical references are provided in the bibliography at the end of the guide. Throughout the guide a number of tables and checklists are provided to help the user during preparation, investigation, and analysis of their corrosion problem.

Understanding the investigative process from start to finish before conducting an investigation will benefit the corrosion detective immensely. Taking the time to read and plan ahead before going off to the pipeline right-of-way will pay off in the end.

Developing a Plan

Why Have a Plan?

It has often been said that those who fail to plan, plan to fail. This sage advice holds true for corrosion investigations as well. Without a plan that describes who, what, where, when, why, and how, it is highly unlikely that a coherent investigation will occur by default.

The goal of a corrosion investigation is to gain an understanding of what caused the internal corrosion in the first place so that it can be prevented in the future. This goal cannot be achieved without some advance planning. Materials, people, and processes must be ready to go as soon as internal corrosion is exposed. Therefore, someone must develop a procedure describing how the organization will handle internal corrosion investigations. If a pipeline company is using internal corrosion data as a part of their integrity management program, then it is even more vital that the investigation process be properly documented and clearly communicated to employees.

What Should the Plan Include?

As mentioned previously, there are six essential questions to address in the investigation plan.

Who will do the investigative work? **Who** will collect samples, both at the investigation site and at gas/liquid source locations? **Who** is responsible for documenting the investigation and writing a report, if needed? **Who** will decide if outside laboratory services are needed? **Who** will stock and maintain testing supplies for

future investigations? Who needs to receive information about the investigation?

What types of testing will be conducted, both immediately in the field and later in the laboratory? What samples must be collected? What tools and supplies are needed to perform the testing and preserve any samples collected? What are the relevant health and safety issues associated with a field investigation?

Where will the investigation be performed? Where will field investigation supplies be stored for quick access? Where do samples need to be sent for analysis?

When are the company “corrosion detectives” called in on the scene? (Will they be notified in enough time to collect the evidence they need?) When are certain types of tests performed? When or how quickly does the cause of the corrosion need to be determined?

Why are we conducting this investigation? Hopefully, by using this field guide and developing specific company plans for corrosion investigation, people involved in the process can begin to understand why this work is important and will lend their support. A proper investigation takes extra time and effort compared to a brief visual assessment.

How do we collect and analyze chemical and biological samples? How does one interpret test data and reach a conclusion about the cause of internal corrosion? This guide is meant to be a resource that explains both how to collect data and how to interpret what the data mean. These questions will be addressed in subsequent chapters, and the answers can become part of individual company plans.

At the end of the chapter, a planning checklist is provided to help readers develop their own internal corrosion investigation plans. Keep in mind that even a high-level plan (one in which all of the details have not yet been resolved) is still better than no plan at all. General George S. Patton said, “A good plan today is better than a perfect plan tomorrow.”² Don’t be intimidated by not knowing all of the details of internal corrosion investigation; go ahead and get started. Even a cursory plan will get the stakeholders talking, which brings us to a final point about what the plan should include.

Any good plan benefits immensely from input and review with all affected parties. There are important realities of both engineering

and field operations that may be overlooked when one is not in the other person's camp very often. For instance, how does the corrosion investigator deal with fire suppressant powder sprayed liberally over the corrosion area from which he was hoping to take a sample? How do field operations personnel respond to the need to saw-cut a pipe sample at a remote location when such equipment is not available? The point is that a good, workable corrosion investigation plan cannot be developed by only one person. The team approach is essential.

Complying with Regulations

This section presents a commonsense approach to considering regulations that could impact a field investigation of internal corrosion. Attempting to convey the implications of specific laws or regulations is far beyond the scope of this guide. Compliance with state, federal, or other jurisdictional regulations must be considered when individual companies are developing their corrosion investigation plans.

In general, there are three regulatory areas to consider: human health and safety, environmental impact, and operational compliance.

Safety of personnel at a pipeline dig site is no different during an internal corrosion investigation than for any other activity under those conditions. Personnel responsible for conducting the investigation should be trained in safe practices for working around excavations and in the vicinity of heavy equipment. Many companies require hard hats, hearing protection, safety glasses, steel-toed boots, and even fire-resistant clothing when working on a pipeline job site. Depending on specific company guidelines and the location of the work site, additional safety equipment and training may also be required. Corrosion investigators often need to collect samples as soon as possible after a pipeline is cut open; therefore, exposure to hazardous liquids, vapors, or airborne particles could be an issue at some work sites. Special regulations govern working in confined spaces as well. In developing a corrosion investigation plan, it is wise to consult with an occupational health and safety professional.

Routine environmental stewardship and compliance with state and federal environmental regulations typically falls to those performing pipeline operations and maintenance on a day-to-day basis. Most companies are aware of environmental issues particular to the areas

in which they operate, and have developed training and standards to address those issues. The corrosion investigation plan merely needs to refer to pre-existing guidelines and/or regulations associated with pipeline work sites, and provide a brief overview of “Do’s and Don’ts” for the investigators. In short, the investigation plan should identify any chemicals used for testing samples at the field site, provide Material Safety Data Sheets for those chemicals, and describe proper transportation and disposal methods. For example, some reagents carried in a corrosion field test kit cannot be transported by aircraft without special packaging and documentation and some chemicals may not be transported by aircraft at all. In terms of disposal of test chemicals, syringes, or excess sample material, it is good practice to prohibit the disposal of *anything* in the field. Be sure to address approved disposal practices in the corrosion investigation plan.

Federal regulations governing gas and liquid pipelines in the United States require that the internal surfaces of the pipe be examined for corrosion whenever they are exposed.³ Operating companies usually document this examination as a matter of regulatory compliance and to track the internal condition of their system. Historically, the internal corrosion is examined only in terms of whether the mechanical integrity of the pipe is affected; the corrosion mechanism is not generally considered. This may be changing, however.

In light of forthcoming revisions to pipeline regulations⁴ in the United States, it is likely that the perceived value of internal inspections will increase, prompting a more thorough and methodical approach to corrosion documentation. Integrity management and risk assessment should also be considered when developing internal corrosion investigation plans. Operators must decide whether a comprehensive investigation approach should be expanded to include all internal pipe inspections. When information about the internal condition of the pipeline is collected in a comprehensive and consistent manner, it may then be suitable for inclusion in integrity management criteria. The potential value and significance of internal corrosion inspection data will certainly increase as the information feeds integrity management and risk assessment programs.

Even when developing an internal corrosion investigation plan is not a specific regulatory requirement, having and using such a plan will help ensure compliance in other key functional areas and provide better internal corrosion data integrity for making long-range planning decisions.

Training is Essential

While training seems to be a separate topic altogether, it goes hand in hand with planning. When training is incorporated as part of the corrosion investigation plan, a good outcome is almost guaranteed. Why? Simply because the greatest plan in the world would still fail

TABLE I Training Issues to Consider in the Corrosion Investigation Plan

Training Area	Issues to Consider
Health and Safety	Use of personal safety equipment Excavation and confined space training Respirator certification Emergency procedures on the job site
Sample Collection	Identification and preservation of pipe samples Collecting liquid/solid/gas samples Samples for microbiological analysis Safe collection and storage procedures for hazardous materials Chain of custody
Field Testing	Tests required on-site (pH, temperature, H ₂ S) Inoculating bacterial culture media Preparing samples for microbial analysis in the lab Dimensional measurement of corrosion damage Nondestructive testing of pipe Gas analysis—field tests
Investigation Management	Understanding the plan Delegation of tasks Collecting relevant information about a system Summing it all up in a report
Laboratory Testing	When to use outside laboratories; what types of tests to request; what type of samples to submit Laboratory type tests that can be performed in-house Documenting corrosion morphology using a microscope
Emergency Response	Notification process/call chain Corrosion investigation procedures in the case of leak, rupture, spill, or fire Communications with the media Corporate risk management program

if nobody knows about it, or if no one is prepared to carry it out. Including some consideration for training into the internal corrosion investigation plan is essential. It may not be necessary to develop a complete training program right away, but at least the plan can identify the training needs of your key people. Qualification and certification may also be required for some tasks that directly impact pipeline operations.

What are some of the training issues that may have to be addressed? Review the list in Table 1 to determine what questions arise in regard to your own specific situation. Then adjust the corrosion investigation plan accordingly.

Plan Development Checklist

Hopefully by now, the value of having an investigation plan is apparent. Use Table 2 as a checklist to begin developing a company-specific internal corrosion investigation plan.

TABLE 2 Internal Corrosion Investigation Plan Checklist

Identify Personnel/Department Responsible for:

- ☐ Conducting field investigations.
- ☐ Setting up field test kits and supplies.
- ☐ Managing all investigations and reviewing/compiling results.

Develop Company Procedures for:

- ☐ Documentation of field investigation data.
- ☐ Notification of field investigators.
- ☐ Sample collection (liquid, solid, gas, pipe).
- ☐ Types of field and laboratory analyses to be performed.
- ☐ When to get outside assistance with the analysis.
- ☐ Collection of operating data to support the investigation.

Consider Broader Scope Issues:

- ☐ Coordination with existing emergency response program.
- ☐ Standardization of regulatory internal corrosion examinations.
- ☐ Training investigators.
- ☐ Input from Health, Safety, and Environmental experts.

Essential to Success:

- ☐ Input and buy-in from all stakeholders.
 - ☐ Backing from management.
-

Detective Work: Searching for Evidence

A New Perspective

In the first chapter, some characteristics of a good criminal investigator were mentioned. These same character traits apply to good corrosion detectives as well.

A good corrosion detective:

...remains objective during the investigation. His or her judgment is not swayed by circumstances surrounding the incident, i.e., “I can’t tell my division vice president how bad this is—he’ll have a fit!”

...gathers as many facts as possible before making a conclusion. It might take extra time to get the results back from a laboratory test but that data may change the whole outcome of the investigation.

...looks for the “big picture” of what conditions led up to the corrosion. The relationship between all the individual pieces of evidence will usually fit together better when viewed from different angles.

The ability to see the “big picture” in a corrosion investigation may first require gaining a new perspective. A perspective is a point of view or way of viewing things. Up close, we see minute details while in the distance we view broad panoramas. Both extremes and every magnification in between tells us something about how the various

pieces of evidence in a corrosion investigation are related to each other. In order to better understand the facts one is presented with, a new perspective is sometimes useful and often essential.

An investigator's perspective is affected by many things: education, age, work experience, workplace politics, the weather, previous corrosion experiences, available resources, time of day, amount of coffee consumed, and so on. The point is that a good investigator works to control all influences and biases so that each investigation is conducted in an objective manner. Further, there are some perspectives that can only be obtained by involving other people in the fact-finding mission. Only a handful of pipeline folks have experience with scanning electron microscopy (SEM) or energy dispersive spectroscopy (EDS), yet these technological tools can provide valuable views of how corrosion initiates and propagates. Therefore, in some cases the investigator must seek different perspectives from other experts and/or through the use of advanced technology.

New perspectives aid the search for evidence in any investigation. In looking for evidence of internal corrosion, there are three main categories to consider: visual evidence, physical evidence, and circumstantial evidence. These categories of evidence are the same for liquid or gas pipelines and transmission, storage, gathering, production or plant piping. Later chapters will discuss how to collect various types of evidence, but for now we will begin by looking at exactly what evidence an investigator should be searching for.

Visual Evidence

Visual evidence is information that can be gathered by observation. As simple as this sounds, it is not easy to be a truly good observer. Important evidence in a corrosion investigation can be easily overlooked because we fail to see the obvious. We are not completely conscious of conditions we accept as being normal. Visual evidence can also be collected using tools to measure and document what is observed. Tools for measurement should include a steel tape measure, a small finely divided steel ruler, a pit gauge, a pipe micrometer, and even an ultrasonic thickness gauge. Documentation of observations and measurements should be provided in both written and photographic form. More information about the tools needed for internal corrosion investigation is presented in the following chapter.

Investigators also need to be aware of the fact that visual evidence can change with time. A cut-out section from a pipeline moist with water will soon be bone-dry when left in the hot sun. Corrosion deposits containing iron that appear reddish-orange in a sample bottle may have originally been black when first removed from the anaerobic conditions in the pipeline. Nodules or occluded material that once covered corrosion pits may have been pried off the pipe by curious technicians or field personnel. Perhaps the pipe was washed or sandblasted to facilitate inspection before somebody decided an investigation was necessary. Whatever the case, visual evidence can be easily altered or even lost. Corrosion investigators need to account for sample handling and mishandling. One of the best ways to get good information is to be on the scene when the pipeline is cut.

In collecting visual evidence, it is also helpful to understand how various factors could affect the internal corrosion environment in the pipeline. What follows are descriptions of visual evidence along with brief explanations of how those observations relate to corrosion. A summary checklist of visual evidence is provided in Table 3.

Location of Corrosion

Many factors can be used to help describe the location of the corrosion and the relationship between corrosion and conditions that may have contributed to the cause.

Physical Location in the Pipe The external climate and environment to which the pipe is exposed can affect internal temperature, which in turn affects corrosion. The orientation of the pipe (vertical, horizontal, degree of inclination) affects where liquids could collect or condense, or where solids may accumulate.

Clock Position in the Pipe Corrosion can be distributed uniformly around the inner surface of the pipe or it may be specific to the top, bottom, or sides. This important evidence is telling of the operating conditions that led to the corrosion. For example, corrosion on the top of the pipe suggests that condensation may be involved. Corrosion that occurs in longitudinal bands along both sides of the pipe often indicates the effects of historical liquid levels in the line.

Location in relationship to other features:

System Design (dead leg, drip, etc.) Design factors that create conditions of low or no flow and allow the accumulation of liquids and solids are often conducive to internal corrosion.

Elevation of Pipeline (low spots) Low spots (river and road crossings in cross-country pipelines) are potential spots for liquids to collect in the pipeline. Low spots also occur in station and plant piping. Keep in mind that gas flow may push standing liquids uphill in the flow direction, so that the most severe corrosion may not be at the lowest elevation.

Girth Welds or Mechanical Joints Welds and joints can affect corrosion in several ways. Most joints create localized changes in flow patterns and some (couplings) could create crevices, depending on design. Welds can exhibit metallurgical and chemical differences from the parent pipe metal, which promote slight galvanic effects at the weld or heat affected zone.

Longitudinal Weld Seams Similar comments as for girth welds also apply to longitudinal seam welds. Electric resistance welded (ERW) pipe may exhibit selective attack of the weld microstructure when exposed to certain corrosive conditions.

Directional Change in Flow Corrosion may be exacerbated by, or unique to, areas where the flow makes abrupt directional changes. Increased corrosion rates due to enhanced mass-transport and mechanical film-disrupting effects of flow are possible.

Inlets, Outlets, Taps, Fittings Observed relationships between pipeline design features and internal corrosion can be significant in determining the cause of the corrosion. These features could be indicative of the source of corrosive materials, or they may actually be involved in the corrosion by inducing changes to flow, metallurgy, or other factors.

Heat Sources or Temperature Changes A general rule regarding temperature suggests that the corrosion reaction rate doubles for every 10 degrees Celsius increase in temperature. This is only a rough approximation, of course, but the point is that elevated temperatures generally result in increased corrosion. It is also possible to create corrosive conditions by cooling. When gas with high water vapor content is cooled, liquid water can condense

on the walls of the pipe. This water can become a corrosive electrolyte if other chemical species are present.

Historical Liquid Levels in Pipe Many times, it is possible to observe deposits, scale, or corrosion oriented in the longitudinal axis of the pipe and which correspond to historical levels of liquids in the pipe. Careful examination of pipe samples removed from the system being investigated will often reveal this evidence. Corrosion may occur in lines along the gas/liquid interface, within the entire wetted region or only along the bottom of the pipe. It is important to distinguish the relationship between the location of corrosion and the location of previous liquid levels in the pipeline.

Deposits, Coating, Debris Any material present on the surface of the pipe has the potential to contribute to underdeposit corrosion. Deposits can promote corrosion directly and indirectly. Deposited materials may be directly corrosive and/or can help form concentration cells. Thus, it is important to note the relationship between the presence and type of corrosion and the location and type of deposits on the pipe surface. Defects or breaks in coatings can also result in localized attack. Disbonded regions beneath relatively intact coatings can help retain the electrolyte in corrosion cells. When the pipeline has been pigged, it complicates the ability to observe relationships between deposits and corrosion. If deposits are suspected of contributing to the corrosion but the line has been pigged, representative surface conditions can often be observed in nearby non-piggable piping, such as in a branch or a vessel.

Nodules Nodules (or tubercles) are mounds of deposit and corrosion product that cover localized areas of metal loss. Tubercles are commonly formed in oxygenated waters with high bicarbonate alkalinity; however, they can also occur under other environmental conditions. The presence of nodules is not diagnostic of microbial involvement in the corrosion mechanism, although microbes have been shown to contribute to the conditions that promote nodule formation in some cases.

Scale Scales can be formed by precipitation of solids from water and by reaction between the pipe and the environment. Scales can be protective or non-protective, in terms of corrosion. Loosely adhered, irregular, and porous scales tend to promote corrosion,

whereas tenacious, continuous, and dense scales may actually be protective to the pipe surface. If scale is present, it is important to note the physical relationship between the scale and the internal corrosion.

Biological Materials Although microorganisms are far too small to observe with the unaided eye, evidence of their existence may sometimes be detectable in the form of heavy biomass or slime deposits. However, note that most slime-forming bacteria are aerobic and gas pipeline conditions are predominantly anaerobic. Other biological materials besides bacteria can also influence corrosion. Although uncommon, algae, molds, plant materials, and larger organisms can be involved in internal corrosion. Plant-based materials are sometimes used for pipeline cleaning and may leave organic residue in the pipe.

Chemical Injection The relationship between the location of any chemical injection equipment and the corrosion should be noted. Some biocides, for example, are fairly corrosive themselves if not diluted in the product stream during injection. Also consider chemicals injected to prevent hydrate formation in locations where freezing is a concern. Methanol can be an energy source for some bacteria. Also consider the potential effects of batch treatment with chemicals for cleaning or corrosion control. Such chemicals may pool in certain spots. Finally, in production and storage field piping, determine whether acidic well stimulation fluids may be contributing to the corrosion being observed.

Processing Equipment Dehydrators, strippers, separators, coolers, and a host of other equipment are used to help move gas and liquids through pipelines. Commonly, changes in pressure, temperature, flow, dew point, and product composition may occur in this equipment. Whether corrosion occurs upstream or downstream of the equipment, it is valuable to consider the effects of the process on the corrosion environment.

Construction/Material Changes Internal corrosion sometimes occurs where something has changed, in either the construction practices or materials used. These changes may not always be visually observable but in some cases they are. New pipe installed in an older system that has a protective scale layer present may be slightly anodic to the older system and corrode faster than anticipated. Joining pipes of different wall thickness could

result in a disruption of flow at the joint surface that allows deposits to build up at the girth weld. Differences in chemical composition and metallurgical condition between adjacent joints of pipe or between pipe and girth weld, could potentially promote galvanic corrosion. Look for clues that show that maintenance or replacement work has occurred. Differences in external coatings between the original and replacement pipe, different type of pipe as evidenced by a change in the longitudinal seam, and so on, are clues that maintenance or replacement has occurred.

Pipe Mill Defects Although uncommon, internal corrosion may be associated with (or even confused with) previously existing surface anomalies in the pipe wall that originated in the manufacturing process. Pits, or sites where rolled-in slugs have become dislodged, could be mistaken for corrosion. Other mill defects that either passed the original pipe inspection or were overlooked could contribute to local attack under the right environmental conditions. Scabs or laps under which water becomes trapped could promote local corrosion cells.

Type of Corrosion Attack

Valuable visual evidence can be collected simply by thoroughly characterizing the type of corrosion attack that is present. Determining the type of attack is identifying the physical manifestation of damage to the original metal surface—not determining the corrosion mechanism. This information is intimately related to the location of the corrosion and deposits as previously described, yet it is unique unto itself. In most cases, the physical forms of corrosion observed in oil and gas pipelines are not adequately diagnostic based on appearance alone; the damage must viewed in terms of prevailing environmental conditions in the pipe. Several physical types of corrosive attack are described below and representative figures are provided to guide the user in evaluating his or her own corrosion specimen. The forms given are not all-inclusive but represent some of those that would commonly be found in steel oil and gas piping.

Isolated Pitting Isolated pitting is present when pits occur singularly or in groups but the pits are not interconnected (see

Figure 1). Isolated pitting can also occur under scales as shown in Figure 2.

Isolated Pitting within Areas of General Corrosion General corrosion or etching may occur over large, continuous areas yet still contain isolated pits or clusters of pits (see Figure 3).

Interconnected Pitting Pitting may also be present in connected clusters or lines. This type of attack is manifested by numerous small pits growing together or by a few large pits that connect only after they have grown to a certain size. Interconnected pitting can be observed in the presence or absence of general corrosion, although when general corrosion is present it becomes more difficult to distinguish the precise form of attack. Figure 4 illustrates a group of severe isolated pits that are beginning to interconnect. Figure 5 depicts a group of larger pits that have already grown together to form one continuous axial pit. In Figure 6, narrow groups of pits that occurred at damaged internal flow coating in a gas pipeline are shown to interconnect, forming long, continuous pits.

General Metal Loss with Infrequent Pits Etching or nearly uniform attack may be the prevalent condition in some cases, with just a few scattered pits present.

Etching or General Metal Loss with No Pitting Occasionally, a system may contain aggressively corrosive fluids that result in relatively uniform attack of the pipe wall. Perfectly uniform attack is rarely observed in the presence of scale or deposits, however. An example of uniform attack is shown in Figure 7. This form of corrosion is observed infrequently in gas pipelines.

Selective Attack at Welds Girth welds and longitudinal seam welds may exhibit preferential attack of the weld metal or heat affected zone of the parent metal (Figure 8). The corrosion may be isolated or more severe at the weld area.

Crevice Corrosion at Flange Joints, Mechanical Joints, etc. Crevice corrosion is a form of concentration cell corrosion that occurs due to concentration or depletion of chemical species within a small area isolated from the bulk fluid stream. Welds, weld defects, flange faces, mechanical joints, and other features that form narrow crevices can experience corrosion in isolated areas while the rest of the pipeline is free of corrosion.

Erosion-corrosion Erosion-corrosion is the combined action of corrosion with erosion due to rapidly moving fluids and/or solid particles (Figure 9). The erosion serves to remove potentially protective corrosion products or films and accelerates the corrosion reaction. This form of corrosion is typically observed where there is an abrupt change in flow direction or velocity.

Environmental Cracking A variety of environmental cracking mechanisms are possible in pipelines, including stress corrosion cracking (SCC), corrosion fatigue, sulfide stress cracking (SSC), hydrogen induced cracking (HIC), etc. While these cracking phenomena are not typically found inside pipelines, they do exist and must be considered while conducting the corrosion investigation.

“Unique” Pit Morphology Since the publication of *MIC Field Guide*⁵ by GRI in 1988, many in the pipeline industry have equated certain corrosion morphology features with the presence of MIC on their pipe. These features included “cup-type hemispherical pits,” pits within pits, striations that run parallel to the longitudinal axis of the pipe, and micro- or macroscopic “tunnels” in the end walls of the pits. Some of these features are exhibited by the corrosion pit in Figure 10. Unfortunately, these morphological features alone are not diagnostic for MIC.⁶ Figure 11 depicts corrosion pitting at a girth weld that was proven, through comprehensive field and laboratory testing,⁷ to have resulted primarily from microbial activity. The corrosion in this figure bears none of the unique features typically attributed to MIC of pipelines.

As mentioned previously, corrosion morphology alone is simply insufficient evidence to confirm a given corrosion *mechanism*. Research has shown that metallurgical features, identical to those ascribed to MIC, can be produced by both organic and mineral acids.⁸ On a microscopic level, most of the steel pipe currently in service in the United States is far from homogeneous—chemically, metallurgically, or mechanically. Therefore, it is not unexpected that “unique” corrosion morphologies result under environmental and electrochemical conditions that differentiate these minor inconsistencies in structure.

All this being said, it is still of value to observe and note the detailed surface and cross-sectional morphology of the corrosion

being investigated. Much can be learned about how the corrosion progressed over time and how the corrosive environment specifically affected the material. For example, metallurgical examination can determine whether selective attack of certain phases of the structure occurred. Some examples of pit cross-sectional morphologies are shown in Figure 12.

Internal Conditions during Inspection

Wet or Dry Document whether the pipe was wet or dry when it was first cut open for inspection. Note whether the entire surface was wetted and whether liquids were settled along the bottom of the pipe.

Debris, Scale, Deposits Describe the type, amount, and location of these materials that may be present.

Color of Deposits, Scale, etc. Upon exposure to air, the colors of corrosion products and deposits can rapidly change. Make note of the colors of these materials when the inside of the pipe is first exposed. Document the color of the deposits with photography whenever possible.

Smell Hydrogen sulfide is a corrosive gas that has a characteristic “rotten egg” odor. Record this information, if detected.

Severity

The severity of the corrosion can be established both through visual observation and physical measurements. Again, consider information about the relative severity of the corrosion in light of other visual evidence already discussed. Identify where the corrosion is most severe relative to its location in the pipe, the presence of scale or deposits, operational factors, and so on. Dimensional documentation of the corrosion is also important, particularly from an integrity point of view. The corrosion may look “bad” to the investigator in the field, but numerical data is needed to make engineering decisions and calculate actual corrosion rates.

Longitudinal Extent Describe how far the corrosion extends down the longitudinal axis of the pipe. This information may

show the extent of a low spot or sag where liquids collected. Determine if the severity is consistent for the entire length.

Circumferential Extent The extent to which corrosion is present about the circumference of the pipe is valuable information, as it can show whether corrosion occurred primarily in the liquid or gas phase, or both. Note whether the severity and type of attack is consistent throughout the circumference of the pipe.

Maximum Wall Loss Using a pit gauge or ultrasonic wall thickness gauge, measure and record the deepest corrosion or thinnest wall caused by the corrosion. In the case of through-wall corrosion, the wall loss has clearly occurred to the maximum extent.

Profile of Wall Loss A profile of the corrosion depth (or a profile of the remaining wall) is useful information for determining the stress levels in the pipe and whether or not the pipe is safe for service. Several software tools are currently available to easily perform this analysis such as RSTRENG or KAPA. The profile is measured along the longitudinal axis in the deepest areas of interconnected corrosion. Ideally, measurements should be taken at .25 in (.635 cm) intervals over the full length of the worst corrosion area.

Maximum/Average Pit Depth Attempt to identify and measure the maximum pit depth and typical or average pit depth. This information is useful in calculating pitting rates. Note the locations of the deepest pits in the pipe.

Maximum/Average Pit Diameter Maximum pit diameter is useful information for describing the extent to which pits are growing laterally. It is also used to calculate depth/diameter ratio.

Pit Length vs Pit Width Examining the typical length and width of the pits and comparing this data with other operating factors indicates whether there is a preferred orientation to the pitting. Pits that are elongated axially with the pipe suggest that flow or possibly pipe metallurgy may be affecting the corrosion mechanism.

Depth/Diameter Ratio Both average depth/average diameter and maximum depth/maximum diameter ratios help to characterize how the pitting is manifested in the pipe. A large depth/diameter ratio indicates a tendency for rapid penetration of the wall via very focused anodic sites.

TABLE 3 Visual Evidence Checklist

Location of Corrosion	Observations
Physical location of pipe	
Clock position in the pipe	
Relationship to other features:	
System design (dead leg, drip, etc.)	
Elevation of pipeline (low spot)	
Girth welds or mechanical joints	
Longitudinal weld seams	
Directional change in flow	
Inlets, outlets, taps, fittings	
Heat sources or temperature change	
Historical liquid levels in pipe	
Deposits, coating, debris	
Nodules	
Scale	
Biological materials	
Chemical injection	
Processing equipment	
Construction/material changes	
Pipe mill defects	
Type of Corrosion Attack	
Isolated pitting	
Isolated pitting within areas of general corrosion	
Linked pitting within areas of general corrosion	

TABLE 3 (Cont.)

Type of Corrosion Attack	Observations
General metal loss with some deeper pits	
Etching or general metal loss with no pitting	
Selective attack at welds	
Crevice corrosion (at flange joints, mechanical joints)	
Erosion-corrosion	
Environmental cracking	
Pit surface and cross-section morphology	
Internal Conditions during Inspection	
Wet or dry	
Debris, scale, deposits	
Color of deposits, scale, etc.	
Smell	
Severity	
Longitudinal extent	
Circumferential extent	
Maximum wall loss	
Profile of wall loss	
Maximum/average pit depth	
Maximum/average pit diameter	
Pit length vs pit width	
Depth/diameter ratio	

Physical Evidence

When most people think of a criminal investigation or court case, the significance of physical evidence usually comes to mind. Fingerprints, photographs, DNA, weapons, vehicles—all are real, physical things that can be used to identify the culprit of a crime. The same concept follows for identifying the cause of internal corrosion. Physical evidence is a very important part of the corrosion investigation. It often must be collected and preserved soon after the crime is discovered or it will be lost.

Unless an investigator knows what to look for at the corrosion scene and the potential significance of various types of evidence, physical evidence can easily be overlooked or destroyed. There are two primary ways in which physical evidence is lost: intentional actions performed on the pipe and unintentional changes that result from how the pipe is handled. Intentional actions such as water washing, sandblasting, wire brushing, and scraping the internal surface of the pipe usually displace or remove most of the chemical, biological, and physical evidence that may have been present. Unintentional changes to the pipe and related physical evidence will occur when the pipe is cut out and left to bake in the hot sun, exposed to the elements, or dragged through the dust and dirt along the right-of-way. Loss or alteration of physical evidence due to these actions could ultimately mean that the cause of the corrosion will not be able to be determined. Thus, the ability to understand the cause and develop preventative measures is also lost.

In order to collect the maximum amount of information possible in a corrosion investigation, it is clearly important that the investigator be present when the pipe is first cut out to collect representative samples and to protect the evidence from alteration. Further, if the investigator understands the potential significance of the evidence that may be there at the scene, he or she is able to guide the efforts of others to protect and preserve that evidence.

An internally corroded pipe, with all of its associated deposits and corrosion products, can be likened to an archaeological dig site. Over time, events occurred at the site that have left changes to the pipe wall or have left deposits and other materials. Archaeologists gather information from a dig site by carefully noting the position of the materials they find there. They methodically examine and document each layer as they excavate further into the site. The depth of each layer

and the artifacts discovered provide valuable information about what has occurred over time at the site. The same is true for many internal corrosion sites. Unless something has happened to drastically alter the conditions (such as recent pigging, for example), there is information present that may tell the story of what has happened over a period of history.

The following types of physical evidence may be collected from an internally corroded pipeline. A checklist of physical evidence is provided in Table 4.

Pipe—Corrosion Leak or Failure Site The most obvious physical evidence is where the corrosion was discovered in the first place, either by visual inspection, in-line inspection tool, leak, or rupture. In the case of leak or rupture, the original internal condition of the pipe has usually been drastically altered by the flowing product or post-rupture events. Sometimes the only remaining evidence of corrosion is wall loss.

