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Service Water Piping Guideline

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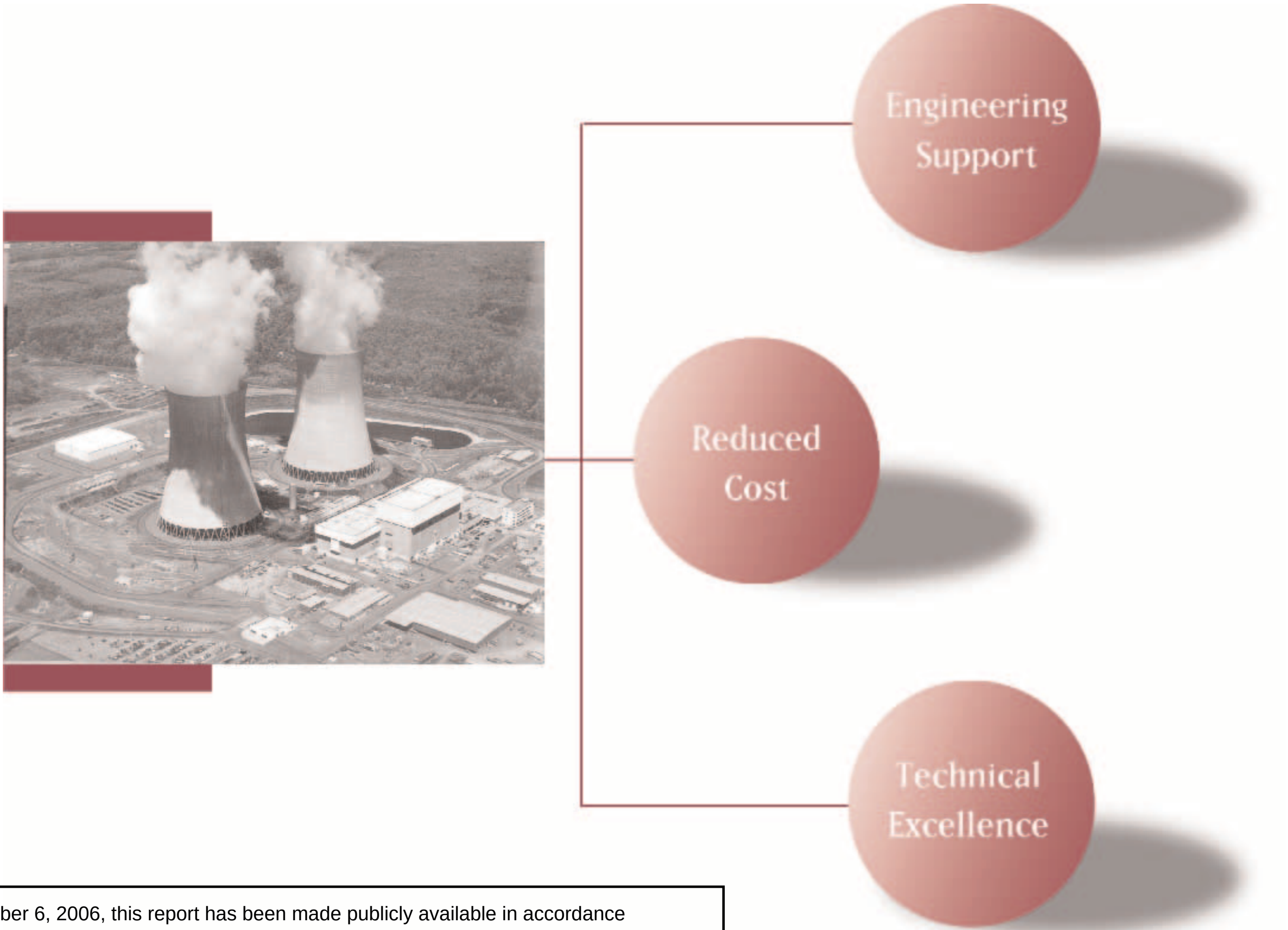

Service Water Piping Guideline

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PRODUCT DESCRIPTION

In the years 1988 and 1989, EPRI organized the Service Water Working Group (SWWG) to identify and help resolve the many issues surrounding service water (SW) systems in nuclear power plants. One issue identified by the SWWG was corrosion in service water piping systems. Interest in this issue resulted in the development of several technical reports: *Guidelines for the Repair/Replacement Welding of Nuclear Service Water Systems,* TR-100386; *Guide for the Examination of Service Water System Piping,* TR-102063; *Service Water System Repair/Replacement Guidelines,* TR-102174; and *Service Water System Repair/Replacement Guidelines: Planning and Implementation,* TR-102410.

In the 2001–2002 timeframe, many plants started to apply for plant life extension and realized that the service water piping would degrade beyond its nominal corrosion allowance if another 20 years were to be added to the piping's design life. A review of the reports listed above showed that the information contained in them needed to be updated and consolidated into a single comprehensive report. This *Service Water Piping Guideline* is the result of that effort.

The report covers service water system piping designs, the various degradation mechanisms the piping might be subjected to, techniques used to assess piping condition, and the various mitigation, repair, and replacement strategies.

Results and Findings

Service water systems vary greatly in design, primarily because the cooling water source varies greatly from location to location. The cooling water source can be fresh water, salt water, or brackish water, and thus the piping materials can vary from unlined carbon steel to titanium. Degradation mitigation techniques can vary from pipe cleaning followed by improved water treatment to wholesale pipe replacement with high-alloy stainless steels.

Challenges and Objectives

This report will be of value to nuclear power plant engineering personnel with service water piping responsibility. The report provides the technical basis for determining if a wholesale piping replacement is necessary or if more cost-effective mitigation and repair techniques might be used.

Applications, Values, and Use

In addition to being of use to the current generation of nuclear plants, this report can help with the proper design and construction of the service water systems of the next generation of nuclear plants, thus greatly reducing the operations and maintenance cost of new stations.

EPRI Perspective

The *Service Water Piping Guideline* reflects the fact that there is much diversity in cooling water sources and in the design of nuclear plant service water systems. A single set of concise rules was therefore not appropriate; rather, many different designs are presented as guidance.

Approach

The *Service Water Piping Guideline* is intended to improve piping reliability by providing reference documents and recommendations for establishing a program to manage service water piping degradation. The document provides guidelines for scope identification, selection of inspection locations, piping inspection techniques, frequency of inspections, data collection, data evaluation, and mitigation strategies.

Keywords

Corrosion
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Piping systems
Service water systems

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INTRODUCTION

Background

A power plant's service water system, especially the service water piping, is a critical part of the plant infrastructure, is crucial to achieving a plant life of 40 years, and is key to life extension.[1] Service water piping systems are low-temperature, low-pressure piping systems, with nominal conditions that typically would not be considered particularly challenging. The primary mode of degradation considered in design was general corrosion. A typical corrosion allowance of 0.040 to 0.120 inches (1–3 mm) is applied for uncoated carbon steel piping to account for degradation in service.[2] Service water systems may attain 25–40 years of life without much special attention; however, for longer lives, some repair or replacement should be expected. The keys are to take appropriate mitigation actions early in order to avoid surprises, or to do the required repair or replacement once and no more.

Since the plant is built over or around the service water system, and piping is not intended to be replaced or even worked on very much, access for repairs, refurbishments, or replacements that may be required to achieve design life or plant life extension can be difficult. Critical issues are prediction and evaluation of the condition of the piping; inspections to verify piping condition; and materials selection, fabrication, and postmaintenance inspection methods for temporary and permanent repairs, for refurbishments (for example, cleaning, coatings, and linings), and for replacements (metallic and nonmetallic).

Design Basis

The U.S. Code of Federal Regulations, 10CFR50 *Generic Design Criterion 44—Cooling Water (Service Water System)* [1-1] defines the design basis for the safety-related service water system as being "to transfer heat from structures, systems, and components important to safety to an ultimate heat sink."

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[1] A glossary of terms is included as Appendix A.

[2] A truly uniform loss of thickness of 40–120 mils (1–3 mm) would change the stiffness of the piping and necessitate a reevaluation of the piping system and its supports.

Historical Perspective

Some plants have experienced degradation, most often from one or more forms of corrosion that produced degradation that was far in excess of the level that had been anticipated during design. That degradation has required refurbishments, repairs, or replacements.

For many plants, reported costs for local repairs have ranged from tens of thousands to hundreds of thousands of dollars per repair [1-2]. Partial-scale and full-scale piping replacements have cost utilities up to $30 million per plant [1-2, 1-3]. In one case, a nuclear plant service water system was completely chemically cleaned and modified from an open to a closed system at a cost of $57 million [1-4].

A number of plants have replaced some or all of their small-bore (less than 2 in. or 4 in. [51 mm or 102 mm]) carbon steel lines with 300-series stainless steel due to tuberculation and occlusion of the carbon steel lines that dramatically reduced flows. Those replacements have been successful in some locations. However, in other locations, the failure mode merely changed from general corrosion and occlusion to pinhole leaks at welds (attributed to microbiologically induced corrosion, or MIC) in roughly the same or shorter time frame.

In many respects, degradation of service water piping is analogous to degradation of high-energy piping due to flow-accelerated corrosion (FAC). FAC occurs under a much more limited set of conditions than service water system degradation, and is therefore more predictable. Further, FAC is more readily controlled than service water system degradation. NSAC-202-L, “Recommendations for an Effective Flow-Accelerated Corrosion Program” [1-5], provides a number of useful parallels regarding approaches that can be applied to service water piping. For example:

- (For both FAC and service water piping degradation) the “rate of metal loss depends on a complex interplay of many parameters including water chemistry, material composition, and hydrodynamics.”
- (The FAC or service water piping) program should include predictions of degradation and degradation rates, as well as defining intervals for regular inspections.
- The owner needs to conduct an appropriate analysis and a limited but thorough (initial) inspection of susceptible piping.
- The owner should determine the extent of thinning and take appropriate actions, which may include repair or replacement.
- The owner should perform follow-up inspections to confirm predictions.
- The owner should take long-term corrective actions.
- The owner should evaluate the ramifications of degradation on structural integrity (for example, Code Case N-597 [1-6]).
- The owner should implement an effective monitoring program and establish a uniform industry approach toward mitigating FAC and service water piping damage.

Objectives

This *Service Water Piping Guideline* is intended to improve piping system reliability by providing specific recommendations and references to existing documents in order to establish a program for managing service water piping degradation. The document will provide guidelines for scope identification, selection of inspection locations, appropriate piping inspection techniques, frequency of inspections, data collection, data evaluation, and mitigation strategies.

This guideline document will incorporate by reference the many documents that are pertinent to service water systems that have been prepared for and by EPRI.

This guideline will provide the background information required for plants to develop programs for inspection, management of piping degradation, corrosion mitigation, and repairs and replacements. **It is not a prescriptive document that produces the same answers in terms of inspections, mitigation, responses to pinhole leaks, ultimate heat sink inventory, handling of repairs, and so forth for every plant.**

Scope of the Guideline

This guideline is applicable to piping in safety-related and non-safety-related open cycle systems only. Closed systems (for example, plant closed cooling water systems) are excluded, as are other components in the service water system (for example, pumps, valves, and heat exchangers). The guideline does not include nonmetallic pipe from original construction.

Both safety-related and non-safety-related piping will be included in this guideline; however, the function of the piping as defined by its safety classification will affect the applicability of potential failures relative to Tech Spec requirements and strict adherence to GL89-13. The consequences of failure for safety-related piping will also elevate its priority in terms of piping and piping systems that are evaluated and inspected. The plant’s probabilistic risk assessment (PRA) should include the consequences of a failure of service water piping.

This guideline will be applicable to bare carbon steel and cast iron as well as to coated steel or cast iron, and to corrosion-resistant alloys. All of those materials will be included in the recommended service water piping program; however, very different approaches to assessment of the system health will be used for each.

Similarly, aboveground and buried service water piping will be included in this guideline. The location of the piping (aboveground vs. buried) will affect its accessibility, different degradation mechanisms (and some different mitigation approaches), and the inspection strategy.

Design and Fabrication Codes; Regulatory Requirements

The original design codes for nuclear service water piping date from the 1960s and early 1970s. In general, the older plants will be ANSI (USAS/ASME) B31.1 (Power Piping) [1-7] or ANSI B31.7 (Nuclear Power Piping) [1-8] code plants, while the newer plants will generally have been designed to ASME Section III Class 3 [1-9] requirements. Table 1-1 summarizes the inspection requirements for welds in the service water piping of plants of various vintages, based upon the requirements for such piping listed in the applicable codes.

Table 1-1
Inspection Requirements for Service Water Piping

Code	B31.1 - Nuclear Power Piping		ASME Boiler & Pressure Vessel Code, Section III, Class 3		
Version	1967	1989	before 1969(3)	1983 (Subsection ND)	2001 (Subsection ND)
Specific Reference	Table 136.5.1	Table 136.5.1	Chapter 3-V	ND-5222(4)	ND-5222(4)
Inspection Requirements	No requirements(1)	Visual examination only(2)	". . . in accordance with USAS B31.10, Chapter VI, except that the following examinations are mandatory:"	Either magnetic particle, liquid penetrant, or radiography for circumferential weld joints greater than 2" pipe size	Either magnetic particle, liquid penetrant, or radiography for circumferential weld joints greater than NPS 2 (DN50)
			random radiography (girth and longitudinal butt welds over 4" pipe size)	Acceptance standards per ND-5300	Acceptance standards per ND-5300
			random examinations of fillet welds, socket welds, and branch connections over 4" pipe size by either magnetic particle or liquid penetrant methods (Appendix B-3 or B-4)		
Summary	No requirements	Visual examination	Same as B31.1 with random radiography for welds >4", including girth welds	Magnetic particle, liquid penetrant, or radiography for circumferential weld joints greater than 2" pipe size	Magnetic particle, liquid penetrant, or radiography for circumferential weld joints greater than NPS 2 (DN 50)

Notes

1. For piping at temperatures less than 925°F and/or less than 2500 psi
2. All welds operating below 350°F and at pressures less than 1025 psig
3. The earliest ASME Section III piping codes were taken from B31.7
4. All categories of piping, pumps, and valve welds

In general, the early versions (for example, the 1967 version) of B31.1/B31.7 for service water piping had no requirements for inspection of welds. Later versions (for example, the 1989 version) required visual examination. The requirements for weld inspections from early (1969) versions of ASME Section III for Class 3 piping (service water) welds were the same as for USAS B31.1 plus random radiography for welds greater than 4 in. (102 mm) pipe size including girth welds. Later versions (1983 and newer) required examination of circumferential welds of greater than 2 in. (51 mm) nominal pipe size by either the magnetic particle, liquid penetrant, or radiographic methods.

In summary, almost none of the welds in service water piping were volumetrically examined at fabrication. As a result, any subsequent inspections that use volumetric methods, as may be required to assess degradation of the service water piping, including some locations at welds, may find “defects” that have been present since fabrication but that have had no detrimental effect on performance. The service water piping inspection plan and analysis program must include evaluation criteria that provide for an assessment of the conditions that are found, specifically as they relate to present and predicted future condition of the piping, and disposition “old defects” appropriately.

Actions to Assess Degradation in Service Water Systems—Generic Letter 89-13

Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment” [1-10], was issued to address the degradation that service water systems will experience. All U.S. licensees must have a program for their safety-related service water system that meets the requirements of Generic Letter 89-13.

The basic requirements of the Generic Letter are summarized below.

- Much of the emphasis is on macrobiological fouling plus potential fouling by corrosion and erosion products, foreign materials and debris, and pipe coating failures.
- Potential NRC requirements are the following:
  - Regular performance testing of heat exchangers that are cooled by service water and that have a safety function.
  - Verification that service water systems are not vulnerable to a single failure of an active component.
  - Inspection of important portions of the piping for corrosion, erosion, and biofouling.
- The five main points of the generic letter are as follows:
  - I. Implement and maintain an ongoing program of surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling. (See also Enclosure 1 to the Generic Letter.)
  - II. Verify the heat transfer capability of all safety-related heat exchangers (frequent maintenance can be done instead, particularly for small heat exchangers).
  - III. Ensure by routine inspection and maintenance for service water piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade performance (remove excess accumulations of biofouling agents, corrosion products, and silt; repair defective protective coatings and corroded service water piping).
  - IV. Confirm that the service water system is consistent with licensing basis.
  - V. Confirm maintenance practices, operating and emergency procedures, and training.

- Enclosure 1 to the Generic Letter (Resolution of Generic Issue 51)—for all service water systems (marine, brackish, and freshwater systems, with or without clams):
  - Chlorinate continuously (or equivalent) for macrobiological fouling. The requirement is included for fresh waters without clams "because it can help prevent microbiologically influenced corrosion."
  - Flush and flow-test redundant and infrequently used cooling loops (at maximum design flow) to ensure that they are not fouled or clogged. Service water loops should be filled with chlorinated or equivalently treated water before layup (some fire protection systems or other systems that also use raw water are also mentioned).
- Supplement 1 to the Generic Letter further requires:
  - The level of detail (in plant records and such) should be sufficient to demonstrate that the heat removal requirements of the system are satisfied.
  - Layup is defined/described in EPRI NP-5106 [1-11].
  - "Infrequently used components" include pumps, pipes, valves, strainers, and so forth that flow, or that are normally in a standby condition and include "parallel branches in which the states of the components in the branches are not often changed."
  - Visual inspection of the intake structure may apply to the intake piping. Minimum wall thickness is defined by the code of record (ANSI B31.1 before 1971; after 1971, ASME Section 3 applies to piping design and fabrication).