Pipe—Undisturbed Obtaining a sample of the pipe from an undisturbed area, particularly in the case of a leak or rupture, is important to understand the true internal condition of the pipe before the catastrophic event occurred. Also, in cases where the pipeline has been only recently pigged, obtaining a pipe sample from a nearby non-piggable section could be important to illustrate the conditions that existed prior to pigging. This sample could come from a nearby lateral line, drip, fitting, or surface piping in the case of production facilities.

Pipe—Cleaned Although much emphasis has been placed on not disturbing any deposits and scale present on the pipe, there is also benefit in obtaining a representative pipe sample that can be cleaned for dimensional examination of the corrosion damage alone. Tenacious deposits and scale often hide the true extent of corrosion damage; therefore, blasting with sand or ground walnut shells can help reveal the corrosion so that accurate measurements can be made. Keep in mind that blasting and chemical cleaning will alter the true morphology of the attack and that cleaned pipe should be used primarily for dimensional analysis.

Liquids—Source For gas pipelines, identifying potential liquid sources upstream of the corrosion investigation site and collecting samples at those locations can provide information about

the environment inside the pipeline. Liquids may also enter gas pipelines as the result of unusual or upset conditions; thus it may be difficult to obtain representative liquid samples at potential input sites. In the case of liquid pipelines, the investigation should attempt to characterize the quality of the products in the line and look for potential contaminants.

Liquids—Corrosion Site When the corrosion site is first exposed and cut open, it may be possible to collect a liquid sample at that time. The investigator should be prepared to collect that sample for on-site and subsequent laboratory analysis.

Gas—Source For gas pipelines, physical evidence in the form of gas samples for on-site and laboratory analysis should be collected from all potential upstream sources.

Gas—Corrosion Site In most cases, a pipeline will be purged prior to making a cut; therefore, collecting a gas sample at the corrosion site is pointless. If corrosion happens to occur at or near a well, it would be useful to collect a gas sample there for analysis.

Sludge Sludge may be present in the bottom or on the walls of the pipe and should be collected as physical evidence for analysis. Note where the sludge is located in the pipe and whether it is consistent throughout. Variations in color or other physical characteristics that appear through the thickness of the sludge should be noted.

Deposits Deposits are materials that were left in the pipe by the transported material or debris carried by product flow. Deposits are important physical evidence to collect as they often contain clues regarding the chemical species involved in the corrosion mechanism. Different deposits may be present at various locations about the circumference of the pipe. For example, deposits on the top of the pipe reflect the gaseous environment and those on the bottom of the pipe may reflect a liquid environment. If any slight variation in deposits is suspected or observed within the pipe, deposits from those locations should be sampled and analyzed independently. If the inside of the pipe has been exposed to foreign material (dirt, ditch water, fire suppressant), make note of the contaminant and obtain a sample of the contaminating substance. Later, the effects of the contaminating material can be “subtracted” from the deposit analysis.

Scale Scale is the result of an interaction between the environment and the pipe wall and may also incorporate debris and precipitates. Scales may be quite thick or almost imperceptibly thin. A scale layer may be so well bonded to the pipe that a hammer and chisel is needed to remove it, while other scales are loose and easily flake off the pipe wall. Scale is useful physical evidence that helps identify the corrosion mechanisms taking place in the pipe. Once again, it is vital to note whether the nature of the scale is consistent throughout the pipeline and to record the physical characteristics of the scale itself. A tightly adhered, uniform, dense scale may be protective while a friable, irregular, porous scale may not.

Nodules Nodules (or tubercles) are small mounds of deposits that sometimes form over growing corrosion pits. Quite often, nodules appear in areas where a deposit or scale layer is present over the majority of the surface. It is important to identify the presence of nodules as they are a valuable clue to the corrosion mechanisms occurring in the pipe. Development of anodic sites beneath non-protective scales may also create nodule-like features where the scale bulges or blisters. Nodules can be disturbed or removed from the pipe wall by cleaning operations (pigging) or by rough handling during removal of the pipe. If nodules exist, be certain to collect a pipe sample that has intact nodules present.

Biofilms/Bacteria/Biological Matter In oil and gas pipelines it is often impossible to directly observe biological matter as one would in open water piping systems. Therefore, it is best for the corrosion investigator to simply assume that biological elements may be present in the pipe and to sample accordingly. As was mentioned for scale and deposits, be certain to collect unique samples from all distinguishable features such as nodules, general deposits, liquid level lines, pits, etc. Also look for foreign plant or animal matter that could have been accidentally introduced into the pipeline during construction or cleaning operations. It is vital to collect samples for microbial analysis immediately after the pipe is cut out, as air exposure and desiccation of the biofilm will quickly alter or destroy the biological conditions that were present. Detailed information about sampling microbial conditions is given in Chapter 4.

Embedments/Replicas Another type of physical evidence that is a little more technically involved to collect is an embedment or a replica. An embedment is made by encapsulating a portion of the pipe surface and associated deposits in a liquid plastic resin. A replica is made using a plastic or silicone material to duplicate the dimensions and profile of the corrosion. Embedments capture the deposits and biofilm and their relation to the corrosion, while replicas are primarily intended to capture the dimensions and physical appearance of the corrosion. The embedment process is also described in Chapter 4.

Coating For pipelines that are internally coated, it may be valuable to collect some of the coating for subsequent identification. Physical evidence regarding the condition of the coating should also be collected. It may be possible that the wrong coating was used, the coating was improperly applied, or perhaps the line was not supposed to be internally coated at all.

TABLE 4 Physical Evidence Checklist

Physical Evidence	Notes
Pipe—Corrosion leak or failure	
Pipe—Undisturbed	
Pipe—Cleaned	
Liquids—Source	
Liquids—Corrosion Site	
Gas—Source	
Gas—Corrosion Site	
Sludge	
Deposits	
Scale	
Nodules	
Biofilms/bacteria/biological matter	
Embedments/Replicas	
Coating	

Circumstantial Evidence

Circumstantial evidence is information that helps describe the operating conditions in the pipeline that resulted in the corrosive environment. Much of this evidence is historical data that may be gleaned from construction and operating records and from interviews with operations personnel. Circumstantial evidence is not always directly observable during the field investigation. In most cases, the corrosion investigator will need to do some “research” to retrieve this information.

The following types of circumstantial evidence may be collected during the investigation of an internally corroded pipeline. A checklist of circumstantial evidence is provided in Table 5.

Pressure Knowledge of the maximum allowable operating pressure (MAOP), design pressure, and typical operating pressure is useful in calculating pipe stress and partial pressure of gas components. For liquid pipelines, pressure cycle history (frequency and amplitude) is important.

Temperature As mentioned earlier, increased temperatures generally result in higher corrosion rates. Consider upstream sources of higher temperature product.

Typical Flow Rates Flow rates can be used to examine surface velocities along the pipe wall and can help describe the type of flow in mixed phase systems. This information is useful when dealing with erosion-corrosion issues and for evaluating potential mitigation strategies. For example, low velocity two-phase fluids subject to laminar flow are problematic in dispersing certain types of inhibitors. Flow modeling software can also be used to predict where liquid hold-up may occur in the system under certain operating conditions.

Liquid Volume Records This information is useful both for tracking the sources of liquids entering the pipeline and in determining required treatment chemical volumes, if such treatment becomes necessary.

Liquid Composition Records Liquid analysis records are extremely valuable when reviewing the historical environmental conditions that existed in the pipeline. It is possible that such records have been maintained to satisfy quality control issues at sales points or in the investigation of operational problems.

Gas Composition Records Review of gas composition records from sales points on a pipeline can reveal much information about the operating conditions in the pipe. NACE standards indicate that CO₂ partial pressure less than 3 psia can be considered non-corrosive and API standards indicate that CO₂ partial pressure less than 7 psia can be considered non-corrosive. The significance of these values, however, depends on other environmental conditions in the pipeline as well, such as water content and temperature. Studies have shown that H₂S and CO₂ ratios can be used to determine the type of corrosion products and corrosion rate. NACE MR0175 indicates that sulfide stress cracking is not expected at H₂S partial pressures less than 0.05 psia. Gas composition values obtained from a sample point at one location are normally considered representative of the gas stream at any other location in the pipeline section for which there are no other sources.

Materials Materials used in the construction of the pipeline may have an influence on where corrosion is observed and what form it takes. Knowledge of the materials involved can help explain why corrosion occurred where it did and may point to options for remediation. Some materials considerations follow.

Age of Pipe The age of the pipe helps indicate the probable steelmaking process and manufacturing technology used to make the pipe. These two factors influence the chemical, metallurgical, and mechanical properties of the pipe. Older pipe, for example, may have a much higher number of manganese sulfide inclusions, which can serve as corrosion initiation sites. Sometimes when newer pipe is installed in older piping systems, more aggressive corrosion occurs in the newer pipe.

Grade/Manufacturer Knowing the specifications and grade to which the pipe was made will provide information about the minimum chemical and mechanical properties.

Type of Seam/Seamless Certain types of electric resistance welded (ERW) longitudinal seams are susceptible to selective seam attack of the fusion line and heat-affected zone of the weld. The wall thickness of older seamless pipe may vary significantly about the circumference as a result of the

manufacturing process. This is important to realize when making wall thickness measurements of corroded areas.

Welding Procedures Anytime welding is used to join pipe, whether in the long seam or girth welds, profound chemical and metallurgical changes occur. Corrosion tends to focus on inhomogeneities within a system; therefore, welds are a likely place for corrosion to manifest itself. Understanding the welding process and procedures used to join the pipe provides the corrosion investigator information about how different the weld may be from the surrounding pipe. Quality of the completed welds also plays a role in promoting or minimizing corrosion. Welds that exhibit poor workmanship at the inner diameter of the pipe will cause greater disruption in local flow conditions or provide crevices in which corrosion can take hold. Also, when a large crater is observed within a pipeline girth weld, investigators would be wise to not immediately conclude that the feature is a corrosion pit; it may in fact be a burn-through or large area of non-fusion.

Design and Construction Practices In the case of natural gas pipelines, the first thing to look for (in terms of corrosion susceptibility) is where liquids will accumulate. This could be an intentional point like a drip or separator or an unintentional spot like an unused bypass or dead leg to an abandoned system. Liquids also accumulate at low spots such as river and road crossings, particularly when there is a large elevation change over a short distance. Low spots can also be accumulation points for water or contaminant build-up in pipelines. Flow modeling programs are now available that can help locate points where liquids could accumulate and where internal corrosion could be the most severe. Also look for construction practices that result in drastic changes to the flow direction or velocity. Such locations could be susceptible to erosion-corrosion.

Hydrostatic Test Records It is valuable to know when the pipeline was hydrostatically tested, to what pressure, and, if possible, determine the source of test water. Fresh, oxygenated surface waters typically contain a wealth of microorganisms that may serve to inoculate the pipeline with bacteria if the line is not properly dewatered and dried. Even without regard for bacteria,

test water left in the pipeline for extended periods can initiate corrosion.

Maintenance Operating records may provide valuable information in determining whether the pipeline was routinely maintained. These records could provide information about routine cleaning operations, repairs that were made, and ongoing inspection results.

Cleaning Records of any internal cleaning or pigging operations will indicate whether the internal surface was disturbed and how often. It is also important to determine whether cleaning chemicals or solvents were used in maintaining the pipeline, as those chemicals would affect any deposits and scale present as well.

Repairs Reviewing the repair history of the pipeline could indicate where problems have occurred historically and help point to potential causes. With this information, an investigator can also look for relationships between internal corrosion and replacement materials.

Inspection Certainly, internal inspection records would be valuable information, whether they originate from visual inspections or in-line inspection tools. Again, this information can be used to examine where internal corrosion has been identified on a larger scale in the system and hopefully related to other causative factors.

Treatments Bulk treatments to the product stream can result in compositional, temperature, and flow changes. Operating information regarding treatments to the product stream such as inhibitor injection, dehydration, stripping, freeze protection, and so on, is useful in characterizing the internal operating environment of the pipe. It is essential that the location of the treatments relative to the corrosion be determined as sometimes the treatments themselves are directly implicated in the corrosion mechanism.

Internal Corrosion Investigators should identify any inhibitor use in the system, whether continuously injected or batch applied. Also look for biocide application records. Determining the type of chemicals used and the application frequency is very important.

Dehydration The relationship between the location of the internal corrosion and any gas dehydration facilities should

TABLE 5 Circumstantial Evidence Checklist

Evidence Type	Notes
Pressure	
Temperature	
Flow Rates—Typical	
Liquid volume records	
Liquid/gas composition records	
Materials	
Age of pipe	
Grade/manufacturer	
Type of seam/seamless	
Welding procedures	
Design and construction practices	
Hydrostatic test records	
Maintenance	
Cleaning	
Repairs	
Inspection	
Treatments	
Internal corrosion	
Dehydration	
CO ₂ or H ₂ S processing	
Freeze protection	
Replacement	
History	
Outside influences	

be examined. Corrosion may occur upstream, downstream, or within the dehydration equipment. For internal corrosion within gas plant facilities, consider that salts and other contaminants often collect in the dehydration system. This makes the dehydration unit a good place to look for corrosive materials carried in the gas stream.

CO₂ or H₂S Processing The fact that such processing equipment is in use in natural gas facilities indicates that potentially corrosive gas constituents are present. As part of the investigation, determine whether or not the equipment is actually reducing CO₂ or H₂S to the output levels for which it was designed.

Freeze Protection Glycol or alcohol drips can affect the chemistry of the internal corrosion environment. Glycol has an affinity for water and corrosive gas.

Replacement As with other maintenance records, historical information regarding pipe replacement may indicate where problems have occurred in the past. If pipe has recently been replaced, the old pipe may be available for examination.

History This all-encompassing category includes when the line was installed, what has been transported over the years, the leak and break history, etc. Pipelines that have been converted from one commodity to another, or that have been transferred between various owners, may be difficult to research.

Outside Influences Infrequently, outside influences may have an effect on the nature and location of internal corrosion in a pipeline. Where two lines are in close proximity for example, the heat from one pipeline may migrate to the adjacent pipeline, resulting in higher corrosion rates in that particular area. Strange things are known to happen in the real world and the corrosion investigator needs to approach each case with his or her eyes open.

Hopefully, this chapter has increased your awareness of the many types of evidence that can be used to help identify the causes of internal corrosion. Remember to remain objective, gather as many facts as possible, and look for the “big picture” during the gathering process. In the next chapter we move on to the field site where many of the observations just described will be performed.

Conducting a Field Investigation

Organizing the Field Investigation

Conducting a successful internal corrosion investigation requires that the people, equipment, and procedures needed to do the job are all ready to go before the investigation begins. In Chapter 2, the importance of having a corrosion investigation plan was emphasized. In Chapter 4, we will look at the specifics of what happens during the field portion of a corrosion investigation. The information presented here can be used to fine-tune the corrosion investigation plan and make it specific to the situations of individual companies.

Who Will Do What?

Good organization and planning will always answer the question, “Who will do what particular task?” This goes beyond simply knowing who will go down in the hole and look at the pipe or, worse yet, who to send the cut pipe to after it bounced around in the back of a pickup truck for days or weeks.

When building the investigation team, consider:

- Who will do the corrosion investigation? Company personnel? Outside consultants? Both? For what part of the investigation is each party responsible?
- Who will notify those conducting the investigation that their services are required? Timing of notification is critical so that investigators can be on-site before the pipe is cut. Have a backup plan in case the primary investigator is unavailable.

- Who will do the excavation and cut the pipe? Are those people aware that they should not cut the pipeline before corrosion investigation personnel are on the scene?
- Who will assist the corrosion investigators in collecting samples from adjoining facilities? Who will provide historical operating information needed to support the investigation?
- Who will help prepare the pipe samples for shipping to the analytical laboratory, if needed?
- Who will review the results of the investigation and use that information to determine whether monitoring and/or mitigation measures are required?
- Who is responsible for developing the overall internal corrosion investigation plan? Who will coordinate training?
- Who will budget for and provide the equipment and supplies needed by investigators to conduct the field analysis?

Determine who will be responsible for various aspects of the corrosion investigation before they are actually needed. Meet with those people and discuss assigned responsibilities and coordination with the others involved. Be certain that contact information for all members of the corrosion investigation “team” is current. Advance communication of expectations and procedures is absolutely vital since most corrosion investigations are initiated on very short notice, such as when a pipeline leak or rupture occurs.

Equipment, Supplies, and Procedures

Equipment and testing supplies need to be available immediately when a corrosion investigation is requested; therefore, these items must be procured in advance and located strategically for accessibility. If only one or two people within an organization are responsible for the complete corrosion investigation, these employees can be fully equipped using easily transportable cases. If the investigators will need to fly to the corrosion site using commercial air transportation, be sure to determine in advance whether all of the supplies are acceptable to be carried in checked luggage. Given the new security controls recently instituted for carry-on luggage, it is now nearly impossible to bring

the corrosion investigation kit into the passenger compartment of a commercial aircraft. If a large company chooses to have a number of technicians trained in each region of their operation, each of these personnel must have ready access to investigation supplies and equipment.

Only a modest amount of equipment is needed to conduct an internal corrosion investigation. A portable pH meter, a decent camera, a few measuring tools, and perhaps an ultrasonic wall thickness meter are the primary needs. Likewise, the supplies needed for field testing and sample collection are not extensive unless very comprehensive analysis is routinely performed. The specific equipment and supplies required for dimensional documentation and chemical/microbial testing during a field investigation are listed later in this chapter where those tests are described.

The best tools and supplies cannot provide useful information unless they are consistently used in accordance with technically correct procedures. The corrosion investigation scene is not the place to attempt using new equipment or test methods for the first time. Corrosion investigators must be familiar with the contents of their corrosion tool kits and understand the procedures for using the tools available to them. The best way to assure familiarity is through training. Formal training may actually be required if some corrosion investigation tasks fall under operator qualification rules.

Knowledgeable and consistent use of investigative procedures will help provide data that permits comparisons between all analyzed occurrences of internal corrosion within a company. This can be very useful when trying to determine the root cause of a corrosion problem and develop an appropriate response. Maintaining documented company procedures is also essential if the internal corrosion investigation data is to be used to support enterprise-wide integrity management efforts.

Practical Safety Issues

Working around a liquid or gas pipeline dig site requires advance planning, equipment, and training to ensure the safety of the investigator and other personnel on the site. Personnel performing the actual cutting of the pipe have additional responsibilities in regard to health, safety, and environmental concerns. Since nearly all companies have

operating procedures that address these issues on pipeline maintenance and repair projects, this guide will focus on the practical safety issues which are under the direct control of the investigator.

First, corrosion investigators should be equipped with the proper personal protective equipment (PPE), including hearing, head, eye, foot, and hand protection. Fire resistant clothing is also required to be worn by many pipeline companies. All PPE used by the investigator should meet ANSI or other prevailing standards, where applicable.

For ambient sound pressure levels between 85 and 115 db(A), ear plugs are the most frequently used form of hearing protection. Where noise levels on the job site exceed 115 db(A), dual protection (ear plugs and ear covering) is used. Investigators should wear a hard hat that meets the minimum standards of ANSI Z89.1.1997 or equivalent. Safety shoes or boots conforming to ANSI Z41.1 are also recommended. Two levels of eye protection may be required on the job site: ANSI-approved safety glasses for general work and a face shield or other full coverage protection for use when grinding or working with hazardous chemicals. Some testing procedures performed by the corrosion investigator will require the full face coverage. At least two forms of hand protection will also be needed on the job site. Latex or nitrile chemical-resistant gloves should be worn while collecting samples for chemical or microbial analysis. In addition, heavy cloth or leather gloves are needed for handling heavy pipe sections with sharp edges. Finally, coveralls or other rugged work clothing helps protect from accidental scrapes against sharp objects and, of course, preserves one's street clothes. Depending on the circumstances at the work site, flame-resistant clothing may be required, or at least advisable. Respiratory protection may also be required in certain work environments where airborne particulate matter is generated or where organic vapors are present.

Working in industrial environments could expose the corrosion investigator to a number of potentially hazardous materials such as radioactive scale, hydrogen sulfide, asbestos, PCB's and aggressive chemicals. The US Department of Labor—Occupational Health and Safety Administration (OSHA) provides occupational exposure limits for many of these materials. Additional guidance regarding exposure to hazardous materials can be found in 29 CFR Part 1910 "Occupational Safety and Health Standards." Naturally occurring radioactive

materials (NORM) are present in some oil and gas gathering facilities where water is produced. The primary safety concern when handling NORM scales and deposits is to prevent contact and ingestion of the radioactive particles. NORM containing materials also present a disposal problem.

Hydrogen sulfide is a gas that can cause loss of consciousness or death. At very low concentrations, H_2S has a characteristic rotten egg odor; however, exposure to the gas quickly deadens the sense of smell. Extreme caution must be used when working around hydrogen sulfide. Iron sulfide is a product of the reaction between steel pipe and H_2S and is capable of spontaneous combustion when exposed to air. Heating and combustion of iron sulfide is typically controlled by eliminating exposure to oxygen or wetting the deposits. Asbestos, like NORM, is an ingestion hazard, particularly by inhalation. Some pipeline coatings and insulation materials are known to contain asbestos. Asbestos is usually controlled by keeping the material wet during removal to prevent particles from becoming airborne. Proper PPE is required when working around asbestos and removal can typically only be performed by trained personnel. The investigator can be exposed to PCB's or aggressive chemicals either from the system being investigated or during some chemical field tests. It is important to be aware of any solvents or acids used in cleaning the pipeline, if cleaning was performed prior to the cut out. Also, the pipeline contents may contain light hydrocarbons, benzene, or other hazardous chemicals. High concentrations of corrosion inhibitor or biocides could also be experienced if those materials accumulated near the cut point. Specific chemical hazards in the chemical and microbial field tests will be discussed in those particular sections.

Common sense and good communication go a long way in ensuring safety on the corrosion investigation site. The investigator needs to be conscious of the activities going on at the job site and stay clear during those tasks where his or her presence is not essential. Working around excavations and heavy equipment requires one to pay attention to the surroundings. The investigator should discuss the investigation plan with the site supervisor before proceeding. It is wise to identify the hazards specific to the work site and determine how the investigation activities will fit in to the overall work schedule at the site. For example, it may be extremely difficult or dangerous to keep an excavation open for very long; thus, most of the analysis will have to be

performed after a pipe section has been cut and moved to a safe area. Flammable gas or vapors may preclude the use of flash photography—ask first! It is quite embarrassing to cause a sudden emergency blow down of a compressor station with one's flash.

Finally, a word on environmental concerns. As stated earlier, the best policy an investigator can adopt is to leave nothing behind at the field investigation site. No chemicals or solid waste should be disposed of in the excavation or on the ground. Syringes used for inoculating bacterial growth media must be destroyed and disposed of in accordance with state regulations. A “sharps” container can be carried to safely transport the used needles. Leaving nothing behind helps ensure that state and federal environmental regulations are met.

Organization Checklist

Table 6 is a checklist that can be incorporated into the internal corrosion investigation plan developed by specific companies. This list can also be used to identify the members of the corrosion investigation team and to facilitate communication between the team members by adding their contact information. Be sure to use this checklist early in the plan development process; once a leak or rupture occurs, there will be no time to prepare individuals for their responsibilities.

Data Collection at the Corrosion Site

In the remainder of this chapter we will be looking at the tasks that are performed by the field investigators. These tasks include data collection, sample collection, and on-site testing.

When You Arrive on the Scene

In many cases, the discovery of internal corrosion is an unusual event that is unexpected and unplanned. When this happens, the corrosion investigator may not be called until the last minute, or until after the pipe has been cut out for some time. In fact, the latter is probably the most common scenario. Nobody plans for internal corrosion to occur.

Sometimes the corrosion is associated with a leak, rupture, or fire, in which case the original conditions at the corrosion site have been

TABLE 6 Organization Checklist

Assignment of Tasks:	Who will do this task?
Field investigations (centrally located or regionally located)	
Lab investigations	
Coordinate and oversee lab work	
Mobilize investigators	
Maintain current contact information for the investigation team	
Excavation of pipe and field work	
Collect samples from nearby facilities	
Provide historical operating records	
Prepare pipe samples for shipping	
Review investigation results and determine future course of action	
Write internal corrosion investigation plan	
Coordinate training	
Budget for equipment, supplies, and labor needs for investigation	
Determine where investigation tools and supplies will be maintained	
Ensure investigators have necessary PPE and are trained in its use	
Communicate process hazards to investigators	
Coordinate investigation activities with job site supervision	
Communicate company environmental policies to investigators	
Provide operator qualification training to investigators as needed	

significantly altered. It is nearly impossible to collect viable bacteria at a failure site that was recently over 1000° F (538° C), for example. Further, the pipeline (or cut-out) may have been flooded with water from the ditch, sprayed liberally with dry powder fire suppressant, washed with solvents, sandblasted, wire brushed, baked in the sun, dragged through the dirt, picked at with pocket knives, and had numerous greasy fingers poked into the pits and any other significant features present prior to your arrival. Even extended exposure to air is enough to seriously alter the conditions that were once present in the pipe. What is a corrosion investigator to do?

“Protect all evidence” is the most important rule to guide the on-site investigation and other activities that may affect the condition of the pipe. The corrosion investigator’s first job is to *protect all evidence* from being lost or altered. As stated above, corrosion evidence can be subjected to a host of perils before it is safely in the hands of the investigator. Upon arrival at the scene, the investigator must assess and deal with whatever alteration or degradation of evidence has occurred. He or she must also take steps to stop further loss or degradation of corrosion evidence.

First, let us imagine a perfect situation where the pipe has not been cut before the investigator arrives on site. This imaginary pipe is in a gas or oil gathering system and is being excavated because a small leak is suspected. The line is exposed and the investigator notes that there is a low spot or sag in the pipe. There could be liquid accumulation here. The 4-in (10.16 cm) diameter pipe is cold-cut with a saw or pipe cutter (no fire to consume the evidence). The investigator has a sample container ready and catches a liquid (water) sample when the pipe is first cut. Field tests for pH and dissolved CO₂ and H₂S are performed immediately. The rest of the liquid will be used for lab analysis. Bacterial culture media is inoculated from the liquid sample.

The cut section is now examined. The internal surface is still wet and a thin layer of sludge is present along the bottom of the pipe where there are corrosion pits of various sizes. It is confirmed that a small leak was present due to a through-wall pit that started inside the pipe. The investigator notes and photographs the internal condition of the pipe before taking any samples. Now some of the sludge layer from a specific, small area is collected in a sterile sample container—the rest of the layer is left undisturbed. The sludge layer is subjected to chemical and microbial field tests and the remainder is preserved for laboratory analysis.

There is no scale layer observed in the pipe; however, there are some deposits built up around the corrosion pits. One or two pits are selected for microbial analysis of the associated deposits. The pits are carefully swabbed with a sterile applicator and the pit contents are tested for viable bacteria. The pit deposits are substantial enough that qualitative analysis for iron sulfide can be performed. Most of the sample surface is still undisturbed by the sampling procedures. Field testing on the cut out sample is now completed and the ends of the pipe are sealed with plastic sheeting to prevent foreign material from entering the pipe. The pipe is transported to a laboratory for comprehensive analysis. Field examination of the corrosion damage is accomplished by carefully cleaning the sludge and deposits from the surface of the pipe adjoining the cut out. Photographic and dimensional documentation of the bare pipe surface is obtained. Two potential upstream liquid sources are identified during conversations with field personnel. Liquid samples from those locations are also collected for field and lab analysis. Operating history information about gas and liquid composition for this system is also collected.

The scenario just described would have produced an abundance of information which the corrosion investigator could use to determine the cause of the attack. Let's quickly review all of the evidence that was collected:

- Physical location information describing the pipe in a low spot and contained liquids.
- Liquid sample from leak site for chemical and microbial field tests and subsequent lab analysis.
- Internal pitting confirmed as cause of leak. Photo documentation of pipe internal condition is collected before disturbing surface.
- Sludge sample from leak site for chemical and microbial field tests and subsequent lab analysis.
- Deposits specific to the pits sampled for microbial analysis and on-site chemical testing.
- Initial field exam and documentation of pipe surface, cleaned to reveal the extent and nature of corrosion damage.
- Potential source liquids sampled for field and lab analysis.

- Operating history data obtained.
- Pipe sample preserved for subsequent laboratory analysis.

Certainly this story represents ideal conditions where the investigator is informed prior to the cut out and he or she comes prepared with a plan and the equipment necessary to do the job. This can actually happen in real life, if advance planning is taken seriously.

Now let's consider how the corrosion investigator should respond when less than ideal situations occur. Remember "Protect all evidence" is rule #1. The second rule is, "Collect all evidence."

The most common problem to be faced by corrosion investigators is the pipe having been cut prior to their arrival on the scene—perhaps days prior to their arrival. The first course of action is to protect what evidence is left from further degradation. Get the pipe sample into a clean, dry location or at least seal the ends of the pipe with something. Then attempt to determine when the pipe was cut and what it was exposed to. Was the pipe washed out with something? Collect a sample, if possible. Was it left exposed to dust and dirt along the right-of-way? Collect a sample of the dust and dirt. Did it get covered with dry chemical fire suppressant? Collect a sample. Why collect all of this stuff that has nothing to do with corrosion? Remember rule #2: Collect all evidence.

The pipe sample may contain evidence of "pipeline" origin and material of "non-pipeline" origin. An investigator needs to identify the material of "non-pipeline" origin so that it can be subtracted from "pipeline" origin material later in the investigation. It is also helpful to know what was introduced into the pipe sample after it was cut so that the effects of the foreign material on the pipe and corrosion products can be considered. If the pipe sample became contaminated with fresh water from the excavation; for example, then bacterial testing results of the corrosion deposits would certainly be regarded warily. "Collect all evidence" is a reminder that no evidence that affects the pipe sample should be overlooked, regardless of its source. It is always better to collect too much rather than too little.

Back to our less than ideal pipe sample. Let's say that the sample was not exposed to any unusual conditions but it was just cut and taken to a protected environment (indoors). Several days passed before the corrosion investigator arrived to examine the pipe. The pipe is now bone-dry but contains some deposits and scale. Once again,

the investigator should attempt to determine what conditions the pipe was exposed to prior to his or her arrival. If no contaminants were introduced, the investigator can proceed to sample the deposits and scale inside the pipe and collect photographic and dimensional documentation. Since the pipe is dry and has been exposed to oxygen for quite a while, the likelihood of recovering viable bacteria that represent the true internal conditions of the pipeline is minimal. In fact, it is likely that bacterial contamination from outside sources may have entered the pipe by this time. So, where does the investigator go for liquid chemistry and bacterial data? He should go back to the pipeline to find a representative liquid sample or pipe surface to sample for bacteria and deposits. This is the most reliable option for collecting evidence that is vitally important in determining the corrosion mechanism.

The idea of using representative pipe, liquid, and surface samples to supplement data from the actual cut out site is an important one. Particularly when the sample has been altered or evidence has been lost due to improper handling, attempting to obtain other representative samples is quite valuable. This is not always possible as the exact conditions present at the cut may not be duplicated anywhere else in the system. In most cases, however, some form of representative sampling can be performed. Where can such samples be obtained?

- At other cut outs or pipe maintenance activities near the corrosion site.
- Where spool pieces can be removed to provide internal access (at well head piping or meter runs, for example).
- At pipeline drips, separators, or pig traps.
- At any potential liquid source to the pipeline.

In summary, two rules guide the actions of the corrosion investigator upon arrival at the scene. These are the top priorities:

Rule #1—Protect all evidence.

Rule #2—Collect all evidence.

These rules seem deceptively simple; however, they require thought and attentiveness on the part of the investigator who is present to observe and collect as much information as possible.

TABLE 7 General Information Checklist

Date/Time of field investigation	
Date/Time corrosion was discovered	
Date/Time pipe was cut out from line	
Person reporting the corrosion	
Person requesting the investigation	
Field supervisor name	
Investigator name(s)	
How was the corrosion detected?	
Leak or rupture? Fire?	
Location of investigation	
Facility description (pipeline, plant, well head, other equipment)	
Facility identification (Line No., Milepost, Wheel count, station no.)	
GPS coordinates	
Pipe diameter and WT	
Pipe grade and specification	
Pipe year of manufacture	
Year of installation	
Joint design (welded, flanged, coupled)	
Internal coating? Type? Condition?	
Original construction or replacement pipe	
Pipe elevation/depth of cover	
Length of pipe cut out	
Method of cut out (hot or cold cut)	
Did foreign material enter the pipe prior to, or during, the cut?	

TABLE 7 (Cont.)

What foreign material entered the pipe?	
Was a sample obtained?	
Name of contract laboratory to be used	
Lab contact information	
How was the pipe preserved for shipping?	
Date pipe was shipped to lab for analysis	

What Information to Collect

For the sake of this analytical process, information will be considered facts and observations while evidence will be considered physical material that can be sampled and collected. Both information and evidence are essential to conducting a good corrosion investigation. This section addresses general information about the corrosion investigation site. Use the checklist in Table 7 to guide the information collection process. Individual companies using this list may want to expand on the site-specific information collected. The following section discusses operational information.

Operating Conditions

Information regarding historical operating conditions, although sometimes hard to obtain, is extremely valuable in helping establish the environment that contributed to the internal corrosion. Table 8 provides a list of information that the investigator can collect to help establish the conditions present inside the pipe. This list is not all-inclusive and can be amended to meet the needs of individual companies based on their operations and the product they transport.

While it is beneficial to collect this data as it currently applies to the pipeline, it is even more beneficial when this information is available for the entire time over which the pipe has been operated. Examining historical trends in throughput, liquid composition, pressure, and so on, may reveal when significant changes occurred that initiated the corrosive conditions in the pipeline.

TABLE 8 Operating Condition Checklist

Product transported	
Typical operating pressure	
Maximum operating pressure	
Number of pressure cycles per month	
Range of pressure cycles (psi)	
Typical range of operating temperatures	
Product analysis data	
—Gas analysis including dew point, carbon dioxide, and hydrogen sulfide	
—Liquid analysis including percent water, metals, and anions in water phase	
—Microbiological analysis results	
Identify source of transported product and all potential sources of contaminants	
Typical flow rate	
Operating mode (continuous, seasonal, intermittent, etc.)	
Distance to nearest compressor/pumping station	
Is the pipeline piggable?	
Has in-line inspection been performed?	
What is the leak/failure history?	
Were previous internal corrosion incidents analyzed? Report available?	
When was the last hydrostatic test?	
Are there currently operating pressure restrictions imposed on this line?	

TABLE 8 (Cont.)

Describe maintenance procedures performed	
Cleaning	
Repairs	
Inspection	
Describe all treatments	
Internal corrosion	
Dehydration	
CO ₂ or H ₂ S processing	
Freeze protection	

Methods of Documentation

Thus far, we are still exploring the information collection stage of the corrosion investigation. We have not yet ventured into collecting physical samples—that is coming in the next section of this chapter.

Three types of information must be documented: (1) background/operating information, (2) visual evidence, and (3) dimensional data. Background and operating information, as just discussed and listed in Tables 7 and 8, is documented in written or electronic form. Keep in mind that original field notes should always be kept, even when the data is later transcribed to an electronic or other more legible form.

Visual evidence (as listed in Chapter 3—Table 3) should be documented in written form and using some manner of photography. Today, digital color cameras are affordable, provide good color rendition, and store large amounts of image data. Electronic images can be easily transmitted to others for viewing at remote locations and can be incorporated directly into a report. One feature that is essential for a digital camera intended for corrosion investigation is the capability of macro-photography. A zoom feature is also beneficial as it allows close-up images to be taken from a distance, which lets more light onto the subject.

Dimensional data can be obtained in a number of ways. Common measuring tools include a retractable tape measure, steel rule, round and pointed anvil micrometers, and a dial indicator type pit gauge. Another very useful tool is the ultrasonic wall thickness meter (sometimes called a “D” meter) equipped with various diameters of transducers. One advantage of the ultrasonic meter is that it provides completely nondestructive measurement of the wall thickness from the external surface of the pipe. Therefore, the pipe does not have to be cut or the corrosion products disturbed in order to obtain measurements. The transducer diameter needs to be taken into account when measuring pit depth, however, because a large diameter transducer will not reveal the maximum depth of a smaller diameter pit. When measuring the wall thickness of pitted pipe, it is advisable to use a small diameter (.635 cm or 1/4” or less) transducer. Even pencil-point sized transducers are available.

Dimensional data also need to be recorded and in most cases this will mean making a scale diagram of the pipe and overlaying the dimensional information onto the diagram. Keep in mind that dimensional data includes not only wall thickness and pit depth measurements but documenting the physical location of corrosion features in relationship to the top and bottom of the pipe and each other. Stress analysis performed later in the investigation requires that the distance between pits be documented. Details about what dimensional and visual information to collect follow in the next section: “Nondestructive Inspection.”

Nondestructive Inspection

Nondestructive inspection usually implies the use of a specialized technique such as magnetic particle, ultrasonic, or radiographic inspection. While these methods may be used in corrosion investigation, visual and dimensional methods are the most significant nondestructive techniques for on-site analysis.

Evidence that must be documented in both written form and photographically is listed in Table 3 Visual Evidence Checklist. This checklist also lists a number of data points that should be documented using dimensional inspection.

A number of nondestructive techniques are commercially available today that make the job of finding internal corrosion much easier.

For inspection of pipe that is exposed, ultrasonic “B” scan technology can provide wall thickness maps of areas suspected of having internal corrosion and “A” scan technology provides a wall thickness profile along the inspection path. Depending on the equipment used to perform these analyses and the skill of the operator, wall thickness data accurate enough to be used in stress calculations can be obtained to facilitate informed decisions about the remaining integrity of the pipe. Thus, unnecessary expense and loss of service can sometimes be avoided by using these inspection technologies. Data from such inspections can also be used as part of the overall internal corrosion investigation of a system.

On a more sophisticated level, nondestructive integrity assessment is also provided by in-line inspection tools using magnetic flux leakage, ultrasound, and other technologies. Inspection data from in-line tools can be used to locate suspected areas of internal corrosion for evaluation and to determine the extent of corrosion damage in a pipeline. Reviewing in-line inspection results in light of other factors that support internal corrosion can help determine potential sources of the attack.

Data Collection Checklist

Table 9 reviews the types of background data that need to be collected in order to adequately perform the corrosion investigation. Keep in mind that, whenever possible, it is better to collect this information before the sample collection and field testing, since it may help guide those activities.

TABLE 9 Data Collection Summary Checklist

Data Collection Actions	Completed?
Collect general information (Table 7)	
Collect operating condition data (Table 8)	
Collect visual evidence (Table 3)	
Check for other nondestructive data	

Sample Collection Procedures

In this chapter, sample collection procedures are presented separately from field testing tasks. The reason for presenting the information in this order is that sampling and analysis are two distinct tasks that may be performed by different individuals. One person may obtain samples while another investigator performs field analysis and preservation of the samples. Of course, in many cases a single investigator must perform sampling and analysis and that is perfectly acceptable as long as certain tests are conducted within the required time frame. Bacterial culture testing or measuring dissolved gases in liquids, for example, must be conducted immediately after the samples are collected to obtain the most accurate results. It is usually beneficial for the corrosion investigator to have some assistance during the sample collection and field analysis phase of the investigation. Therefore, these procedures are presented in a way that will help define the responsibilities of everyone involved in the project. In some cases, it may be impossible for the investigator to be on the site when the cut is performed. In this case, it is helpful to have contingency plans ready so that other personnel on the site know what to sample and how to protect those samples until the investigator arrives.

What Should I Sample?

The basic types of samples to collect include gas, liquids, sludges or solids, and pipe. Specific information about the significance of these samples has already been discussed in Chapter 3. Knowing the potential significance of different types of samples helps the investigator to look for evidence that is relevant.

Gas Sampling

Collecting gas samples for subsequent laboratory analysis requires special procedures and equipment. Gas samples are commonly collected in stainless steel sample bottles (pressurized) or Tedlar® bags. Samples are commonly collected by attaching the sample container to a valve on the pipeline using a length of tubing. Typically, gas is allowed to flow through the container to purge out any remaining air and then the sample is gathered. Care must be taken in collecting and handling the gas samples to prevent degradation of the sample. Changes in

temperature, pressure, and exposure to sunlight after sample collection can result in immediate changes in the gas composition. If gas analysis is to be performed off-site, consult with the laboratory that will be performing the analysis to determine how the gas samples should be collected.

Hydrogen sulfide, being extremely reactive, is problematic when collecting samples for analyses to be performed off-site as the levels can drop quickly. The most reliable method for determining H_2S levels is to perform gas chromatography on-site using a portable chromatograph. Field chromatography requires a substantial investment in equipment and adequate training to achieve reliable results. The equipment can also be rather large and cumbersome, depending on the type of analysis desired. If the field chromatograph option is not possible, then field testing with stain tubes when the sample is collected is another good choice. Field analysis of the gas for CO_2 , water vapor, mercaptan sulfur, and other components can also be performed in the field using stain tubes. The use of stain tubes is explained later under "Gas Analysis."

Liquid Sampling

Liquid samples can sometimes be collected at the corrosion investigation site and also at potential liquid source locations upstream of the corrosion site. The first place to attempt collection of a liquid sample is at the site of the cut. Always have a clean sample container ready when the pipe is first cut. Collect at least 500 ml of liquid, if possible, in two 250 ml sample containers. Each sample bottle should be filled to the top to eliminate air and the bottle should be capped once it is full. Avoid touching the inside of the sample container with anything that could contaminate the sample. Keep one container sealed for lab analyses and use the other bottle for field tests. Often the sample to be used for laboratory analysis will be pre-treated with nitric acid to acidify the liquid sample and keep dissolved metals from precipitating. Typically, the sample for lab analysis is kept at a pH of less than two. This requirement should be coordinated in advance of any field sampling with the chemical analysis laboratory that will be performing the analyses. Be sure to properly label each container and record the date and time the sample was taken.

Liquid samples can also be obtained from either flowing (e.g., pipeline) or static (e.g., vessel, storage tank) systems that are potential

sources of liquids to the corrosion site. The samples should be obtained by first allowing the liquids to flow from the source for several seconds to flush the valve and associated piping of any foreign matter and/or dead-space material before collecting the sample. In some instances (such as with tank bottoms), a specially designed sampling apparatus is required. Samples just removed from high-pressure equipment may contain significant levels of dissolved gases. If the sample is immediately sealed in a leak-tight container, pressure could build up and cause the container to leak or rupture. Samples from high-pressure facilities may be left loosely sealed for a short time to prevent pressure from building up in the container.

When an oil-water emulsion is obtained, it is helpful to collect a larger total volume of sample and then let the phases separate by gravity so that the water phase can be collected. A 5 gallon (19-liter) container with a spigot at the bottom is handy for this. In some instances the sample may appear to be nearly all organic. If uncertain whether any water is present in an emulsion, Hydrion water finding test paper can be used.

Keep in mind that certain field tests need to be performed immediately after the samples are collected. If field testing cannot be performed on the samples right away, keep the samples sealed in a cool, dark place, if possible.

All applicable safety precautions should be used when collecting liquid samples. Pipeline facilities are operated at high pressure. Extreme care should be exercised by personnel collecting samples from in-service equipment. Always identify safety concerns and precautions to be taken in the event that a valve used for sampling malfunctions or a high-pressure surge blows the sample container and contents out of the sampler's hand. Sample valves are notorious for plugging with debris and then suddenly releasing a high-pressure stream of sample onto the sampler. Investigators should not stand in front of valves that appear to be plugged while trying to collect samples. Additional safety apparel must be worn if a specific chemical's Material Safety Data Sheets (MSDS) suggest the need for such apparel.

Solid / Sludge Sampling

Solids or sludges may be collected from piping and equipment that is opened for inspection. Solids could be present in the form of debris,

scale, or deposits. Sludge is usually a combination of solid material suspended in an organic or aqueous liquid. Biofilm or slime deposits could also be present.

Solid or sludge samples should be collected from defined areas of the pipe using clean, sterile implements. Soft, loosely adhered materials can be collected using a sterile tongue depressor or stainless steel spatula. Hard, tenacious deposits may require more vigorous scraping and chiseling to remove. Solids and sludges that are not completely dehydrated at the time of sampling should be kept moist and protected from air exposure. This can be accomplished by using sample containers of appropriate size that can be completely filled with the sample or using plastic sample bags (WhirlPak®) from which air can be mostly eliminated after placing the sample in the bag.

There are two issues to consider when collecting solid samples: (1) damaging other corrosion evidence, and (2) identifying the significance of the solids in terms of physical location.

In regard to the first issue, do not collect solid or sludge samples from the same area of pipe to be used for any subsequent laboratory analysis. Take the samples from an adjacent area of pipe that is representative of the conditions in the corroded area. Often, this is not difficult as the conditions inside the pipe are the same over quite a long area. The pipe section to be used for lab analysis should be preserved, as much as possible, in the condition it was found.

Second, solids and sludges may not be of uniform composition or origin on all areas of the pipe. Perhaps certain materials have settled on the very bottom of the pipe while other deposits have formed on the top of the pipe due to a corrosion reaction with the gas phase. In low-flow hydrocarbon piping, water typically creeps along the bottom of the pipeline. This greatly affects what solids are present on the bottom of the pipe vs what is found elsewhere. The person taking the samples must identify specifically where the sample is being taken from and must look carefully for any differences in color, texture, density, or composition in the solid materials present inside the piping. This information may be very important in helping to determine the root cause of the corrosion. Collect samples from any areas that appear the least bit different from each other.

If field analysis of the solids or sludges cannot be performed immediately, keep the samples in a cool, dark place, if possible. Be certain to properly label all samples collected.

Pipe Samples

In conducting a field investigation of internal corrosion, it is usually beneficial to remove sections from the pipeline to a different location for analysis and sampling. As mentioned earlier, some samples need to be collected and analyzed as soon as possible after the pipe is cut. Once this sampling is completed, however, other examinations and measurements can be taken with the pipe in a more workable location than in the ditch. In most cases of internal corrosion, there is more corrosion present in the pipeline beyond the site of a leak or isolated pit. When other representative areas of corrosion are present, several pipe samples can be taken if this does not interfere with the ongoing repair work being performed on the pipeline.

If laboratory analysis of the corrosion is to be performed, it is important that a pipe sample that has been minimally disturbed be obtained and preserved. Usually, a pipe section about 1 meter (3 feet) in length will provide sufficient material for all laboratory analysis. When possible, the pipe should be cut using a portable band saw or wheel-type pipe cutter to prevent torch cutting debris from entering the sample. When torch cutting is the only option, the accessible internal surfaces of the pipe can sometimes be protected by covering with pieces of plywood, sheet metal, aluminum foil, or even clean, wet rags. If cutting debris is simply unavoidable, do not attempt to clean the internal surfaces. Just note how the pipe was cut and let the laboratory investigators know how the pipe was sectioned. Using a permanent paint marker, be sure to mark relevant operating information on the pipe sample such as flow direction, top and bottom of the pipe, and location information such as mile post, wheel count, etc. Once the pipe sample for laboratory analysis has been cut and has cooled, seal the ends of the pipe with plastic sheeting and duct tape to prevent the introduction of foreign materials. If the inside of the pipe was wet when it was cut, attempt to seal the pipe as quickly as possible and move it out of direct sunlight. Transport the sample to the analytical laboratory as soon as possible.

If the internal condition of the pipe has been documented and samples for chemical and biological analysis have already been taken, another portion of the pipe can be cut out and even split in half lengthwise to facilitate inspection and measurement of corrosion features during the field investigation. When large diameter pipe is involved, splitting may not be necessary; but for smaller diameter pipe, this does aid inspection efforts. Consider this pipe section as a “sacrificial”

sample that can be disturbed, cleaned, and probed as needed during the field investigation. Never use the location of a leak or failure as the “sacrificial” sample.

Corrosion sometimes occurs at girth welds, flange faces, changes in flow direction (fittings), and so on. When this is the case, those features or components must be cut out for analysis. If the corrosion being investigated is isolated to only one small spot or one particular component, then it may be best to preserve that sample for subsequent laboratory analysis after performing any necessary chemical and biological sampling. When in doubt, remember the rule, “Protect all evidence.”

When a pipe sample cannot be removed from the system for analysis (for example, if an internal corrosion leak is clamped to repair it), all evidence will need to be collected from the pipe in situ. All of the previously described methods of sampling liquids and solids and documentation of the pipe condition still apply if the pipe will not be cut out, provided some way of accessing the internal surface is possible. However, the value of performing a surface embedment is especially significant when no pipe sample will be available for analysis. The surface embedment removes and preserves all corrosion deposits/biofilm and their spatial relationship to the corrosion for subsequent lab analysis. The procedure for making a surface embedment is explained toward the end of this chapter.

Chain of Custody

With any type of evidence, the person who offers real evidence into the official record at a trial must account for its whereabouts from the moment it comes into their possession until the moment it is offered into evidence at trial. Chain of custody is an official document that describes the source of the evidence and who has been in possession of the evidence from the time the investigator first recovered or received it. Chain of custody also describes how samples may have been subdivided or cut into smaller samples during testing and analysis and the disposition of those subsamples.

Certainly, the majority of corrosion investigations will not end up being presented as evidence in a court trial. However, for any investigation that could potentially involve future litigation, it will be essential to document the chain of custody of all samples used to support the determined cause. When it is likely that litigation will be involved, always verify the chain of custody form to be used with the client’s or your company’s legal counsel.

In all investigation cases, it is simply good practice to document who and where samples originated from and the time and date they were received. These data are the essential components of a chain of custody document: sample description, source or person providing the sample, date and time. Every time the sample or a portion of the sample changes possession, the exchange should be documented and both the receiver and deliverer of the sample must sign the chain of custody form.

Proper labeling and identification of all samples is an inherent requirement of the chain of custody process. Permanent paint markers or permanent marking pens should be used to label sample containers and pipe sections. Odd-shaped materials or those which cannot retain markings can be tagged. Small sections or pieces can be placed in plastic bags and labeled. It seems to be human nature that multiple samples are taken during a field investigation and the investigator thinks it obvious where each sample originated from, only to find that a day or two later one's memory is not as good as one thought. Marking and labeling samples when they are taken in the field is the sign of a good investigator. Don't rely on memory.

Sample Collection Checklist

Table 10 summarizes the types of samples that can be collected during the internal corrosion field investigation.

TABLE 10 Sample Collection Summary Checklist

Sample Collection Actions	Completed?
Collect gas samples	
Collect liquid samples—corrosion site	
Collect liquid samples—source locations	
Collect solid and sludge samples	
Identify pipe samples for;	
—Laboratory analysis	
—Field investigation	
Mark identification on all samples	
Establish chain of custody document	

On-site Testing and Analysis

Testing internal corrosion samples on-site is an important part of the investigation because the condition of the samples can change drastically in a short amount of time. If testing is not performed on-site, it is likely that some evidence will be lost. Such evidence may have been essential to determining the cause of the corrosion. In some corrosion investigations, it may not be possible to conduct laboratory analysis of the samples; therefore, the analytical data collected in the field tests may be the only information available to determine the cause.

This section is divided into the following on-site testing activities:

- Chemical Testing of Liquid Samples
- Chemical Testing of Solids/Sludges
- Microbial Testing
- Gas Analysis
- Special Techniques

Within each category of on-site testing, procedures for a number of individual tests are explained.

Chemical Testing of Liquid Samples

Overview of Methods

Measurements and tests that can be performed on-site for aqueous liquid samples include temperature, pH, total alkalinity, and dissolved H_2S and CO_2 .

The temperature of the liquid is measured using a common laboratory thermometer or with an electronic thermometer. The pH of aqueous samples is measured using a pH meter or pH paper. Note that when dissolved gases leave a previously pressurized sample, it is possible for the pH to rise. In some cases, when water samples containing significant levels of dissolved iron are exposed to air, oxidation/hydration of the iron can cause pH levels to drastically drop over time. Therefore, it is always important to measure pH in the field when the samples are collected.

When the pH of an aqueous sample changes, total alkalinity concentrations also are affected. One type of total alkalinity test is

a titration procedure where a measured amount of water is placed in a test tube or bottle with a pH indicator. Dilute sulfuric acid is commonly added until the color of the sample changes from green to red to indicate that the pH is less than 4.5. The number of drops used to change the color of the liquid corresponds to the concentration of bicarbonate in the sample and is used in a calculation to find total alkalinity, typically expressed as mg/L of CaCO_3 . The significance of the number of drops used in the test is explained in the manufacturer's instructions provided with each test kit. When a water sample has a pH of 4.5 or less, there is no need to perform the total alkalinity field test since total alkalinity can be assumed to be zero. Other types of alkalinity tests are also available.

Several field tests are available for measuring H_2S . A common one involves using an Alka-Seltzer® tablet to liberate the dissolved H_2S from 3.38 oz (100 mL) of sample. A sensitive test paper is placed over the top of the testing bottle and the liberated H_2S gas reacts with the treated paper to form a brown color. Using a color chart provided in the test kit, the shade of the brown color is compared to the appropriate concentration (in parts per million, or ppm) of dissolved H_2S . Other tests are available that require less sample volume. Dark colored water samples might be difficult to interpret using this method. Field test kits are also available to determine the amount of dissolved CO_2 in the sample.

Remember to take samples for microbial testing before conducting chemical tests on the liquid samples to prevent contamination.

Testing for the Presence of Water

Many times, samples from oil and gas pipelines are a mixture or emulsion of water and hydrocarbons. Sometimes it is not obvious whether or not the sample contains any water at all. A special water-finding test paper, Hydriion, is available specifically for the purpose of finding trace amounts of water in hydrocarbon samples.

To use the paper, a 1-in (2.54 cm) long piece is torn off and immersed in the sample. A pink or lavender color on the test paper indicates that water is present in the sample. Be careful not to get moisture on the paper from hands or surroundings, as a false positive may result. If the sample is too dark in color or turbid and a water layer is not visible, vigorously shake the sample and then test it with

the paper. The presence of glycol or methanol in the sample may cause erratic readings on the test paper.

As samples settle, the different phases present may separate on their own. If a suspected water layer is present, withdraw a small amount of the liquid from the layer with a syringe and place a few drops on the paper to verify whether or not it is water. When water is a small percent of the overall liquid, a large pre-sample must sometimes be taken so that sufficient water for analysis can be obtained. A 5-gallon (19-liter) carboy container with a spigot at the bottom is convenient for this purpose. Collect the large volume sample, then let it sit undisturbed until the water phase settles out at the bottom. The water phase can then be sampled from the larger container.

Measuring Temperature

Measuring liquid temperature is one test that is often overlooked. It is such a simple and useful test, however, that it should not be forgotten. Liquid samples taken from down-hole piping, for example, can be drastically warmer than ambient surface temperatures. Depending on the ambient temperature, the temperature of a liquid sample may change relatively fast; therefore, it should be one of the first measurements performed on-site.

Using a clean thermometer or an electronic temperature probe, insert it into the liquid sample. As soon as a stable reading occurs, record the temperature using the temperature scale (Fahrenheit or Celsius) provided on the instrument.

Results in Celsius can be converted to Fahrenheit using the following equation:

$$(^{\circ}\text{C} \times 1.8) + 32 = ^{\circ}\text{F} \quad (\text{Equation 1})$$

Measuring pH

The pH of water is a measurement of hydrogen ion concentration, which is an indicator of the water's acidity or alkalinity. The pH scale ranges from 0 to 14. A pH of 7 is considered to be neutral; a pH reading lower than 7 falls into the acidic portion of the scale, while a reading greater than 7 is alkaline.

Generally, low-pH water increases the potential for corrosion of equipment fabricated from steel and other materials. High-pH water can cause precipitation of carbonates and other scales. It has been reported that most bacteria prefer environments near neutrality (between pH 5 and pH 9) although some species can exist in more extreme environments.

A pH test should be performed as soon as possible after sample collection. By conducting the test immediately, the pH reading is most likely to be representative of the actual service conditions in the system. A pH test conducted on a sample that has been exposed to the atmosphere for extended periods of time could produce misleading data.

The pH of aqueous samples can be measured using a pH meter or pH test paper. Many types of pH meters are available in scientific supply catalogs. If a pH meter is used, always calibrate the instrument in the field before taking measurements. A pH meter with a micro-electrode sensor is very convenient for corrosion investigation since very small amounts of aqueous liquid can be tested as well as corrosion products, scales, soils, etc. Purchase calibration solutions when purchasing the pH meter. Using a meter, measurements are taken by either immersing part of the meter in the sample or by placing a few milliliters of sample on the pH probe.

A lower cost alternative is pH test paper or strips. Rolls of pH paper or pH test strips are readily available from scientific supply houses. Be certain to obtain pH paper with the appropriate measurement range. The pH paper generally registers a certain color or shade when exposed to the sample and then must be visually compared with a color chart on the package to determine the pH. This can sometimes be a problem for dirty or dark-colored samples as the sample color interferes with the color reading. In some cases, the use of pH paper is preferred over a meter, for example, when there is only a thin layer of water on a pipe surface. Measurements are taken by immersing the pH strip or paper in the sample or by placing a drop of sample on the paper.

When measuring the pH of multiple samples, be certain to rinse the pH probe with distilled water after each reading. Samples that are strictly water are straightforward to measure. If any oil or hydrocarbon is present in the sample, however, this can cause problems for the pH meter sensor. When a water/hydrocarbon emulsion is present, use a syringe or pipette to collect a small amount of water and place a couple drops of the water onto the meter's sensor (if it has one) or the pH paper. If the meter is the immersion type, remove enough of the

water phase to carefully fill a small container with enough liquid to cover the probe and get a reading. If the pH meter is contaminated with oil, try to clean the sensor carefully using a stream of distilled water and very gentle wiping with a soft cloth. Sensors are typically quite fragile.

Measuring Total Alkalinity

Total alkalinity, which consists of bicarbonate (HCO_3^-), carbonate (CO_3^{--}) and hydroxide (OH^-) alkalinity, is a pH-dependent test and thus it should be performed as part of the on-site investigation procedures. Follow the manufacturer's instructions provided with the test kit for performing the total alkalinity test. Some kits offer procedures for high and low ranges of alkalinity. If some previous knowledge of liquid composition in the system is available, this can help direct the type of test conducted first which will save time and sample volume. Since this is a test that depends on color change to determine the results, interference can be caused by dark colored or turbid samples.

Measuring Dissolved H_2S and CO_2

Some hydrogen sulfide test kits require a sample volume of 150 mL, while others require as little as 0.85 oz (25 mL). Large test volume requirements could be a concern when only a small liquid sample has been collected. Sometimes the investigator must make a judgment call in the field as to what tests will take priority. Keep in mind that gases dissolved in solution will not stay there for very long. Since dissolved H_2S is often unstable, this test needs to be performed quickly after sample collection for the most accurate results.

Follow the manufacturer's instructions for performing the hydrogen sulfide test and carbon dioxide test.

Chemical Testing of Solid/Sludge Samples

Limited chemical testing of solids and sludge samples can be performed during the field investigation. Generally, only the pH of the sample and a qualitative test for sulfides and carbonates can be performed, in addition to microbial testing (which is described later.)

Measuring pH

The pH of solid/sludge samples can be approximated by suspending some of the sample in a small amount (5 ml) of distilled water. If a microsensor-type pH meter is available, place a small amount of the solid or sludge directly on the sensor and moisten it with several drops of distilled water. Record the pH once the reading is stable. This should be considered a qualitative test only. Do not perform this test if the samples are suspected of containing hydrocarbons. If using pH paper or strips, these can be immersed in the sample for about one minute then rinse the solid material away from the pH strip and compare the color with the standard chart provided with the strips. The pH of solids and sludges should be measured soon after the pipe is cut and exposed to atmosphere; otherwise, the results may be misleading.

Sulfides and Carbonates

Carbonate compounds in scales or solids are fairly stable and can be analyzed in the laboratory; however, sulfides tend to be less stable upon exposure to air. In the event that scale samples are not being sent to a lab for analysis, or the samples are too unstable to ship, qualitative tests can be performed in the field.

Some sulfides can be hazardous; therefore, safety measures should be taken when handling such samples. Iron sulfide (FeS) can form due to the reaction between H_2S and the pipe, the H_2S being produced geologically or originating from the activities of bacteria. Iron sulfide is usually present in the form of a black powder that can oxidize rapidly when exposed to oxygen in the atmosphere. When dry iron sulfide is exposed to the atmosphere, the oxidizing reaction gives off heat and can ignite a fire. Samples of iron sulfide containing solids should be purged with nitrogen and the containers sealed with tape to prevent the ingress of air. Alternatively, the samples can be covered with mineral oil to preclude exposure to oxygen and prevent heating. Be extremely cautious in shipping and transporting such samples—follow all required packaging and labeling regulations for pyrophoric materials.

The presence of carbonates in solids from the pipe may indicate that carbon dioxide (CO_2) has reacted with the steel pipe to form iron carbonate or that a water-borne scale, calcium carbonate for example, may be depositing in the system.

Note that if the sample to be tested is covered with oil, paraffin, or other organics, it will not react well with the hydrochloric acid used in this test and poor results may be obtained.

A qualitative test procedure for determining the presence of sulfides and carbonates in solid samples is listed below. The test requires a small test tube, lead acetate test paper, and a small amount of 15% hydrochloric acid.