In the course of service, the service water piping will be subject to degradation, primarily from corrosion. Degradation will be discussed in detail in Section 4 of this guideline. As noted above, a primary objective of this guideline is to provide methods for assessing the degree of degradation and for assuring that the system meets its design bases throughout the life of the plant.

Repairs

Repairs to ASME Section III, Class 3 piping will be done in accordance with the requirements of ASME Section XI [1-12]. Piping designed to B31.1/B31.7 may also be repaired (in effect upgraded) using the same requirements. In addition, Generic Letter 90-05 [1-13] and ASME Code Case N-513 [1-14] provide guidance for temporary repairs of low-energy piping such as service water piping.

This service water piping guideline is an asset management activity. The EPRI LCM sourcebook [1-15] describes the philosophy and approach that have been applied to management of the aging and life cycle of various nuclear power plant components. That approach provides guidance for evaluating the impact of system degradation over time on safety and power generation. Application of that overall guidance, for example to evaluations of non-safety-related piping based upon potential loss of revenue from power generation curtailments, will be applied throughout this guideline.

As noted at the very beginning of this section, the service water system is a critical part of the plant infrastructure. Portions of the service water system have a direct impact on safety and continue to receive NRC scrutiny for their potential safety functions. Other portions of the service water system provide “generation-critical” functions that have no direct effect on safety or little potential impact on safety but that can have a profound effect on the economic viability of the plant.

Priorities for the plant owner are to:

1. Assure that structural integrity of piping is maintained.
2. Assure that system function (for example, adequate flow of cooling water, per the design basis) is maintained.

   Both 1 and 2 can be assured in the presence of one or more pinhole leaks, provided that the impact of the leak(s) on structural integrity and operation, including effects on adjacent equipment, has been evaluated.
3. Avoid surprises relative to degradation of the pipe wall thickness, leakage, or degradation of operation.
4. Anticipate and monitor degradation so that appropriate mitigation or remedial actions can be scheduled and implemented.
5. Provide input to the plant’s long-range plan, especially if pipe replacements, or other system modifications that require large expenditures, are identified.
6. Protect the asset (that is, the service water system as a whole) by proactive or timely responses to degradation by adhering to items 1–5.

Specifically, the plant owner needs to:

- Manage pinhole leaks (note that all leaks must be repaired, via Code repair, eventually)
- Manage long-term degradation economically

Safety evaluations and economics may dictate that for some systems or portions of a system (for example, service water piping inside containment), elimination of all pinhole leaks will be required (often at a high cost). In other systems, the most effective management approach will be to walk down the system regularly, looking for leaks that present themselves, then managing the leakage and scheduling a repair or replacement. The latter activities will often factor into the plant’s long-term strategy.

References

1-1. Generic Design Criterion 44—Cooling Water, 10CFR50.

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1-3. J.N. Leech, et al., “Nuclear Plant Service Water System Inspection, Monitoring, and Upgrade Case History,” Service Water Systems Reliability Improvement Seminar, EPRI, July 14–16, 1993.

1-4. T.O. Brice, W.A. Glover, “Service Water Chemical Cleaning at River Bend Gets Results,” Service Water Systems Reliability Improvement Seminar, EPRI, July 14–16, 1993.

1-5. NSAC-202L R2, Recommendations for an Effective Flow-Accelerated Corrosion Program, April 1999.

1-6. Requirements for Analytical Evaluation of Pipe Wall Thinning, ASME Section XI, Division 1, Code Case N-597, March 2, 1998.

1-7. Power Piping, ANSI/ASME B31.1.

1-8. Nuclear Power Piping, ANSI B31.7.

1-9. Rules for Construction of Nuclear Power Plant Components, ASME Boiler and Pressure Vessel Code, Section III.

1-10. “Service Water System Problems Affecting Safety-Related Equipment,” Generic Letter 89-13, 7-18-89 (and Supplement 1, 4-4-90).

1-11. *Plant Lay-Up and Equipment Preservation Sourcebook.* EPRI, Palo Alto, CA: 1987. NP-5106.

1-12. Rules for Inservice Inspection of Nuclear Power Plant Components, ASME Boiler and Pressure Vessel Code, Section XI.

1-13. “Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping,” Generic Letter 90-05, 6-15-90.

1-14. “Evaluation Criteria for Temporary Acceptance of Flaws in Class 3 Piping (Section XI, Division 1),” ASME Code Case N-513, August 14, 1997.

1-15. *Life Cycle Management Sourcebook for Nuclear Plant Service Water Systems.* EPRI, Palo Alto, CA: 2005. 1008282.

2

ELEMENTS OF AN EFFECTIVE SERVICE WATER PIPING PROGRAM

As noted in Section 1, there are a number of parallels between programs to manage degradation of high-energy lines due to FAC and programs to manage service water piping degradation. The general criteria for the elements of an effective FAC program as described in NSAC 202-L [2-1] have been used as the basis for the discussion that follows.

Management Commitment

A management commitment to asset management for service water piping is essential to managing and preserving the service water piping. That top-level, global commitment must include definition of the plant needs, clear guidance on priorities, and a budget to execute the plan.

A corporate-level document that defines the program and methodology for managing service water piping is recommended. This top-level document should define procedures or instructions for the assessment of service water piping. The document needs to define the scope of the assessment by defining the piping and systems that are specifically included as well as those that are excluded.

This service water piping guideline is provided as an example for top-level corporate documents on service water piping. For example, this guideline covers both safety-related and non-safety-related piping, as well as both aboveground and buried piping, and also covers bare carbon steel and cast iron, coated carbon steel and cast iron, and corrosion-resistant alloys. Differences will exist in the prioritization and methods use for assessment of the different types of systems; however, the corporate document should be all-inclusive.

The basic flow of the top-level procedure should be to:

- Understand risk/define commitments
- Identify susceptible systems
- Perform preliminary analysis (review system design and operating conditions to assess the susceptibility of the system and specific locations)
- Select inspection locations
- Schedule initial inspection(s)
- Perform inspections

- Evaluate inspection data and revise piping analysis if required
- Mitigate degradation
- Repair and replace as required
- Select and schedule follow-on inspections
- Document the basis for selection of inspection locations and all results

Analysis

The analysis needs to determine if the system is degraded, determine the nature and extent of degradation, and make projections of degradation rates. From the analysis and inspection results, a strategy for mitigation of degradation or for repairs or replacements can be made. The predictive methodology that is used to define susceptibility and to select locations for inspection of service water piping degradation needs to consider the effects of the material, geometry, temperature, flow (including flow history), water chemistry, and water treatments. High-stress locations may require specific consideration because of the sensitivity of those locations to wall loss. Predictions of service water piping degradation should also incorporate measured data from the system to improve the accuracy of plant predictions.

The analysis process will most often be used to define a sample of locations to be inspected from the thousands of pipe spools and fittings and the miles of pipe that are potentially susceptible. The analysis process will identify the most susceptible locations based on system operating and design parameters. Risk, which will always be a combination of the susceptibility to degradation and the consequences of failure (from both lost production and safety perspectives), will also enter into the selection process for inspection locations. For bare steel and cast iron, there are generally not specific areas, such as welds or fittings vs. straight pipe, where inspections can focus to define the limiting cases. The analysis process needs to identify the most susceptible locations. From the analysis, a limited sample is chosen, based upon both economic and practical considerations, to select the components with the greatest susceptibility. Finally, based upon the inspection results, the next inspection interval will be defined and mitigation processes, repairs, or replacements will be scheduled as necessary.

There are definite trade-offs that will exist between the types or levels of analysis used to predict susceptibility and make inspection decisions. For example, highly simplified analyses will require far more inspections (several hundred locations) than will more sophisticated analyses that also incorporate inspection data to (further) refine the degradation rate predictions (dozens; less than 100 locations). The Internal Corrosion and External Corrosion Direct Assessment procedures that have been developed within NACE [2-2 through 2-5] for evaluating buried gas pipe lines, literally millions of miles of pipe, provide a good example of approaches that consider the material, geometric, and environmental factors that can influence internal and external corrosion of those pipelines to evaluate their susceptibility and to prioritize locations for inspections. The ICDA and ECDA direct assessment methodologies are both four-step procedures:

1. **Preassessment** includes collection of design and operating data, as well as environmental information and any corrosion protection measures, to determine the feasibility of applying the direct assessment procedure to the pipeline in question. Preassessment also separates the line into discrete segments based upon various design and operating characteristics.
2. **Indirect Inspection** considers further details of the design and operation to determine the most susceptible locations. As defined in the ICDA and ECDA methodologies, indirect inspection is not a physical examination of piping, but rather a detailed review of design, operation, treatment, repair, and inspection reports.
3. **Direct Examination** includes actual volumetric measurements as well as predictions of corrosivity, corrosion monitoring results, other inspection results (for example, visual), and elimination of consideration of some segments depending upon the results from locations considered to be more susceptible to corrosion.
4. **Postassessment** analyzes the data from the first three steps to assess the overall effectiveness of the direct assessment process and determines the reassessment intervals.

Defining components or portions of the system that can be excluded from the evaluation is also an important part of the analysis process. For example, for FAC, NSAC-202-L excludes systems or portions of systems (for example, stainless steel or high chromium materials, dry steam systems, low temperature, and so forth) from the evaluation due to their low susceptibility. For service water piping, the different strata of susceptibility will be addressed by using different inspection approaches. For example, coated systems will be included but will include coating examinations (relying primarily on visual inspection); stainless steel systems will have very low susceptibility to degradation over random areas, but welds will need to be included; highly corrosion-resistant alloys (for example, 6% molybdenum stainless steels or titanium), which have even lower susceptibility, will be examined visually for deposits or other anomalies, with minimal volumetric examination of selected locations (such as welds, dissimilar metal welds, and flanged joints).

Industry Experience

Service water piping degradation has varied dramatically across the industry, partly because service water systems experience an extremely broad set of water chemistries (hard and soft fresh waters, brackish water, seawater) with corrosion mitigation approaches that range from none (bare carbon steel) to extensive (coated piping or corrosion-resistant alloys). In addition, flow and flow history have been shown to exert strong influences over the forms of corrosion that can exist within and across systems. Industry operating experience reviews will continue to provide examples of degradation.

Uncoated carbon steel, cast iron, and low-alloy steels have failed by general corrosion at rates that were significantly higher than anticipated in design, from pitting, and from MIC. At least two plants have also experienced preferential corrosion in carbon steel systems at weld joints, as well as galvanic corrosion. Failure modes for those materials have included occlusion of lines such that flow capabilities were degraded significantly and pinhole leaks or local areas where structural integrity of the piping was compromised. Coated materials have most often failed due to corrosion that was confined to areas where the coating failed, producing pinhole leaks. In addition, pieces of failed coating, along with dislodged corrosion products, have contributed to degradation in other locations in the service water system.

Corrosion-resistant alloys have exhibited good resistance to general corrosion, however all of the corrosion-resistant materials used for initial construction—typically the austenitic stainless steels such as Type 304 and 316—have exhibited susceptibility to localized corrosion from pitting, crevice corrosion, underdeposit corrosion and MIC. Pinhole leaks were the result, most often at discrete areas such as welds or creviced areas.

Individual plant programs should incorporate the lessons learned from the industry, from both the susceptibility perspective and the control perspective. Lessons learned from mitigation approaches that have been unsuccessful are as valuable as lessons learned from those that have been successful.

Inspections

Inspection of service water piping serves several purposes:

- Determining whether the piping has experienced degradation
- Defining the degree of degradation (extent and depth)
- Identifying the locations of maximum degradation (extent and depth)
- Providing input to assessment of the overall health of the system
- Characterizing trends
- Generating feedback regarding element selection

For high-energy systems where FAC damage can proceed rapidly and where personnel safety can be jeopardized, the primary emphasis is on identifying components where definite degradation exists or where degradation is proceeding, so that replacements can be made or scheduled. These damage assessments are done from a sampling of locations that are predicted to have the worst case thinning. The sample usually represents several percent of all of the potentially susceptible locations. In high-energy systems, the emphasis with regard to inspection is based upon danger to personnel and loss of power generation capability in the short term.

For service water piping, the emphasis is different, because the degradation generally does not proceed rapidly, risks to personnel are essentially nonexistent, and in some cases, the sample size is a much smaller fraction of the potentially susceptible areas (fractions of a percent of the miles of pipe and of the thousands of pipe spools and fittings). In service water piping inspections, the primary objectives are to determine if degradation processes that were not addressed in the design of the piping (for example, localized corrosion or MIC) are present at all, to estimate the rates of degradation, and to assess the impact of the degradation on structural integrity in order to plan for mitigation actions (for example, water treatment, or cathodic protection for OD degradation of buried pipe), refurbishments (for example, cleaning or the addition of a coating or lining), repair, or replacement. In service water systems, piping inspections will be driven primarily by long-term integrity of the system and economic considerations; for example, controlling the number and magnitude of any pinhole leaks to avoid repetitive repair situations.

Training and Engineering Judgment

The creation of an effective service water piping program will require a knowledge of system design, system operation, and treatment and maintenance practices. Also important are an understanding of degradation mechanisms, particularly corrosion, and how to apply that understanding of degradation to the system.

The required knowledge described above often necessitates an interdisciplinary team made up of plant system engineering or design engineering personnel; maintenance specialists; plant or utility general office personnel with significant experience in degradation, codes, and repairs; and NDE specialists. In most cases, one or more contractors will be required to provide the team with the proper level of expertise.

Plants must avoid overcompartmentalizing responsibilities on service water piping and its degradation. The plant must be certain that the service water piping and the degradation of that piping has a single “owner” who coordinates all of the required activities for service water piping management. That owner should have sufficient training in all aspects of the service water piping and its degradation to assemble the required team, to develop the processes for the plant, and to continue to apply those processes.

Long-Term Strategy

The piping system’s design bases must be satisfied through the end of plant life.

The top-tier system characteristics are:

- Structural integrity
- System functionality as affected by material condition

Neither of those top-tier system characteristics precludes operation with small leaks that do not jeopardize structural integrity, system design basis, or collateral damage (for example, to nearby electrical equipment).

The second-tier system characteristics are:

- Coating condition is maintained.
    - Potential source of flow blockages
    - Degradation rates are being kept under control

- Corrosion products remain attached (potential source of flow blockages).
- Fouling (silt and mud, macroscopic organisms such as clams and mussels, and microbes and biofilms) are not impacting functionality.
- The number of pinhole leaks is under control and tolerable.
- Important economic considerations are met.
- Inputs are made to the plant's long-range plan, especially if pipe replacements or other system modifications that require large expenditures are identified.
- System performance and rates of degradation are well characterized (that is, no surprises).

Programmatic Performance Indicators

The following criteria shall be considered in the development of a service water piping program.

1. The program is complete.
    a) An evaluation is performed for the entire system, considering all applicable design and operating characteristics.
    b) All potentially operative degradation mechanisms are considered.
2. Degradation mechanisms are addressed as follows.
    a) General thinning or other mechanisms that can jeopardize structural integrity are accounted for adequately in design; degradation from those mechanisms is bounded by corrosion allowances. A truly uniform loss of thickness of 40–120 mils (1–3 mm) would change the stiffness of the piping and necessitate a reevaluation of the piping system and its supports.
    b) Buildup of corrosion products or fouling is adequately addressed through materials selection (for example, use of corrosion-resistant alloys, or coatings).
    c) Localized corrosion mechanisms are the only operative mechanisms identified that may jeopardize leak-tightness of the system.
    d) Degradation typically does not occur only in discrete areas (for example, only at welds or fittings).
    e) Effects are limited to leakage only; structural integrity is not jeopardized.
3. Documentation is complete.
    a) Influences of design and operation parameters on operative degradation mechanisms are documented.
    b) All inputs and assumptions for input values used in the evaluation are documented.

   c) Evaluation results are documented.

4. Element selection reflects the following points:
   a) Selected elements include the most susceptible locations determined from evaluation and service history.
   b) The highest-risk locations are included.
   c) The program also includes typical locations (or locations selected randomly, if typical locations were not identified in the evaluation).
   d) The number of elements inspected ensures that the condition of the system has been addressed.
5. Appropriate examination methods are used to accurately detect and characterize localized corrosion.
6. Internal validation is performed and predictions compare favorably to failure, repair, and examination history.
7. Benchmarking/peer reviews and self-assessments are used as appropriate.
8. Acceptance criteria are defined and documented [2-7].
9. Sample expansion criteria are defined, and additional examination locations will be based on inspection results [2-7].

Consistency with Plant Strategy

Programmatic performance indicators should also be consistent with the list of criteria for long-term strategy—that is, with regard to the number of leaks, the number of thin spots, the cost of inspections, the cost of mitigation measures, and so forth, and trends for all (see discussion earlier in this section).

The program should be a living program that includes periodic reviews and reevaluation of program scope and rankings.

References

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2-2. "Internal Corrosion Direct Assessment (ICDA) for Transmission Pipelines Carrying Normally Dry Natural Gas," Proposed NACE Recommended Practice, DRAFT #1b, NACE International, Houston, TX, 2003.

2-3. O. Moghissi, L. Perry, B. Cookingham, N. Sridhar, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Application," CORROSION/2003, Paper No. 03204, NACE International, 2003.

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2-6. *Revised Risk-Informed Inservice Inspection Evaluation Procedure.* EPRI, Palo Alto, CA: 1999. TR-112657.[1]

2-7. "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping," Generic Letter 90-05, 6-15-90.

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[1] Section 3.6.7.2 provides an acceptable method for determining acceptance criteria.

3

PLANT DESIGN PARAMETERS

Design Bases

The overall design basis for service water systems is that the system must deliver sufficient flow at an adequate pressure to provide cooling to plant equipment [3-1]. The primary design condition for safety-related service water systems is that the service water system provides the ultimate heat sink under an accident condition, and thus it must be capable of removing sufficient heat for a sufficient time that the reactor can be brought under control and maintained in a safe shutdown state. Non-safety-related service water systems provide cooling to various loads that do not have a direct influence on reactor safety. However, those nonnuclear heat loads have a definite economic impact and can, if cooling is lost to the nonnuclear loads for an extended period, impact safety-related equipment (for example, mode changes).

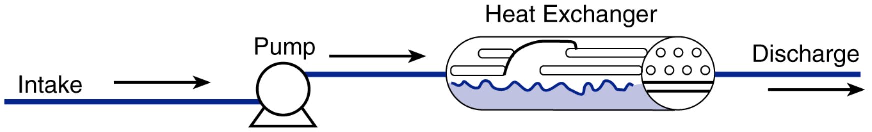
The normal operating condition for service water systems, both safety-related and non-safety-related, is to provide cooling for selected plant heat loads, usually on an as-needed basis. Those heat loads include a wide variety of coolers (lube oil, diesel-generator, closed cooling water, and so forth). The diverse and redundant design philosophy applied to service water systems, particularly safety-related service water piping, means that much of the service water piping is filled but not flowing much of the time.

The service water piping must maintain its structural integrity throughout plant life. The design and fabrication of service water piping is based upon accepted design and fabrication codes (for example, ASME Boiler and Pressure Vessel Code, Section III, Class 3 [3-2], or ANSI/ASME B31.1, Power Piping [3-3]) to ensure that the system will be built such that it will provide its required functions. The differences in inspection requirements for welds designed and constructed to the different codes were compared in Section 1 (Table 1-1). As discussed previously, the probable real differences in quality are likely to be nil. Often, the safety-related systems will be built to “higher” code requirements (for example, ASME Section III, Class 3) than the non-safety-related systems, however, as noted above, the real quality that is built in is probably no different. The resulting fabrication records, inspection requirements, and so forth will thus be more complete for the safety-related system. In essentially all cases, the required inspections during fabrication will be less stringent than for the reactor primary systems or systems that have a direct safety function.

System Layout

Figures 3-1 through 3-3 are schematics of the three basic types of service water system layouts that will exist: once-through systems, open recirculating systems, and closed systems. A detailed discussion of the pros and cons of each type of system is included in the EPRI *Service Water System Corrosion and Deposition Sourcebook* [3-4].

Once-through systems (Figure 3-1) take water from the system's water source, pump it through the system to the various heat exchangers in the system, and then return that water to the source. Once-through systems will experience the greatest amount of fluctuation of the environment, as the system will be subject to all of the seasonal, day-to-day, and daily changes in water chemistry and temperature, and to the full spectrum of changes that the water source goes through, because 100% of the inlet water comes from the source. There is no amount of recirculation. As a result, there will be minimal concentration of impurities in the system, which is often a positive effect. Some minimal amount of concentration of various chemical species will be unavoidable. System piping surfaces will be subject to alternate wetting and drying of some portions of the system, and consumption of some constituents at the expense of others can occur. Also, precipitation of some compounds as influenced by temperature and solubility effects will occur (especially in waters with high concentrations of dissolved solids), as will settling of particulates onto surfaces (for waters with high suspended solids), or growth of microorganisms. A major negative factor for once-through systems is that water treatments are limited by economic or environmental constraints, because the full volume of water in the system must be treated, and essentially all of the treatment chemicals will (eventually) return to the system's water source or else the chemicals must be removed or diluted to acceptable limits.



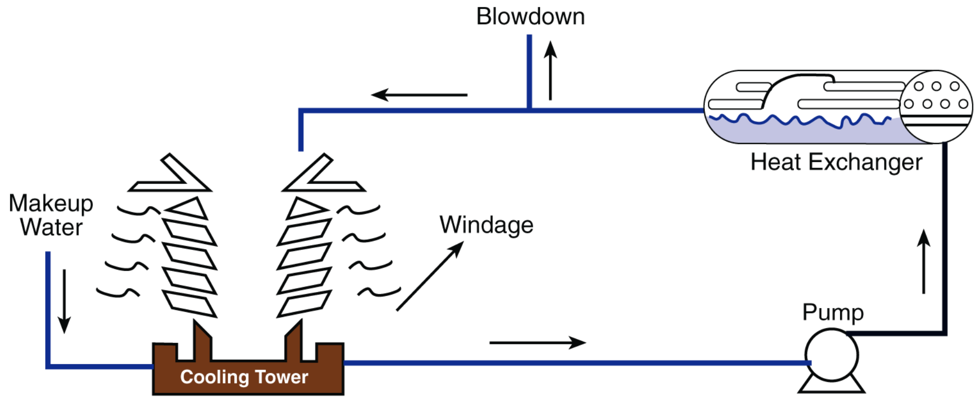
Common Problems:
- Scale
- Fouling
- Corrosion
- Wood Decay
- Microbiological Contamination

Examples:
- Potable Water Systems
- Process Water
- General Service

Operating Conditions:
- Average Temperature Change: 5–10˚F
- Amount of Water Used: Extremely Large

Figure 3-1
Once-Through System

Open recirculating systems (Figure 3-2) use a cooling tower or spray pond to remove a significant amount of heat via evaporation. The volume of water that is evaporated (plus droplets that are physically lost from the system) is made up from the water source. The majority of the water in the system is recirculated through the system a number of times. Since the evaporated water leaves as essentially pure H_2O, whatever impurities it contained will be left behind in the system. As a result, the total impurity level in the system will continually increase. A portion of that higher-impurity-content water will periodically be discharged as blowdown to maintain the system purity within the desired levels. Open recirculating systems will concentrate impurities. The concentrated impurities can increase the corrosivity of the water, its scaling tendencies, or both. In addition, the water source, cooling towers, and spray ponds are all open to the air and thus permit oxygen and other gases, along with dust, pollen, animal excretions, and so forth, to be added to the system environment. The major advantages of the open recirculating system relative to once-through systems are that fluctuations of system chemistry and temperature will be less because only a small portion of the water is "new" at any time; less water from the water source is actually used so fewer potential contaminants are ever introduced to the system; and water treatment chemicals that are applied for the control of corrosion, scaling, or microbiological growth can be used economically because a large fraction of those chemicals will be recirculated.



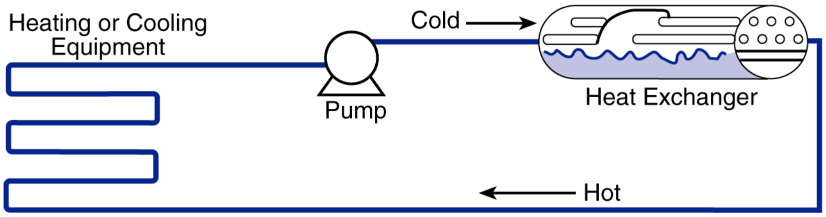
Common Problems:
- Scale
- Fouling
- Corrosion
- Wood Decay
- Microbiological Contamination

Examples:
- Spray Ponds
- Cooling Towers
- Evaporative Condensers

Operating Conditions:
- Average Temperature Change: 10–30˚F
- Amount of Water Used: Moderate

Figure 3-2
Open Recirculating System

Closed systems (Figure 3-3) remove heat from the various plant heat loads to a second system via a water-water or water-air heat exchanger. In either case, the heat sink for the closed loop is another cooling system. The closed-loop environment can be carefully controlled and can include corrosion inhibitors and biocides. Deposit or scale inhibition chemicals are typically not necessary, because the scale- or deposit-forming constituents will have been removed from the environment at the plant's water treatment plant prior to the addition of that water being admitted to the closed loop system. The initial fill and makeup water will be treated by softening, deionization, or similar processes. In closed-loop systems, corrosion must be controlled completely, because the generation and eventual deposition of corrosion products in the system cannot be tolerated readily without blowdown to remove the corrosion products and eliminate their potential for fouling the systems and producing areas for underdeposit corrosion.



Common Problems:
- Corrosion
- 15˚F
- Fouling

Examples:
- Diesel Engine Jackets
- Automobile Radiators
- Chilled Water Systems

Operating Conditions:
- Average Temperature Change: 10–15˚F
- Amount of Water Used: Negligible

Figure 3-3
Closed System

The 15°F ΔT shown in Figure 3-3 is suggested as a limit based upon the approach temperature for a water/water closed-loop cooling system.

All nuclear plants will have one or more closed cooling water systems, which may have a variety of system names. At least one of those closed systems will remove heat from critical equipment or equipment that can be in communication with radioactive or safety-related components. Other service cooling systems (non-safety-related) will provide cooling to generation-critical equipment (typically not safety related). Those systems have been addressed in other EPRI reports and in regulatory documents [3-5]. Those closed systems will be cooled by the plant service water system or circulating water systems.

Closed cooling water system piping is not included in the scope of this document, even for systems where that piping is the plant's service water piping. The plant design documents will differentiate and define the closed cooling water system and service water systems (which may happen to be closed systems).

Some plants, typically seawater-cooled plants, may have relatively small open service water systems, consisting of pumps and minimal piping to and from the heat exchangers that provide the interface between the closed-loop system and the service water or circulating system water. In such plants, the majority of the service water heat loads are cooled via a closed-loop system.

As noted above, the primary advantages of closed cooling water loops are that corrosion and deposition should be readily controllable via the initial purity of the water of the various chemical additions that are made to that treated water. Additional contaminants are excluded from the closed loop, because it is not open to the environment. The primary disadvantages of closed-loop cooling are the limitations on thermal capabilities, the necessity for careful and consistent corrosion and deposition control, and the significant expense related to converting an open loop to a closed loop.

Interties may exist. Some service water systems are completely independent of the circulating water (CW) system (used for heat removal from the main condenser during power operation), while others may have inter ties to the CW. In other service water systems, the safety-related portions of the system may be totally independent of the “normal” (that is, non-safety-related) service water system or may interconnect with the normal service water much of the time (for cooling of loads under other than accident conditions or system demonstrations), yet have a separate water source, pumps, and so forth for operation in the safety-related mode. The water quality and water treatments for CW, (normal) service water, and safety-related service water may be different. In cases where service water piping will be exposed to such different environments, predictions of service water piping degradation must consider all of the environments that the piping may be exposed to, as well as any interactions that may occur as result of the change from one environment to another over the plant’s life.

Environments

Unlike nuclear plant primary or secondary environments, fossil plant boiler water, or other closed loops, the service water environment is “dirty.” That is, the environment is typically a high-conductivity water (much higher conductivity than primary, secondary, or boiler water) that contains a variety of impurities that can produce deposits or corrosion. The service water environment is very dynamic. Its chemistry will vary seasonally, from day to day, and even during the day, and is not readily controllable. Economics and discharge limits restrict the amount and types of additions for control of corrosion, scale, particulates, or micro- and macroorganisms.

Water Sources

Water sources may include lakes (both natural and artificial lakes), rivers, ponds and reservoirs, ground water (typically wells), estuaries, or oceans. The latter two sources are generally used only when an adequate supply of fresh water is unavailable.

All of the water from the available surface or ground water sources starts as rain or snow—high-purity sources. These waters pick up various gases (oxygen, CO_2, SO_2, various oxides of nitrogen) as they fall, dissolve materials that are contacted as the water flows (for example, rocks and soils), become contaminated with various chemicals (for example, industrial, municipal, or agricultural pollution), and serve as a breeding ground for plants and animals, some of which contribute to fouling and corrosion of the service water system.

Fresh Water

Water is considered “fresh” if it has a low content of minerals, primarily chlorides. Most fresh waters contain less than 50 ppm chloride, often much less than 50 ppm.

Fresh water may be “hard,” which means that it contains a relatively high concentration of various scale-forming minerals that tend to precipitate on surfaces, or “soft” (that is, scale-dissolving). A “neutral” water is one that is neither scale-forming nor scale-dissolving. Since hardness salts tend to be more soluble at lower temperatures, the scaling characteristics of the water will be temperature-dependent. Waters with a total hardness of less than 60 ppm (measured as $CaCO_3$) are considered soft waters; those with more than 60 ppm total hardness are defined as hard [3-6]. All fresh waters are further classified as to the actual degree of hardness (more specifically, their scale-forming or scale-dissolving tendency). Several indices that provide a quantitative measure of the scaling tendency of the water have been developed [3-7 through 3-9].

Other indices, such as the Larson-Skold Index [3-10] provide a measure of aggressiveness of the water. The Larson-Skold index, developed as an index of the aggressiveness of fresh waters toward carbon steel and cast iron, is determined from the chloride, sulfate, and alkalinity (carbonate and bicarbonate) contents. A higher value of the index indicates a more aggressive water.

In very general terms, hard water is less corrosive than soft water, primarily because the presence of a calcium carbonate scale provides a physical barrier between the metal and the environment. Chlorides and, to a lesser extent, sulfates, have a strong influence on the aggressiveness of cooling water. These effects are discussed in greater detail in Section 4.

The EPRI *Service Water System Corrosion/Deposition Sourcebook,* TR-103403 [3-4], the EPRI *State of Knowledge Report on Low Temperature Corrosion Problems in Fossil Plants* [3-6], and the *Nalco Water Handbook* [3-11] are valuable resources for background on water sources and water quality. Those documents, especially [3-4], provide more extensive discussion of the scaling indices and factors that influence scaling and aggressiveness of waters.

The sources of fresh water may be lakes, rivers, ponds, or groundwater sources (for example, wells). Open recirculating systems, where evaporative cooling is provided via a cooling tower or spray pond, will serve to increase the concentration of all dissolved chemicals in the water as relatively pure water is evaporated away, leaving the impurities behind. Some amount of concentration will occur in impoundments, as natural evaporation will concentrate impurities.

Lakes may be large (for example, the Great Lakes) or relatively small, and natural or manmade. Table 3-1 is a sampling of water analyses from the Great Lakes and several other natural lakes from the *Nalco Water Handbook* [3-11]. Generally, the source of waters for lakes will be rain, runoff (including snowmelt), and one or more rivers or streams. In most deep lakes (for example, more than 200 feet [61 meters]), the water at the bottom remains at the temperature of maximum density (about 4°C) year round. When ice thaws in the spring, the transition from lower temperature (for example, freezing) to the temperature of maximum density (or the reverse in the fall and winter) produces circulation between the waters from the top and middle portions of the lake, which changes the temperature and chemistry of the lake at any given depth.

Shallower lakes (25 to 200 feet [8 to 61 meters]) can also experience this turnover by a similar phenomenon. While the shallower lakes do not have a truly stagnant zone as a result of the temperature, the bottom will be nearly stagnant and the turnover phenomenon occurs similarly; however, more of the total volume of the lake is involved.

Truly shallow lakes (less than 25 feet [8 meters] deep) will be in almost constant turnover, with the circulation between the top and bottom driven almost totally by surface currents resulting from wind.

Table 3-1
Water Chemistry of Some Typical U.S. Lakes (from [3-11]).[1] All values are shown as ppm $CaCO_3$.

		Superior	Michigan	Erie	Seneca Lake	Lake Coeur d'Alene	Clear Lake
Constituent	As	Duluth	Chicago	Erie, PA	Geneva, NY	Idaho	West Palm Beach, FL
Calcium	$CaCO_3$	35	80	90	100	18	686
Magnesium	"	9	41	33	41	10	11
Sodium	"	6	19	20	135	2	23
Total Electrolyte (Hardness)	$CaCO_3$	50	**140**	**143**	**276**	30	**102**
Bicarbonate	$CaCO_3$	42	113	91	97	19	50
Carbonate	"	0	0	0	0	0	0
Hydroxyl	"	0	0	0	0	0	0
Sulfate	"	1	18	25	35	10	12
Chloride	"	5	9	27	142	1	40
Nitrate	"	2	NR	Nil	2	Nil	NR
Fluoride	"	TR	TR	TR	TR	TR	1
M Alk.	$CaCO_3$	42	113	91	97	19	50
P Alk.	"	0	TR	0	0	0	0
Carbon Dioxide	"	4	Nil	5	5	4	2
pH		7.4	8.2	7.5	7.6	7.0	7.7
Silica	SiO_2	3.3	2.3	1.2	1.9	10	2.2
Iron	Fe	0.2	0.1	TR	TR	NR	0.6
Turbidity		1	12	Nil	NR	7	18
TDS		54	171	172	323	58	173
Color		1	3	2	1	NR	25
Hardness (per LSI, RSI, PSI)		Soft	Neutral	Neutral	Neutral	Soft	Soft
Aggressiveness (per Larson-Skold Index)		Benign	Benign	Mild	Aggressive	Benign	Aggressive

NR = Not reported
TR = Trace
LSI = Langelier Saturation Index
PSI = Puckorius or Practical Scaling Index
RSI = Ryznar Stability Index

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[1] Hardness values shown in bold face are values that exceed the 60 ppm cutoff for hard vs. soft water. Note that this simplistic criterion does not always agree with the various scaling indices.

Rivers will generally exhibit total dissolved solids (TDS) values that range from 60 to 700 ppm. In general, lower TDS values are found in rivers along the Atlantic and Gulf Coasts (where most of the U.S. nuclear plants are), in the Pacific Northwest, and along the Great Lakes. Higher TDS concentrations are observed for rivers near the Western Gulf, midcontinent, and southwestern regions of the United States. Table 3-2 (from [3-11]) provides a sampling of water analyses from U.S. rivers.