- a) Crush a small sample of the solid (about .06 in³ or 1 cm³) and place the crushed powder in a test tube.
- b) Prepare a strip of lead acetate paper for the test by moistening it with distilled water.
- c) Add 2 or 3 drops of 15% hydrochloric acid to the solid sample.
- d) Immediately place the strip of lead acetate paper over the top of the test tube or fold it over the rim so it hangs inside the tube. Loosely cover the mouth of the tube with the cap and wait approximately one minute. Do not tightly cap the tube as the gases generated could burst the container or spill the acid.
- e) Rapid generation of gas from the solid (indicated by vigorous bubbling of the solid or a color change of the indicator strip) indicates the sample contains carbonate or sulfide compounds.
- f) If the lead acetate paper remains white (or the gas has no rotten egg odor in the absence of lead acetate paper), the scale is primarily carbonate.
- g) If the gas smells like rotten eggs and/or the lead acetate paper darkens (usually to a tan or brownish color), the scale is primarily composed of sulfide compounds.

Microbial Testing

Microorganisms are ubiquitous, that is, they can be found nearly everywhere. Bacteria are small, resilient organisms that are not uncommon to the pipeline environment. Sometimes their presence and activities can promote internal corrosion. Determining what general types of bacteria are present, identifying the populations of those bacteria, and understanding precisely where they are present can aid the investigator in establishing the degree of microbial involvement in the corrosion process. Since bacteria are present nearly everywhere, simply determining that bacteria are present in the corrosion environment

does NOT lead to the immediate conclusion that the cause of the corrosion is MIC. Research has shown that bacteria can be attracted to corrosion products formed by abiotic mechanisms.⁹ Microbial testing is simply one of several important tools used to understand the environment that led to the internal corrosion.

Two procedures are typically performed during the field investigations that help establish the presence of microbes in the corrosion environment. These procedures are bacteria culturing and sample fixation/microscopic examination. Culturing is a procedure that helps determine the levels of different types of viable (living or vegetative) bacteria. Fixation is a process that kills any living organisms in a sample and preserves them for later examination using optical microscopy. Keep in mind that as soon as a liquid or solid sample is taken, the levels of viable bacteria may increase or decrease quickly due to the effects of oxygen, change in temperature, and other factors. Thus, it is imperative that microbial testing be performed as soon as possible after the samples are collected—otherwise the true microbial conditions in the pipeline may not be represented by the testing.

Bacterial culturing in artificial growth media is accepted as the standard technique for the estimation of bacteria numbers. However, investigators should be aware of the limitations of culturing methods, as stated in NACE Standard TM0194-94, *Field Monitoring of Bacterial Growth in Oilfield Systems*;

- Any culture medium grows only those bacteria able to use the nutrients provided.
- Culture medium conditions (pH, etc.) prevent the growth of some bacteria and enhance the growth of others.
- Conditions induced by sampling and culturing procedures, such as exposure to oxygen, may hamper the growth of strict anaerobes.
- Only a small percentage of the viable bacteria in a sample can be recovered by any single medium, i.e., culture media methods may underestimate the numbers of bacteria in a sample.
- Some bacteria cannot be grown on culture media at all.

Liquid samples are typically tested in the field for levels of planktonic (free floating) bacteria by inoculating liquid media culture vials

using serial dilutions. Solid and sludge samples can also be used for inoculating culture media by first suspending the sample in a sterile, anaerobic buffer solution. Surface related samples give a far better representation of the sessile (attached) bacterial populations, which is often where the bulk of the biotic activity (and corrosion) resides. Surface samples for bacterial analysis can also be obtained by wetting a sterile cotton applicator with sterile, anaerobic phosphate buffer solution and swabbing a one square inch area of the pipe surface. The swab is then broken off in the vial containing the buffer solution. The buffer is capped and shaken vigorously to disperse the swabbed materials into the solution, which is then used to inoculate media or fixed for microscopic analysis.

Liquid cultures identify broad groups of viable microorganisms (APB, SRB, facultative anaerobes, etc.) present in liquids on a semi-quantitative (as a range of organisms vs a specific number) basis. Other microbiological tests are also available for field enumeration of bacteria that are more specific in nature (e.g., RapidChek® for SRB).

Sterile instruments and containers should be used to collect samples for microbial testing. Soil, ground water, and human hands are good sources of bacteria and contamination of the sample can cause misleading results. Wear latex gloves when collecting and handling samples. Sterile cotton applicators and tongue depressors are useful for collecting surface deposits. Implements used to collect surface samples can be sterilized using isopropyl alcohol or by passing the item through a flame and allowing it to cool before using.

A variety of liquid culture media is commercially available. These media are formulated to grow specific groups of bacteria based on the salts and nutrients used. The two most common types of liquid media used in the pipeline industry are for general acid producing bacteria (APB) and sulfate reducing bacteria (SRB). APB media is usually a carbohydrate broth with a phenol red indicator. SRB media are usually made according to the Postgate B formulation. A typical commercially provided test kit is shown in Figure 13.

Inoculation Procedure

1. Label the vials in each row 1 through 5 in sequential order.
2. Remove the metal tab from the top of each bottle and then sterilize the rubber stopper using an alcohol pad.

3. Draw slightly more than 1 ml of sample into a new syringe. Invert the syringe and force out all but 1 ml of liquid, ensuring that no bubbles are present in the syringe.
4. Insert the syringe into vial #1 and gently dispense the liquid.
5. Leave the syringe in the vial and withdraw and re-inject 2 ml of liquid. Do this three times to thoroughly mix the sample.
6. Withdraw 1 ml of liquid into the syringe from vial #1, avoiding the introduction of bubbles.
7. Insert the syringe into vial #2 and dispense the liquid.
8. Repeat this procedure from steps 5–7 until all vials in the series have been inoculated with 1 ml from the previous vial.

If the first SRB bottle turns black shortly after inoculation, the sample may contain excessive H_2S , which causes the rapid color change. This does not mean that SRB are present.

All inoculated media bottles should be stored (incubated) at room temperature for the full duration of the test (28 days) or as described in the media supplier's instructions. Incubate the media in a dark place. Exposure to direct sunlight can inhibit the growth of some bacteria. If using a microbiological test kit, the bottles can be kept in the tray and stored in the cardboard box to keep them organized.

Interpreting Media Results

APB Unused bottles contain a clear, red, or reddish-orange media. A positive indication for APB is when the contents of the bottle turn yellow and turbid (cloudy). The color change indicates that the pH of the solution has become more acidic due to the production of acidic byproducts of bacterial growth. Turbidity, formation of slimy deposits, or growth of small clumps of cells (colonies) also indicate positive bacterial growth. Note that if the first one or two vials are clear and yellow with no turbidity or deposits, it is likely that the sample tested was highly acidic in the first place.

SRB These media bottles normally contain a small nail or iron filings in a clear medium. A positive indication for SRB is when the contents of the bottle turn black or a black precipitate forms. Black stringy material and gas generation (as evidenced by the

stopper bulging) are also possible positive indications of growth. The black solids are produced when SRB convert sulfate in the media to sulfide, which reacts with the iron from the nail or filings and iron in solution to form iron sulfide.

Figure 14 shows positive and negative indications for APB and SRB.

The number of vials that show positive indications of bacterial growth represents the number of viable bacteria per milliliter of original sample, according to Table 11.

Fixing Samples for Microscopic Examination

Liquid, solid/sludge, and surface swab samples may also be preserved in the field by “fixing” them in a glutaraldehyde or formaldehyde buffer solution so that microscopic analysis and microbial enumeration can be performed at a later time. Microscopic analysis will quantify *all* organisms present in the liquid sample regardless of whether the organisms were dead or alive when the sample was collected. Fixing the sample kills any viable microorganisms in the sample and prevents decomposition of the cellular structures prior to analysis if the samples are properly cared for. The minimum detection limit for this method is about 1,000 cells per mL; that is, greater than 1,000 cells per mL must be present in the liquid examined in order to detect any organisms at all.

TABLE 11 Bacteria per mL of Sample Based on Culture Results

Number of Positive Bottles	Actual Dilution of Sample	Positive Bottle Indicates (Bacteria per mL)	Reported Bacteria per mL of Sample
1	1:10	1 to 9	10
2	1:100	10 to 99	100
3	1:1,000	100 to 999	1,000
4	1:10,000	1,000 to 9,999	10,000
5	1:100,000	10,000 to 99,999	100,000
6	1:1,000,000	100,000 to 999,999	1,000,000

Preservative solution can usually be purchased in septum-topped vials from suppliers of bacteria culture media. Typically, liquid samples are diluted 1:1 or 1:10 by injecting the sample into the preservative vial using a syringe. Mark the dilution factor used on the preservative vial. Solids and sludges may be preserved by peeling open the top on the vial and placing a small amount of sample into the media. Swab samples can be obtained using a cotton-tipped applicator moistened with preservative to swab a one square-inch area of the pipe surface or specific corrosion features. Once the swab is completed, break the tip of the swab off in the vial and re-seal the vial using the original stopper and electrical tape.

Microscopic analysis of fixed (or unfixed) samples may be performed in the field if a high quality light microscope is available. Otherwise, it is usually more practical to have the samples examined in a laboratory. The laboratory examination involves drying a small, measured amount of the fixed sample on a glass microscope slide and applying a biological stain to the sample to highlight the organisms present. Simple Gram's staining techniques are sometimes useful; however, fluorescent stains seem to produce better resolution of cells in most pipeline related samples due to the large amount of debris and particulate matter often present. A microscope equipped with epi-fluorescent capabilities is required for this. Acridine Orange and FITC (Fluorescein iso-thiocyanate) are useful fluorescent biological stains. Samples that contain oil or hydrocarbons may be difficult to examine using fluorescent techniques as these materials cause background fluorescence that obscures the stained cells. Since bacteria are very small, examination of the stained samples is usually performed at magnifications of at least 1,000 $\times$. The microscopic exam determines the quantity of cells present, the morphological shapes of the cells (e.g., rod, cocci, vibrio, spores), and identifies any other biological materials present such as fungi, molds, or algae. Again, microscopic examination does not distinguish between living and dead organisms.

Gas Analysis Tests

Information about the gas stream that can be collected during the field investigation includes hydrogen sulfide content, carbon dioxide content, water content, temperature, and pressure. Hydrogen Sulfide

and Carbon dioxide can be measured using a stain tube or with an electronic meter. The stain tube is filled with a porous substance that is coated with a chemical that reacts with the particular gas to be tested, causing a color change. Typically, gas from the pipeline is directed through tubing into a vented container until all air is purged from the container. Then, using a hand pump, a measured amount of gas is drawn through the tube and the reading at which the color change stops in the tube indicates the concentration of H_2S or CO_2 indicated in ppm. One example of commercially available stain tube test equipment is shown in Figure 15. Electronic measurement instruments can provide a direct readout of the H_2S or CO_2 content present in the gas. Follow the manufacturer's instructions supplied with the stain tube or electronic instrument when measuring gas composition.

The water vapor content of the gas is important because it determines the level of saturation, and fully saturated gas at a given temperature will condense water that could support corrosion. Water vapor content can be measured with a stain tube. The chemical in water content stain tubes reacts with water vapor to cause a color change. Water vapor content can also be measured using an electronic meter.

Pipeline gas pressure is read from either a pressure gauge or an electronic gauge. The pressure can be used to calculate the carbon dioxide and hydrogen sulfide partial pressures after the percentage of CO_2 and H_2S in the gas stream are determined. Partial pressure may be calculated using the following equation:

$$\text{Partial pressure} = [\text{Fractional mole \%} \times \text{Total pressure}]$$

(Equation 2)

where: Fractional mole% = $[\text{mol.\%/100}]$ and

Total pressure (psia) = $[\text{pressure (psig)} + \text{atmospheric pressure}]$

On-site Testing Checklist

Table 12 provides a brief checklist of on-site tests that can be performed during the field investigation of internal corrosion.

TABLE 12 On-site Testing Checklist

Tests on Liquid Samples	Source of Sample(s)	Result(s) of Analysis
—Presence of water		
—Temperature		
—pH		
—Total alkalinity		
—Dissolved CO ₂		
—Dissolved H ₂ S		
—APB and SRB cultures		
—Fixation for microscopy		
Tests on Solids/Sludges/Scales		
—pH		
—Sulfide/carbonate spot test		
—APB and SRB cultures		
—Fixation for microscopy		
Gas Analysis Tests		
—Water vapor		
—Carbon dioxide		
—Hydrogen sulfide		
—Temperature		
—Pressure		

Special Techniques

Some special techniques are available to the corrosion investigator to aid in collecting all the information possible about the corrosion environment. In some cases, it may be of particular importance to perform a comprehensive examination when more simple techniques have not been able to provide resolution of a problem. Recurring corrosion problems that seem to resist mitigative efforts, for example, may require more comprehensive analysis than has been performed in the past. In any case, this section describes some of the more technical procedures that can be used to supplement the corrosion investigation.

Embedment of Corrosion Sites

An embedment is something that penetrates and preserves the scale, corrosion product, microbes, and deposits that are present on an internally corroded pipe. These features are important evidence that is often essential in determining the cause of internal corrosion. Another important benefit of the embedment is that, if done carefully, it preserves the spatial relationship between the deposits, bacteria, and corrosion features on the pipe. This spatial relationship can help reveal the significance of the various materials present in terms of whether and how they contributed to the corrosion.¹⁰

Once a pipe surface is embedded, the embedment can be left in place until the pipe section is cut out for laboratory analysis or the embedment can be removed and sent away for lab analysis. Preparation of the embedment for subsequent analysis is useful when no pipe sample can be removed, for example. If the embedment is prepared in the pipe before it is cut out, be sure to protect the embedment from excess heat or flame-cutting swarf during pipe sectioning.

Laboratory analysis of the embedment may include optical microscopy of sections taken through the replica, SEM and EDS analysis of the deposits, and transmission electron microscopy (TEM) can also be performed on thin sections through the embedment. These tests can show the locations and numbers of bacteria present in the corrosion layer and their relationship with the corrosion and corrosion products.¹¹

The embedment process described here is one that follows a typical histological procedure in which cells are fixed, dehydrated, and

infused with an acrylic resin. This method has proven successful in many field investigations of corroded natural gas pipelines. Materials needed for making the embedment are listed below.

Materials for Embedding Corroded Pipe Surfaces

2% Formalin or glutaraldehyde fixative solution

Sterile Phosphate Buffer Solution

Sterile de-ionized water

Solutions of 25%, 50%, 75% and 100% pure ethanol (not denatured)

LR White® medium grade acrylic resin

Resin/ethanol solutions of 30% LR White and 70% LR White

Catalyst for LR White

Tube of silicone caulk

Sterile swabs and tongue depressors

Several 5 mL disposable pipettes

100 mL plastic beakers for measuring and mixing reagents

Preparation Before Field Investigation

Accurate mixing of reagents for the embedding process is best performed in a laboratory or other clean, indoor work area. The field embedding process will be more organized and expedient if all necessary solutions for the process are prepared in advance and stored in individual bottles. The solution bottles can be numbered according to their order of use in the procedure. Plastic 125 mL screw-top sample bottles usually provide enough solution to make one larger embedment (3.8 cm × 3.8 cm, or 1.5" × 1.5") or two smaller embedments that are less than one square inch in size. If large pits are embedded, the entire contents of each bottle will probably be needed to make one embedment.

The ethanol series dilutions are made using sterile de-ionized water with pure ethanol. Denatured ethanol typically contains kerosene or some other denaturant that interferes with the infusion process and should not be used. Formalin fixative (formaldehyde in phosphate buffer solution) can be prepared or purchased. Phosphate buffer can be purchased in pre-measured packets that make 1 L each. Use de-ionized water that has been filter sterilized to prepare the buffer.

The water-based solutions and LR White solutions should be stored under refrigeration and transported in a cooler lined with ice packs.

Embedment Procedure

Detailed instructions for performing the embedment are shown below, followed by a checklist of the steps in Table 13. The entire procedure takes approximately 1-1/2 hours to complete from start to finish. An example of a completed embedment is shown in Figure 16.

1. Select a representative area or areas of corrosion on the pipe surface to preserve by embedment. The area selected does not need to be where the corrosion is the most severe. If a through-wall corrosion pit resulted in a leak, choose a different area to embed if possible. If the through-wall pit is the only corrosion present, then seal the leak by applying heavy duty plastic tape to the external-surface before performing the procedure. The area to be embedded must be on the bottom of the pipe; otherwise, the preservation liquids will be lost. If the pipe sample that is being embedded has been cut out of the line, then it is a simple matter of rolling the pipe to the correct position.
2. Using cotton swabs, tongue depressors, or a clean, lint-free cloth, carefully clean the pipe surface around the perimeter of the area to be embedded. This must be done so that the silicone caulk will stick to the pipe and prevent the embedding fluids from leaking out. If heavy debris or scale is present, attempt to remove only that material around the perimeter of the corroded area. Be careful not to touch or contaminate the area that is being embedded.
3. Using the tube of silicone caulk, build a "dam" or barrier around the area to be embedded. The dam should be approximately 1/2 in (1.3 cm) high. Allow the surface of the caulk to cure before proceeding.
4. Begin the embedding process by transferring a sufficient amount of fixative (Step 1) into the embedment area such that the pipe surface within the area of interest is completely immersed in a shallow layer of the solution. The solution must be added very gently to the embedment area so that the corrosion products and biofilm are not disturbed. The solution can be slowly added

using a disposable pipette. Allow the recommended dwell time to elapse before proceeding to the next step.

5. To withdraw the solution from the embedment area, again use the disposable pipettes provided, working from one of the lowest corners of the embedment. Always try to add and remove liquids from the same corner to minimize disruption to the biofilm. Waste solutions should be kept in labeled bottles and properly disposed. Do not re-use any solution. Repeat solution transfers according to the order and dwell times indicated in Table 13.
6. For the final step (Step 11), measure a volume of LR White resin into a clean plastic beaker such that an embedment about 1/4 to 3/8 in (.6 cm to 1 cm) thick will result. Next, add to the beaker one drop of the LR White catalyst for each 10 mL of LR White solution. Gently stir the catalyst into the LR White for about 30 seconds and then slowly pour the resin into the embedment area. The resin will become warm and cure within minutes depending on the ambient temperature. Allow the acrylic to harden for at least 15 minutes before handling or moving the pipe.

TABLE 13 Corrosion Surface Embedment Procedure

Step No.	Solution	✓	Dwell Time (minutes)
1	Fixative		5
2	Phosphate buffer		5
3	De-ionized water		5
4	25% ETOH		5
5	50% ETOH		5
6	75% ETOH		5
7	100% ETOH		5
8	30% LR White		10
9	70% LR White		10
10	100% LR White		10
11	100% LR White + Catalyst		15 (before moving)

TABLE 14 Field Analysis Summary Report Form

Company/person requesting the analysis—contact information	
Investigator's name, company and contact information	
Location of corrosion investigation	
How corrosion was discovered	
Pipe information—diameter, wall thickness, grade, age, seam type	
Nature of internal corrosion observed in the pipe	
List of liquid and solid samples collected	
List of field tests performed	
Description of pipe samples collected	
Internal operating conditions	
Disposition of samples collected for lab analysis	
List service providers for follow-up testing of samples	
Contact person to provide historical operating information	
Other observations from the field investigation/comments	

No analysis of the embedment is possible in the field. Laboratory procedures that can be used in analyzing corrosion embedments are presented in Chapter 5.

Other Techniques

Other more technically sophisticated analytical methods are described toward the end of the next chapter. Some of these techniques include identification of the specific strains of bacteria present in the pipeline and the analysis of scales or gas for biologically produced sulfides. While these are not field analysis techniques, special sample collection and preservation procedures are required when these techniques are employed. Generally, it is best to coordinate the type of sampling and preservation required with the laboratory that will be conducting the testing.

In summary, a variety of different tests and techniques are available to collect information that can later be used to identify the cause of internal corrosion. Proper use of field testing is essential for capturing information that is easily lost a short time after the pipe is cut or a sample is collected. When several samples are collected as part of the field investigation it is helpful to document the origin of the samples and their disposition. Table 14 provides a field analysis summary report form to help the investigator document what was found in the field and what analyses are intended to be performed on the samples in subsequent testing.

Laboratory Analysis

Laboratory analysis of internally corroded pipe or samples taken during field testing can provide information that helps define the conditions leading to the corrosion. A number of analytical techniques are available to investigators. Knowing the strengths and limitations of these techniques can help the corrosion investigator to choose the appropriate test methods and correctly interpret the results. This chapter looks at some of the more popular analytical techniques and explains the information that can be gained by employing these techniques.

Do I Need a Laboratory Analysis?

There are several reasons why the corrosion investigator would perform laboratory testing. First, if the cause of the corrosion is not clearly and positively identifiable from the field testing results, additional analysis is needed to determine the cause of the attack. Normally, field testing and observations are not sufficient to adequately characterize the corrosive environment that was present. Laboratory testing can provide more accurate and specific results. Second, even if field testing results are conclusive as to the cause, more information may be required to determine what mitigation strategies should be used to control the corrosion. Finally, if the corrosion has resulted in a leak, spill, or rupture, it is likely that government agencies will require a thorough analysis and formal report. Use of a corrosion expert outside the company can also provide objective third-party investigation of an incident that is of interest to pipeline regulating agencies.

In the United States, federal regulations governing jurisdictional natural gas pipelines require that operators establish procedures for

analyzing leaks and failures,¹² including those due to internal corrosion. The procedures must include instructions on how to select samples for laboratory examination where appropriate so that the cause of the damage can be identified sufficiently to minimize the likelihood of recurrence. In pipeline facilities where internal corrosion could be the cause of a leak or failure, the inclusion of specific sampling and laboratory testing in company procedures should be seriously considered. Even in cases where a leak or failure has not occurred but internal corrosion has been observed, federal regulations require that steps be taken to minimize the internal corrosion. In some cases, it may be necessary to conduct field and laboratory tests to determine how to minimize the internal corrosion. Thus, laboratory testing of corroded pipe and other related samples may be necessary to ensure compliance.

Keep in mind that including laboratory analysis as part of a corrosion investigation does not imply that the entire case be turned over to a third party contractor. Knowledgeable engineers and corrosion personnel can provide competent oversight and coordination of the analytical process if they know what questions to ask and which techniques to employ.

Organizing a Laboratory Analysis

As is the case in all other aspects of corrosion investigation, organization is a key component in effective integration of laboratory analysis in the investigation process.¹³ There are three main points to consider when bringing laboratory analysis into the investigation plan. The first point is identifying who will do the work. Second, ensure that proper samples are provided for analysis and, third, ask for and supply the right information.

Is It an Inside Job?

The first questions to answer are, “Who will direct the lab work and who will perform the lab work?” Hopefully, the person or organization responsible for directing the investigative work was indicated in the plan that was developed back in Chapter 2. If not, then several considerations exist in regard to who should direct the lab work. If the expertise and manpower exist within the organization to direct the lab work, in most cases the work should be directed from within the

company. More often than not, company personnel are more familiar with the issues impacting internal corrosion of their systems than a third party would be. In some high profile cases, however, where corrosion has resulted in a major incident causing substantial damage or loss of life, it may be necessary to employ a third party expert to direct the investigative lab work. The impetus for this decision could originate from government agencies or legal counsel or both. It is best to plan in advance who will direct the analytical work so that if a third party is brought in, they can be involved sooner rather than later, after evidence has potentially been lost or compromised.

Second, the question of who will perform the lab work must be addressed. This question is fairly easy to answer. If the analysis is being managed in-house and the laboratory capabilities exist within the company, it certainly makes sense to use those resources. Many companies, however, do not have access to in-house chemical or metallurgical laboratory services and must rely on outside service providers. Finding laboratory service providers who understand what you are trying to accomplish is an important goal. If your organization will need to use outside laboratory services at some time in the future, it would be advantageous to contact those providers in advance.

If the laboratory work to support the corrosion investigation is being directed internally within the company, analytical service providers must be selected. Here are some issues to consider when choosing outside laboratory services:

- Capability and experience in the type of testing to be performed
- Qualifications of the organization and the personnel
- Equipment and facilities necessary to conduct the testing
- Area of specialization—types of clients and industries served in the past
- Location of the firm, a consideration in some cases as not all types of samples are easily shipped
- Ability to communicate clearly with the vendor and have your concerns understood. Establishing a good rapport is important. As a customer, you need to know that you are getting what you want.

The best time to work at locating suitable laboratory service providers is before they are required during a corrosion investigation.

Based on the anticipated analytical needs, a corrosion investigator should identify and, if possible, meet with lab service providers to establish contacts and directions on how to submit samples. This is an important step. Most laboratories will provide guidance on sampling and preservation procedures as well as sample containers for liquid and gas samples. Establish an understanding of the quantity of sample required to perform the various analyses that may be requested. For example, identify the volume of liquid sample that is needed for comprehensive chemical analysis or how large a pipe coupon is required for tensile testing.

When talking with laboratory service providers, use the list provided in Table 15 to guide your discussion.

Supplying Adequate Information

Those who work in a laboratory that provides services to outside clients can attest to the fact that some samples arrive in a cloud of mystery. That is, unidentified samples from unknown origin show up for unspecified analysis from unknowing individuals. As funny as this sounds, it happens more often than it should. A metallurgical lab receives a greasy, broken engine part with a scrawled note asking why it broke; a chemical lab receives odiferous ooze of obscure origin in a leaking Mason jar. Will the senders of these samples get the information they need? Probably not. Without adequate information about the samples and clarification of the questions that need to be answered, these lab customers are likely to be disappointed.

All of this hyperbole seeks to make a point, however: Satisfaction with, and usefulness of, laboratory services is directly related to good communication between the customer and the service provider. Lab customers may not be aware of the special capabilities and knowledge a service provider has at their disposal. Customers are probably not trained metallurgists or chemists and may not be asking the right question to begin with. Likewise, lab service providers have no way of knowing the unique circumstances surrounding each sample a customer submits or precisely what the customer is trying to find out through the analysis. Service providers may have no idea of the conditions under which pipeline samples are collected. These issues can only be resolved through good communication and rapport. Therefore, each party needs to be sure they understand the ultimate objective

TABLE 15 Topics to Address with Lab Service Providers

✓	Checklist of Questions for Lab Service Providers
	Qualifications
	—Years of experience in field
	—Credentials and certifications of facility and personnel
	—Equipment and resources
	—Type of customers served in the past
	Samples for Testing
	—Type of sample
	—Size or amount of sample
	—Preservation or special handling of sample
	—Shipping and delivery of sample
	Work Coordination
	—Key contact names and numbers
	—Type of report needed
	—Timetable for completion of work
	—Distribution of final report
	—Confidentiality agreement or legal concerns
	—Cost of work
	—Billing information

of the analysis. The more information that is available about the background of the sample, how it was collected, and why it is being analyzed, the better.

Information that may be helpful to lab service providers has been described in Chapters 3 and 4. Specifics about samples for certain types of analysis are provided in the next section of this chapter.

Get the Deliverables You Need

Getting what you need from laboratory analysis of your corrosion samples depends on knowing why the analysis is being performed, good communication with the service provider, and supplying proper information/samples for analysis. This section has provided suggestions on how to get the greatest benefit from laboratory analysis of corrosion samples. The wise corrosion detective uses every tool at his or her disposal to help solve the case. Laboratory analysis can certainly add to the understanding of why a pipeline corroded. The following section will discuss various types of laboratory analysis and how they can be helpful in understanding the corrosion environment.

Types of Laboratory Analysis

There are many different types of laboratory analysis the corrosion investigator can use to help determine the cause of internal corrosion in a pipeline. Depending on the amount of time and financial resources available, investigators may want to include some types of analysis on a routine basis, particularly as they become familiar with the utility of the results. Laboratory analysis will be described here in four general categories: chemical analysis, microbiological analysis, metallurgical analysis, and corrosion testing. Chemical analysis methods can generally be divided into two major categories based on the type of samples that can be analyzed. Samples for chemical analysis can be characterized as bulk samples, where some amount of material can be removed for analysis, or surface samples.

Chemical Analysis of Bulk Samples

In general, the purpose of chemical analysis of bulk liquids, solids, or sludges, removed from pipelines is to characterize the environment at the internal pipe surface and determine how corrosion is affected by that environment. Chemical analysis is one of the most important laboratory analysis tools a corrosion investigator can use. Corrosion, after all, is an electrochemical process and understanding the chemical species present will help significantly in understanding that process.

A wide variety of chemical analysis techniques are available. Techniques discussed in this section are considered appropriate for bulk samples, e.g., those that have been removed from the pipe in some quantity. When only very small amounts of solid corrosion products are available, microscopic surface analysis techniques may be more appropriate. Those techniques are discussed later in this chapter.

As is true in many areas of life, to get what you want, you need to know what to ask for. This is particularly true in chemical analysis. Different techniques are used to determine different chemical information about a sample. Each technique has its strengths and limitations. Putting all of the different information together and determining its significance in terms of corrosion is the challenge. As various techniques are described here, their applicability, strengths, and limitations will be discussed.

Other challenges to the use of chemical analysis include sample contamination, analytical interference, and sample degradation. Knowledge of these concerns, however, can at least promote correct interpretation of analytical results. Remember that the goal of chemical analysis is to describe the true conditions inside the pipe as they relate to internal corrosion.

Contamination can occur before or during sample collection. One example of contamination occurring before sample collection is when a pipeline is flushed or pigged with a liquid prior to the pipe being cut open. If a sample of the liquid used to clean the pipe is collected and analyzed, at least some understanding can be gained of how that liquid changed the original chemical conditions. If the investigator was not aware that the pipe was cleaned before cutting, misleading results could be obtained from subsequent chemical analysis of corrosion products. Contamination can also occur during sampling by poor handling practices or by re-using sample containers.

Interference is an analytical and interpretation problem that can occur when two similar materials that cannot be discriminated from one another are both present in a sample. It could also occur when the presence of one substance masks the presence of another substance. One example of this would be trying to quantify the amount of amine-based corrosion inhibitor in a sample when other amines have been introduced from a nearby gas treatment plant. The best way to deal with this concern is to obtain good background information about the sample location during the field investigation and communicate this

information to the analytical lab. If a chemical analysis laboratory is aware of possible interferences, they may be able to suggest methods that can resolve the conflict.

Finally, sample degradation prior to analysis can also be a concern. As described in the field testing portion of this book, some tests absolutely must be performed in the field when the sample is collected; otherwise, the data is of no value. Since the pH of an aqueous sample can change significantly over a 24-hour period, the measurement must be performed in the field if a true representation of conditions in the pipe is desired. In some cases, as the pH of a sample changes, certain chemical species precipitate out of the liquid or dissolved acidic gases such as H_2S and CO_2 can escape from the liquid. If these changes are not accounted for in sample preparation or analysis, the chemical conditions in the sample could be misrepresented by the test results. Depending on the type of analysis being performed, sample degradation may be more or less of an issue. Communication with the laboratory service provider about sample collection and preservation methods is a good preventative step. Often analytical labs will provide the proper sampling containers, some of which may be chemically treated to preserve the sample for a specific type of analysis.

Descriptions of several common types of chemical analysis used for corrosion related samples are detailed next. The methods are divided between those used primarily for surface analysis and those used for analysis of bulk samples.

Methods for Chemical Analysis of Bulk Samples

X-Ray Diffraction (XRD)

X-ray powder diffraction is a fairly common technique performed on corrosion products. It is useful in identifying crystalline phases in unknown materials. One of the greatest benefits of XRD is that crystalline phases are described as compounds, rather than elements or ions as in most other methods. Knowing which compounds are present in the corrosion products is beneficial in understanding the corrosion reactions that have taken place in the pipe. Another advantage is the small sample size required, typically only a few grams. The elemental composition of amorphous (non-crystalline) components of a sample is also identified by this method. When interpreting XRD results, the

investigator must be aware that some corrosion products are unstable and may change composition in going from the anaerobic pipeline to the oxygen-rich atmosphere. One example is mackinawite, an unstable form of iron sulfide that may transform to magnetite or hydrated iron oxide ($\text{FeO}\cdot\text{OH}$) upon exposure to oxygen. Generally, XRD requires only a small amount of sample, about 1 gram. When an insufficient amount of material is obtainable, surface analysis methods may be used.

Ion Chromatography

Ion chromatography is a popular method for determining the concentrations of ionic species in aqueous samples. Typical results would identify ions such as sulfate, sulfite, nitrate, nitrite, phosphate, chloride, bromide, and fluoride. Many other ions can also be detected; however, the seven listed previously are most commonly used for corrosion investigation. Results are reported in parts per million (ppm) or milligrams per liter (mg/L). A relatively small volume of sample is required for the analysis; the necessary volume should be verified with the laboratory performing the analysis. Solid corrosion product samples or corroded surfaces can also be analyzed by extracting the water soluble components using a de-ionized water rinse. Two phase water/hydrocarbon samples can also be analyzed by decanting the water phase. An ion chromatograph can also be used to identify the organic acids present in an aqueous sample. This is discussed under “Microbiological Analysis” later in this chapter.

Atomic Absorption

Atomic absorption spectrometry (AAS) is a long established technique that can be used to identify nearly 70 different elements in liquid and solid samples, often to detection limits of parts per billion. AAS has been widely used since the 1960s and although DCP/ICP methods have gained popularity in recent years, AAS is still used in many labs. For solid and particulate samples, a few grams is usually sufficient for analysis. Solids must first be dissolved in acid before analysis can take place. Application of this technique to corrosion products would help to identify the metallic elements present that could not have been identified using ion chromatography, for example. Analysis of liquid

samples using AAS could provide an overview of all elements present. The investigator would then consider the results in light of which elements would most likely be present as cations, anions, or solid precipitates in liquids or as compounds or elements in solids. One limitation of AAS is that carbon, nitrogen, and sulfur cannot be analyzed.

DCP/ICP

Direct current plasma (DCP) and inductively coupled plasma (ICP) atomic emission spectroscopy are analytical methods that can quantitatively identify over 70 elements in liquids, solids, and particulates. Both methods allow simultaneous analysis of multiple elements which facilitates shorter analysis times than for AAS. For this reason, the use of DCP and ICP has become quite common in the last decade. Results from this type of analysis are used in the same manner as described for AAS above. Sample size requirements of 100 mL for liquids and 1 gram for solids are common.

Wet Chemistry

Wet chemistry is a general term that describes laboratory analysis techniques such as gravimetry (weighing), titrimetry (volume), and numerous separation techniques. Most spectrographic methods examine a very small portion of the overall sample and must assume that the portion analyzed is representative of the overall sample. For samples that are highly non-homogeneous, spectrographic methods may not accurately describe the true nature of the sample. This is where wet chemical methods can provide very useful information. One example of a non-homogeneous pipeline sample would be sludge from a cleaning pig run that contains an aqueous phase, an organic phase, and a variety of particulate materials (scale, sand, corrosion products, debris, coating, etc.). At least some form of separation must occur before spectrographic methods can be applied.

Wet chemistry is time-consuming. Methods vary widely with sample type and composition and often require some educated guesswork to assemble all of the analytical pieces to describe a non-homogeneous sample. Many laboratories would rather provide analysis of the individual components and leave the interpretation up to the customer. This can be workable as long as the investigator is aware of all components present in the sample, not just the components that

were analyzed. (Example: A lab runs ICP and ion chromatography on an aqueous sample but fails to address a layer of precipitate on the bottom of the sample container.)

Wet chemistry is commonly used for more straightforward analyses as well, such as determining the bicarbonate alkalinity of aqueous samples using titration methods. A number of titration methods are also available for determining the residual levels of inhibitors and biocides.

Gas Chromatography/Mass Spectrometry

Gas (or liquid) chromatography/mass spectrometry are sometimes employed in corrosion sample analysis to look for corrosion inhibitors, biocides, methanol, glycol, and other organic materials of interest. Generally, the investigator must have some idea of the organic material for which they are searching. Seldom is GC/LC used simply to evaluate “what might be there,” as methods appropriate to the material being identified must be used.

Scaling Index

Liquid chemistry data is often used to calculate a scaling index number that provides some indication of whether or not scale may form in a particular system. Two popular methods are the Langelier Scaling Index (LSI) and the Stiff-Davis Index (SDI). Most corrosion experts suggest that there is no correlation between the scaling index and corrosion of steel in waters. The index values are simply indications as to the propensity for deposition or dissolution of calcareous deposits. Whether or not corrosion will occur depends on a number of other factors including the presence of suspended particulates, temperature, flow rate, substrate condition, and so on. Nonetheless, scaling index can at least provide another piece of information that can be used to help understand the conditions present in the pipeline.

Miscellaneous Tests

Conductivity and pH are two tests commonly performed on aqueous samples submitted for corrosion analysis using standard laboratory instruments. Another common procedure used to determine the amount

of carbon and sulfur in a solid sample is the combustion technique. Alkalinity and reactive sulfide tests are also routinely performed on liquid samples from pipelines.

Chemical Analysis of Surfaces and Thin Films

In some corrosion investigations, there may be insufficient sample volume to employ bulk analysis techniques. Surface analysis techniques provide elemental chemical composition data about distinct regions or particles in a sample. When used in conjunction with microscopy, morphological data about films and particles can also be obtained. These techniques can be applied to particulate matter but are often used to characterize corroded surfaces and related deposits. The ability of certain methods, such as EDS, to provide spatial differentiation of elements helps the investigator determine the significance of these elements in relationship to the corrosion damage. For instance, chlorides are often found to be concentrated in corrosion pits. When this condition is documented via chemical surface analysis, the investigator then has evidence to explain part of the overall corrosion mechanism. In another example, the chemistry of striated scale deposits may be observed to have changed over time. These changes could then be correlated with operational upsets in the pipeline based on historical data about the system.

For some investigators, considering the use of these sophisticated methods may cause anxiety about the cost and value of the data. The best answer to this problem is to develop good relationships with service providers who understand what you are trying to achieve with these analytical techniques. Rarely will you want to simply drop off a sample have the results mailed when the testing is complete. The investigator should plan on being present when the analysis is being conducted and two-way dialog between the electron microscopist and the investigator is essential. Corrosion investigation with micro-analytical methods works best when the investigator combines his or her knowledge of the problem with the technical expertise of the analyst. If the service provider discourages this interaction and observation process, a different provider should be sought.

One caution must be advised regarding selecting and preparing samples for microscopic surface analysis: Contamination or undue alteration of the sample must be avoided. Due to the sensitivity of these

methods, miniscule amounts of contaminants can significantly alter the results. Most analytical techniques require that small sections of the sample be provided for examination; sometimes as small as $\frac{1}{4}$ to $\frac{1}{2}$ in (.6 to 1.3 cm) square. Sectioning such a minute specimen from a large pipe while retaining the corrosion deposits and not imparting contamination (by cutting fluid, for example) is not an easy task. The investigator needs to provide direction to the sample preparation process and be mindful of any changes that may have occurred throughout handling and processing.

The following are some brief overviews of popular surface analytical techniques that can be employed in corrosion investigations.

Methods for Chemical Analysis of Surfaces and Thin Films

Scanning Electron Microscopy/Energy Dispersive Spectroscopy

This is perhaps one of the most popular techniques used for examining and analyzing elemental surface components of corrosion-related samples. SEM/EDS is available at many lab service providers and at some universities that accept work from commercial clients. Scanning electron microscopy (SEM) provides a high-resolution view of the corroded surface and corrosion products, while energy dispersive spectroscopy (EDS) provides elemental chemical composition data of both discrete particles and larger areas. Sample size is dictated by the capacity of the SEM stage and chamber. Most instruments can handle a one square inch sample and some with larger chambers can accommodate much larger samples, perhaps up to 4 in (10 cm) in diameter. The samples must be free of oil and grease. Often, corrosion samples must be coated prior to examination or a condition known as charging will occur when the sample is examined. When non-conductive materials are present on the surface, the sample must be coated with a very thin layer of carbon or a gold alloy. Most labs with an SEM will also have carbon or gold sputter-coating equipment. Sometimes carbon paint or adhesive carbon or copper tape can also be used to reduce the charging that occurs with poorly conductive samples.

The SEM examination provides information about the results of the interaction between the corrosive environment and the steel pipe, specifically with regard to the surface of the pipe and morphology of

deposits and corrosion products. While SEM is capable of magnifications up to 100,000X, most work is performed below 5,000X. In fact, working magnifications for corrosion examination are typically from 10 to 1,000X. Observations of exposed steel in the corroded area can reveal how the corrosion environment is interacting with the microstructure, e.g., intergranular, focused on inclusions, pitting, uniform attack, etc. When possible, it is generally useful to examine corroded areas in addition to those areas that do not appear (visually) to be corroded. Beside the corrosive effects on the steel, the morphological nature of the corrosion products or scale can also be determined. Deposits may be crystalline or amorphous; uniform, irregular, striated or layered, or vary with location in the pipe. Backscattered electron imaging may help reveal chemical and textural differences between adjacent areas. Such clues can guide further examinations with EDS to determine specific chemical differences between areas.

EDS is used to provide elemental chemical information about the features being examined via SEM. Although EDS indicates only elemental composition, it is often possible to postulate the probable nature of the corrosion product, particularly when EDS is applied in conjunction with other chemical analysis methods. EDS can detect elements that are present at roughly one atomic percent or greater. Often, the relative amounts of elements detected are categorized as major, minor, or trace values. The degree of light element detection varies with the detector used; often elements with atomic numbers higher than beryllium can be detected, although sensitivity for lower atomic numbers is not as good as for heavier elements.

One strength of EDS is determining regional variations in chemistry on a corrosion sample. Such information may help identify the chemical species associated with pits, for example. Chemical differences are normally identified by performing several EDS analyses at different locations on the sample. Another way to identify variances in distribution of elements is by x-ray mapping. In this method, a larger area of the sample is analyzed for several key elements and individual concentration/distribution maps are created for each element. Some instruments also permit "line mapping" where spectra are acquired along a line drawn on the displayed image. Line mapping is less time-consuming than area mapping and can clearly illustrate elemental differences between different features or layers in cross sectional samples. Large variations in the spatial concentrations of elements may provide insight on how or why the corrosion is occurring.

SEM/EDS analysis is an investigative procedure that the corrosion investigator should directly observe and participate in whenever possible. New information is often revealed as the examinations and analyses progress and this new information may guide the investigator to look for additional data of significance. Coming into the SEM/EDS examination with knowledge of the operating environment is extremely valuable, as it helps determine the significance of the analytical information being collected.

It is important to thoroughly document the examination process, identifying where samples were from, what specific areas were examined and analyzed, and exactly where particular high magnification images were taken on the sample. It is difficult to remember these specifics weeks after the examination was performed; hence, documentation is essential. Be sure to establish a labeling system for EDS spectra and SEM images collected, i.e., "Sample A—Area 1—Inside of Pit."

EDS is also useful for quick chemical analysis of bulk solid and powder samples. Often, EDS is used prior to XRD or other more involved methods to get an overview of the major elements present in the sample. It should be noted that under most circumstances, EDS provides only qualitative (or semi-quantitative) analysis. Truly quantitative results require flat, polished samples and appropriate calibration standards, which is rarely applicable to corrosion samples.

Don't be afraid to employ this technique! It is one of the most useful and intuitive investigation methods available to corrosion investigators. Participating in the exam and knowing what may be there beforehand can also help keep the cost of the analysis at a reasonable level.

Transmission Electron Microscopy

Transmission electron microscopy (TEM), often in combination with EDS or other elemental detection methods, is used more frequently in the study of microorganisms than of corrosion. However, since bacteria and other organisms have been shown to be associated with corrosion initiation and propagation, TEM can be used to provide a better understanding of these corrosion mechanisms. TEM is also used to study the crystal structure of metals and other solids. Histological embedments of corrosion products and biofilms (described in Chapter 4)

can be used for TEM analysis by taking thin sections from the embedment. Excellent imaging of sulfate reducing bacteria associated with corrosion has been accomplished using this technique.

The primary limitations in applying TEM to corrosion analyses are the length of time required for sample preparation and the cost. In some cases, however, these limitations can be overcome by the need for a deeper understanding of bacterial involvement in the corrosion. Gold labeled antibodies are used to identify specific organisms for which the antibodies have been developed, although this technique presents some challenges with corrosion samples as products of the corrosion reaction sometimes “block” the antibody labeling sites in the cell. Most providers of TEM services are well versed in cell science but not in corrosion; thus, finding someone who is willing to meld these two sciences is important when delving into this area of investigation.

Auger Electron Spectroscopy

Auger electron spectroscopy (AES) provides elemental compositional analysis of very thin (3 nm) surface layers. AES has better spatial resolution and sensitivity and is more quantitative than EDS. All elements can typically be detected by this method except hydrogen and helium. Auger, while a sensitive and useful technique, is only appropriate for certain types of corrosion related samples. The samples must be free of organic and high vapor pressure material and the region of interest must, of course, be quite thin. In practical terms, the region for chemical analysis would exist as a film, e.g., not as a discrete deposit or scale unless the scale could be prepared in cross-section. Application could be found in situations where aggressive attack under flowing conditions leaves little or no deposits behind, only corroded metal. AES would also be appropriate for examination of grain boundary chemistry on fractured samples, where perhaps selective corrosion at grain boundaries or other metallurgical features is occurring.

Secondary Ion Mass Spectroscopy

Like Auger, secondary ion mass spectroscopy (SIMS) is another method that analyzes atomic surface layers for elemental composition. Like AES, SIMS is more sensitive and has better spatial resolution than EDS. SIMS looks at a 5 to 10 nm-deep surface layer and is very sensitive to trace elements in the parts per million and

parts per billion ranges. Since SIMS can also detect hydrogen, this method can characterize both inorganic and organic surface materials. Typically, SIMS is used for compositional depth profiling (to 2,000 nm), bulk impurity analysis, and examination of specific metallurgical features. Normally, the required sample size is very small, about $1 \text{ cm}^2 \times 1 \text{ mm}$ thick. SIMS also works best with fairly smooth, flat samples. Powder samples may be pressed into a soft foil for analysis of the particles. As in AES, corrosion samples appropriate to SIMS may be those where only a thin film of corrosion product is present in the corroded areas. The ability of this method to detect organic materials also suggests interesting applications when inhibitors are present in corrosive environments. As in other high technology analytical methods, application of SIMS may be limited by cost unless the results provide quantifiable value to the investigation.

Fourier Transform Infrared Spectroscopy and Raman Spectroscopy

Fourier transform infrared spectroscopy (FTIR) and Raman spectroscopy are analytical methods that can be used to identify small amounts of organic materials on surfaces. Both methods are used with microscopes to enable examination of small areas or specific features. FTIR has a lateral resolution of about 10 to 20 μm , while the lateral resolution of Raman is about 1 to 2 μm . Both methods usually allow chemical mapping of the surface as well. FTIR is limited to organic materials while Raman can analyze for nearly all materials. Both methods are also used for bulk sample analysis.

Microbiological Analysis

It was not until the late 1980s that the gas pipeline industry in the United States began to realize that microscopic organisms could contribute to the corrosion of pipes. Since then, the amount of corrosion attributed to microbiologically influenced corrosion (MIC) has grown tremendously, primarily because bacteria are commonly found on corroded pipe (and nearly everywhere else, if one was to look). In recent years, many have come to realize that the mere presence of bacteria is not an indication that MIC is occurring or will occur. Microorganisms may be directly or indirectly involved in corrosion or their presence may be completely benign. A deeper understanding of the relationship

between the bacterial community present within a pipeline, its energy sources and metabolic waste products, system chemistry, operational considerations, and corrosion is needed to determine whether MIC is truly an issue.

Bacteria are believed to influence corrosion by a number of mechanisms, including cathodic depolarization, formation of occlusions and crevices, fixing of anodic sites, and promoting acidic conditions beneath deposits. Understanding the types of bacteria present in a corrosive environment may help to identify how bacteria could be contributing to the corrosion.

Laboratory testing to define the microbiology of a system can range from fairly simple, inexpensive examinations to extremely complex, costly investigations. The selection of specific laboratory tests depends on how precisely the microbial environment needs to be defined in order to understand the problem and determine how to control it. In most cases of corrosion investigation, the primary goal is to identify whether bacteria are present, what general types are present, and their actual relationship to the corrosion observed in the pipe. The latter goal is one of the most difficult, however, and research has not yet identified a sure-fire method of ascertaining the degree to which microorganisms are responsible for corrosion in any given environment. Obtaining a better understanding of the microbial consortia in a pipeline system can, however, provide some useful insights into how microorganisms could be contributing to a corrosive environment. Classification of the organisms present in a system can be established in a number of ways such as by morphological type, oxygen requirements, nutrition, and respiration.

In most cases when in-depth microbiological analysis will be employed, the corrosion investigator will benefit by involving an experienced industrial microbiologist in the process. A trained microbiologist is aware of the analytical tools available and can help interpret the results of laboratory tests as they apply to the system being examined. Some examples of more common laboratory analysis that can help characterize the microbiology of a system are listed next.

Optical Microscopy Techniques

Optical microscopy of solids, liquids, sludges, residues, and coupon surfaces can be performed to identify the numbers, distributions, and

morphological types of bacteria present in a sample. Different optical microscopy techniques are available, such as direct observation (wet mount), phase contrast examination, and epifluorescent microscopy. These techniques can be employed as is appropriate for the sample type. Generally, the detection limit for microscopic methods is about 1,000 cells/mL of solution; however, this can be improved by various methods such as membrane filtration of liquid samples. It is important to note that optical microscopy does not distinguish between living and dead cells unless special sampling and staining techniques are used. It must also be emphasized that unless samples are properly preserved and “fixed,” bacteria and other organisms in the sample can quickly decompose and disappear. In other cases, the organisms in a sample may grow and reproduce exponentially before the examination is performed, resulting in misleading data. Unless a special “live” stain technique is to be used, fixing the sample is almost always essential prior to microscopic examination.

Fixing involves exposing the sample to glutaraldehyde or formaldehyde in an aqueous buffer solution to prevent changes to the cells themselves or the populations of organisms present. Fixing kills the cells by inactivating most enzyme activity and cross-linking proteins. As long as the samples are kept reasonably cool, the fixed cell structures will be preserved. When samples cannot be fixed immediately after they are collected, the samples can be kept on ice (not frozen) for up to 24 hours until fixation is possible.

To increase the amount of information available from samples for optical microscope examination, a multitude of different staining techniques are used. Simple stains are commonly employed, such as methylene blue or crystal violet, or differential stains such as Gram stain, spore stain, or nuclear stain can be used. Fluorescent stains have also gained popularity in the examination of pipeline related samples, as they help distinguish cells from some debris in corrosion samples. Epifluorescent microscopy uses reflected UV light of specified wavelengths to excite fluorescent dyes so that the cells glow bright green, yellow, blue, or red against a dark background. Fluorescent stains can be labeled with antibodies for specific organisms, although this technique has had only limited success in corrosion samples as the labeling sites on the cells seem to become blocked by corrosion reaction products. Background interference is sometimes a problem in pipeline samples containing light hydrocarbons or fluorescent debris.

On a simplistic level, optical microscopy provides a check against culture media results. In one example, organisms in a pipeline heavily treated with biocide grew when inoculated into culture media. Optical microscopy, in this case, revealed that the bacteria in the pipe were spore forming organisms (*Clostridium*). The cells became dormant spores when exposed to biocide and then were able to grow again when they moved to a non-biocide treated environment. Another example of applying optical microscopy is determining whether the bacteria in a system respond to growth media. A common example of this is when bacteria from a high salinity system are inoculated into a commonly used 2% salinity liquid culture medium. The difference in osmotic pressure across the cell wall can be enough to kill (rupture) the bacteria, resulting in no viable cells being cultured when in fact the system contains viable bacteria. Optical examination of the liquid in this case may have shown a high number of cells, causing the investigator to become suspicious of his or her culture media results.

Surface embedments of corrosion surfaces, as described in Chapter 4, can also be examined using epifluorescent and phase contrast microscopy. Histological embedding media are water permeable and allow water-based stains to reach the embedded cells. Further, the relationships between microorganisms, corrosion products, and surface features can also be observed using this technique.

Optical microscopy is currently an underutilized tool for corrosion investigations. Given the rising number of corrosion incidents attributed to MIC (based on sometimes tenuous premises), one hopes that the use of this tool will increase as corrosion investigators begin to seek a better understanding of their corrosion problems.

Organic Acid Analysis

Dissimilation is a process that bacteria use to break down food materials to yield energy and compounds used for cell growth. The process also results in the formation of organic acids such as formic, pyruvic, acetic, propionic, butyric, and others. In systems where bacterial activity is significant, measurable amounts (in the parts per million range) of these organic acids may exist and can be detected using a suitably equipped ion chromatograph. Sample preservation and immediate analysis is necessary to prevent the organic acids from degrading before analysis can occur. Liquid samples are typically injected into

a nitrogen-purged vial through a 0.2 μm filter to remove most solid particles. The vial is then kept on ice and shipped to an analytical lab.

Culturing and Identification

Bacteria only grow and reproduce when the proper energy (food) sources and environmental conditions are present. When a sample from a pipeline or any environment is placed into a culture medium, only the organisms that respond to the nutrients present and environmental conditions provided will grow. The types of organisms that respond may be a small percentage of the total community of bacteria present. Possibly none of the organisms will respond to the test medium. These limitations of culture testing are often overlooked by those employing commercially available serial dilution test kits. Laboratory culture of bacteria from field samples allows much greater control over the test conditions. The critical element is properly transporting the field sample to the laboratory without substantially changing the microbial makeup of the sample.

Laboratory culture of bacteria can help identify the general types, or even specific organisms, present in the corrosion environment. Liquid, plate, and other types of culture techniques may be used in lab testing, whereas these techniques are not practical for field testing. NACE has published a number of standards that describe various culture techniques and media formulations appropriate to oil and gas pipeline samples (such as TM0194–94). The purpose of identifying the bacteria present in a corrosion sample is not to find the “bad bugs” that are causing the corrosion (seldom is one species solely responsible) but to characterize the microbial community and understand the metabolism of the predominant organisms. Bacteria utilize organic molecules for energy, produce waste products, secrete exopolymers and require a certain environment to grow and reproduce. When these factors are known, then the corrosion investigator has a much better idea of how bacteria could contribute to the corrosion and how they can be controlled.

Other Techniques

Several other techniques or test kits for evaluating the microbial conditions in a pipeline system are also available. One method detects

enzymes such as sulfate reductase or hydrogenase which are associated with the presence of SRB. Another test has been developed to detect ATP (adenosine triphosphate), which is a key metabolite of many organisms. Reverse sample genome probe (RSGP) is another forthcoming technique used to identify the presence of organisms suspected of contributing to internal corrosion. In this technique, DNA from organisms previously isolated from field problems is spotted on a master filter. DNA isolated from current field samples is then labeled with either a radioactive or fluorescent indicator and exposed to this filter. Further approaches based on the conversion of a radioisotopically labeled carbon source have been used to assess the potential activity of microbial populations in field samples, although this is predominantly a laboratory technique. Finally, isotopic fractionation¹⁴ has been used to distinguish biogenic hydrogen sulfide from geochemical hydrogen sulfide with some success.

Metallurgical Analysis

Metallurgical analysis is most commonly a destructive technique primarily conducted through the use of metallography. The method is considered to be destructive because the pipe sample must be cut or sectioned to produce samples of suitable size for preparation. Metallography usually involves mounting a small cross section of interest from the pipe in a plastic resin and then grinding and polishing the surface to be examined through a progressively finer series of abrasives. The final polishing steps often utilize diamond and alumina particles, the goal being to produce a mirror-finish that is free of scratches and mechanical deformation of the structure. This surface may then be examined microscopically, both in the as-polished condition and also chemically etched to reveal certain features of the microstructure. In situ metallography is sometimes performed on large structures that cannot be sectioned for sampling, although on a pipeline this would only be applicable to the outside surface of the pipe. For corrosion investigation, in situ metallography would not be of great value in terms of information gained.

Metallographic specimens are normally examined at several magnifications ranging from 50X to 1,000X. The microstructure observed is normally documented by photography. Observations may include grain size, inclusion content and distribution, uniformity of

the structure, type of structure, percent of each phase present, and interaction between the corrosion and the microstructure. Although there are no published standards for the microstructure of API pipe steels, a metallurgist experienced with pipe steel could observe whether the structure observed was typical for the grade and vintage of pipe being examined.

On a microscopic level, the steel in most pipe, particularly older pipe, is not homogeneous except in modern high strength steels. Depending on the steelmaking process, certain elements may be distributed non-uniformly through the wall thickness, sometimes in bands or segregated in the center of the plate. Some older pipe has less carbon in the structure at the outer and inner wall surfaces. Other pipe has elongated manganese sulfide inclusions in the rolling direction of the plate used to make the pipe. Certain elements may accumulate at the boundaries between grains in the steel, making the boundaries more susceptible to corrosion. Microstructure may exert an influence on pipeline corrosion but would virtually never be considered a primary contributor.

When pipe comes in contact with a corrosive environment, these microscopic inhomogeneities affect where corrosion first starts and how it progresses over time. The effects of microstructure on the resulting appearance of corrosion may be observed as “tunnels” and striations in the rolling direction or longitudinal axis of the pipe or an undercutting in the walls of a pit. These features are not observed in all cases of corrosion on pipe prone to developing such features because their presence is dependant upon the nature of the corrosive environment. Research and field observations on corroded line pipe have shown that mildly acidic conditions can result in tunneling or striation type features. The same pipe exposed to very acidic conditions may not show the same corrosion discrimination between metallographic features.

Metallographic analysis can be used in three primary ways in a corrosion investigation: (1) to characterize the microstructure of the pipe, (2) to observe the relationship between the microstructure and the corrosion, and (3) to evaluate the size and shape of any pits. Metallographic characterization of the microstructure could be used to determine that the material is “normal” for the grade of pipe, consistent throughout the pipe, and to identify the chemical and structural uniformity of the steel in general. Observing the relationship between the corrosion and the pipe could help identify whether certain components

of the microstructure are more prone to attack in the given corrosion environment. This could be the grain boundaries, certain phases, inclusions, or regions of different concentration (bands) of elements within the steel. Also, in the case of an isolated corrosion pit, metallographic examination could verify whether or not the pit was the direct (or indirect) result of some highly localized anomaly in the structure such as a rolled-in piece of foreign material. Finally, close examination of pits in metallographic sections helps characterize the cross-sectional morphology of the pits. Pits can take a variety of forms as referred to earlier in Figure 12. Pit cross-sections may appear cavernous, parabolic, deep and narrow, elliptical, sub-surface, or exhibit preferential attack of the macro- or microstructure of the material.

Metallographic examination may also be used to determine the nature of tenacious scales or well-bonded corrosion deposits. This poses many challenges for the metallographic lab. Because most deposits are a different hardness than the steel, debris may break loose from the deposits during polishing and scratch the steel and water-corrosive anions are retained in the deposits causing rapid attack of the deposit to steel interface. The latter concern is most problematic; however, there are special preparation techniques available that can help overcome all of these issues. Microscopic observation of deposits can help identify whether they are of uniform composition, porous or non-porous, and provide some indication of how long they have been forming. Mounted specimens with scales or deposits may also be examined using scanning electron microscopy and x-ray spectroscopy to understand the chemical nature of the material. When performing chemical micro-analysis of metallographic specimens, however, caution must be used in interpreting the results as the polishing steps can introduce foreign elements (silicon, aluminum) and remove other species that were present as water soluble salts.

One way in which metallographic specimens should *not* be used is to determine the presence of microbiologically influenced corrosion by observing what happens to the mounted sample over time. One popular misconception present in some metallographic circles purports that if a mounted, polished corrosion pit sample exhibits corrosion “growing” out across the sample from the pit interface after some time, then MIC is implicated. This legend is not rooted in the realities that, (1) corrosion products in the pit are still corrosive to a polished surface, and (2) no matter how diligent the metallographer,

water is still present in the corrosion products. The mounted specimen attracts and retains some water due to capillary action and the hygroscopic nature of the corrosion deposits. Thus, unless very special efforts are made, corrosion almost always “grows” out from a mounted corrosion pit over time. This is not an indication of MIC.

Since preparing a metallographic specimen requires cutting the pipe, this is often one of the last steps to be employed in a corrosion investigation so that no evidence is lost. In the case of a leak or failure, it may not be possible to section the actual pit that leaked or caused a rupture. In that case, it is advisable to locate a representative corroded area nearby and prepare a metallographic specimen from that area. A longitudinal section through a pit will typically show the effects of grain structure on the corrosion at the upstream and downstream ends of the pit. If an outside laboratory will be used to provide metallurgical services, be certain to clearly explain the type of information and documentation that is desired. Adequate photo documentation is essential!

Corrosion Testing

Instrumented electrochemical corrosion testing methods may find some application in the evaluation of the corrosive conditions believed to be present inside the pipe. When the environmental conditions in the pipe are well documented and actual liquid samples are available from the system, corrosion tests may be conducted in the lab to provide some understanding of the corrosive nature of the environment. The primary consideration here, however, is that the actual system conditions be replicated in the lab tests. This includes all aspects of the operation, not just the liquid composition. More difficult issues such as flow rate, pressure, temperature, microbiology, dissolved gases, surface deposits, and so on, must be properly addressed. Alternatively, it may be more appropriate to install on-line monitoring equipment in the pipeline, the liquid source location, or a side-stream loop. Whenever electrochemical techniques are used, it is also helpful to compare the results of those techniques with exposed steel surfaces from the pipe environment. This could be from the pipe itself or through the use of concurrent coupon testing. Typical electrochemical corrosion analysis techniques include corrosion potential measurements, linear polarization resistance, cyclic polarization, and electrochemical noise.

TABLE 16 Laboratory Analysis Data Summary

Sample Identity/ Location	Type of Sample	List Analytical Techniques Used	Summary of Results
		Chemical, Bulk:	
		Chemical, Surface:	
		Microbiological:	
		Metallurgical:	
		Corrosion Testing:	
		Other:	

Establishing realistic test conditions and obtaining data that correlates with the actual corrosion observed in the pipe will be of great benefit when corrosion management and mitigation plans are developed.