Table 3-2
Water Chemistry of Some Typical U.S. Rivers (from [3-11]). All values are shown as ppm $CaCO_3$.

	Delaware	**Edisto**	**Chattahoochee**	**Ohio**	**Tennessee**	**Mississippi**	**Missouri**	**Missouri**	**Neches**	**Colorado**	**Columbia**	**Sacramento**
Constituent	**Morrisville, PA**	**Charleston, SC**	**Atlanta, GA**	**Steubenville, OH**	**Decatur, AL**	**St. Louis, MO**	**Great Falls, MT**	**Kansas City, MO**	**Evadale, TX**	**Los Angeles, CA**	**Wenatchee, WA**	**Sacramento, CA**
Calcium	35	17	9	57	58	125	100	152	17	198	50	12
Magnesium	19	3	4	30	20	57	49	70	16	105	16	8
Sodium	4	10	5	14	18	66	47	86	23	220	25	5
Total Electrolyte (Hardness)	58	30	18	**101**	**96**	**248**	**196**	**308**	56	**523**	**91**	25
Bicarbonate	10	19	12	13	55	128	140	158	17	113	60	20
Carbonate	0	0	0	0	0	0	0	TR	0	7	0	0
Hydroxyl	0	0	0	0	0	0	0	0	0	0	0	0
Sulfate	35	2	2	79	15	93	36	120	13	302	22	2
Chloride	10	8	3	8	21	23	16	27	25	100	2	2
Nitrate	3	1	1	1	4	4	2	3	1	Nil	1	1
Fluoride	NR	NR	0	trace	1	NR	2	NR	0	1	TR	0
M Alk.	10	19	12	13	55	128	140	158	17	120	60	20
P Alk.	0	0	0	0	0	0	0	TR	0	4	0	0
Carbon Dioxide	1	20	2	15	10	3	TR	NR	4	0	4	2
pH	7.1	6.1	6.9	6.4	7.0	7.9	8.4	8.3	6.7	8.4	7.7	7.2
Silica	4.7	5	10	5.6	5.6	13	19	12	16	8	9.6	9.2
Iron	0.1	0.2	0.1	TR	0.1	NR	TR	NR	0.6	Nil	TR	0
Turbidity	NR	NR	26	88	50	NR	150	2000	35	NR	3	36
TDS	84	46	33	143	113	326	234	365	96	661	100	36
Color	7	54	4	2	30	19	NR	NR	60	NR	NR	15
Hardness (per LSI, RSI, PSI)	Soft	Soft	Soft	Soft	Soft	Neutral	Hard/Neutral	Hard/Neutral	Soft	Hard/ Neutral	Neutral/Soft	Soft
Aggressiveness (per Larson-Skold Index)	Aggressive	Mild	Benign	Aggressive	Mild	Aggressive	Benign	Aggressive	Aggressive	Aggressive	Benign	Benign

Note: All constituents are reported as ppm $CaCO_3$

Ponds and impoundments may be artificial or manmade. Water sources may include runoff, creeks or streams, or municipal/industrial sources. Due to their smaller size, these water sources may be subject to greater concentration phenomena from evaporation than other surface water sources. Table 3-3 (from [3-11]) provides a summary of some typical water chemistries.

Table 3-3
Water Chemistry of Some Typical U.S. Impoundments (from [3-11]). All values are shown as ppm $CaCO_3$.

Constituent	As	Greenville, SC	NYC (Catskill)	Boston, MA	Fredrick, MD	Little Rock, AR	Colorado Springs, CO
Calcium	$CaCO_3$	3	12	10	2	6	15
Magnesium	"	2	7	3	1	4	4
Sodium	"	4	4	1	6	1	11
Total Electrolyte (Hardness)	$CaCO_3$	9	23	14	9	11	30
Bicarbonate	$CaCO_3$	6	8	5	4	8	15
Carbonate	"	0	0	0	0	0	0
Hydroxyl	"	0	0	0	0	0	0
Sulfate	"	2	11	6	3	0	4
Chloride	"	1	4	3	2	3	4
Nitrate	"	0	0	0	0	0	1
Fluoride	"	0	0	0	0	0	6
M Alk.	$CaCO_3$	6	8	5	4	8	15
P Alk.	"	0	0	0	0	0	0
Carbon Dioxide	"	6	2	5	8	2	2
pH		6.2	6.9	6.3	6.1	7.1	7.4
Silica	SiO_2	7.8	2.5	0.9	3	3.5	8.4
Iron	Fe	0	0	0.1	0	NR	0.4
Manganese	Mn	0	0	0	0	NR	0
Turbidity		NR	2	1	1	10	NR
TDS		17	34	33	12	25	33
Color		6	1	7	3	35	NR
Hardness (per LSI, RSI, PSI)		Soft	Soft	Soft	Soft	Soft	Soft
Aggressiveness (per Larson-Skold Index)		Benign	Aggressive	Aggressive	Aggressive	Benign	Benign

Groundwaters such as wells may serve as the cooling water for power plants. Surface waters are usually less hard and less concentrated than groundwaters. Table 3-4 (from [3-11]) illustrates the water chemistry from some typical groundwaters.

Table 3-4
Water Chemistry of Some Typical Groundwaters (from [3-11]).[2] All values are shown as ppm $CaCO_3$.

Constituent	Manhattan, KS	Amarillo, TX No. 1	Baytown, TX No. 1	Phoenix, AZ	Norman, OK	Richland, WA	Camden, NJ No. 1	Camden, NJ No. 7	Camden, NJ No. 9N	Ft. Lauderdale, FL	Bastrop, LA	Dallas, TX No. 39
Calcium	282	145	25	192	**5**	125	60	18	42	230	**4**	**15**
Magnesium	86	255	14	230	**3**	65	38	19	41	8	**2**	**9**
Sodium	65	84	**593**	319	462	38	42	28	31	22	616	838
Total Electrolyte (Hardness)	**433**	**484**	**632**	**741**	**470**	**228**	**140**	**65**	**114**	**260**	**622**	**862**
Bicarbonate	352	366	384	220	295	169	50	1	91	235	356	452
Carbonate	0	0	0	0	57	0	0	0	0	0	0	TR
Hydroxyl	0	0	0	0	0	0	0	0	0	0	0	0
Sulfate	54	86	**Nil**	128	98	45	38	42	12	**TR**	**2**	270
Chloride	25	24	245	312	18	13	50	18	10	25	262	134
Nitrate	1	3	0	**79**	1	1	1	4	1	NR	1	1
Fluoride	1	**5**	3	2	1	Nil	1	0	0	NR	1	5
M Alk.	352	366	384	220	352	169	50	1	91	235	356	452
P Alk.	0	0	0	0	**29**	0	0	0	0	0	0	trace
Carbon Dioxide	35	20	20	5	0	8	80	80	30	10	5	Nil
pH	7.3	7.6	7.6	7.9	**9.1**	7.7	6.0	**4.6**	6.8	7.7	8.0	8.2
Silica	31	**61**	26	27	9.7	**55**	13	6.1	3.9	22	11	22
Iron	**6.9**	Nil	0.3	Nil	Nil	Nil	1.2	TR	**21**	1.6	TR	TR
Manganese	**1.4**	NR	0	NR	NR	0	0.3	TR	**5.6**	NR	NR	0
Turbidity												
TDS	488	530	733	887	550	307	181	103	118	314	697	**1040**
Color	2	NR	10	3	5	5	3	2	3	**59**	35	0
Hardness (per LSI, RSI, PSI)	Neutral	Hard	Hard	Hard	Hard/ Neutral	Neutral	Soft	Soft	Soft	Neutral	Hard	Hard
Aggressiveness (per Larson-Skold Index)	Benign	Benign	Mild	Aggressive	Benign	Benign	Aggressive	Aggressive	Benign	Benign	Aggressive	Aggressive

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[2] Entries that are shaded are identified as an "unusual value" per the Nalco Water Handbook

Brackish Water

Brackish waters are much higher in dissolved minerals, including aggressive species such as chlorides and sulfates (although note that sulfates may inhibit corrosion of stainless steels), than fresh water.

Estuaries or rivers where tidal action has a significant influence on water quality are common sources of brackish water. Reference 3-12 discusses estuarine sources. Some treated or partially treated municipal or industrial wastewaters are also brackish waters [3-13]. Brackish waters from treated municipal or industrial sources can be scaling or aggressive or both or neither, and like estuarine waters, can be (and often are) highly variable in quality.

Often, brackish waters will be highly scaling and aggressive. Expected chloride levels may be in the hundreds, thousands, or even tens of thousands of ppm, and can include numerous other constituents. Brackish waters, which are most often estuarine waters where tidal and seasonal influences (for example, rainfall or snowmelt) can be significant, will usually be the most widely variable, seasonally, day-to-day, and even from tidal cycles during the day.

Seawater

The ASM Handbook Volume on Corrosion [3-12] provides a good summary description of the chemistry of seawater. The paragraph and table that follow were excerpted from that reference.

> Seawater generally contains about 3.5% NaCl (about 20,000 ppm chloride) plus high concentrations of numerous other constituents [see Table 3-5]. Seawater is obviously highly scale forming and is extremely aggressive, especially to bare steels. General corrosion rates of 5 mpy or higher on carbon steel are typical; localized rates can be several times more rapid still. Although the major chemical constituents of seawater are consistent worldwide, the minor constituents vary from site to site and with season, storms, and tidal cycles. These minor constituents include dissolved trace elements and dissolved gases. In addition, seawater contains dissolved organic materials and living microscopic organisms. Frequently, the minor chemical constituents of seawater, together with the organic materials and living organisms, are the rate-controlling factor in the corrosion of structural metals and alloys. Changes in those minor constituents can occur rapidly and often. Sulfides, often found in polluted seawater, will increase the aggressiveness of seawater to carbon steel and can be particularly damaging to copper alloys.

Table 3-5
Major Constituents of Seawater (from [3-12]). Note that units are in parts per thousand vs. the parts per million used for fresh waters.

Ion or molecule	Concentration (g/kg of Seawater)
Na^+	10.77
K^+	0.399
Mg^{2+}	1.290
Ca^{2+}	0.412
Sr^{2+}	0.008
Cl^-	19.354
Br^-	0.067
F^-	0.0013

Distribution of Water Sources for Service Water Systems

An initial survey of the participants in the Service Water Piping Task Group provided the following information on system water sources.

- 45 U.S. nuclear stations (77 units) use fresh water.
- 9 U.S. stations (14 units) use brackish water.
- 9 U.S. stations (15 units) use salt water.
- 4 Canadian stations (21 units) use fresh water.
- 1 Canadian station (1 unit) uses salt water.

Materials

Service water piping is constructed from bare carbon steel, coated or lined carbon steel, bare cast iron, coated or lined cast iron, or corrosion-resistant alloys that include austenitic stainless steels such as Types 304 and 316 (including low carbon “L” grades), more highly corrosion-resistant stainless steels (typically the 6% molybdenum stainless steels), and nonferrous materials, most commonly copper-based alloys including brasses, bronzes, and copper-nickel alloys. More recently, some plants have installed titanium piping in critical locations.

Material selection, both for original design and for replacements, will be a strong function of the water source. For example, coated steel or cast iron or corrosion-resistant alloys will be used for highly corrosive waters like seawater and brackish water. Bare carbon steel or cast iron is often used in fresh waters. Buried piping may be bare or coated on the ID, depending upon the nature of the fluid that it carries; however, the OD will generally be coated and will often be cathodically protected.

In general, when plants have been faced with service water piping corrosion problems, the most common response has been to replace pipe locally or generally with more corrosion-resistant alloys (CRAs). For example, many of the plants in the southeastern United States experienced problems with occlusion of small-bore carbon steel service water piping from original construction due to corrosion products (tubercles) and particulates. Many of those plants replaced the carbon steel with austenitic stainless steel. Other plants, often those in more aggressive brackish water environments, replaced bare carbon steel or coated or lined carbon steel with 6% molybdenum stainless steels.

A summary of information on materials of construction for original and replacement materials of construction used for service water piping was compiled from the Service Water Piping Task Group. The results appear in Appendix B.

Carbon Steel and Cast Iron

All of the uncoated or unlined materials will corrode in the service water environment. The bare carbon steel and cast iron will exhibit visible evidence of corrosion products and will lose metal at a readily measurable rate. Carbon steel and cast iron systems are nearly always designed with a corrosion allowance that accounts for the expected amount of metal loss over the life of the plant. Those corrosion allowances will be based upon the anticipated level of general corrosion.

Localized corrosion (pitting, crevice corrosion, underdeposit corrosion, or MIC) or occurrences of general corrosion at rates that are significantly higher than the rate considered in design are usually what produces unacceptable thinning. The general corrosion at higher rates may also be fairly localized in that the corrosion is general corrosion that is confined to specific areas (for example, a function of flow). Selective weld attack and galvanic corrosion have also been observed in at least two plants. The consequences of those localized effects are pinholes rather than a loss of structural integrity.

Carbon steels and cast iron are also subject to cavitation damage. Cavitation is discussed in greater detail in Section 4.

A corrosion allowance that is adequate for a 40-year design life may not be adequate for service water piping that will experience a 60- or 80-year service life, even if the corrosion rate defined at the plant design stage was correct.[3]

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[3] A truly uniform loss of thickness of 40–120 mils [1–3 mm] would change the stiffness of the piping and necessitate a reevaluation of the piping system and its supports.

Corrosion-Resistant Alloys

Service water piping fabricated from corrosion-resistant alloys may have a corrosion allowance included in the system design, but most often it does not. If there is a corrosion allowance, it will be very small. The corrosion-resistant alloys should not exhibit readily perceptible evidence of corrosion, and the measured thickness of those alloys should not be degraded, either generally or locally, relative to the as-fabricated thickness.

Corrosion-resistant alloys rely upon a highly corrosion-resistant “passive” film that decreases the corrosion rate to essentially zero. The key factor in achieving that high level of corrosion resistance is the formation and maintenance of the film.

For corrosion-resistant alloys, the most common degradation mode is localized corrosion, producing pinhole leaks (usually much smaller ones than in carbon steel) due to pitting, crevice corrosion, underdeposit corrosion, or MIC. This localized corrosion is almost always due to breaks in the passive film from mechanical damage or very aggressive and highly localized environmental conditions that cause the film to break down locally, permitting corrosion to proceed at the breaks in the film.

Corrosion-resistant alloys will also be subject to cavitation. Although alloys like the 300-series stainless steels are more resistant to cavitation than carbon steel, the stainless steels are far from immune to cavitation damage.

Coatings and Linings

The primary purpose of a coating or lining is to provide a barrier between a corrosive environment and the underlying metal in order to prevent corrosion. Coatings permit materials like carbon steel and cast iron to be used in environments where they would otherwise corrode at unacceptably high rates. The presence of an intact coating with no defects stops corrosion completely by isolating the material from the environment. As the coating ages and develops defects, corrosion will occur at those defects. The basic effect of a coating from the design perspective is that the coating defers the onset of corrosion and permits piping materials that do not have inherent corrosion resistance to achieve a long life.

The distinction between coatings and linings is as follows:

- A coating is a barrier typically less than 50 mils [1.27 mm] thick that is applied between a corrosive environment and the underlying metal in order to prevent corrosion. Coatings permit materials like carbon steel and cast iron to be used in environments where they would otherwise corrode at unacceptably high rates.
- A lining is a barrier typically greater than or equal to 100 mils [2.54 mm] thick that is applied to a pipe or vessel interior between a corrosive environment and the underlying metal in order to prevent corrosion.

Commonly used coatings and linings for service water piping include:

- Cement mortar
- Rubber lining
- Acrylics[4]
- Alkyds
- Bituminous
- Chlorinated rubber
- Epoxy amine
- Epoxy coal tar
- Epoxy ester
- Epoxy phenolic
- Epoxy polyamide
- Inorganic and organic vinyls
- Urethanes

All coatings exhibit some degree of permeability to water, so they provide a barrier that is effective but less than 100% effective in keeping the environment away from the metallic pressure boundary. Permeability will be a function of the coating type and the coating thickness. Coating life, where life is defined as the time period during which the coating is nearly 100% effective at protecting the metal from corrosion, will typically be less than the life of the component (less than 40 years). These considerations require that the condition of the coating be examined periodically and that coating repairs or replacements be anticipated during the life of the service water piping.

In some situations, the general or localized failure of the coating will lead to very rapid attack of the metal (for example, coated or lined carbon steel or cast iron in seawater or brackish water service). In other cases, coating failure will lead to corrosion that proceeds at rates that are in excess of the assumed rate, however the damage that can occur between inspections will generally be relatively minor (for example, OD coatings of buried pipes; ID coatings in fresh water service).

If the coated or lined carbon steel or cast iron pipe is also galvanically coupled to a signficant area of corrosion-resistant material, either piping or heat exchangers, the situation is more serious. In the case of coated steel or cast iron that is coupled to CRAs, damage at failures in the coating can occur much more rapidly because of a large or very large cathode-to-anode area ratio (the cathode being the CRA).

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[4] Less likely to be used on piping (more cosmetic than protective)

Fabrication

Welded construction is used for the vast majority of aboveground piping fabricated from steel or corrosion-resistant alloys. Further, most buried steel and iron-based corrosion-resistant alloy piping will be welded. As noted in Section 1, inspection requirements imposed during fabrication of those welds were generally minimal. Volumetric techniques were essentially not required. The most common weld configurations will be butt welds and socket welds (Figure 3-4 and 3-5). Butt welds, the most common configuration for large bore (>2-in. pipe) may be made with or without backing rings (Figure 3-4a and 3-4b). The presence of the backing ring can have a significant effect on corrosion damage in service, because the backing ring creates a crevice where impurities can collect or microbes can grow. Crevice corrosion can also initiate and propagate beneath the backing ring. Socket weld fittings also have a built-in crevice that can have corrosion ramifications. In addition, socket welded piping can be subject to failure by fatigue produced by vibration [3-14].

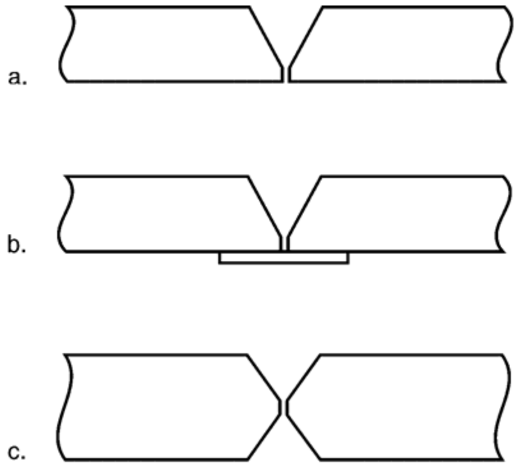


Figure 3-4
Butt Welds: (a) Open Butt; (b) with Backing Ring; (c) Double-V. (For service water piping, double-V welds will typically be the longitudinal seam weld, which is made at the pipe manufacturer.)

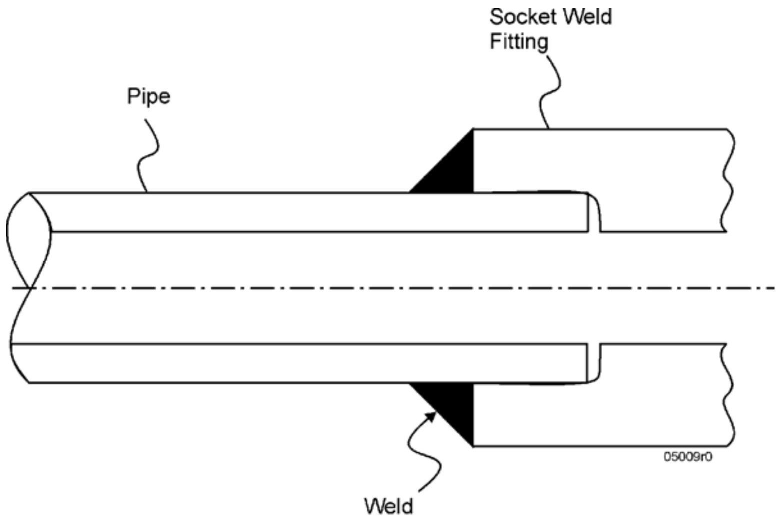


Figure 3-5
Socket Weld

Bell-and-spigot joints (Figure 3-6) are commonly used for buried cast iron pipe or prestressed concrete pipe. Crevices exist on both the fluid side and the soil side of those joints, with the potential for crevice attack and failure of protective coatings at thin spots where the coating must accommodate an irregular geometry. Inspection of the steel bell ring is important.

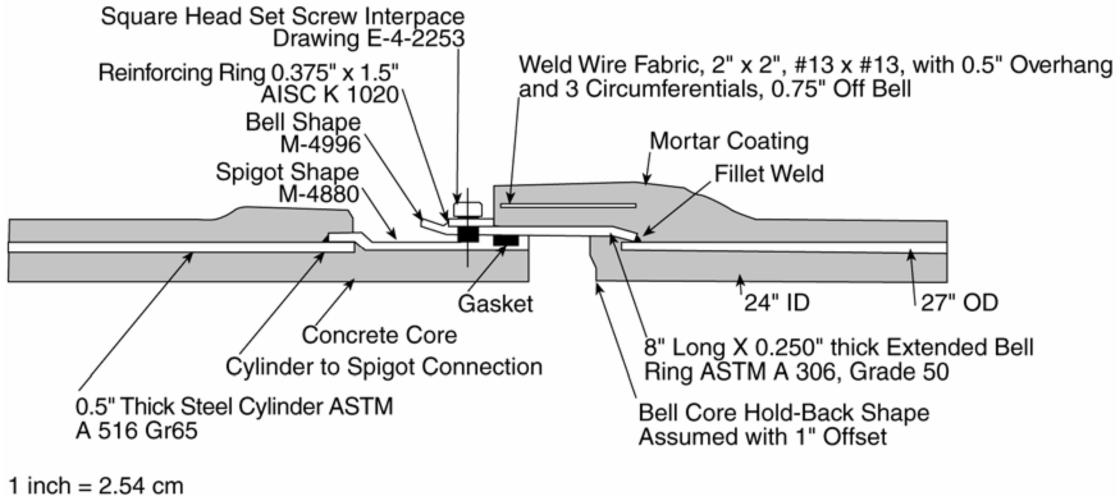


Figure 3-6
Bell-and-Spigot Joint (Drawing Courtesy of Jim Melchionna, PSEG)

Flanged joints are often used for both aboveground and buried piping. For alloys where welding is difficult or nearly impossible (for example, titanium, cast iron, or copper alloys), flanged joints, as illustrated in Figure 3-7, are common. Flange faces are crevices. Corrosion at flanges rarely has any impact on structural integrity, because the flanges are typically very thick. Corrosion degradation at the flange faces can produce leakage. Fasteners, which can be difficult to coat due to their irregular geometry, are a common location for failure and corrosion damage

(Figure 3-8). For buried pipe that is cathodically protected, electrical continuity between spools must be assured.

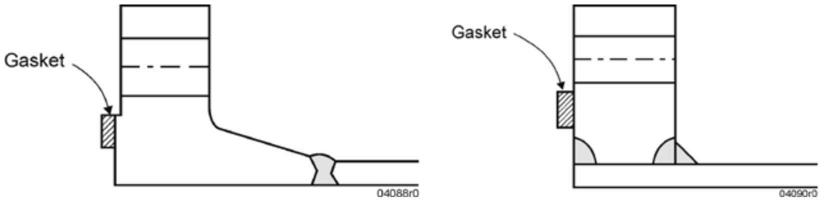


Figure 3-7
Flanged Joints

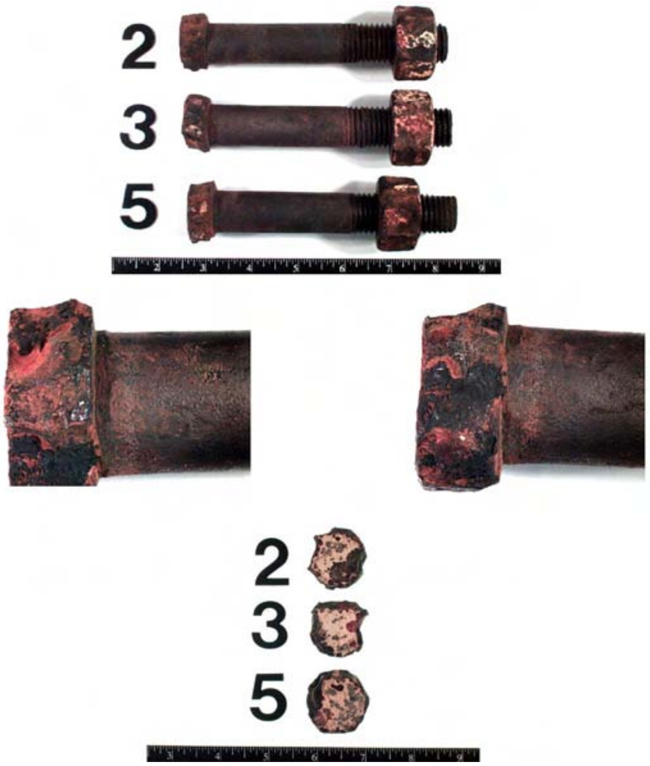


Figure 3-8
Corroded Bolts from RHR Bay

Other mechanical joints (as shown in Figure 3-9, for example) can be subject to leakage if and when the structural members that hold the mating surfaces together fail due to degradation of the protective coating and corrosion.

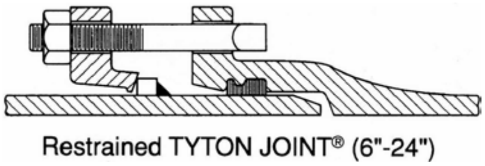
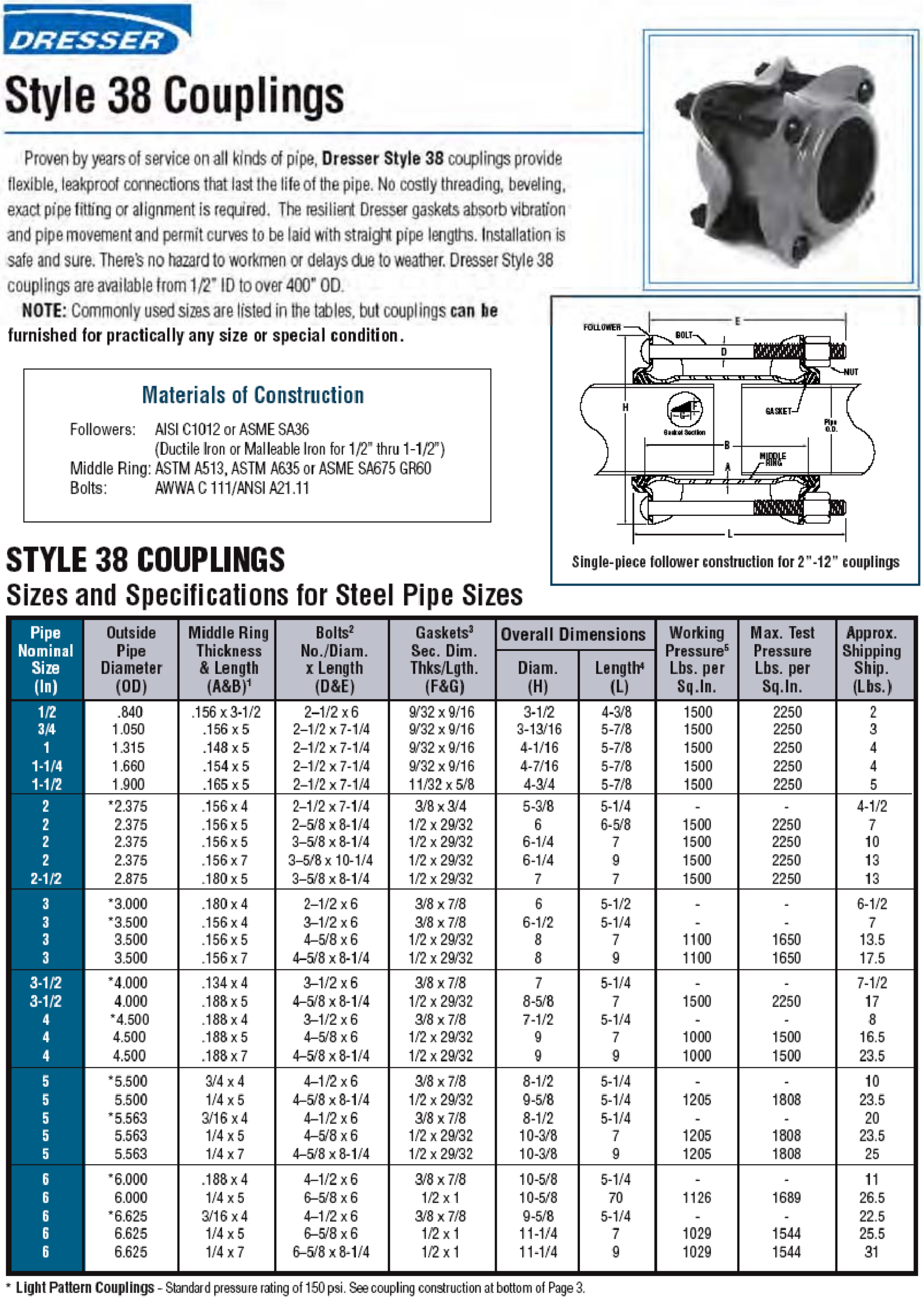


Figure 3-9
An Example of a Jointing System for Ductile Iron Pipe Sections [3-15]

A Dresser coupling is another mechanical connector that can be used to seal leakage in structural piping. A typical Dresser coupling is presented in Figure 3-10.



DRESSER

Style 38 Couplings

Proven by years of service on all kinds of pipe, **Dresser Style 38** couplings provide flexible, leakproof connections that last the life of the pipe. No costly threading, beveling, exact pipe fitting or alignment is required. The resilient Dresser gaskets absorb vibration and pipe movement and permit curves to be laid with straight pipe lengths. Installation is safe and sure. There's no hazard to workmen or delays due to weather. Dresser Style 38 couplings are available from 1/2" ID to over 400" OD.

NOTE: Commonly used sizes are listed in the tables, but couplings **can be furnished for practically any size or special condition.**

Materials of Construction

Followers:	AISI C1012 or ASME SA36 (Ductile Iron or Malleable Iron for 1/2" thru 1-1/2")
Middle Ring:	ASTM A513, ASTM A635 or ASME SA675 GR60
Bolts:	AWWA C 111/ANSI A21.11

Single-piece follower construction for 2"-12" couplings

STYLE 38 COUPLINGS

Sizes and Specifications for Steel Pipe Sizes

Pipe Nominal Size (In)	Outside Pipe Diameter (OD)	Middle Ring Thickness & Length (A&B)[1]	Bolts[2] No./Diam. x Length (D&E)	Gaskets[3] Sec. Dim. Thks/Lgth. (F&G)	Overall Dimensions		Working Pressure[5] Lbs. per Sq.In.	Max. Test Pressure Lbs. per Sq.In.	Approx. Shipping Ship. (Lbs.)
					Diam. (H)	Length[4] (L)			
1/2	.840	.156 x 3-1/2	2–1/2 x 6	9/32 x 9/16	3-1/2	4-3/8	1500	2250	2
3/4	1.050	.156 x 5	2–1/2 x 7-1/4	9/32 x 9/16	3-13/16	5-7/8	1500	2250	3
1	1.315	.148 x 5	2–1/2 x 7-1/4	9/32 x 9/16	4-1/16	5-7/8	1500	2250	4
1-1/4	1.660	.154 x 5	2–1/2 x 7-1/4	9/32 x 9/16	4-7/16	5-7/8	1500	2250	4
1-1/2	1.900	.165 x 5	2–1/2 x 7-1/4	11/32 x 5/8	4-3/4	5-7/8	1500	2250	5
2	*2.375	.156 x 4	2–1/2 x 7-1/4	3/8 x 3/4	5-3/8	5-1/4	-	-	4-1/2
2	2.375	.156 x 5	2–5/8 x 8-1/4	1/2 x 29/32	6	6-5/8	1500	2250	7
2	2.375	.156 x 5	3–5/8 x 8-1/4	1/2 x 29/32	6-1/4	7	1500	2250	10
2	2.375	.156 x 7	3–5/8 x 10-1/4	1/2 x 29/32	6-1/4	9	1500	2250	13
2-1/2	2.875	.180 x 5	3–5/8 x 8-1/4	1/2 x 29/32	7	7	1500	2250	13
3	*3.000	.180 x 4	2–1/2 x 6	3/8 x 7/8	6	5-1/2	-	-	6-1/2
3	*3.500	.156 x 4	3–1/2 x 6	3/8 x 7/8	6-1/2	5-1/4	-	-	7
3	3.500	.156 x 5	4–5/8 x 6	1/2 x 29/32	8	7	1100	1650	13.5
3	3.500	.156 x 7	4–5/8 x 8-1/4	1/2 x 29/32	8	9	1100	1650	17.5
3-1/2	*4.000	.134 x 4	3–1/2 x 6	3/8 x 7/8	7	5-1/4	-	-	7-1/2
3-1/2	4.000	.188 x 5	4–5/8 x 8-1/4	1/2 x 29/32	8-5/8	7	1500	2250	17
4	*4.500	.188 x 4	3–1/2 x 6	3/8 x 7/8	7-1/2	5-1/4	-	-	8
4	4.500	.188 x 5	4–5/8 x 6	1/2 x 29/32	9	7	1000	1500	16.5
4	4.500	.188 x 7	4–5/8 x 8-1/4	1/2 x 29/32	9	9	1000	1500	23.5
5	*5.500	3/4 x 4	4–1/2 x 6	3/8 x 7/8	8-1/2	5-1/4	-	-	10
5	5.500	1/4 x 5	4–5/8 x 8-1/4	1/2 x 29/32	9-5/8	5-1/4	1205	1808	23.5
5	*5.563	3/16 x 4	4–1/2 x 6	3/8 x 7/8	8-1/2	5-1/4	-	-	20
5	5.563	1/4 x 5	4–5/8 x 6	1/2 x 29/32	10-3/8	7	1205	1808	23.5
5	5.563	1/4 x 7	4–5/8 x 8-1/4	1/2 x 29/32	10-3/8	9	1205	1808	25
6	*6.000	.188 x 4	4–1/2 x 6	3/8 x 7/8	10-5/8	5-1/4	-	-	11
6	6.000	1/4 x 5	6–5/8 x 6	1/2 x 1	10-5/8	70	1126	1689	26.5
6	*6.625	3/16 x 4	4–1/2 x 6	3/8 x 7/8	9-5/8	5-1/4	-	-	22.5
6	6.625	1/4 x 5	6–5/8 x 6	1/2 x 1	11-1/4	7	1029	1544	25.5
6	6.625	1/4 x 7	6–5/8 x 8-1/4	1/2 x 1	11-1/4	9	1029	1544	31

* **Light Pattern Couplings** - Standard pressure rating of 150 psi. See coupling construction at bottom of Page 3.