Other Techniques

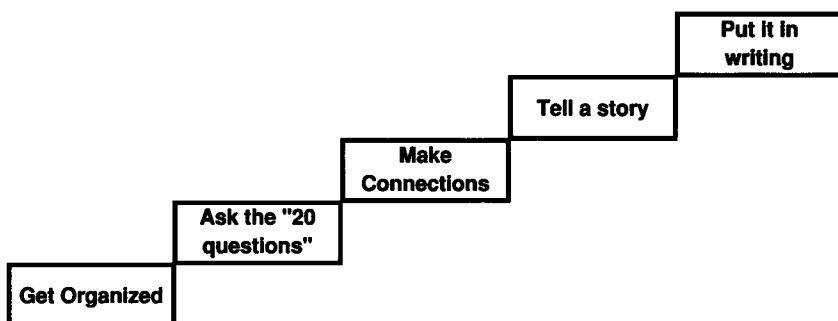
This section has only touched on some of the more popular laboratory analysis methods that can be applied to corrosion investigation. There are certainly other methods that can be employed. Isotopic fractionation of gas to distinguish hydrogen sulfide of thermo chemical origin from that of biotic origin has been successfully used in some cases. Characterization of microbes in corrosion environments has been accomplished using rapid DNA sequencing and genome probe techniques. Advances in the medical industry have brought about a variety of rapid assay methods that use biochemical reactions or enzymes as indicators of certain organisms. Hydrogenase, for example, is an enzyme related to SRB for which a rapid test kit was developed. Clinical microbiologists now have access to multi-cell growth plates that can be used to classify viable bacteria in a very short time and similar systems are available for environmental organisms. The corrosion investigator should not limit himself or herself to the methods described here but should remain vigilant for new technology that will improve the quality of the investigation and conclusions.

In summary, laboratory analysis sometimes produces a large volume of test data and results. Once the analyses are completed, the investigator's job is to begin sorting through the data to determine its significance. Table 16 provides a form where the laboratory results can be condensed. The process of distilling results down to a few significant points is a necessary part of the investigation process. Significant points could include what primary chemical elements were found in a sample, whether high numbers of specific bacteria were detected, identifying how the pipe metallurgy affected the corrosion, and so on. In the next chapter, where we begin examining all data resulting from the investigation, having succinct descriptions of the lab results will help in determining the overall cause of the corrosion leak or failure.

Reviewing the Results

Thus far in the corrosion investigation we have made plans, looked for evidence, collected samples, and performed numerous tests in the field and in the laboratory. Perhaps it now appears that enough evidence is available to reach a conclusion and the investigator feels he or she knows who committed the crime. This may be the case; yet, there is still a process to follow to be certain that we have not missed something or that our perspective is slanted in the wrong direction. Simply reporting findings is not the same as reaching a technically justifiable, logical, fully supported conclusion. A formal review process helps the investigator tie all of the clues together to present the case in a way that average, everyday folks can understand.

Steps in the Review Process



The goal of reviewing the results of an investigation is to distill a conclusion from the information gathered. The review process has

several steps: getting organized, asking questions, making connections, telling a story, and summing it all up in a report. This chapter walks you through each of these steps. A few case histories are also included, primarily to help illustrate the review process. The reader will not find lists of diagnostic conditions here, for it is impossible to adequately address all possible corrosion environments in a field guide. Many excellent references are available that address specific mechanisms in detail.^{15,16} Rather, as has been the case all along, the user of this guide is given the tools needed to reach his or her own conclusion. Hopefully, by the end of this chapter, you'll be ready to close the book on your own corrosion investigation.

Putting it All Together

First, Get Organized

By now it should be apparent that this field guide stresses the importance of conducting a corrosion investigation in a methodical, progressive, organized manner. This approach will work even for investigators who are relatively new to the internal corrosion world. Using this organized approach not only helps the investigator understand his or her corrosion problem but it will also be of value when consulting with other corrosion experts. The ultimate benefit of viewing internal corrosion via this process is being able to treat and control the corrosion correctly because the true cause is understood.

Usually, the data and test results from an investigation must be presented in a report of some kind. Many people, however, are not particularly fond of writing technical reports—perhaps traumatic childhood experiences with term papers are to blame. Whatever the case, producing a report of the findings is almost always a worthwhile exercise. One benefit is that the results of the investigation will be available to other people in the organization in a readily useable form. A pile of undigested results stuffed into a file folder is of marginal value when someone is trying to understand corrosion problems years later. Another benefit of producing a report is that the investigator is forced to critically review the results and their significance. In the bustle of the investigation work, it is certainly possible

to overlook a key piece of evidence or a test that would help clarify a point. Summarizing the results for a report helps catch these missing pieces at a time when something can still be done to address the questions raised. This chapter discusses how to organize and understand the data that has been collected during the investigation.

If the reader has been collecting information using forms similar to those provided in this field guide, the organization process is a simple one. Many problems can be defined by viewing them at different levels of observation or magnification, i.e., from a panoramic view of the mountain to the atomic crystallographic structure of a grain of sand on the mountain. Describing the corrosion situation by starting with the “macro” conditions and progressing to the “micro” conditions helps put a large amount of data into perspective. So, first let’s organize the investigation data in this same way. Here is one way to physically arrange your corrosion investigation data from macro to micro:

Overall Operating Conditions

—Background information

Specific Evidence

—Visual, physical, circumstantial

On-site Testing Results

—Chemical, microbial, physical

General Laboratory Test Results

—Chemical, metallurgical, microbial, surface analysis

A progression like this would be acceptable for an investigation that did not go into great depth in the laboratory analysis. When multiple corrosion sites are examined and analyzed, this same progression would be useable as long as the data from each site was clearly identified. If laboratory analysis is used to a greater extent, for instance to describe a pitting mechanism, another layer may be added to the data hierarchy for each pit site analyzed. That additional data layer could look like this:

Specific Laboratory Test Results (e.g., Pit 1,2,3...)

Chemical Analysis

—Bulk deposit vs pit contents

Metallurgical Examination

- Cross-sections through pit vs general microstructure
- Chemical and mechanical properties of the pipe vs requirements

Microbiological Analysis

- Viable/total organisms in bulk fluid vs bulk surface
- Viable/total organisms in pit
- Other analyses (enzymes, organic acids); pit vs bulk phase

Surface Analysis Techniques

- Surface chemistry in pit and around pit vs bulk deposits, fluid composition, gas and liquid inputs to the system

It is important to *physically* arrange the investigation results in logical progression either on paper or electronically. Include photographic images, measurements, and test results as well. Use any means of organization that helps group the data together: file tabs, sticky notes, binders, spreadsheets with multiple pages, and so on.

Check to see if anything is missing. Sometimes missing information becomes obvious once the entire project file has been cleaned up and organized. If any data or results need to be obtained, be sure to make that an action item before proceeding to the next step. If you don't have all the data, you won't be able to answer the "20 questions."

20 Questions to Answer

There are 20 questions that every corrosion investigation should try to answer. Actually, there are more than 20 but if you can answer these, you can consider yourself a successful corrosion detective. The data from the investigation should now be organized; the next step will be to make connections between the different types of data. Asking yourself these questions will help define the connections, or may point out where more information is required before moving forward. Table 17 contains the 20 questions:

TABLE 17 20 Corrosion Investigation Questions to Answer

1	What is significant about where the corrosion occurred?
2	What were the operating conditions in the pipe where the corrosion occurred?
3	What evidence from the investigation can help characterize the corrosive environment?
4	Which potential corrosion mechanisms could be involved?
5	Did material properties, system design, or construction methods have any contributing affect on the corrosion?
6	If corrosive species have been identified, has their source or origin been identified?
7	Does the time frame in which the corrosion occurred have any significance? How?
8	Is the corrosion being investigated an isolated occurrence? If not, has the cause of other corrosion in the system been analyzed?
9	What conditions could have been changed that would have prevented this corrosion from occurring, or drastically reduced its severity?
10	How does the severity of the corrosion affect the integrity of the pipeline system?
11	Did the corrosion initiate and propagate due to the same factors?
12	Do similar operating conditions exist at locations where there is no corrosion? If so, how can this be explained?
13	If mitigation treatments were applied to this portion of the pipeline, why where they ineffective?
14	If surface deposits were involved in the corrosion, when did they form and for how long were they present?
15	Have adequate samples, which have not been compromised by mishandling or contamination, been provided for analysis?
16	Have field and laboratory tests been performed according to technically correct procedures?
17	If assumptions about the internal environmental conditions have been made by the investigator, have these been supported by other personnel knowledgeable about the pipeline system?
18	Can the investigator present an unbiased conclusion? Is the conclusion supported by any published case histories or other reference material?
19	Has the investigation provided enough information to answer these questions? If not, can additional data be obtained?
20	What is the most probable cause of the corrosion?

Making Connections

One way to help answer questions about internal corrosion and determine (to the degree possible) what caused the corrosion is to look for connections between different types of data that have been produced by the investigation. This process can also be described as looking for relationships or correlations between the data points. A simple example of a relationship would be when chlorides are detected in the corrosion deposits and a liquid sample upstream of the corrosion site was found to have a high salinity. The suggested relationship in this case could be that the chloride in the corrosion deposit came from the upstream liquid source.

Data Point 1	Relationship between Data Points: Positive Correlation	Data Point 2
High chlorides in corrosion deposits	The origin of the chlorides	Upstream liquid source with high salinity

At first examination, there appears to be a positive correlation between the nature of the corrosion deposits and the nature of an upstream liquid source. This relationship needs to be verified to the greatest extent possible, however, before it is assumed to be valid. Asking questions about the relationship is a good way to prove its credibility. Questions in this case could address whether this was the only possible upstream liquid source, whether other chemical species showed a similar relationship as for chloride, and whether the deposits could have been contaminated with chlorides at some point before they were analyzed. Other questions could also be explored as appropriate to the specific situation. If these subsequent questions about the relationship can be answered, increased confidence in the correlation between the two data points is obtained. Each time this process occurs for different combinations of data points, the cause of the corrosion becomes more defined.

Looking at negative correlations can also help the investigator sift through the data for clues. In the previous example, what would have happened if an upstream liquid source did not indicate any chlorides,

yet chlorides were still found in the corrosion deposits? Is a negative correlation between these two factors possible?

Data Point 1	Relationship between Data Points: Negative Correlation	Data Point 2
High chlorides in corrosion deposits	The origin of the chlorides	Upstream liquid source shows no chlorides

Looking at this kind of relationship causes the investigator to ask different questions than were asked in the first example where a positive correlation was suspected. Perhaps there is an unidentified source of chlorides upstream of the corrosion, or perhaps the deposits were formed many years ago and operating conditions have since changed. Both questions would be worthy of further investigation before a conclusion was drawn as to the cause of the corrosion. Thus, consideration of both positive and negative correlations between data points can help the investigator pose some important questions that otherwise may not have been asked during the investigation. Seeking answers to these questions moves the investigator closer and closer to a conclusion.

Let's look at another example of this process using some different data points.

Data Point 1	Relationship between Data Points: Positive Correlation	Data Point 2
High viable bacteria levels found in sludge from cleaning pigging of the pipeline	Cause of (or contributor to) the pitting	Isolated corrosion pits found in pipe

In this common scenario, a number of questions should come to mind regarding how to support this positive correlation. The list of questions might include:

- What types of bacteria were detected? How long have bacteria been detected in this line?
- What other environmental conditions in the pipe could contribute to the corrosion mechanism?
- What influence does pigging have? How long has the pipe been pigged? How often? Is the sludge always removed?
- Is there other evidence that supports a link between bacteria in the pig sludge and pitting corrosion such as microscopic analysis of pit contents or embedment analysis of a pit?
- Do the corrosion products involve metabolic products of bacteria?

Again, this one observation of a potential relationship between data points leads to a number of other very significant questions that could validate or negate the positive correlation observation.

Obviously, there are many correlations that an investigator could examine in any given case of internal corrosion. With experience, the investigator will begin to identify which data relationships are meaningful in certain situations. Let's look at one more example.

In this example, several joints of pipe in a 40-year-old pipeline have been replaced with new pipe at various locations as part of an upgrade program. After only two years of service, internal corrosion leaks develop at the girth welds joining the new pipe to the old. Examining the relationship between pitting at girth welds and the age of different pipe in the pipeline would be a natural one to explore.

Data Point 1	Relationship between Data Points: Positive Correlation between new pipe and pits in weld	Data Point 2
Age of pipe in system	Cause of (or contributor to) the pitting	Pits found at welds between new and old pipe

In this case, someone might jump to the conclusion that the pitting results from dissimilar surface conditions (new vs old pipe) causing a galvanic effect at the joint or that welders today can't weld like they used to in the good old days. This, however, is a good example of

where asking critical questions about this relationship pays dividends to those willing to look a little deeper at corrosion problems. Without gaining insight on the specific reason for this corrosion, the integrity of any future replacement pipe could be at risk. Here are some questions that could be asked about this relationship:

- Did selective corrosion of girth welds occur at other times in the history of the pipeline?
- Is there a chemical, metallurgical, or surface condition difference between the adjoining pipes that could cause a galvanic cell to form when water is present in the line? Can this be confirmed in a laboratory test?
- Was the weld quality acceptable? Were proper welding procedures used? What about weld and heat affected zone (HAZ) chemistry and metallurgy vs that of the pipe?
- Do the new welds exhibit greater (or excessive) penetration into the pipe than older welds, causing more turbulence or collecting debris? Has excess penetration of the weld root caused localized turbulent flow or build-up of deposits on the downstream edge of the weld?

Again, answering these questions will help justify or refute the observed correlation and will yield important clues about how to deal with the problem in the future.

So far, we've only looked at three fairly simple examples of data point relationships. The tables provided in this book listing suggested data to collect during an investigation contain over 100 different data points that could be compared in thousands of different ways. Which data points are compared and how they are correlated will be unique to each investigation. What follows are some ideas or hints (presented as questions) for each data point that can help the investigator explore relationships between the data points (see Table 18). Review this list and then use the form in Table 19 as a guide to making correlations between your own data points.

Telling a Story

At this point, all data should have been collected and organized and relationships between data points examined and tested by answering questions about them. The investigator should be well aware of what is

TABLE 18 Questions to Consider—Relationships between Data Points

General Information	Questions
Date/Time of field investigation	Did timeliness of the investigation affect the quality of the evidence?
Date/Time corrosion was discovered	How much time elapsed between finding the corrosion and examining it? Did the conditions change before analysis was performed?
Date/Time pipe was cut out from line	Was the sample cut out before investigators arrived? How long was it exposed to air?
How was the corrosion detected?	Visual, leak, failure, suspected problem, ILI tool?
Leak or rupture? Fire?	Did fire or post rupture events alter the evidence?
Location of investigation	Was the investigation performed on-site or off-site? What happened to the pipe in transit?
Facility description (pipeline, plant, well head, other equipment)	What operating conditions are specific to this type of facility? Has corrosion been found in similar facilities in the same system? Different facilities in the same system?
Pipe diameter and WT	There is a relationship between flow rate and diameter—is it significant in terms of where the corrosion occurred?
Pipe grade and specification	Is the corroded pipe the same grade as the adjoining pipe? Does the pipe meet specifications? Was the pipe installed in new or used condition?
Pipe year of manufacture	What is the relationship between vintage and metallurgy/chemistry?
Year of installation	Is the age of pipe related to occurrence of corrosion in this system?
Joint design (welded, flanged, coupled)	Corrosion at joints? All joints or only certain joints?

TABLE 18 (Cont.)

General Information	Questions
Internal coating? Type? Condition?	What is the condition of the internal coating?
Original construction or replacement pipe	Is the corrosion specific to old or new pipe?
Pipe elevation/depth of cover	Is the corrosion in a low spot or sag where liquids could collect?
Length of pipe cut out	Was a representative sample obtained?
Method of cut out (hot or cold cut)	Did the cutting method contaminate the sample?
Did foreign material enter the pipe prior to, or during, the cut out?	If so, was a sample of the foreign material collected? Could contamination have entered the pipe and affected the chemical composition?
What foreign material entered the pipe?	Is the foreign material inert or reactive? Was the material identified?
Was a sample of the foreign material obtained?	If no sample of the foreign material was obtained, is some still available now?
How was the pipe preserved for shipping?	Was it preserved so that subsequent analyses were not adversely affected?
Date pipe was shipped to lab for analysis	How much time elapsed between detection, removal and shipping of the sample?

Operating Conditions	Questions
Product transported	Is the product corrosive? Can it contain corrosive contaminants? Has the product always been the same composition or type?
Typical operating pressure	Is the pipeline normally operated at full pressure?
Maximum operating pressure	What is the difference between typical and maximum allowable operating pressure, and why?

(Continue)

TABLE 18 (Cont.)

Operating Conditions	Questions
Number of pressure cycles per month	Could pressure cycling contribute to corrosion fatigue in this line?
Range of pressure cycles (psi)	What is the magnitude of the stress cycle?
Typical range of operating temperatures	Did the corrosion occur where increased temperatures exist or have existed?
Product analysis data	
—Gas analysis including dew point, water content, carbon dioxide, oxygen and hydrogen sulfide	Are corrosive gas components present or have they been present in the past? Are there records to show this? Have these components been within allowable limits?
—Liquid analysis including percent water, metals and anions in water phase	Are liquids present? What is the typical composition? Are they corrosive?
—Microbiological analysis results	What types of bacteria are present? What do they utilize for energy? What environmental conditions do they require?
Identify source of transported product and all potential sources of contaminants	What are the sources of the transported commodity and potential corrosive contaminants? Are they known? Has the composition of the incoming material been tested regularly?
Typical flow rate	Is the flow rate in the corroded area the same as elsewhere in the pipeline?
Operating mode (continuous, seasonal, intermittent, etc.)	Does the line sit idle for long periods or during frequent short periods?
Distance to nearest compressor/pumping station	Is the corrosion upstream or downstream? Is the corrosion close enough to the station to have been influenced by it in some way?

TABLE 18 (Cont.)

Operating Conditions	Questions
Is the pipeline piggable?	Can the line be pigged for cleaning or inspection? Has it been? What comes out of the line when it is pigged?
Has in-line inspection been performed?	If ILI data is available, how does the integrity of the pipeline correlate with the corrosion being analyzed?
What is the leak/failure history?	Have previous leaks or failures been documented? Analyzed?
Were previous internal corrosion incidents analyzed? Report available?	What information can be obtained from previous analyses? Were the analyses performed correctly?
When was the last hydrostatic test?	Were there test failures? Why? How was dewatering accomplished? Was the line dried after testing?
Are there currently operating pressure restrictions imposed on this line?	Have integrity concerns resulted in lowering of MOP, either voluntarily or by regulatory agencies? What are the concerns?
Describe maintenance procedures performed	
Cleaning	What type of cleaning is performed (pigging, sweeping, solvent batch, scale removal, etc.)
Repairs	Can corrosion data be gleaned from repair records? Have field personnel observed corrosion during routine repairs and maintenance?
Inspection	What types of routine inspections are performed?
Describe all treatments	
Internal corrosion	Is inhibitor or biocide used in this pipeline or in upstream product sources?

(Continue)

TABLE 18 (Cont.)

Operating Conditions	Questions
Dehydration	Is dehydration used? Is it working properly?
CO ₂ or H ₂ S processing	Is equipment used upstream to remove corrosive gases? Does it work? Has it worked? When was it installed?
Freeze protection	Is glycol or methanol used for freeze protection? When? Is composition of the product tested for quality?

Visual Evidence	
Location of Corrosion	Questions
Physical location of pipe	Is there anything unique about the physical location where the corrosion occurred?
Clock position in the pipe	How does clock position relate to the potential for water being present?
Relationship to other features:	
System design (dead leg, drip, etc.)	Does the design cause liquids or debris to accumulate? Are no-flow regions present?
Elevation of pipeline (low spot)	How does elevation profile in the area of the corrosion correlate with the potential for liquids to accumulate?
Girth welds or mechanical joints	Is the corrosion specific to welds or joints? Why?
Longitudinal weld seams	How does weld quality or metallurgy impact the corrosion?
Directional change in flow	Is flow direction always the same? Does flow change abruptly where the corrosion occurred?
Inlets, outlets, taps, fittings	How is proximity of the corrosion to these features significant?
Heat sources or temperature change	Is there increased or decreased temperature where the corrosion occurred? Why?

TABLE 18 (Cont.)

Visual Evidence	
Location of Corrosion	Questions
Historical liquid levels in pipe	Does visual evidence of liquid levels correlate with operating records in any way?
Deposits, coating, debris	Does the composition or location of these materials affect the corrosion?
Nodules	What is chemically unique about the nodules? From what are they formed?
Scale	Does scale chemistry correlate with liquid/gas composition? Has the liquid or gas composition changed significantly over time?
Biological materials	What materials are present? What are the potential sources?
Chemical injection	Is the location of the corrosion near a chemical injection point? How has the chemical affected corrosion upstream and downstream of the injection point?
Processing equipment	Does on-line processing equipment cause the corrosion to increase for some reason?
Construction/material changes	Is the corrosion specific to changes in construction practice or material?
Pipe mill defects	Are mill defects in the pipe serving as starting points for corrosion? Does metallurgical examination show this to be true?
Type of Corrosion Attack	
Isolated pitting	What chemical or physical condition promotes this type of attack? What is the pit morphology? Is it consistent?
Isolated pitting within areas of general corrosion	What is different about where the pits form within the field of general corrosion?

(Continue)

TABLE 18 (Cont.)

Visual Evidence	
Location of Corrosion	Questions
Type of Corrosion Attack	
Linked pitting within areas of general corrosion	Why does the pitting seem to be linking? Is a liquid “trough” present?
General metal loss with some deeper pits	Does chemical analysis suggest aggressive, low-pH liquids are present?
Etching or general metal loss with no pitting	Is general attack specific to a physical location in the pipe? Where and why?
Selective attack at welds	What does metallographic examination tell about the composition and structure of the weld and heat affected zone?
Crevice corrosion (at flange joints, mechanical joints)	Are other crevices present in the pipe? Are they also attacked?
Erosion-corrosion	What is the reason for the increased velocity?
Environmental cracking	What chemical species is supporting this cracking?
Pitting morphology	If unique features are present, how do they relate with the presence of certain chemical species or bacteria? How does microstructure contribute to the features?
Internal conditions during inspection	
Wet or dry	Is “wetness” from water, organics or both?
Debris, scale, deposits	Are these identical everywhere on the ID surface of the pipe? At other locations in the pipe?
Color of deposits, scale, etc.	Do color changes relate to compositional or operational changes?

TABLE 18 (Cont.)

Visual Evidence	
Location of Corrosion	Questions
Type of Corrosion Attack	
Smell	Was sulfide noticeable during field inspection but no sulfides were found later in the chemical analysis? Why?
Severity	How does severity relate to position in the pipeline?
Longitudinal extent	How does extent relate to flow conditions?
Circumferential extent	
Maximum wall loss	Where is the maximum wall loss? Why were the most corrosive conditions present there?
Profile of wall loss	Is the profile gradual or severe? Why?
Maximum/average pit depth	How does maximum compare with average? Was one pit much worse than all the rest? What was different about that location?
Maximum/average pit diameter	
Pit length vs pit width	Do the pit exhibit preferred growth in one direction? What seems to cause this?
Depth/diameter ratio	Are the pits wide and shallow or narrow and deep? If narrow, what could promote this focused attack?

Physical Evidence	Questions
Pipe—Corrosion leak or failure	How much did the internal conditions change after the rupture or leak? Are they no longer representative?
Pipe—Undisturbed	Is truly “undisturbed” or representative pipe available?

(Continue)

TABLE 18 (Cont.)

Physical Evidence	Questions
Pipe—Cleaned	Is only cleaned pipe available for analysis? How can better information about the internal conditions be obtained?
Liquids—Source	Is the liquid source known? Are samples available? Are the samples representative?
Liquids—Corrosion site	Do corrosion site liquids represent typical conditions?
Gas—Source	Is the source gas composition known? What about history of composition?
Gas—Corrosion site	Does the source gas sample represent the gas that would be present at the corrosion site?
Sludge	What is the composition of the sludge/ deposits/scale and where is it coming from? Is it unique to the corrosion site? Can these materials be differentiated?
Deposits	
Scale	
Nodules	Are nodules present? Were they present but somehow removed? Are they only present in a specific place?
Biofilms/bacteria/biological matter	Were uncontaminated samples obtained in a timely manner? What sources of contamination were present?
Embedments/Replicas	Were embedments or replicas obtained from significant areas of interest?
Coating	Was internal coating present? What was its condition? What type of material was it? Should it have been there?

On-site Testing Results	
Tests on Liquid Samples	Questions
—Presence of water	In what form was water present during operation, e.g., bulk liquid, vapor, film, condensed, emulsion, etc.

TABLE 18 (Cont.)

On-site Testing Results	
Tests on Liquid Samples	Questions
—Temperature	Does sample temperature reflect actual operating temperature?
—pH	How does bulk fluid pH relate with local pH under deposits or nodules?
—Total alkalinity	Does the fluid exhibit some capacity for buffering changes in pH?
—Dissolved CO ₂	Do these levels relate with known gas composition data?
—Dissolved H ₂ S	
—APB and SRB cultures; other microbial culture results	How do viable populations in the liquid relate to surface populations? What energy sources are available to support cell growth?
—Fixation for microscopy	If cells were detected by optical analysis, how do the observations relate to viable bacteria levels detected? Were spore forming organisms found?
—Corrosion inhibitor or biocide residual levels	Were residuals present? Are the sources known? Should residuals have been detected? What do the levels reveal?
Tests on Solids/Sludges /Scales	
—pH	How does surface pH correspond to bulk fluid pH?
—Sulfide/carbonate spot test	Were these results corroborated by other test results?
—APB and SRB cultures; other microbial culture results	Were cultures prepared from specific features such as pits or nodules?
—Fixation for microscopy	Were cell counts much higher on the surface? Why? Were biofilms or colonies observed?

(Continue)

TABLE 18 (Cont.)

On-site Testing Results	
Tests on Liquid Samples	Questions
Tests on Solids/Sludges /Scales	
—Physical morphology	Is the sludge or scale layer consistent or striated (suggesting changes over time)? Can compositional changes be identified in the strata? Can the strata be related to operating conditions?
Gas Analysis Tests	This applies to samples from investigation sites or sources to the site.
—Water vapor	Do downstream operating conditions cause water to condense?
—Carbon dioxide	Are these components reflected in the scale or deposits?
—Hydrogen sulfide	
—Temperature	How does gas temperature change downstream of the sample point?
—Pressure	Does pressure change downstream of the sample point?

Laboratory Analysis Results			
Sample Identity/ Location	Type of Sample	List Analytical Techniques Used	Questions
		Chemical:	How do the chemical analysis results correlate with known operating conditions? Are there materials present for which the origin is unknown? How is the corrosion mechanism linked to chemical composition?

TABLE 18 (Cont.)

Laboratory Analysis Results			
Sample Identity/ Location	Type of Sample	List Analytical Techniques Used	Questions
		Microbiological:	What types of organisms are present? What is their involvement with corrosion and surface deposits? What are their energy sources? What does chemical analysis data reveal?
		Metallurgical:	Is pit morphology related to specific metallurgical features? Is isolated attack related to features in the weld or pipe? Does the pipe meet specifications? Is it typical for the grade/age?
		Corrosion Testing:	What was revealed about the corrosivity of the pipeline environment by testing liquids or other samples?
		Surface Analysis:	What did surface analysis reveal about local chemical changes associated with corrosion, deposits, nodules or bacterial colonization? What chemical species are associated with the corrosion mechanism? What was observed about pit morphology?
		Other Methods:	How do the results of other lab analysis methods relate to operating conditions?

TABLE 19 Data Point Comparison Form

Data Point 1	Data Point 2
Relationship: Correlation:	
Questions to Validate Relationship:	

Data Point 1	Data Point 2
Relationship: Correlation:	
Questions to Validate Relationship:	

Data Point 1	Data Point 2
Relationship: Correlation:	
Questions to Validate Relationship:	

known and what is still unknown about the corrosion at this juncture. One of the final activities of the review process is using the results, observations, and relationships to tell a story—a true, factual story of what happened in the pipeline to cause the corrosion that was found. Once this step is completed, the investigator will be ready to move on to writing a technical report because he or she knows what he or she needs to say in the report. Trying to write a report before one knows what needs to be said, and in what order, is a frustrating exercise indeed.

Telling a story is a good analogy here for several reasons. First, all stories have a timeline—a chronology of events that take place in a certain order that conveys something about how the events are related. Showing how a character goes from victim to victor, or how a pipe goes from intact to corroded, is the core framework of the story. Next, all stories occur in some context and setting that provide the reader a better understanding of how and why the events on the timeline occur. Likewise, the story of “how the pipe corroded” also occurs within the context of the construction and operational history of the pipeline. Finally, most good stories end with the resolution of some conflict or problem. Hopefully, the story of “how the pipe corroded” also ends with a conclusion of who the villain is and what can be done to stop him next time. Now we have identified three important things that the story of corrosion must contain:

- Events described in chronological order
- The context in which the events occur
- A conclusion and resolution of the problem (if possible)

Let’s look at each one of these aspects individually (in chronological order, no less). First, there are two chronologies to address, one of the pipeline and the other of the investigation activities. The chronology of the investigation activities is laid out in the following section on writing the report. The investigation chronology is essentially duplicated in how the results are presented in the report. The chronology of events occurring in the pipeline is a bit tougher to describe but generally at least some facts are known in most cases. These facts can be presented in the order in which they occurred, i.e., “the pipeline was placed in service in 1946 and no corrosion leaks occurred until 1999.” Compare the previous sentence with, “A corrosion leak occurred on the pipeline in 1999; it was placed in service in 1946.” The latter

sentence is less clear because the chronology is backwards. Presenting facts in chronological order helps both the reader and investigator. Review the facts about the case and arrange them in chronological order.

Second, in the case of a corrosion investigation report, the context in which the events occur could be the physical location of the pipe, the age of the line, the product transported, operating pressure, and so on. Corrosion is occurring within the context of these relatively stable conditions. These can usually be described once at the beginning of the report to set the stage and are only revisited when they become particularly relevant to the analysis. Tables of general background information about the pipe and investigation can serve as the source of context information.

Last, getting to the conclusion and resolution of the problem is, of course, why people bother to read all the preliminary matter in the first place. Taking the reader through a chronology of events within a clear context naturally leads to a conclusion of some sort. Sometimes the conclusion is not what we expected and so it is with corrosion as well. Perhaps the investigation could only go so far in describing the corrosive environment—not enough to state with confidence the exact cause. This is perfectly acceptable. A good scientist (or corrosion detective) is one who knows where the boundaries of factual evidence are exceeded and stays within those boundaries. This is not to say that all educated speculation is off limits in a technical report, rather that it should be made very clear to the reader when speculation is occurring.