Figure 3-10
A Typical Dresser Coupling (Photo and Drawing Courtesy of Dresser)

Cast iron and ductile iron piping is typically manufactured in 18- and 20-foot lengths. Although there are several different types of joints available for ductile iron pipe, including various types of push-on joints and mechanical joints, all employ a rubber-gasket connection.

This method of joining ductile iron pipes can also introduce several different corrosion degradation issues:

- Unless electrical jumper cables are specified and installed, the rubber gasket connection employed in the ductile iron pipe joints can electrically isolate 20-foot sections of pipe. Without electrical continuity, cathodic protection systems (for protection of the OD against soil corrosion) are ineffective, and the possibility of stray current corrosion is increased.
- Mechanical bolting joints have been a source of failure. The relatively sharp corners on the bolting and flanges are characteristically where the coating is the thinnest, and are usually the first place where the coating fails. Further, if the jumper has also failed on this connection, the cathodic current will discharge at the edges of the bolt and further accelerate the corrosion. This is a common industry experience; bolts preferentially corrode, eventually leading to a mechanical failure at the joint.

Some copper alloy piping may be brazed. The geometric configuration will be similar to that of socket welds. Corrosion or cracking of the brazing filler and vibrational fatigue are the most common degradation modes.

Operation

In addition to the wide variety of materials and water chemistries that service water piping will experience, operating conditions can also vary significantly with time. As a result, the piping will experience numerous different flow regimes. The diverse and redundant design philosophy that pervades nuclear plant design certainly applies to service water systems. Systems will typically be designed for the most limiting condition (for example, a LOCA), however normal heat loads are generally minimal. As a result, duplicate or triplicate paths will exist for the cooling water such that one, two, or three legs of the system will be filled with cooling water, but remain in a standby mode, awaiting a need for cooling of equipment. All of those systems will be operated periodically for testing on a regular basis. For many portions of a service water system, especially a safety-related service water system, periodic operation, interspersed with extended periods of wet layup, will be the most common condition of “operation.” Changes in the flow conditions in the piping can dramatically change the nature of the degradation that the piping will experience by producing local conditions that are significantly different from those that were considered in design.

Normally Flowing Conditions

Corrosion allowances for service water piping are based upon 40 years of operation at design flows and design temperature in the nominal water chemistry. Typical fluid velocities may range from less than 1 foot per second to flows of the order of 10 fps [3 m/s]. Most often, normal flows produce fluid velocities of 3 to 7 fps [0.9 to 2.1 m/s].

Normally flowing conditions, and the associated general corrosion, are what the piping was designed for. Under these conditions, uncoated carbon steel or cast iron would be expected to degrade by general corrosion that produces a fairly protective oxide film. The key consideration relative to the form and rate of the corrosion is the protective nature of the oxide, which is a function of dissolved oxygen, temperature, flow, and water chemistry. Details on all forms of service water system degradation are discussed in Section 4.

Normally Stagnant Conditions

Nuclear plant service water systems will have a number of legs that will be stagnant for extended periods ranging from weeks to months, and will only flow (at rates at or near design flow rates) for a few hours during testing. Those legs may also experience flow for longer periods under off-normal conditions, for example, following an accident or for other unusual heat removal tasks.

Many sections of the service water piping will have experienced one or more extended periods of stagnation during construction. During construction, system piping will have been hydrostatically tested with local water that may or may not be the same as that used for normal system operation. Often, the piping remained filled with the hydro test water for an extended period prior to plant commissioning, when normal operation began.

As a result, for pipe that is normally stagnant, degradation may be far less than design levels (that is, minimal general corrosion) or far greater than design levels (for example, where alternate mechanisms such as MIC or underdeposit corrosion can occur as a result of the stagnation).

Intermittent Flow Conditions

Portions of the service water system can cycle between periods of stagnation and periods of flow at a variety of flow rates, based upon cooling demands from the various heat loads or from rotating the flow time between parallel legs. Intermittent flow conditions can produce degradation that is intermediate between that of the normally flowing and normally stagnant legs (for example, time-averaged based upon the fraction of time flowing) or degradation of a form and at rates that are far worse than either flowing or stagnant conditions. When the nature of the environment and the time period of the stagnation are such that the stagnation periods can set up conditions that reinforce aggressive conditions during flow periods that follow the stagnation periods, extremely rapid degradation that has not been considered in design can occur.

Dead Legs

Because of the miles of piping and numerous branches in service water piping systems, a number of dead legs will exist, where normally stagnant or intermittent flow legs are connected to normally flowing legs. The degradation that occurs in dead legs can often be the worst in the service water piping system, depending upon the material of construction, the environment, the flow rate in the flowing section, the relative sizes of the piping in the flowing pipe and the dead leg, and the length and orientation of the dead leg (for example, a long or short length of pipe from the connection to the flowing branch, or a vertical dead leg at the bottom of the flowing line, where sediments can accumulate, as opposed to other orientations).

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3-3. Power Piping, ANSI/ASME B31.1.

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4
DEGRADATION

Types

Pinhole Leaks

Pinhole leaks in service water piping will occur as the result of general or localized corrosion phenomena in carbon and low-alloy steels or as the result of highly localized corrosion (for example, as the result of MIC or chloride pitting) in stainless steel or copper-based alloys. In either case, the primary effect is leakage from the system, usually at an extremely low rate. Pinhole leaks generally have no effect on the function of the service water system (flows from the leak are measured in drops per minute, compared to system flows of hundreds or thousands of gallons per minute), but a leak may have an effect on neighboring equipment if the leak persists for an extended time. Both the potential collateral damage (for example, flooding, or drips or sprays on nearby electrical equipment) and the potential impact of the localized thinning on the structural integrity of the piping must be considered. Usually there are no ramifications on the structural integrity of the system.

As a result, operation with a leak can be acceptable. Nonetheless, all leaks must eventually be repaired, and during operation with a leak, augmented inspections will be required.

Corrosion damage, whether generalized or localized, will be cumulative. Figure 4-1 is an example that shows that for much of the plant life, the probability of a through-wall failure (a leak) is very low, and failure rates (number of leaks vs. time) are also very low. For the example shown in Figure 4-1, for the first 20 years or more of system operation, which may significantly predate commercial of the plant, the failure rate may be zero or nearly zero, however, over longer time, as corrosion keeps marching on, low through-wall failure rates (for example, 1–2 leaks/year) may begin to appear. If no corrective actions are taken, the number of leaks per year will continue to increase, eventually reaching a rate that may cause the integrity of the piping to be questioned. In any case, as the number of leaks per year increases, the economic effects associated with disposition and repair of the leaks will become significant.

For the specific example shown in Figure 4-1, the probability of one or more leaks is essentially zero for the first 15 years of service (1984–1999), increasing to a probability of about 10% at 25 years, about 50% at 35 years, and 100% at 45 years. The cumulative total number of leaks predicted is very low (0 or 1) for the first 20 years of service; a total of 1–5 leaks is predicted after 40 years of service, but 20–35 leaks are predicted after 60 years of service.

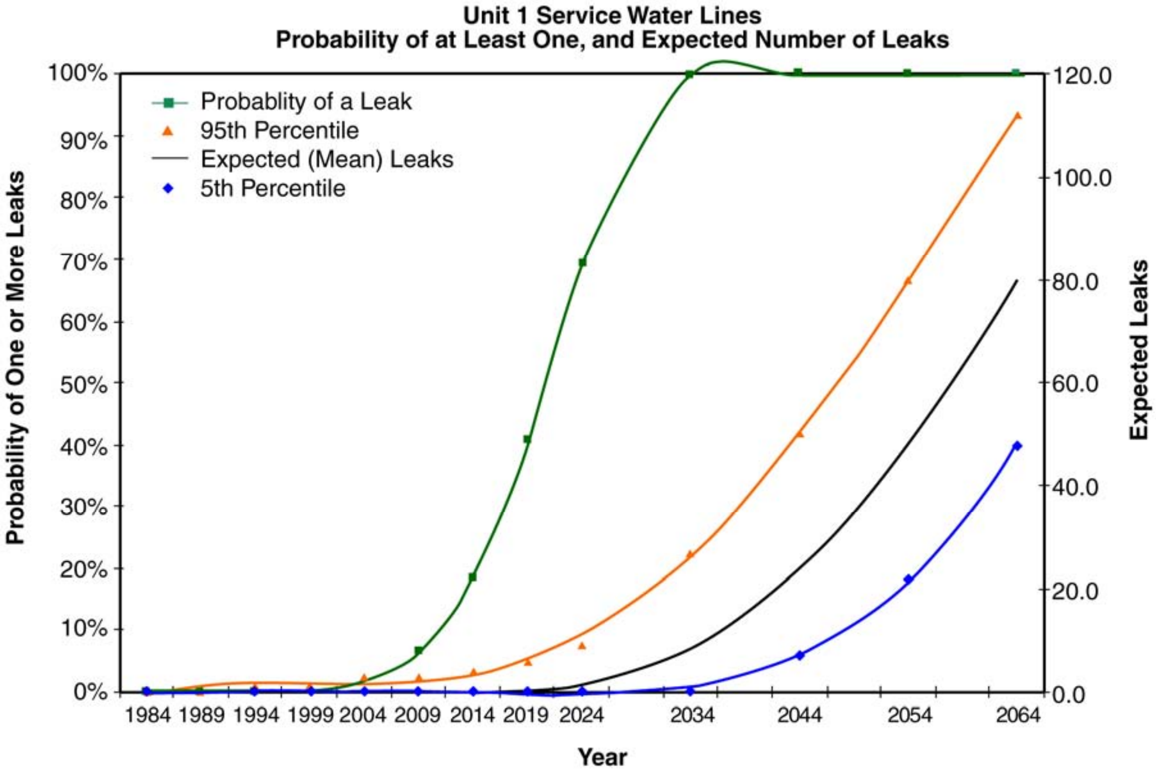


Figure 4-1
Example of Degradation of Service Water Piping: Pinhole Leaks

One goal of a service water piping program should be to manage leaks and minimize the number of leaks. The actions taken toward managing pinhole leaks may be based on safety or economic considerations. Risks to neighboring equipment must always be considered.

Generalized Thinning

General thinning can (and at some level of thinning will) have an impact on structural integrity. Very simplistically, since the stress in the material is determined by the applied load (pressure, dead weight, and so forth) divided by the cross-sectional area, as that area decreases, from generalized thinning, the stress will increase and will eventually reach the point where the stress exceeds the useful strength of the component (typically yielding will occur followed by fracture) and functionality of the component will be lost. The corrosion allowance built into a plant's design was intended to accommodate the general thinning that was expected to occur over the life, such that the stresses in the piping at the end of life were sufficiently low that the piping would always retain its structural integrity. The key parameters related to generalized thinning are the depth and extent of metal loss, and their effects on the load-carrying capability of the piping under normal and off-normal conditions.

Code Case N-597 [4-1] provides guidance on generalized thinning and localized thinning. For generalized thinning, the thickness at any location must be greater than 90% of t_{min} required for the design loading as defined by the Construction Code. For local thinning, the depth, area, and orientation of the localized thinned area are all considered, because the effect of the thinning on the load carrying capability of the piping will be a function of how well that the surrounding material can share and support the higher stresses in the locally thinned area.

Cracking

Cracks, especially deep cracks, will impact structural integrity of piping very dramatically. Deep cracks can change the failure mode from one in which failure only occurs when the stresses are very high (relative to the ultimate tensile strength of the material) and produce extensive deformation to one in which a brittle rather than a ductile overload type of failure will occur. Cracking can also produce leakage.

Fortunately, cracking is not a common degradation mode in service water piping. The environments, loadings, and temperatures are such that cracking from fatigue, stress corrosion cracking, or corrosion fatigue generally does not occur for the materials used for service water piping.

Occlusion

The buildup of corrosion products or deposits can decrease the flow-carrying capability of a service water pipe. Figures 4-2 and 4-3 illustrate the effect. The overall occlusion will be affected by debris, macrofouling, and corrosion products. In some extreme cases, biological fouling can cause occlusion of the service water piping. Degradation due to occlusion is much more common in smaller-bore piping, where the surface-to-volume ratio is higher so that the corrosion products, which are less dense than the underlying material from which they were formed, will “impinge” upon each other, producing a restriction to flow. In large-bore pipe, the same volume of corrosion products (or other deposits) will be a much smaller fraction of the cross-sectional area of the pipe. Corrosion products can be released from surfaces from any size of pipe and deposit elsewhere, producing detrimental effects at those locations.

Corrosion product buildup can also affect the flow carrying capabilities of the pipe, due to increases in surface roughness, even before the cross-sectional area of the pipe is significantly degraded [4-2, 4-3].

Figure 4-2
Occlusion of Service Water Piping (Relatively Minor)

Figure 4-3
Occlusion of Service Water Piping (Dramatic)

Coating Failure

Coatings are used to provide corrosion protection for piping materials, most often by providing a simple barrier between the environment and the metal. In some cases (for example, coated carbon steel in seawater or brackish water service), the coating permits the use of a material that would have a very short life if it were in direct contact with the environment. In all environments, corrosion can start at areas of coating failure, and in some cases, such as coated carbon steel exposed to seawater, can proceed very rapidly.

In addition, the failure of the coating can also contribute to system damage, for example, via flow blockage of piping or heat exchangers [4-4 and 4-5].

The inspection priorities for coated pipe will be different from those for bare pipe. For coated pipe, visual inspections of the condition of the coating will provide much of the necessary insight regarding degradation of the underlying metal. If the coating is in good condition, corrosion of the pressure boundary material will be nil. If the coating is degraded, further investigation is required to assess the condition of the pipe, and an evaluation of how the damaged coating may impact other functions (for example, blockage of piping, valves, heat exchangers, and so forth) will also be required.

Differences in inherent quality between factory-applied and field-applied coatings will also influence the most probable locations for degradation. For example, field-applied coatings at welds or repairs will be more likely to fail than factory-applied coating elsewhere on the pipe. As a result, inspections of coating condition should focus on welds, repairs, and the like.

The number of holidays in buried pipe and other coated and lined pipe will be a strong function of the quality of the coating operation and the holiday testing inspection. Holidays will expose the underlying pipe surface to the environment. Coating imperfections come from sources such as the following:

- Holidays generated during coating application. (Improper surface preparation or environmental conditions during application and curing can be a significant contributor.)
- Physical damage created during transportation and installation of the pipe.
- Holidays generated due to aging of the coating.
- Service loadings (cavitation, abrasion, and so forth).
- Cathodic disbondment from overprotection (buried, cathodically protected pipe only).

Holidays from Application: Coating holidays are created during the application process. Most pipe mills pass the pipe through a holiday detector prior to shipping.

Installation Damage: The coating can be damaged in a number of ways during the installation process. Welding and other sources of heat can be particularly damaging. After coating, pipe is generally “holiday tested” to confirm 100% coverage. Holiday testing is a simple electrical test where the coated pipe is placed in a conductive solution and the resistance between the uncoated side of the pipe and an electrode in the solution is measured. Gaps or voids in the coating will allow the electrolyte to contact the metal, producing a lower resistance measurement. Some construction specifications require “over the ditch holiday detection” (in contrast to the factory field detection) for buried piping.

Aging of Coating: All coatings degrade over time. For example, coal tar enamel, commonly used for buried piping, can have a service life ranging from 15 years to over 50 years, depending on the soil environment. Both mechanical and environmental effects will influence coating life.

Cathodic Disbondment: For buried piping, excessive amounts of cathodic protection current can cause disbondment of the coating. Cathodic disbondment results from water and ion migration through the coating, generating increased pH at the pipe surface, which results in the coating separating from the pipe and forming defects called blisters. Unlike with other coating defects, cathodic current does not always effectively mitigate corrosion of blistered areas, which can result in unfettered local corrosion of the piping. The amount of over-voltage necessary to generate cathodic disbondment can vary. However, an industry rule of thumb suggests avoiding applied voltages that are more negative than -1,100 mV with respect to the voltage measured in the instant off condition.

Figure 4-4
Typical Coating Failure

Modes

Corrosion

The EPRI *Service Water Corrosion and Deposition Sourcebook*, TR-103403 [4-6], provides an extensive discussion of corrosion effects, both in general terms and with specific reference to service water systems. An overview discussion of corrosion processes follows.

All metallic corrosion involves the oxidation of the metal, from the metastable metallic state to the more thermodynamically stable state as a mineral (oxide, carbonate, sulfate, sulfide, and so forth).

Oxidation involves a loss of electrons to produce a metal ion (M^{+n}) and n electrons. The oxidation process is called a half-reaction because such a reaction cannot occur independently; a balancing half-reaction that accepts or generates the electrons that appear as reactants or products is required for a "full" reaction. Oxidation and metal loss occur at the anode.

As just stated, the electrons released by the oxidation process must be accepted by another process (material cannot spontaneously become electrically charged). Those electrons are accepted by reduction processes. Reduction occurs at the cathode.

A slow step in either the anodic or cathodic process will control the overall rate of the reaction for many corrosion processes. For most corrosion processes, including corrosion processes in cooling water environments, the rate of the cathodic half-reaction is typically the controlling step.

The anodic process (for example, dissolution of iron) under such circumstances can only proceed as rapidly as the cathodic half-reaction, which may itself be limited by the rate at which dissolved oxygen is reduced at the surface or the rate at which nascent hydrogen atoms combine to form hydrogen gas. Dissolution may proceed rapidly for a short period of time, but will be quickly halted by these limitations at the cathode. Increasing the rate of hydrogen removal at the cathode (for example, as the result of microbial metabolism or by the addition of a catalyst that reduces the activation energy of hydrogen combination) effectively depolarizes the cathodic reaction and thereby produces an increase in the rate of the overall process.

In neutral or alkaline waters, the reduction of dissolved oxygen in water is the most common reduction reaction (Equation 4-1), while in acidic environments the reduction of hydrogen ion to hydrogen atoms (and eventually hydrogen gas) is the most common reduction reaction (Equation 4-2). In cooling water environments, the rate of the cathodic reactions limits the overall process. Relatively minor changes in the amount of dissolved oxygen, or the presence of other oxidants such as oxidizing biocides, can have a profound effect on the corrosion rate in such waters.

$$O_2 + H_2O + 2e^- \rightarrow 2OH^- \qquad \textbf{Eq. 4-1}$$

$$H^+ + e^- \rightarrow H \qquad \textbf{Eq. 4-2}$$

Anodes and cathodes can occur randomly over a metallic surface and can move around over time. The movement or nonmovement of anodic and cathodic sites is the key feature that determines whether corrosion will be generalized (when anodes and cathodes move and all areas of the surface average about the same amount of time as an anode as a cathode) or localized (when anodic sites remain stationary and all or most of the corrosion occurs at only a few locations and proceeds rapidly there and only there).

As noted in TR-103403 [4-6], environmental influences on the cathodic half-reaction will be much more prevalent than anodic effects. This should not be surprising, as the cathodic half-reaction in cooling waters will typically involve the reduction of dissolved oxygen (neutral or alkaline environments) or hydrogen ions (acidic environments).

In cooling waters, the corrosion rate of carbon steel depends upon the amount of dissolved oxygen in the solution, often in direct proportion to the oxygen content. The reduction events will be proportional to the amount of oxygen that is available. In closed systems, where oxygen is consumed by corrosion events, the corrosion rate will decrease over time. A concern arises when alternative cathodic reactions (for example, from acidification of the environment that can occur as the result of acid-producing bacteria, or from other effects such as the metabolism of sulfate-reducing bacteria) become available to accept the electrons produced by dissolution of the carbon steel. In cases where alternative cathodic reactions become available, corrosion can proceed even though oxygen has been consumed.

For passive alloys like stainless steel, nickel-base alloys, or titanium, where the anodic current does not change over a wide range of potential, changes in oxygen content may increase or decrease corrosion.

Whether the corrosion is generalized or localized, the cathodic reaction will still be controlling, so the greater the oxidizing power of the solution (that is, the more powerful the cathode), the greater will be the driving force for the overall corrosion reaction, either for general or localized corrosion. In a situation where localized corrosion is active, a more powerful cathodic reaction can have an even more dramatic effect than for a situation where general corrosion is operative, because the cathodic reaction will occur over a much larger area than the anodic reaction.

General Corrosion

General corrosion (Figures 4-5 through 4-8) is a metal loss that occurs essentially uniformly over the exposed surface. Most components are built with a corrosion allowance that represents the expected metal loss over the life of the component. For carbon steels exposed to typical fresh waters at temperatures near a normal room temperature, average corrosion rates of several mils per year (mpy) would be expected. Normal design practice for service water systems include a corrosion allowance of 0.040 to 0.120 inches (1 to 3 mm) for bare steel service water piping designed for a 40-year life. As noted previously, a truly uniform loss of thickness of 40–120 mils (1–3 mm) would change the stiffness of the piping and necessitate a reevaluation of the piping system and its supports.

Figure 4-5
General Corrosion

Figure 4-6
General Corrosion (Additional Examples)

Figure 4-7
General Corrosion (Another Example)

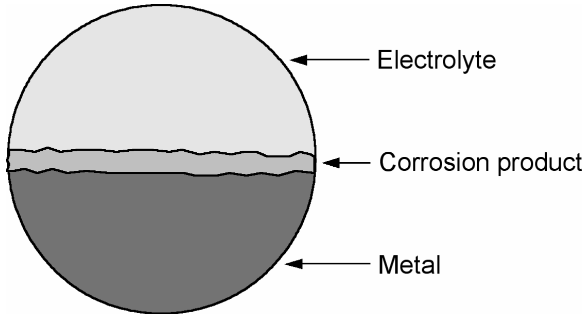


Figure 4-8
General Corrosion—Schematic

In most cooling water applications, where temperatures stay well below boiling and the pH of the environment is in the range of about 6 to 10, cathodic reactions control the overall corrosion process (Figure 4-9). For open cooling water systems, the corrosion rate is strongly dependent upon the dissolved oxygen in the water. At high levels of dissolved oxygen, rates are higher (Figure 4-10). In continuously flowing, open systems, oxygen is continuously transported to metal surfaces and general corrosion proceeds at a fairly high rate. In stagnant systems, such as many of the legs of the service water system, corrosion reactions and biological oxygen demand will consume the oxygen in the closed system so that the corrosion rate will decrease during the time that the system is closed and oxygen content is low. The protectiveness of the corrosion product will be a strong function of the oxygen content of the environment. For example, at high oxygen contents and low temperatures, a loose and poorly protective corrosion product will form. At relatively low oxygen contents and higher temperatures, a more protective corrosion product forms. At very low oxygen contents (on the order of tens of parts per billion, as compared to the 6 to 10 parts per million dissolved in normal surface waters), as may be attained in high-temperature systems where the water is treated specifically to decrease the oxygen content, a nonprotective corrosion product film is formed. High corrosion rates result. Extremely low oxygen is one of the primary factors that produce FAC in high-energy lines such as feedwater (Figure 4-11).

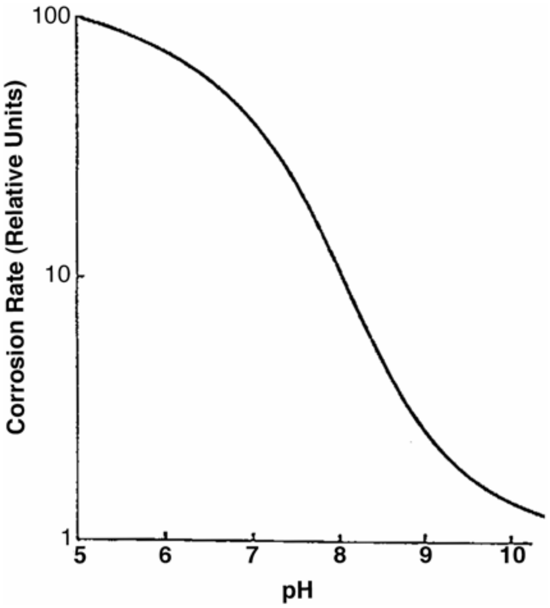


Figure 4-9
Corrosion Rate Versus pH

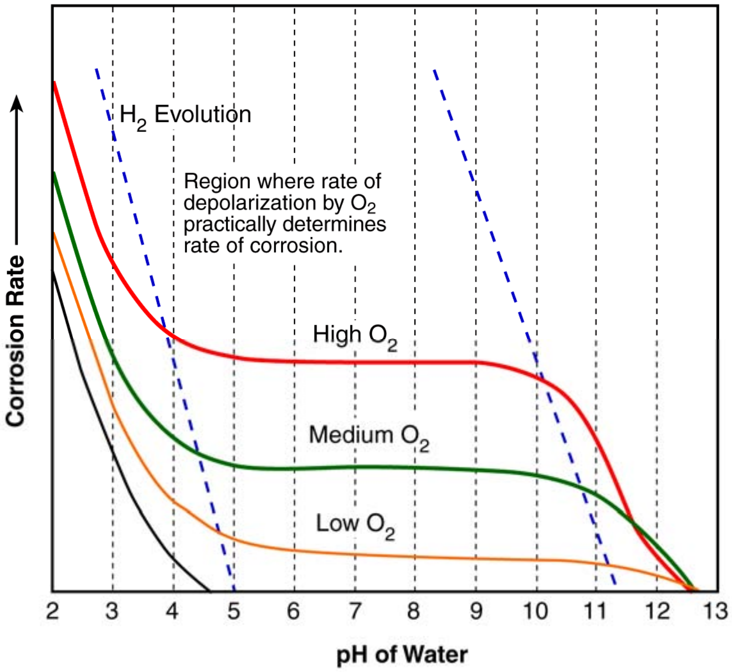
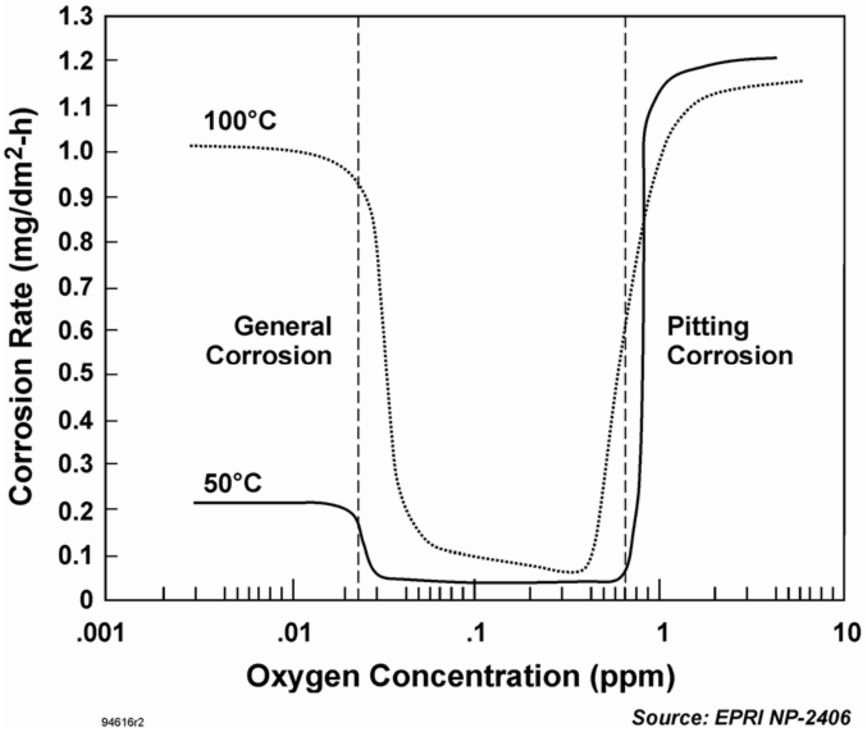


Figure 4-10
Effect of Dissolved Oxygen on Corrosion Rate



Source: EPRI NP-2406

Figure 4-11
Effect of Dissolved Oxygen on Corrosion Rate, Including Extremely Low Oxygen Contents

General corrosion is also dependent upon flow and temperature. As the flow rate increases in carbon steel cooling water systems, the corrosion rate also will increase; essentially linearly with flow. Under stagnant conditions or at very low flows, rates of general corrosion will be lower, often much lower, than they are under normal flow conditions. In low-energy systems, the extremely rapid metal loss from carbon steels associated with FAC is not observed. Note that purely erosive wear due to particulate matter in the water is another matter.

A general rule of thumb for the effect of temperature on the general corrosion of carbon steels is that corrosion rate will double for every 15°F (8.3°C) increase in temperature, up to about 160°F (71C°). The upper limit on temperature exists because the solubility of oxygen decreases with increasing temperature. At the higher temperatures, in both open and closed systems, the lower oxygen content has a greater effect on decreasing the corrosion than the effect of temperature has in increasing the kinetics of metal loss.

The primary differences in terms of general corrosion (and general corrosion only) among systems like circulating water (which flows essentially all of the time), fire protection systems (which almost never flow), and service water systems (which experiences a wide variety of flow conditions) are related to flow and the level of dissolved oxygen or other oxidants in the water. The effects of flow on the different forms and rates of corrosion that might be expected are discussed in detail later in this section.

Researchers have attempted, with some success, to define indices or other predictors for the general corrosion of carbon steel and other commonly used alloys as a function of water chemistry. As shown in Figure 4-12, the reported incidence of corrosion problems with carbon steel increases as the scale-forming tendency of the water (as measured by the hardness and alkalinity) decreases, assuming that all other factors remain constant. As described in [4-7], various indices, including the Langelier Saturation Index, the Ryznar Saturation Index (which is plotted in Figure 4-12), and the Puckorius or Practical Scaling Index, have all been developed to provide a quantitative measure of the scale-forming or scale-dissolving tendency of waters. As noted above, oxygen content has the greatest influence on the corrosion of steels in fresh untreated waters. Other constituents of the water, such as chlorides, sulfates, and carbon dioxide, also cause the corrosion rate to increase (Table 4-1).

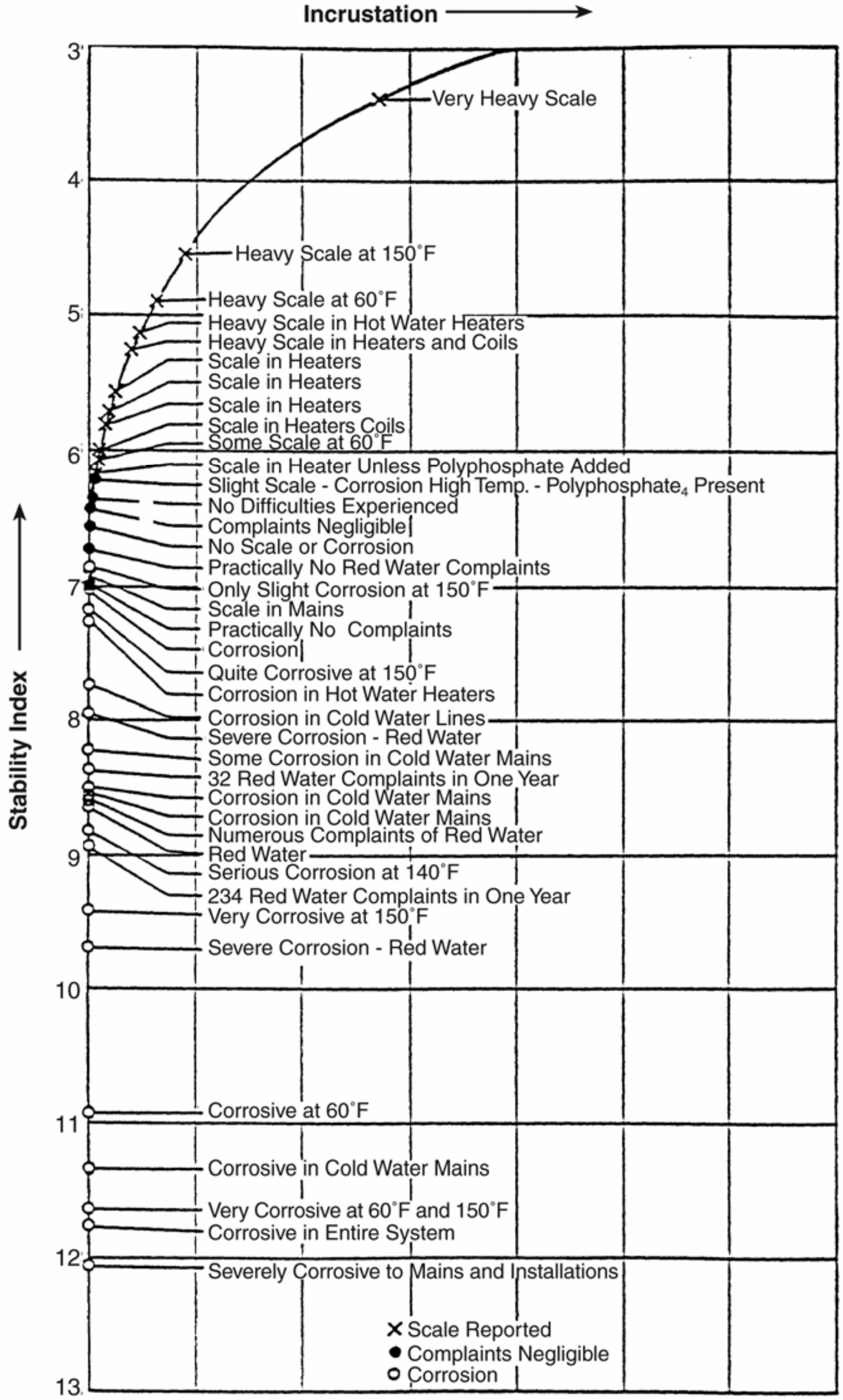


Figure 4-12
Effect of Hardness on Corrosion of Carbon Steel (from [4-7]; Reproduced Courtesy of Ashland, Inc.)

Table 4-1
Effects of Common Parameters on Corrosion of Service Water Piping Materials (Most Commonly, General Corrosion of Carbon Steel)

Parameters for Which an Increase Results in an Increased Corrosion Rate	Parameters for Which an Increase Results in a Decreased Corrosion Rate
Dissolved oxygen	Hardness and alkalinity
Chloride	pH
CO_2 [1]	
Flow[2]	
Temperature[3]	
Sulfide[4]	
High iron and manganese[5]	

Assuming air-saturated conditions and a typical fresh water chemistry for a slightly scaling water, a neutral water, and a scale dissolving water (all with 50 or 100 ppm chloride at 70°F [21°C]), the respective average corrosion rates predicted for carbon steel would be 0.8 mpy, 1.1 mpy, and 1.4 mpy (0.02 mm/y, 0.03 mm/y, and 0.04 mm/y). Using the same basic approach, predicted corrosion rates for brackish water (1000 ppm chloride) and seawater (35,000 ppm as NaCl) were 2.5 mpy and 17 mpy (0.07 mm/y and 0.4 mm/y), respectively.