Sometimes an investigation has a meaningful conclusion in what was not found. Perhaps bacteria were found in the pipe but no MIC was present. Maybe a scale layer was present on the pipe but it was protective so that little corrosion occurred. Sometimes liquid analysis results from a grab sample indicate that the liquid was not corrosive. This may seem like a disappointing conclusion, yet it points to the fact that liquid chemistry was different at one time and something has changed (for the better). Other times, there is simply insufficient evidence available at the end of the investigation to conclude much of anything. In such a case, all one can do is state the facts about what was found, indicate that the data is inadequate to make a conclusion, and suggest what could be done to obtain more information (additional sampling, another cutout, more testing, etc.).

To communicate your findings in writing so that other people, even non-technical people, can understand, it is important to be sure

your report has the three essential components of a good story: a timeline, a vivid context, and a conclusion. Prepare these three things by reviewing all of the information that has been collected and organized so far and writing an outline showing how the data will be presented. Then, in bullet form using short sentences, draft your conclusion. If developing recommendations on how to control or respond to the corrosion is the responsibility of the investigator, these would go after the conclusions. Often, extensive recommendations are not included with a corrosion analysis report because other stakeholders need to review the findings and provide input. Unless the investigator has been specifically charged with developing recommendations, these should be omitted or presented merely as considerations for others to review. The investigator is not a whistle-blower or policeman; he or she is simply compiling and stating the facts—nothing but the facts!

Putting It in Writing

Now comes grand finale of this chapter—putting your findings in writing. If you have followed along with this chapter from the beginning, you now have everything needed to prepare a technical report:

- All observations, background information, field and lab testing data arranged in logical order.
- Answers to questions that the reader of your report will want to know about.
- An understanding of the relationships between the different data you have collected in this investigation and awareness of what facts are significant.
- Knowledge of three essential parts of “telling the story” of corrosion in the pipe you investigated.

With these things in hand, there is no need to fear the reporting process. Pour yourself a strong cup of coffee and get to work.

Every organization may require something a little different in a technical report; however, the basic organization of the report should look generally like the outline in Table 20.

Some people like to start with the field and laboratory test results sections; in other words, start on the “inside” of the report and work your way out. Then move on to the discussion and conclusion

TABLE 20 General Outline for a Corrosion Investigation Report

Summary—What did you do and what did you find? Keep it simple.
Introduction—How did this all begin?
Overall Operating Conditions
—Background information
Specific Evidence
—Visual, physical, circumstantial
On-site Testing Results
—Chemical, microbial, physical
General laboratory Test Results
—Chemical, metallurgical, microbial, surface analysis
(or)
Specific Laboratory Test Results (e.g., Pit 1,2,3...)
Chemical Analysis
—Bulk deposit vs pit contents
Metallurgical Examination
—Cross-sections through pit vs general microstructure
Microbiological Analysis
—Viable/total organisms in bulk fluid vs bulk surface
—Viable/total organisms in pit
—Other analyses (enzymes, organic acids); pit vs bulk phase
Surface Analysis Techniques
—Surface chemistry in pit and around pit vs bulk deposits, fluid composition, gas and liquid inputs to the system
Discussion of Relationships between Data Points
—Point out significant relationships and their validity
—Tell the story of what happened to cause the corrosion
Conclusion: Simply Summarize
—Start at the end of the story and work backwards.
—Only include test data that is imperative to the reader.
Appendix Material
—Tables of data, photographs, test results
—References, significant historical data

when all of the findings are fresh in your mind. You may even want to start by first compiling all of the data tables, images, and appendix materials. Whatever order you choose to write in is fine. Just be sure to cover all the points in the outline. The writing does not need to be highly technical or of great literary stature—just state the facts as

clearly and concisely as possible. Better to get the ideas on paper first then go back and do the clean-up work. If a formal written report is not required, it still pays off to present your findings in an organized, logical progression. For example, you could summarize observations in a few short sentences at the top of each page or section of results. That way, readers don't have to digest pages of data and try to determine what is significant. Hopefully, that is something the corrosion investigator has already done.

In the following section, three short case studies are presented to help illustrate the review process described in this chapter.

A Few Examples: Case Studies

Case Study #1: Natural Gas Storage Field Well Line

How was the corrosion detected?	Visual inspection
Leak or rupture? Fire?	No
Location of investigation	Field and Lab
Facility description (pipeline, plant, well head, other equipment)	Natural gas well line in storage field
Pipe diameter and WT	4" OD × 0.250" WT
Pipe grade and specification	API 5L Grade B seamless
Pipe year of manufacture	1960
Year of installation	1960
Joint design (welded, flanged, coupled)	Welded—SMAW
Internal coating? Type? Condition?	None
Original construction or replacement	Original
Pipe elevation/depth of cover	5 feet
Method of cut (hot or cold cut)	Cold
Did foreign material enter the pipe prior to, or during, the cut out?	No
What foreign material entered the pipe?	none

Was a sample obtained?	n/a
How was the pipe preserved for shipping?	Wrapped in plastic after field tests were completed
Operating Conditions	
Product transported	Natural gas (wet)
Typical operating pressure	400–800 psi
Maximum operating pressure	850 psi
Number of pressure cycles per month	n/a
Range of pressure cycles (psi)	n/a
Typical range of operating temperatures	52°F
Product analysis data	
—Gas analysis including dew point, carbon dioxide and hydrogen sulfide	H ₂ S < 0.2 ppm CO ₂ 0.66 mol% O ₂ 0.12 mol% Water 25#/mmscf
—Liquid analysis including percent water, metals and anions in water phase	100% water Chlorine 201,000 ppm Calcium 48,000 ppm Sodium 61,000 ppm Magnesium 6,400 ppm Iron 110 ppm TDS 564,000 ppm Scaling Index(LSI) 10.1
—Microbiological analysis results	Liquid sample: APB 1–10 cfu/mL SRB 0
Identify source of transported product and all potential sources of contaminants	Gas well #1234
Typical flow rate	Varies
Operating mode (continuous, seasonal, intermittent, etc.)	Seasonal—inject in summer, withdrawal in winter
Distance to nearest compressor/pumping station	3 miles

Is the pipeline piggable?	No
Has in-line inspection been performed?	No
What is the leak/failure history?	None
Were previous internal corrosion incidents analyzed? Report available?	No
When was the last hydrostatic test?	1960
Are there currently operating pressure restrictions imposed on this line?	No
Describe maintenance procedures performed	None for internal
Cleaning	No
Visual Evidence	
Location of Corrosion	
Physical location of pipe	Predominantly bottom
Clock position in the pipe	5 to 7 o'clock
Relationship to other features:	
System design (dead leg, drip, etc.)	Well line
Elevation of pipeline (low spot)	Not a low spot
Girth welds or mechanical joints	Welds not corroded
Longitudinal weld seams	None
Directional change in flow	N/a
Inlets, outlets, taps, fittings	No
Heat sources or temperature change	No
Historical liquid levels in pipe	Not obvious
Deposits, coating, debris	No
Nodules	No
Scale	Pits occur at breaks in the scale
Biological materials	No

Chemical injection	No
Processing equipment	No
Construction/material changes	No
Pipe mill defects	None
Type of Corrosion Attack	Isolated pitting within areas of general corrosion
Internal Conditions During Inspection	
Wet or dry	Wet
Debris, scale, deposits	Thin layer of friable scale
Color of deposits, scale, etc.	Dark brown
Smell	No
Severity	
Longitudinal extent	Extends beyond the area sampled
Circumferential extent	Between 5 and 7 o'clock
Maximum wall loss	0.090"
Profile of wall loss	Isolated pits within uniform corrosion 0.010" deep
Maximum/average pit depth	0.090" max. /0.055 avg.
Maximum/average pit diameter	0.37" max. /0.25 avg.
Pit length vs. pit width	Equal L and W
Depth/diameter ratio	$0.55/0.25 = 2.2$
Field Tests on Liquid Samples	
—Presence of water	Yes
—Temperature	55°F

—pH	6.4
—Total alkalinity	131 mg/L
—Dissolved CO ₂	85 ppm
—Dissolved H ₂ S	0.2 ppm
—APB and SRB cultures	Yes—reported above
—Fixation for microscopy	Yes
Corrosion inhibitor or biocide residual levels	No—none used
Field Tests on Solids/Sludges/Scales	
—pH	No
—Sulfide/carbonate spot test	Negative for sulfide
—APB and SRB cultures	APB 10–100 cfu/mL SRB 0
—Fixation for microscopy	Yes
Field Gas Analysis Tests	
—Water vapor	Not performed
—Carbon dioxide	Not performed
—Hydrogen sulfide	Not performed
Laboratory Analysis	
Chemical: XRD and semi-quantitative EDS analysis of scale	Major phases were iron carbonate, calcium carbonate, and iron oxyhydroxides. EDS showed 86% iron with remainder Al, Si, S, Ca, Mg, Cl
Microbiological: Microscopy of fixed liquids and solids	Higher numbers of bacteria were observed in the optical exam than could be cultured.

Metallurgical: Examined a pit cross section and a section including scale. Chemistry and tensile properties of the pipe were tested and met specifications.	Pitting was not selective to metallurgical features; microstructure was normal for this grade. Scale was layered and exhibited many through thickness cracks.
Corrosion Testing: None performed	Calculated maximum pitting rate over the life of the pipe was 2 MPY.
Micro-analytical:	Chlorides shown to be concentrated in pits along with some sulfur.
Other Methods:	None

Summary of Findings—Case Study #1: Natural Gas Storage Field Well Line

The corrosion in this case is primarily manifested as pitting that is occurring beneath a thin layer of nonprotective scale. The scale is iron carbonate and calcium carbonate with some sediment contained within the scale matrix. Narrow cracks and voids in the scale allow water to reach the pipe surface. Liquids from the well showed high chlorides, high total dissolved solids, and a high scaling tendency. Acid producing bacteria were low in number and no SRB were detected. It is possible that more APB are present than indicated by the culture tests since the chloride levels in the growth media are significantly lower than those in the field conditions. Gas analysis indicated low levels of carbon dioxide and essentially no hydrogen sulfide. The water content of the gas is high and condensed water could be expected.

Scale was present around the full circumference of the pipe, yet pitting within the field of scale only appeared on the bottom of the pipe between the 5 and 7 o'clock positions. This observation first suggests that condensed water containing carbon dioxide was involved in forming the iron carbonate scale on all surfaces. Second, the position of the pits suggests that water containing high chlorides from the well was probably involved in their formation. The nature of the pits, their positional relationship to scale features, and the low levels of bacteria

measured all indicate that the corrosion mechanism is not intimately linked to the presence of bacteria.

SEM/EDS analysis showed elevated concentrations of chlorine in the pits. Water from the well contained high chloride levels and breaks in the scale allowed this brine solution to reach minute areas of the steel pipe. This situation resulted in ion concentration cells forming at the voids in the scale. Further, chloride ion concentration at breaks in the scale can promote acidic conditions through a hydrolysis reaction, accelerating the pitting.

The produced liquids were not particularly corrosive in this case; the pH was 6.4 and the calcium and magnesium in solution helped buffer the pH-lowering affects of dissolved carbon dioxide. Even the average pitting rate (over the 42-year life of the pipe, assuming conditions have been fairly constant) was quite low, only 2 MPY.

Case Study #2: Liquid Hydrocarbon Line

How was the corrosion detected?	Leak
Leak or rupture? Fire?	Leak
Location of investigation	Field and Lab
Facility description (pipeline, plant, well head, other equipment)	Plant—liquid processing facility
Pipe diameter and WT	12–3/4" OD × 0.500" WT
Pipe grade and specification	API 5L Grade X42
Pipe year of manufacture	1985
Year of installation	1986
Joint design (welded, flanged, coupled)	Welded
Internal coating? Type? Condition?	No
Original construction or replacement pipe	Original
Pipe elevation/depth of cover	Above grade, flat, horizontal
Length of pipe cut out	2'
Method of cut (hot or cold cut)	Hot

Did foreign material enter the pipe prior to, or during, the cut out?	Yes—torch cutting debris
What foreign material entered the pipe?	Same as above
Was a sample obtained?	Yes
How was the pipe preserved for shipping?	It was not preserved.
Operating Conditions	
Product transported	Liquid hydrocarbons
Typical operating pressure	100 psi
Maximum operating pressure	200 psi
Number of pressure cycles per month	Constant pressure
Range of pressure cycles (psi)	n/a
Typical range of operating temperatures	Ambient (30 to 110°F)
Product Analysis Data	
—Gas analysis including dew point, carbon dioxide and hydrogen sulfide	No gas
—Liquid analysis including percent water, metals and anions in water phase	Organic liquid 99% Water 1%
—Microbiological analysis results	SRB and APB normally present
Identify source of transported product and all potential sources of contaminants	Mixed fluids from offshore producers
Typical flow rate	3 fps velocity
Operating mode (continuous, seasonal, intermittent, etc.)	Continuous
Distance to nearest compressor/pumping station	1 mile
Is the pipeline piggable?	Some of it
Has in-line inspection been performed?	Yes
What is the leak/failure history?	Several leaks due to internal corrosion pits

Were previous internal corrosion incidents analyzed? Report available?	No.
When was the last hydrostatic test?	1986
Are there currently operating pressure restrictions imposed on this line?	No.
Describe maintenance procedures performed	Piggable portion of line is pigged monthly with spherical pigs—not where leak occurred
Cleaning	No.
Visual Evidence	
Location of Corrosion	
Physical location of pipe	Flat, horizontal
Clock position in the pipe	6 o'clock
Relationship to other features:	
System design (dead leg, drip, etc.)	Straight run of pipe
Elevation of pipeline (low spot)	Flat
Girth welds or mechanical joints	Not at weld
Longitudinal weld seams	No
Directional change in flow	No
Inlets, outlets, taps, fittings	No
Heat sources or temperature change	No
Historical liquid levels in pipe	All liquids
Deposits, coating, debris	No coating; essentially no deposits
Nodules	No
Scale	No
Biological materials	Not visible
Chemical injection	1 mile upstream

Processing equipment	40' downstream of separator
Construction/material changes	No
Pipe mill defects	Not apparent
Type of Corrosion Attack	
Isolated pitting	
Internal Conditions during inspection	
Wet or dry	Wet, oily
Debris, scale, deposits	No
Color of deposits, scale, etc.	none
Smell	Organic
Severity	
Longitudinal extent	1 pit
Circumferential extent	1 pit
Maximum wall loss	Through-wall
Profile of wall loss	No other corrosion
Maximum/average pit depth	0.500"
Maximum/average pit diameter	1/4"
Pit length vs pit width	1
Depth/diameter ratio	.50/.25 = 2
Field Tests on Liquid Samples	
—Presence of water	Slight
—Temperature	Ambient—70°F
—pH	6.8
—Total alkalinity	NE
—Dissolved CO ₂	NE

—Dissolved H ₂ S	NE
—APB and SRB cultures	NE
—Fixation for microscopy	Yes
—Corrosion inhibitor or biocide residual levels	Residual levels of amine-based inhibitor were present
Field Tests on Solids/Sludges/Scales	Pit contents
—pH	3.2
—Sulfide/carbonate spot test	High sulfide
—APB and SRB cultures	Nearby Pipe Surface: APB 100 cfu/mL SRB 1,000 cfu/mL Pit Contents: APB 10,000 cfu/mL SRB > 100,000 cfu/mL
—Fixation for microscopy	Black debris and numerous bacteria observed. Bacilli and vibrio morphologies.
Field Gas Analysis Tests	
—Water vapor	No
—Carbon dioxide	No
—Hydrogen sulfide	No
Laboratory Analysis	
Chemical: There was essentially no residue in the pipe and the pit contained only a small amount of material.	Analysis of water from a separator on the pipeline showed 40,000 ppm chloride, 3,200 ppm sulfate, 120 ppm iron.
Microbiological: No additional tests	
Metallurgical: Examined cross section of pit.	The pit was a narrow, through-wall pit. There was no apparent metallurgical reason

	for why the pit occurred where it did. The pit became wider and more cavernous as it moved into the pipe.
Corrosion Testing: ER probe in water separator line	Corrosion rates typically < 2 mpy
Micro-analytical: SEM/EDS of cross sectioned pit and some deposits.	SEM examination showed surface features of acid attack. The interior of the pit had little deposit material or corrosion product. Some sulfur and chlorine was detected.
Other Methods:	None

Summary of Findings—Case Study #2: Liquid Hydrocarbon Line

This hydrocarbon liquid line carried co-mingled fluids from a large number of offshore sources. Although most of the water had been removed before the liquid entered this pipeline, a small amount of water carried over and collected at the bottom of the pipe under the low flow conditions. The water was not generally corrosive, although it contained chlorides and sulfates; residual inhibitor levels were also detected. High numbers of APB and SRB were present in the water as well. Examination of the pipe upstream and downstream of the leak location revealed a few similar but much smaller pits as the one that leaked. The pits were isolated with very small diameters (less than $\frac{1}{8}$ in or 3 cm) but considerable depth. A thick, black deposit was also found in the smaller pits.

EDS analysis identified sulfur in the pit and sulfides were detected in the pit deposits during the field testing. The pH in the pit was also quite low when the pipe was cut, pH 3.4 compared to the bulk water pH of 6.8. The microscopic pit morphology was representative of acid attack. Thus, it appeared that the pit was driven by extremely localized acid forming conditions. No deposit or general corrosion was observed to be associated with the leak or any of the smaller pits

nearby. Although viable bacteria were detected on the pipe surface away from the leak, higher levels of SRB and APB were present in the pit and observed in the fixed sample for optical microscopy as well.

In this case it was concluded that isolated colonization of bacteria initiated a small pit on the bottom of the pipe. Once the pit began to grow, it provided environmental conditions that were favorable to further bacterial growth and metabolic activity. This activity produced a highly acidic localized condition that continued until the pipe wall was perforated by corrosion. Sulfate-reducing bacteria were believed to be significantly involved in the process.

Case Study #3: Gas Transmission Line Header

When was the pipe cut?	Not applicable
How was the corrosion detected?	Rupture
Leak or rupture? Fire?	Rupture—no fire
Location of investigation	Field and lab
Facility description (pipeline, plant, well head, other equipment)	Pipeline header where 3 gathering lines connect
Pipe diameter and WT	24" OD × 0.500" WT
Pipe grade and specification	API 5L X52
Pipe year of manufacture	1964
Year of installation	1964
Joint design (welded, flanged, coupled)	Welded
Internal coating? Type? Condition?	None observed
Original construction or replacement pipe	Original
Pipe elevation/depth of cover	42"
Length of pipe cut out	Various
Method of cut out (hot or cold cut)	Torch cut
Did foreign material enter the pipe prior to, or during, the cut out?	Yes

What foreign material entered the pipe?	Dirt and cutting debris
Was a sample obtained?	Yes
How was the pipe preserved for shipping?	Protected from further rusting and mechanical damage
Operating Conditions	
Product transported	Natural gas
Typical operating pressure	800 psi
Maximum operating pressure	852 psi
Number of pressure cycles per month	0
Range of pressure cycles (psi)	n/a
Typical range of operating temperatures	55–60°F
Product Analysis Data	
—Gas analysis including dew point, carbon dioxide and hydrogen sulfide	25# mmscf water, 3 psi carbon dioxide, 3 ppm hydrogen sulfide typical
—Liquid analysis including percent water, metals and anions in water phase	Samples from all three lines are brine with 3–6% Cl, Ca 1,500 ppm, Mg 990 ppm, Ba 578 ppm, Fe 980 ppm, pH 6.3, high suspended solids
—Microbiological analysis results	From line #1: None detected From line #2: None Detected From line #3: APB 100–1,000 cfu/mL SRB 1–10 cfu/mL
Identify source of transported product and all potential sources of contaminants	3 gathering lines—many wells on each line
Typical flow rate	Varies from zero to?
Operating mode (continuous, seasonal, intermittent, etc.)	Intermittent
Distance to nearest compressor/pumping station	25 miles

Is the pipeline piggable?	No
Has in-line inspection been performed?	No
What is the leak/failure history?	No leaks or failures
Were previous internal corrosion incidents analyzed? Report available?	No
When was the last hydrostatic test?	1972 uprating program
Are there currently operating pressure restrictions imposed on this line?	No
Describe Maintenance Procedures Performed	None
Cleaning	No
Visual Evidence	
Location of Corrosion	
Physical location of pipe	Low spot where 3 lines tie-in
Clock position in the pipe	4 to 8 o'clock
Relationship to other features:	
System design (dead leg, drip, etc.)	Trunkline Header
Elevation of pipeline (low spot)	Low spot
Girth welds or mechanical joints	Girth welds
Longitudinal weld seams	Yes—was located at bottom of pipe
Directional change in flow	No
Inlets, outlets, taps, fittings	3 tee fittings
Heat sources or temperature change	No
Historical liquid levels in pipe	Yes—levels at 5 and 7 o'clock
Deposits, coating, debris	Deposits and scale probably existed

Nodules	No
Scale	Yes
Biological materials	No—pipe disturbed
Chemical injection	No
Processing equipment	No
Construction/material changes	The header is built from pipe and three extruded tee fittings and end caps.
Pipe mill defects	None observed.
Type of Corrosion Attack	
Linked pitting within areas of general corrosion and selective attack at seam weld.	Various
Internal Conditions during Inspection	Pipe ruptured and opened up, exposing internal surfaces to blowing gas and dirt. Most parts were coated with mud and dirt.
Wet or dry	Dry
Debris, scale, deposits	Yes—mixed with debris from rupture events
Color of deposits, scale, etc.	Various
Smell	No
Severity	
Longitudinal extent	Entire length of header but more severe in pipe than fittings.
Circumferential extent	4 to 8 o'clock
Maximum wall loss	0.500"

Profile of wall loss	Most severe at 6 o'clock—varies significantly in the longitudinal axis. Selective attack at long seam.
Maximum/average pit depth	0.500"/0.250"
Maximum/average pit diameter	3"/1"
Pit length vs pit width	Roughly equal
Depth/diameter ratio	.25"/1" = .25
Field Tests on Liquid Samples	No Samples
—Presence of water	None
—Temperature	N/A
—pH	N/A
—Total alkalinity	N/A
—Dissolved CO ₂	N/A
—Dissolved H ₂ S	N/A
—APB and SRB cultures	N/A
—Fixation for microscopy	N/A
—Corrosion inhibitor or biocide residual levels	N/A
Field Tests on Solids/Sludges/Scales	No Samples
—pH	N/A
—Sulfide/carbonate spot test	N/A
—APB and SRB cultures	N/A
—Fixation for microscopy	N/A
Field Gas Analysis Tests	No Samples
—Water vapor	N/A
—Carbon dioxide	N/A
—Hydrogen sulfide	N/A

Laboratory Analysis	
Chemical: A small amount of scale was recovered from a pipe fragment that had not been severely affected by the rupture.	Scale was predominantly iron carbonate, iron sulfide and various salts.
Microbiological: Any deposits present were compromised by blowing water and mud in post-rupture events, thus no analysis was performed.	None
Metallurgical: Cross sections through corroded and uncorroded areas were examined. Sections through the corroded longitudinal weld seam were also made.	Corrosive attack in the pipe was not specific to microstructural features, except for selective attack in the seam weld. The chemistry and mechanical properties of the pipe were within specified values.
Corrosion Testing:	None
Micro-analytical: Much of the internal surface of the pipe had been essentially sand blasted clean by blowing soil during the rupture.	None
Other Methods: Dimensional and visual examinations to determine the origin of the failure. Burst stress calculations.	The origin of the failure was traced to a point where the corrosion had thinned the pipe to approx. 0.025" for considerable length. Stress calculations verified that this condition would have resulted in failure at the operating pressure.

Summary of Findings, Case Study #3: Gas Transmission Line Header

Perhaps this example is the most typical of what pipeline investigators find when they reach a failure site: little evidence that has not been compromised in some way. In this case, the pipe ruptured and the internal surfaces were exposed to blowing dirt, mud, and water. This, of course, removed or contaminated nearly all of the chemical and biological evidence. Internal corrosion was apparent, however, occurring throughout the length of the header along the bottom between 4 and 8 o'clock. The corrosion damage became more severe toward the 6 o'clock position, suggesting that varying liquid levels were present over the life of the header. The corrosion was also more severe in the pipe sections of the fabricated header assembly—not affecting the extruded fittings as severely as the pipe. One of the pipe sections had been installed with the ERW seam near the bottom, not considered a good practice by most companies. The seam exhibited selective corrosion attack but it was not severe enough to cause the failure. Wall loss due to general and pitting corrosion was shown by stress calculations to have caused the rupture.

The only chemical evidence obtained directly from the failure site was a small amount of scale. The scale contained iron carbonate, iron sulfide, and chloride salts. Chemical and microbial data was available for the three lines tying into the header. All three lines carried brine, hydrocarbon liquids, and gas with varying levels of carbon dioxide and hydrogen sulfide. Only one of the lines carried liquids with low levels of bacteria. Liquid composition data indicated a moderate scaling tendency. No upstream corrosion mitigation chemicals were used in any of the three lines.

By design, the header was lower than the three incoming lines so that liquid would collect there and then be removed by routinely blowing down the header. For whatever reason, the practice of blowing down the header was discontinued several years prior to the incident and liquids were allowed to collect. Liquids accumulated to the point where the header filled up to a certain level then overflowed into the downstream pipeline. Some liquids were apparently always present in the header.

Even though little direct evidence was obtained from this investigation, several important facts and observations are revealed about what caused the corrosion:

1. Potentially corrosive liquids and gases have been present.
2. A certain liquid level has been present in the header for some time due to lack of maintenance activities and the design of the header.
3. The design of the header also allowed solids and particulate matter to settle out and stay in the bottom of the pipe.
4. The historical presence of liquid levels was confirmed by the location and nature of the corrosion (clock position, varying severity).
5. Both general and pitting corrosion were observed but the overall effect of the corrosion was more generalized than isolated.
6. Scale was present. The scale contained carbonates and sulfides.
7. Low levels of bacteria were noted in one of the three liquid sources.
8. Selective attack of an ERW seam was present when the seam was located at the bottom of the header. The seams located on the top of the header in other pipe sections were not corroded.

These facts help the investigator tell the story of how corrosion occurred in this case. Several potential contributors to the corrosion are possible, however; system design, corrosive gas, corrosive liquids, scale, accumulated solids, and possibly bacteria are all present. Since a good deal of evidence was lost during the rupture, it may be impossible to identify the precise mechanism(s) responsible for the corrosion. However, ranking the significance of these factors to determine which ones had the greatest influence would be helpful in determining how to mitigate future corrosion at this site. Here is how these factors were ranked from most significant to least significant in terms of contributing to the corrosion failure, and why:

System Design

Preventing liquids and solids from accumulating in the first place would be the most significant factor in controlling corrosion at this site. All three pipelines that fed into the header had not experienced leaks due to internal corrosion, yet they carry the same material as was present in the header.

Liquid Chemistry

The composition of the liquids and solid particulates carried into the header promoted corrosion. Deposits and nonprotective scale most likely facilitated under deposit and concentration cell corrosion mechanisms.

- Gas Composition** Since a large volume of liquid was usually present in the header and more liquids were constantly flowing through, it is unlikely that acid gases significantly lowered the pH of the fluid standing in the header. The liquid composition also indicates some buffering capacity from calcium and magnesium. Carbonates and sulfides were found in the scale, however, so gas composition played some role.
- Bacteria** Although levels of planktonic bacteria are not a reliable indicator of surface populations, this is the only microbial information available. Further, internal corrosion that is initiated and propagated primarily by microbial activity tends to be isolated pitting rather than broad areas of general attack. It is certainly possible that bacteria played some role in the corrosive environment in the header; however, based on the information available, it appears to have been a minor one.

Conclusion

Steps in the Process

Throughout this guide we have explored the process of investigating the cause of internal corrosion in pipelines. By following the steps presented here, the corrosion investigator has a good chance of finding the culprit that caused the corrosion, if not at least narrowing down the list of suspects. In most every corrosion investigation, the investigator will:

- ✓Develop an investigation plan.
- ✓Know what evidence and information to look for.
- ✓Collect corrosion evidence in a field investigation.
- ✓Use laboratory analysis to gain further insight.
- ✓Organize and analyze the results so they make sense.
- ✓Present the findings in a form useful to others.

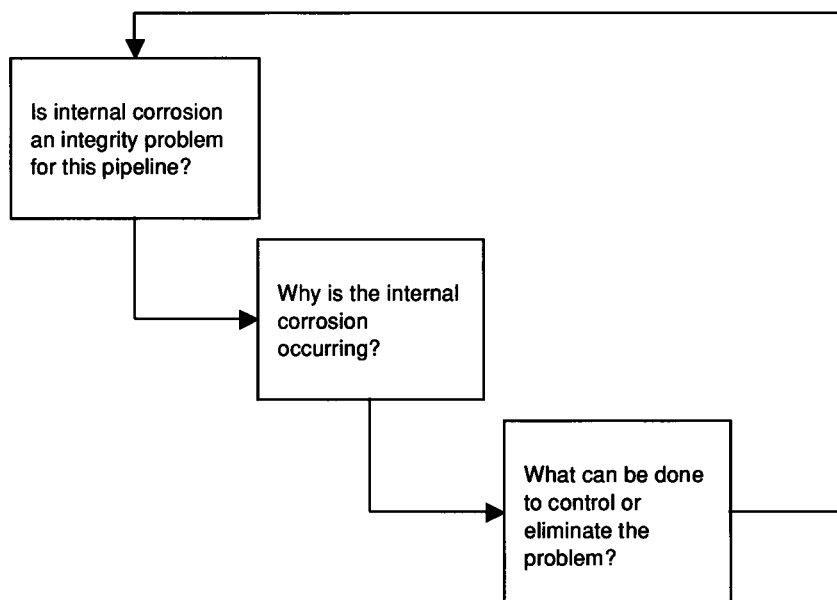
Notably, we have not delved into describing the chemical reactions behind corrosion mechanisms, nor have numerous case studies and photographs of corrosion been presented. Other excellent reference books¹⁷ on these topics are available to the investigator seeking to supplement his or her investigation with this information. What has been described in this field guide is the process that a corrosion investigator should follow in order to determine the cause of the corrosion, regardless of their background or experience. The process is proven for both the neophyte and the seasoned investigator.

This final section looks at how the internal corrosion investigation fits into the overall picture of corrosion management. Investigators who are knowledgeable about how their findings are used

by others in corrosion control are able to produce the most valuable results.

Looking for Trouble, Finding It, and Fixing It

Conducting a corrosion investigation and determining why internal corrosion occurred really only answers the second part of a three-part question. The three questions about internal corrosion that pipeline operators need to answer are shown in the diagram below:



While we cannot explore the answers to the first and last questions here, it would benefit the corrosion investigator to at least be aware of the technology that seeks to address these issues. The three questions are truly inseparable from a pipeline integrity point of view. If the operator does not know whether corrosion is present, he or she is unaware of a potential integrity concern and the problem cannot be analyzed or controlled. If the conditions responsible for the corrosion are not understood, the proper mitigation actions cannot be taken. Once efforts are made to control the internal corrosion, the condition of the pipe needs to be re-assessed to ensure the mitigation is successful.

Thus, an internal corrosion integrity management plan seeks to continuously answer these three questions.

As a corrosion investigator, it helps to understand how the investigation fits into the overall pipeline integrity process. Identifying the cause of corrosion and the source of corrosive liquids, for example, can narrow the search of where corrosion is likely to occur in an extensive pipeline system. Likewise, understanding the environment that led to the corrosion helps identify the most effective mitigation steps to perform. So while the corrosion investigator may not be expert in integrity management or mitigation methods, the information he or she contributes to the success of the overall endeavor is indeed significant.

This book is focused on answering the second of the three questions: Why is internal corrosion occurring? Let's look briefly at the other two questions in the integrity process.

Identifying a Corrosion Problem

The first question, "Is internal corrosion an integrity problem?" is not as simple to answer as it may first appear. Integrity addresses not only the potential occurrence of leaks or failures due to internal corrosion but the impact that such events could have on people and property. An integrity program also facilitates compliance with regulations governing the operation of the pipeline and helps ensure reliable system operation. Different levels of risk exist within a system depending on a number of variables. The probability of negative consequences for a pipeline running near a shopping mall is certainly greater than that for a pipeline in a remote farm field. Imagine an operator that has hundreds or even thousands of miles of pipe to manage. Now within that system, a multitude of variables affect the potential for internal corrosion to occur and the consequences associated with internal corrosion at any given location. Some of these are shown in Table 21.

So, in light of these factors, it is apparent that determining what constitutes an internal corrosion "problem" is a multifaceted process when managing an extensive pipeline operation. The integrity management process is further complicated by the availability and quality of data available and access to a suitable means of managing and integrating the data.

TABLE 21 Internal Corrosion Integrity Factors

Factors Increasing the Potential for Internal Corrosion	Factors Increasing the Integrity Risk or Consequences
Gas quality	Class location of line
Composition of liquids present	Loss of throughput; line not looped
Line not piggable	Line is not piggable for ILI
Internal corrosion leak history	Type of customers supplied
Mitigation history	Physical location of line
Operating conditions (flow, temperature)	Pipe grade and properties
System design factors	Operating pressure
Control over system inputs	Diameter of pipeline
Microbiological conditions	Predicted failure mode

Most integrity management programs are designed to provide three basic functions:

1. Manage all integrity related data.
2. Identify and prioritize threats, based on the data.
3. Indicate when action is required by the operator.

Even though a pipeline has been in operation for some time and there have been no leaks due to internal corrosion, this alone is not sufficient evidence to conclude that internal corrosion is not an integrity threat. Other assessment methods must normally be implemented to ensure the integrity of the pipeline. The most significant methods are hydrostatic testing and in-line inspection (ILI) tools. For some sections of pipeline in high consequence areas (HCA), the use of one of these two methods or an approved alternative such as Internal Corrosion Direct Assessment (ICDA) will soon be required by federal regulations in the United States. Other methods are also being explored as alternatives to hydrostatic testing or ILI; however, the acceptance of these methods by regulators or industry as replacements for hydrostatic testing or ILI is uncertain.

Internal Corrosion Direct Assessment methods have recently been developed to assess the corrosion impact of short-term upsets on natural gas transmission line integrity.^{18,19} The method is applicable for gas transmission lines that normally carry dry gas. The concept behind ICDA is that detailed examination of locations along a pipeline where an electrolyte would first accumulate provides information about the remaining length of pipe. Results of multiphase flow modeling are used to predict the critical angle of inclination that would hold-up water. The program examines critical angle vs gas velocity for given pipe diameter, pressure, and temperature. Also considered are features that might trap water (e.g., drips, valves, etc.). Areas where water could accumulate are then examined to determine if internal corrosion exists. If corrosion is not observed in any of the areas identified as likely to collect water, it is presumed that the remainder of the pipeline does not contain internal corrosion.

The corrosion investigator aids the integrity process by analyzing corrosion when it occurs and by monitoring the chemical, biological, and physical conditions within the pipeline. When internal corrosion is found, determining why the corrosion occurred provides valuable information about where other corrosive conditions are likely to exist in the system. The corrosion analysis also helps identify the origin of corrosive constituents. Thus, the results of the corrosion investigation directly impact the effectiveness of an internal corrosion integrity management program.

Mitigating Corrosion

Once corrosion is located and its cause is determined, the next step is to take action to control or eliminate further internal corrosion. Even if corrosion-damaged pipe is removed from service, the conditions that caused the damage must still be addressed.

Mitigation of internal corrosion can occur in several different ways. The most effective way to minimize internal corrosion damage long term is to remove the environment that promotes the corrosion in the first place. In some cases, sources of corrosive gas or liquids can be shutoff until the supplier is in compliance with contractual requirements. Perhaps liquid separation equipment, dehydration, or gas scrubbers can be installed where corrosive liquids or corrosive gases are present. When possible, removing the corrosive environment

is always the most desirable option since it minimizes the need for mitigation altogether.

Eliminating the corrosive environment is not always possible, however, and in many cases some additional action must be taken. A second choice would be to change the internal environment by altering operating and maintenance procedures. For example, increasing flow rates would tend to sweep standing liquids from low spots in the pipe, reducing the likelihood of corrosion attack. Pigging the pipeline is another very effective way of altering or removing the corrosive environment by removing liquids and debris that can promote internal corrosion. A wide variety of options exist for pigging in terms of materials and design. It may be more cost-effective to make a pipeline piggable by installing launchers and receivers than by injecting chemical treatment for years to come. Also, when solids and scales are present, it is difficult for chemical treatments to act effectively unless the internal surface can be cleaned first. Pigging can also be used to batch treat pipelines with inhibitors or cleaning agents.

Another mitigation option is chemical treatment with inhibitors or biocides. When most people think of internal corrosion control, invariably chemical treatment is the first thing on their lists when in fact it should be perhaps third. The two biggest challenges to using chemical mitigation effectively are (1) selecting a chemical that will *effectively* reduce corrosion in the given environment, and (2) delivering the chemical in sufficient quantity to the locations where it is needed. The risks, regulations, costs, and potential liability of chemical use dictate that corrosion control chemicals be used with discrimination. The operating conditions and corrosive environment in the pipe must be adequately understood before proceeding down the chemical treatment path. Adding treatment chemicals to a system that is not understood can simply complicate problems for the pipeline operator. Inhibition, for example, has often been mistakenly perceived as “insurance” against internal corrosion in gas transmission lines or other pipelines with low corrosivity.

A wide variety of corrosion treatment chemicals and strategies are available. Corrosion inhibitors are used to slow the rate of corrosion or prevent corrosion from initiating on steel surfaces. Inhibitors generally work by affecting the polarization behavior, reducing diffusion, or altering the resistance of the metal surface. Chemicals used for corrosion inhibition may be classified according to chemical type or by their method of functionality. The five functionality groups of inhibitors include organic filming type, passivating, cathodic,

precipitation, and volatile. Organic inhibitors, which are often used in pipeline applications, can be anionic (e.g., sulfonates) or cationic (e.g., amines). Further, inhibition chemicals may be strictly water soluble, strictly oil soluble, oil soluble/water dispersible, or even vapor phase distributed. Inhibitors can be applied by continuous injection based on volumes of gas or liquid transported or delivered via batch treatment using pigs or product flow alone. Delivery of the active chemicals to the area of the pipe where they are needed is a primary concern when inhibitors are employed. Finally, when selecting inhibitors for a specific system, screening tests to identify the optimum chemical are typically used before initiating treatment.

When MIC (not merely the presence of bacteria) has been positively identified to be a concern, biocides or bactericides may be required. Biocides are chemicals that kill all types of microorganisms while bactericides are specific to bacteria only. A number of chemicals that are strictly biocides are available and many corrosion inhibitors are claimed to have some biocidal properties as well. Again, delivery of sufficient biocide to the areas of concern within the pipe is a key objective. Surfactants are sometimes used to aid penetration of biocide through organic films and debris. Biocides can also be tested for effectiveness against the microbes in the operating environment before instituting a large scale program. Compatibility between the biocides and any corrosion inhibitors used is an important consideration as some combinations of chemicals may render one or both materials ineffective or even hazardous.

The final and most important part of instituting a corrosion mitigation program is monitoring the effectiveness of the treatment. Federal regulations in the United States require gas pipeline operators to monitor effectiveness whenever mitigation actions are employed²⁰; however, any operator who is investing in treatment should certainly be concerned about its effectiveness as well. Selection of the techniques used to monitor effectiveness of mitigation must consider both the corrosion mechanism being treated and the type of mitigation used. A variety of methods can be used to monitor effectiveness, the most popular of which are corrosion coupons which are considered a direct monitoring technique.

Corrosion coupons are small pieces of steel, similar in metallurgy to the pipeline being monitored, that are inserted into the product stream using different types of holders. The coupon is exposed for a period of time then removed and analyzed for corrosion. Typically, only a corrosion rate (based on weight loss) is determined; however, a

great deal of additional information can be obtained from more comprehensive analysis of corrosion coupons. NACE and ASTM both provide references on the use of corrosion coupons.^{21,22} Strategic placement of coupons in the system is essential to get the best representation of the conditions being treated.

On-line corrosion monitoring probes are another option for direct monitoring. These probes typically use one or several traditional electrochemical corrosion monitoring methods such as linear polarization resistance (LPR), electrochemical impedance spectroscopy, (EIS) or electrochemical noise (EN). Some monitoring devices combine several electrochemical techniques, as some are more sensitive to general corrosion and others more readily detect pitting. Electrical resistance probes are also used. Again, placement of the monitoring device is extremely important so that the findings represent the internal conditions of concern.

Chemical analyses of pipeline contents is an indirect technique for corrosion monitoring in that it does not provide direct observation of internal surface conditions. The measurement of conductivity, pH, dissolved oxygen, metallic and other ion concentrations, concentration of suspended solids, water alkalinity, inhibitor concentrations, and scaling indices are examples of indirect measurements. Several of these measurements can also be made on-line using specific sensors. Indirect monitoring through chemical analysis is more suitable for environments that are of fairly constant composition (e.g., boilers), which often does not apply to pipeline situations. Monitoring inhibitor or biocide residual levels can provide valuable information; however, treatment chemical residuals *are not* an indicator of the effectiveness of the treatment—only direct monitoring methods can assure effectiveness of the treatment, within statistical limitations.

Again, the corrosion investigator becomes a key part of the mitigation process by analyzing corrosion when it occurs and by monitoring the chemical, biological, and physical conditions within the pipeline after treatment begins. Determining why corrosion occurred in the first place provides valuable information about where corrosive conditions are likely to exist and how they can be mitigated. Proper treatment can thus be targeted to the areas where it is most beneficial and effective.

Obviously, corrosion investigation plays an essential role in the overall scope of internal corrosion integrity management for pipeline operators. A good investigation helps identify whether an integrity issue exists, the cause, and how it can be dealt with effectively.

Employing the investigation procedures described in this field guide will help pipeline operators achieve these vital objectives.

The Key to Being a Good Detective

Being a really good corrosion detective requires that a person possess several important traits, such as organization, logical thinking, an inquisitive mind, persistence, and the ability to view things in different perspectives. While these abilities will certainly help investigators perform their jobs, there is one trait that is more important than all the rest. This ability is the key to being a good detective.

Before we reveal this secret, however, we digress to a story. This is an old story about a student and a fish, a story which some may already be familiar with. Although it may seem misplaced in a guide about pipeline corrosion investigation, it is nonetheless quite relevant to up-and-coming detectives. So please bear with this brief digression and enjoy the fishy tale.

Louis Agassiz (1807–1873) was a professor of natural history at Harvard from 1848–1873. His student, Nathanael Southgate Shaler (1841–1906), went on to become a professor of paleontology and geology at Harvard from 1869–1906. Shortly after Shaler became a student under Agassiz around 1860, he penned this tale of his first assignment. This is the story of “The Student, The Fish and Agassiz.”

The Student, The Fish, and Agassiz^{23,24}

By the Student

It was more than fifteen years ago that I entered the laboratory of Professor Agassiz and told him I had enrolled my name in the scientific school as a student of natural history. He asked me a few questions about my objective in coming, my antecedents generally, the mode in which I afterwards proposed to use the knowledge I might acquire, and finally, whether I wished to study any special branch. To the latter I replied that while I wished to be well grounded in all departments of zoology, I purposed to devote myself specially to insects.

“When do you wish to begin?” he asked.

“Now,” I replied.

This seemed to please him and with an energetic “Very well,” he reached from a shelf a huge jar of specimens in yellow alcohol.

“Take this fish,” said he, “and look at it; we call it a Haemulon [pronounced Hem-yú-lon]; by and by I will ask what you have seen.”

With that he left me, but in a moment returned with explicit instructions as to the care of the object entrusted to me.

“No man is fit to be a naturalist,” said he, “who does not know how to take care of specimens.”

I was to keep the fish before me in a tin tray, and occasionally moisten the surface with alcohol from the jar, always taking care to replace the stopper tightly. Those were not the days of ground glass stoppers, and elegantly shaped exhibition jars; all the old students will recall the huge, neck-less glass bottles with their leaky, wax-besmeared corks half eaten by insects and begrimed with cellar dust. Entomology was a cleaner science than ichthyology but the example of the professor, who had unhesitatingly plunged to the bottom of the jar to produce the fish, was infectious; and though this alcohol had “a very ancient and fishlike smell,” I really dared not show any aversion within these sacred precincts, and treated the alcohol as though it were pure water. Still, I was conscious of a passing feeling of disappointment, for gazing at a fish did not commend itself to an ardent entomologist. My friends at home, too, were annoyed when they discovered that no amount of eau de cologne would drown the perfume which haunted me like a shadow.

In ten minutes I had seen all that could be seen in that fish and started in search of the professor, who had, however, left the museum; and when I returned, after lingering over some of the odd animals stored in the upper apartment, my specimen was dry all over. I dashed the fluid over the fish as if to resuscitate it from a fainting fit and looked with anxiety for a return of the normal, sloppy appearance. This little excitement over, nothing was to be done but return to a steadfast gaze at my mute companion. Half an hour passed, an hour, another hour; the fish began to look loathesome. I turned it over and around; looked it in the face-ghastly; from behind, beneath, above, sideways, at a three-quarters' view—just as ghastly. I was in despair; at an early hour I concluded that lunch was necessary; so, with infinite relief, the fish was carefully replaced in the jar, and for an hour I was free.

On my return, I learned that Professor Agassiz had been at the museum but had gone and would not return for several hours. My fellow students were too busy to be disturbed by continued conversation. Slowly I drew forth that hideous fish and with a feeling of desperation again looked at it. I might not use a magnifying glass; instruments of all kinds were interdicted. My two hands, my two eyes, and the fish; it seemed a most limited field. I pushed my finger down its throat to feel how sharp its teeth were. I began to count the scales in the different rows until I was convinced that that was nonsense. At last a happy thought struck me—I would draw the fish; and now with surprise I began to discover new features in the creature. Just then the professor returned.

"That is right," said he; "a pencil is one of the best of eyes. I am glad to notice, too, that you keep your specimen wet and your bottle corked."

With these encouraging words he added,

"Well, what was it like?" He listened attentively to my brief rehearsal of the structure of parts whose names were still unknown to me: the fringed gill-arches and movable operculum; the pores of the head, fleshy lips, and lidless eyes; the lateral line, the spinous fin, and forked tail; the compressed and arched body. When I had finished, he waited as if expecting more, and then, with an air of disappointment:

"You have not looked very carefully; why," he continued, more earnestly, "you haven't seen one of the most conspicuous features of the animal, which is as plainly before your eyes as the fish itself; look again, look again!" and he left me to my misery.

I was piqued; I was mortified. Still more of that wretched fish! But now I set myself to my task with a will and discovered one new thing after another, until I saw how just the professor's criticism had been. The afternoon passed quickly, and when, towards its close, the professor inquired:

"Do you see it yet?"

"No," I replied, "I am certain I do not, but I see how little I saw before."

"That is next best," said he earnestly, "but I won't hear you now. Put away your fish and go home; perhaps you will be ready with a better answer in the morning. I will examine you before you look at the fish."

This was disconcerting, not only must I think of my fish all night, studying, without the object before me, what this unknown but most visible feature might be; but also, without reviewing my new discoveries, I must give an exact account of them the next day. I had a bad memory; so I walked home by Charles River in a distracted state, with my two perplexities.

The cordial greeting from the professor the next morning was reassuring; here was a man who seemed to be quite as anxious as I that I should see for myself what he saw.

"Do you perhaps mean," I asked, "that the fish has symmetrical sides with paired organs?"

His thoroughly pleased, "Of course, of course!" repaid the wakeful hours of the previous night. After he had discoursed most happily and enthusiastically—as he always did—upon the importance of this point, I ventured to ask what I should do next.

"Oh, look at your fish!" he said, and left me again to my own devices. In a little more than an hour he returned and heard my new catalogue.

"That is good, that is good!" he repeated, "but that is not all; go on." And so, for three long days, he placed that fish before my eyes, forbidding

me to look at anything else, or to use any artificial aid. "Look, look, look," was his repeated injunction.

This was the best entomological lesson I ever had—a lesson whose influence has extended to the details of every subsequent study; a legacy the professor has left to me, as he has left it to many others, of inestimable value, which we could not buy, with which we cannot part.

A year afterward, some of us were amusing ourselves with chalking outlandish beasts upon the museum blackboard. We drew prancing star-fishes; frogs in mortal combat; hydra-headed worms; stately crawl-fishes, standing on their tails, bearing aloft umbrellas; and grotesque fishes, with gaping mouths and staring eyes. The professor came in shortly after and was amused as any at our experiments. He looked at the fishes.

"Haemulons, every one of them," he said. "Mr. ——— drew them."

True; and to this day, if I attempt a fish I can draw nothing but Haemulons. The fourth day, a second fish of the same group was placed beside the first, and I was bidden to point out the resemblances and differences between the two; another and another followed, until the entire family lay before me and a whole legion of jars covered the table and surrounding shelves; the odor had become a pleasant perfume; and even now, the sight of an old, six-inch, worm-eaten cork brings fragrant memories!

The whole group of Haemulons was thus brought in review and, whether engaged upon the dissection of the internal organs, the preparation and examination of the bony framework, or the description of the various parts, Agassiz's training in the method of observing facts and their orderly arrangement was ever accompanied by the urgent exhortation not to be content with them.

"Facts are stupid things," he would say, "until brought into connection with some general law."

At the end of eight months, it was almost with reluctance that I left these friends and turned to insects; but what I had gained by this outside experience has been of greater value than years of later investigation in my favorite groups.

Thus, whether examining ancient, embalmed, ichthyological specimens or corroded pipelines, carefully observing the facts and putting them in sensible order is the key to becoming a good scientist and a good corrosion detective. As Professor Agassiz impressed upon his student, "Look, look, look!" and you will indeed find what you are looking for.

Color Section

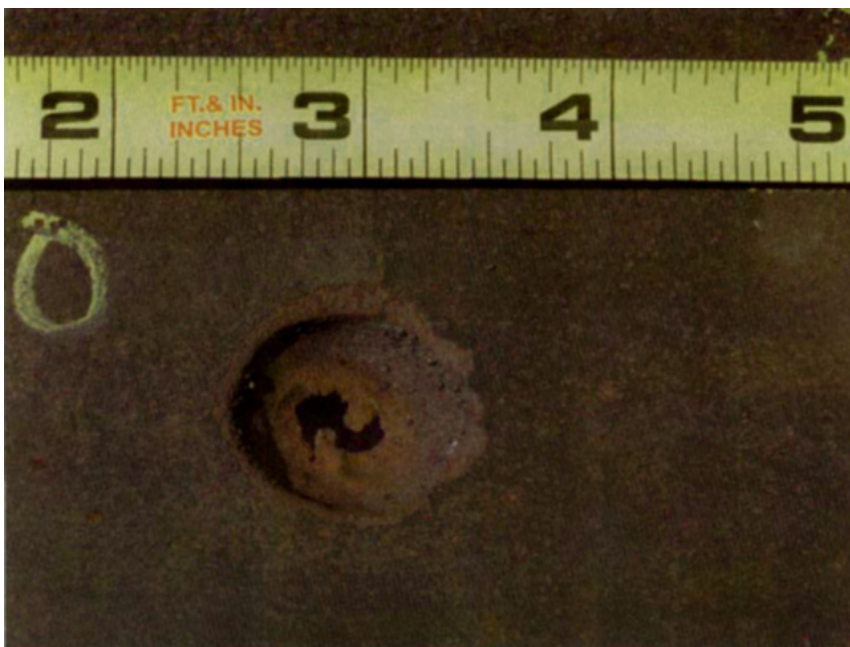


FIGURE 1 A single isolated corrosion pit that perforated the wall of a pipe. No other pitting or general corrosion was present.



FIGURE 2 Numerous isolated pits have formed on this pipe surface beneath a semi-protective scale.

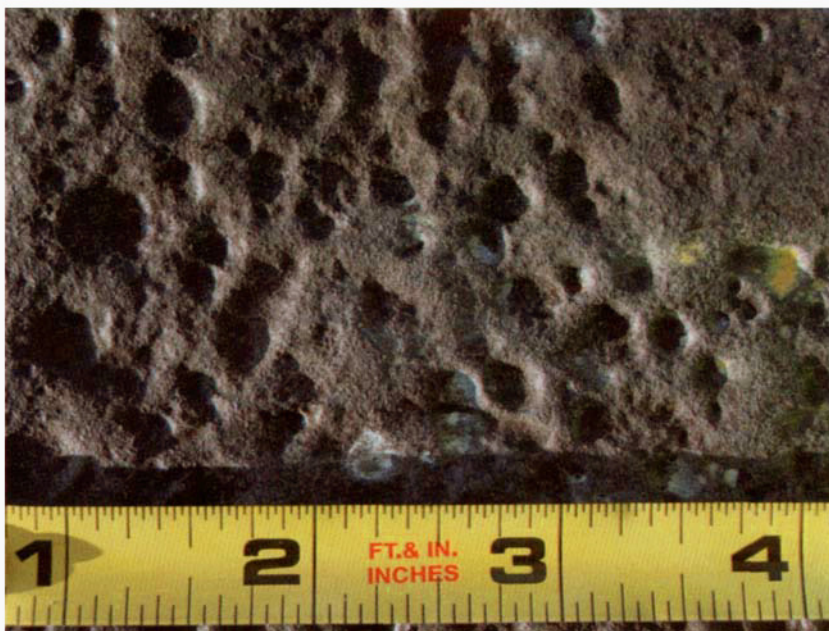


FIGURE 3 Isolated pitting has occurred here within a region of general corrosion. This sample had been sandblasted to remove corrosion products and debris.



FIGURE 4 On this pipe sample, a group of deep, narrow pits were discovered at the point where they were just beginning to interconnect.



FIGURE 5 A group of larger pits have grown together to form one continuous axial pit in this pipeline sample.



FIGURE 6 Close examination of this sample showed that narrow groups of corrosion pits occurred at damaged internal flow coating in a gas pipeline, forming long, continuous pits.



FIGURE 7 General attack of the pipe surface (at right) has occurred here beneath a thin layer of non-adherent debris (left).



FIGURE 8 The root pass and heat affected zone of this girth weld exhibited preferential attack as compared to corrosion of the surrounding pipe metal.

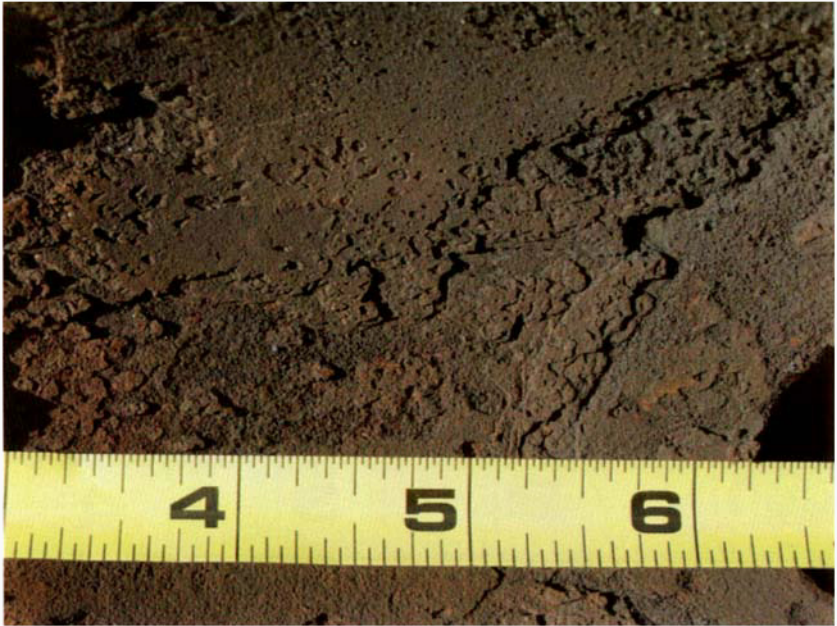


FIGURE 9 Accelerated corrosion occurred on the inside of this 90-degree elbow due to the change in direction of a high velocity corrosive liquid stream in the pipe.



FIGURE 10 A corrosion pit that displays “cup-type hemispherical pits,” pits within pits, and faint striations that run parallel to the longitudinal axis of the pipe. These features alone are not diagnostic for MIC, rather, they are reported to occur as the result of under deposit acid attack of low carbon steels.



FIGURE 11 Corrosion pitting at a girth weld that was proven, through comprehensive field and laboratory testing, to have resulted primarily from microbial activity.

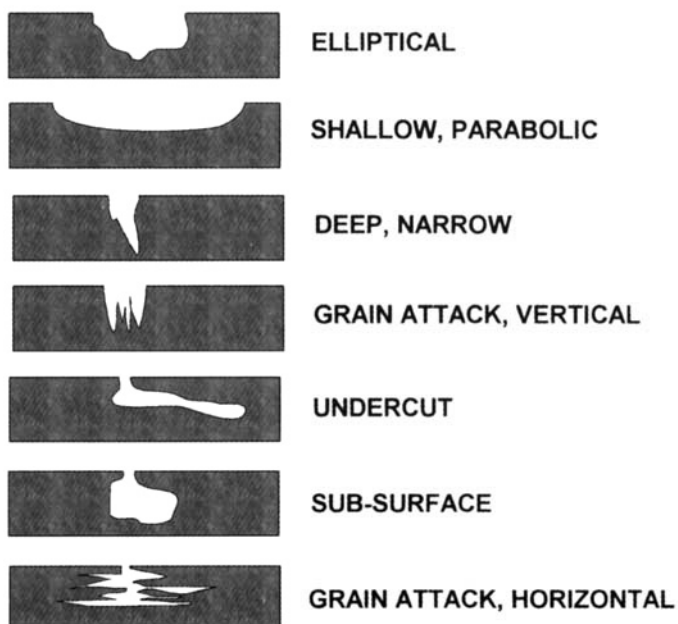


FIGURE 12 Common pit profiles as viewed in cross-section.



FIGURE 13 A typical commercially supplied bacteria culture test kit for APB and SRB.

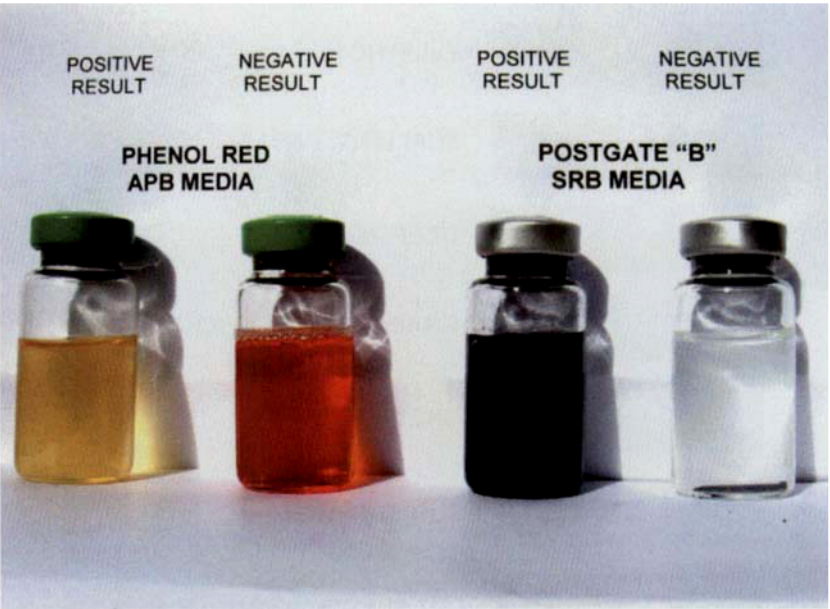


FIGURE 14 Positive and negative bacteria culture test results for APB and SRB using commercially available liquid media.

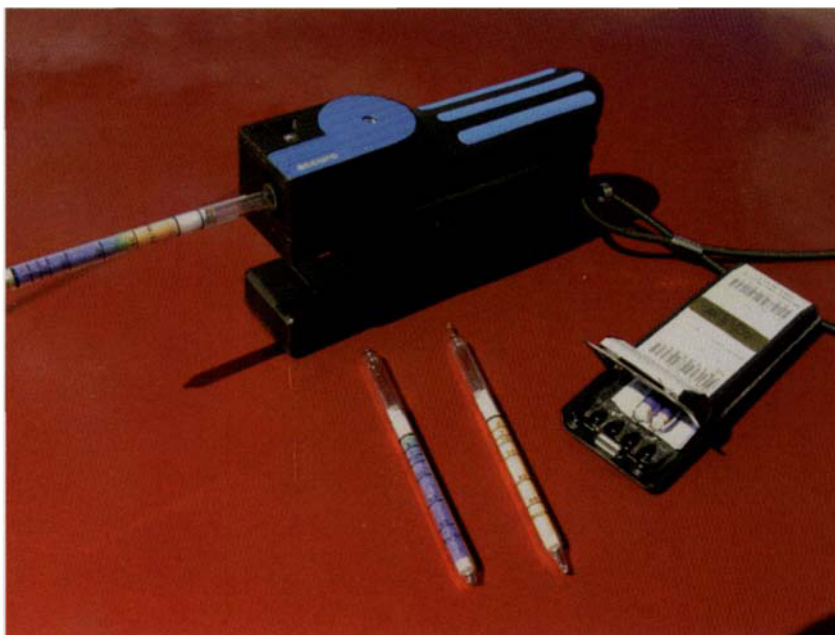


FIGURE 15 One example of stain tube gas analysis equipment for field use.



FIGURE 16 (Top) An embedment that has just been performed on a corroded pipe surface. (Bottom) embedment removed from pipe.

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