Tuberculation

Tuberculation, the formation of mounds of corrosion product that are significantly less dense than the metal from which they were produced, is common and should be anticipated for steels in oxygenated environments. Figures 4-13 through 4-15 show three examples of tuberculation. The relatively massive deposits of corrosion products can impinge upon one another to occlude lines, dramatically reducing their flow capabilities (Figure 4-16), and can serve as initiation sites for underdeposit corrosion, including MIC. Corrosion products in general and tubercles in particular can also affect flow by increasing the surface roughness [4-2, 4-3].

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[1] Primarily as a contributor to decreasing pH.

[2] Higher flows typically do not affect corrosion rates of stainless steels; however, periods of stagnation can be very damaging.

[3] Up to about 160°F (71°C).

[4] Effects on copper alloys are even more dramatic.

[5] Especially for localized corrosion of stainless steel and copper alloys.

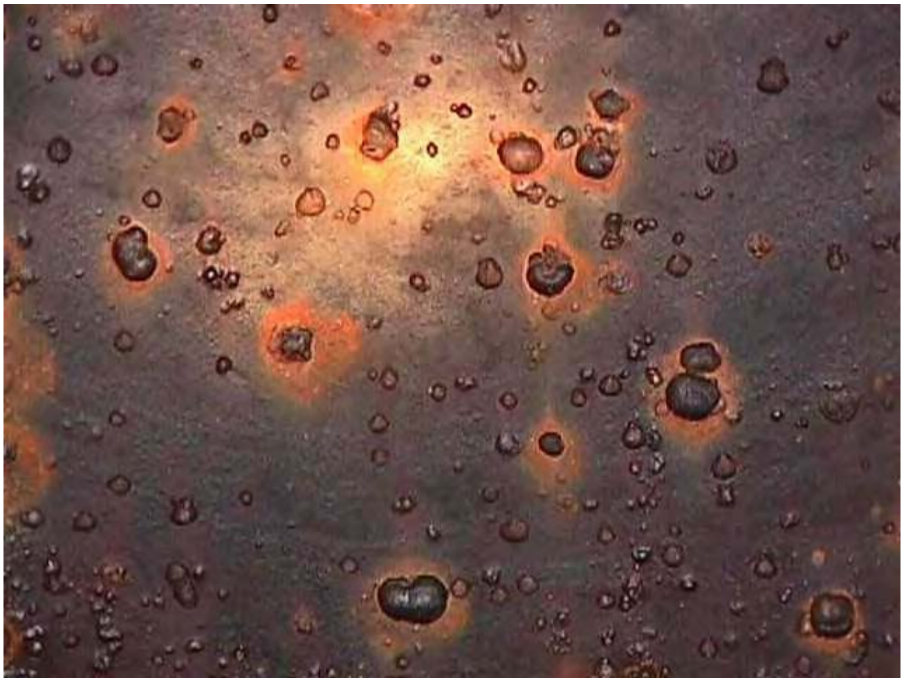

Figure 4-13
An Example of Tuberculation

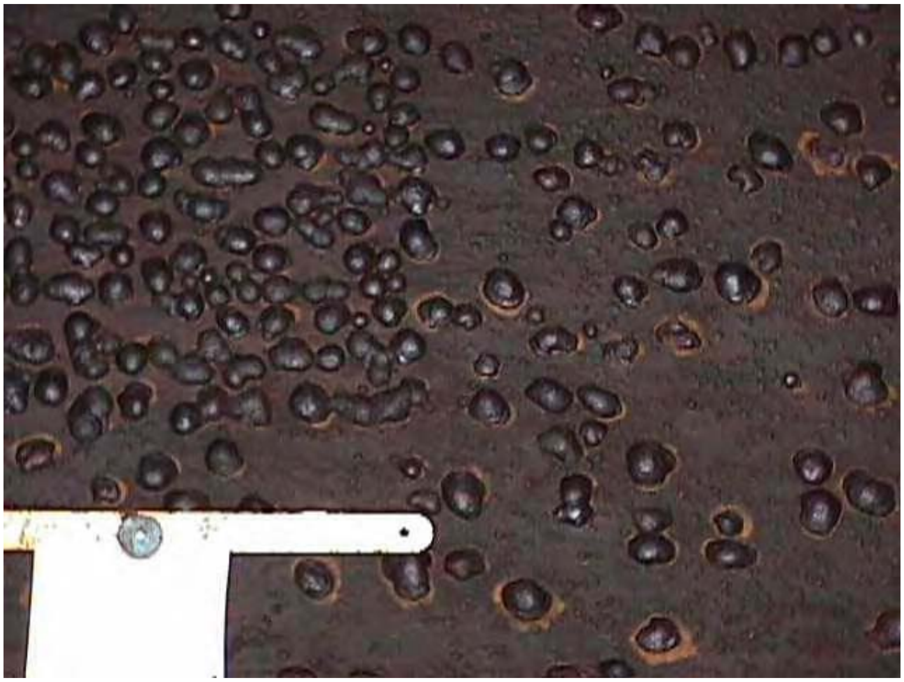

Figure 4-14
A Second Example of Tuberculation

Figure 4-15
A Third Example of Tuberculation

Figure 4-16
Occlusion of Carbon Steel Service Water Pipe with Corrosion Products

Reference 4-3 (from Dr. Peter Angell) and References 4-8 and 4-9 (from Dr. Harvey Herro) provide a detailed discussion of tubercles. The salient points of that discussion are listed below. A drawing of a typical tubercle is included as Figure 4-17.

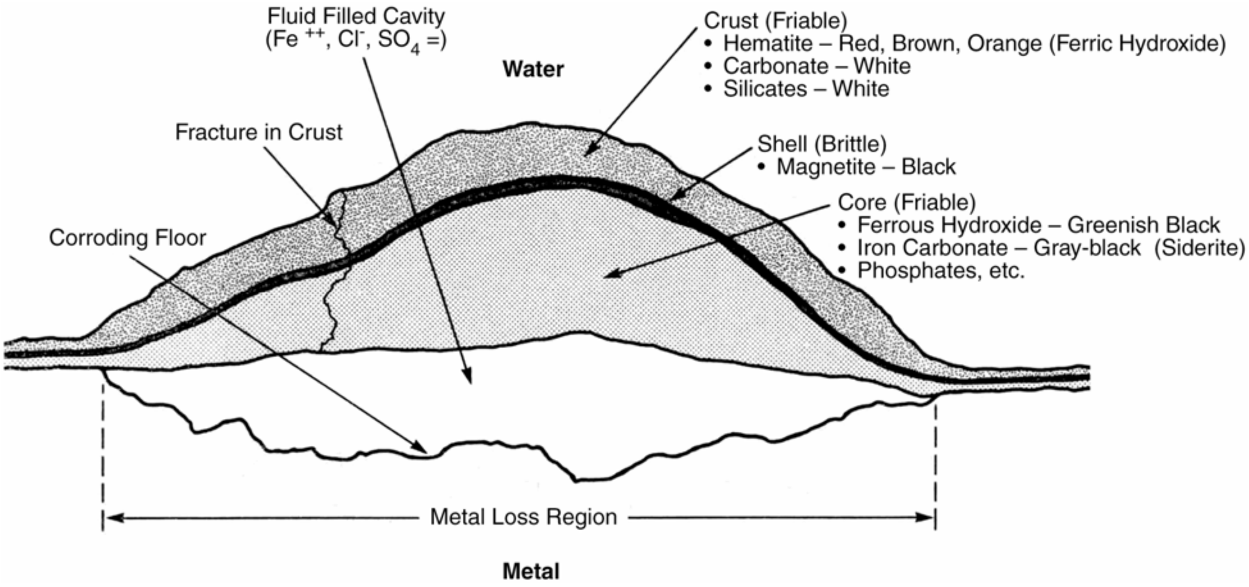

Figure 4-17
Structural Features of a Typical Tubercle (from Herro [4-8])

Tubercles are very common on carbon steel and cast iron exposed to oxygenated water. They are usually found over anodic regions where corrosion has occurred or is occurring. Various oxidation states of the iron are involved. A tubercle will occupy a volume many times greater than the metal that has been corroded. Tubercles are often porous and will contain an inner cavity that is fluid filled. They can grow and plug pipes before perforations can occur. Tubercles have little mechanical strength.

The outer crust of hydrated ferric oxide is formed from the rapid oxidation of ferrous ions to the ferric state. Repeated fracture of the crust produces multiple shells.

Cathodic processes occur immediately adjacent to the shell and immediately beneath the outer crust (a thin, black, magnetite-rich layer). Hydroxyl ion will be present at cathodic areas, increasing local pH and promoting precipitation of carbonate. The insides of a tubercle become deaerated, become enriched in chloride and sulfate, and can form acid, producing alternative cathodic reactions.

According to Herro, the "pH of water in an active tubercle is always acidic, even when water outside the tubercle is alkaline" [4-10 and 4-11], and the cathodic reaction at and outside the inner shell is always reduction of oxygen.

Five common structural features of tubercles [4-17] are the following:

- An outer crust, consisting of carbonate, silicate, phosphate, and other material with normal pH solubility. These materials deposit atop the tubercle, intermixed with ferric hydroxide. Ferrous ions diffuse out of the lower regions within the tubercle and are rapidly oxidized to ferric hydroxide near the crust. Thickness and friability are a function of the chemical composition (however, the outer crust will be mostly rust and precipitated solids). The outer crust will generally comprise less than 20% of the weight of the tubercle. The outer crust will contain fissures and cracks. Nodularity or irregularity is evidence of flow of material from within to build up the nodule. Fast growth implies profuse nodularity. Nodularity increases with age.
- An inner crust, consisting of a brittle black magnetite and goethite shell. Magnetite separates high oxygen regions outside from the very low oxygen concentrations within. The thickness of the magnetite may be loosely correlated with the rate of corrosion. Herro notes that low flow and high chloride promote thin shells; thick shells are promoted by high flow and less aggressive water. Thickness of the inner crust may vary from a fraction of a millimeter to greater than 1 cm.
- Core material is the bulk of the tubercle mass; 90% or more ferrous hydroxide formed during tubercle growth. The core material will oxidize to ferric hydroxide once the tubercle is exposed to air (changing from dark to light brown or reddish orange). The core material will also contain friable, small-particulate oxides and hydroxides and may form a filamentous structure (which has been attributed to iron oxidizing bacteria). Ferrous ion plus hydroxide (from the decomposition of water that occurs at a low rate all the time) causes $Fe(OH)_2$ to precipitate.
- A fluid-filled cavity. The amount of fluid varies with acidity (acidity prevents precipitation of oxides and hydroxides). Ferrous ion plus chloride in this cavity reacts with water to form $Fe(OH)_2$ precipitate and HCl at the top; the HCl reacts with ferrous ion to make the ferrous ion and chloride.
- A corroded floor, which can be deep or essentially nil. The corrosion beneath the tubercle will generally be dish-shaped and shallow. The depth will be less than the tubercle's breadth (see Figures 4-13 and 4-18). Herro notes, "average localized corrosion rates are highly system-dependent, but may approach 100 mpy." Less than 20 mpy is more typical of moderate corrosion. "Corroded areas have rolling, irregular topographies" and may be heavily striated (for example, see Figure 4-18) when acidity is high.

Full immersion and oxygen, as well as prolonged exposure time, are typically required to produce tubercles.

Growth rings often appear early in the life of the tubercle, as shown in Figure 4-18.

Figure 4-18
Corrosion Coupons—As-Received and After Cleaning

Tubercles can become very large. Carbonate in the crust may cause buffering of internal acidity.

A key to the impact of tubercles on corrosion of the underlying metal is related to what goes on beneath the tubercles. Herro notes that "tubercles **may** [emphasis added] house organisms" (both macroorganisms and microorganisms) and that there is evidence for some degree of involvement by sulfate-reducing bacteria (SRB), acid-producing bacteria (less evidence than for SRB), and metal-depositing bacteria.

Tuberculation will be a strong function of the independent influences of flow and dissolved oxygen. Both of those parameters affect the relative level of uniformity, porosity, and so forth of the corrosion product and the level of protection it affords.

Tuberculation is to be expected for carbon steel in oxygenated waters, especially in intermittent flows or in slowly flowing waters (less than 3 fps [0.9 m/s], possibly with flows as high as 7 fps [2 m/s]), in contrast to the more uniform and more protective corrosion product that will form in normally flowing waters.

Localized Corrosion

Pitting, crevice corrosion, and underdeposit corrosion are discussed in detail in [4-6].

Localized corrosion, rather than general corrosion, will occur when anodic sites are fixed by geometric, environmental, or metallurgical conditions. In contrast to general corrosion (where the amount of time that any particular location will be anodic is approximately the same as that for any other location), when anodic sites are fixed, all or most of the dissolution will occur at those locations, supported by cathodic events occurring over other parts of the surface. Since the metal is electrically conductive, electrons "lost" at the anodic sites can be "gained" at cathodic sites that are great distances away. The effect of area on the extent of corrosion is pronounced in localized corrosion events—a small anode supported by reactions on a large cathode produces the greatest corrosion. (In other words, the usually limiting cathodic reaction is no longer limiting because the cathodic area is so large relative to the anode.) All dissolution, or the huge majority of the dissolution, occurs from the localized anodic site, while reduction processes can occur on the remainder of the surface. In a passive metal such as stainless steel, the surfaces that are outside the pit may be (and frequently are) passive (Figure 4-19).

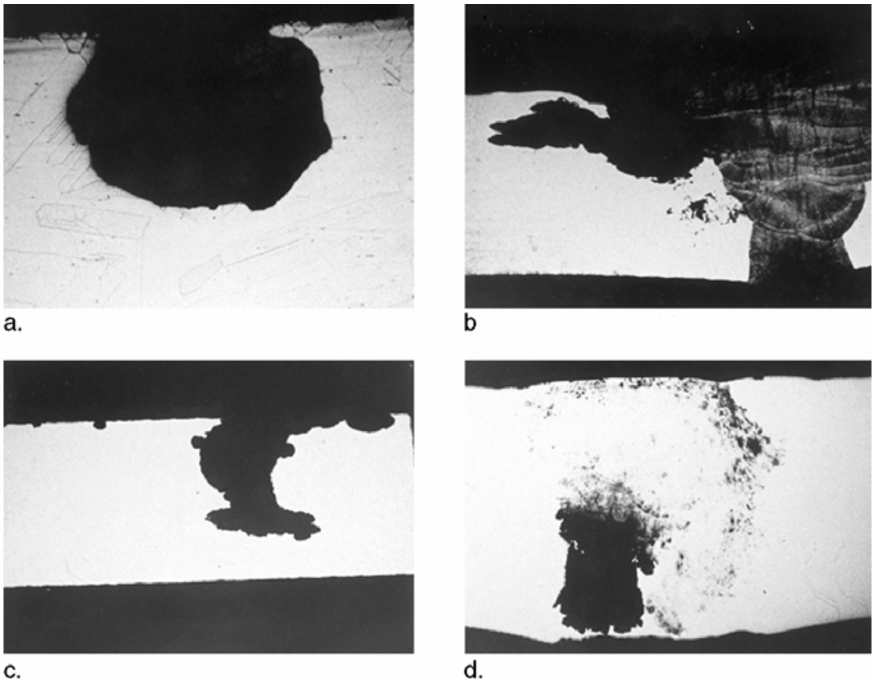

Figure 4-19
Pitting of Stainless Steel (Photos Courtesy of Susan Borenstein)

Figure 4-20 is an example of pitting in a carbon steel line. Such pitting is much less localized than the pitting observed in stainless steel.

Figure 4-20
Pitting of Carbon Steel

Although localized corrosion can produce penetration of the pressure boundary, the failure sites are generally pinhole leaks, they rarely contribute to a loss of system function, and a single pit or most groups of pits will not jeopardize the structural integrity of service water piping because the commonly used piping materials are sufficiently tough to tolerate small flaws, even when such flaws penetrate through-wall.

Pitting, which is localized corrosion on boldly exposed surfaces, often in a passive alloy, requires a breakdown of the passive film, influenced by the material/environment pair.

Once a pit initiates, it can propagate to great depth, including through-wall penetration, in a fairly short time. Propagation is much easier than initiation. Once localized corrosion has initiated, corrosion pits can continue to propagate as long as the environmental conditions are conducive to pit growth. Localized corrosion is dynamic and statistical: pits will initiate; some will grow; some will become inactive. In some cases, surfaces may be pocked with pits that became inactive after only a little propagation. In that situation, a localized corrosion event has become general corrosion. In other cases, pits may grow completely through-wall.

Pit propagation is autocatalytic. For example, the mechanism of pitting of stainless steel in an aqueous environment containing chloride and oxygen is illustrated in Figure 4-21. The half-reactions are the dissolution of metal and the reduction of oxygen, just as in general corrosion. However, as dissolution proceeds, the inside of the pit will contain an excess of positively charged metal ions, and negatively charged ions (anions) in the bulk solution will be attracted to the pit due to their opposite charge. Chloride ions are among the most mobile and aggressive anions. The presence of the chlorides inside the pit accelerates dissolution rates, and the metal chloride solution inside the pit rapidly becomes more concentrated as pitting proceeds. Hydrolysis of the metal chloride solution will occur as represented in Equation 4-3:

$$M^{+} + Cl^{-} + H_2O \rightarrow MOH \downarrow + H^{+} + Cl^{-} \qquad \textbf{Eq. 4-3}$$

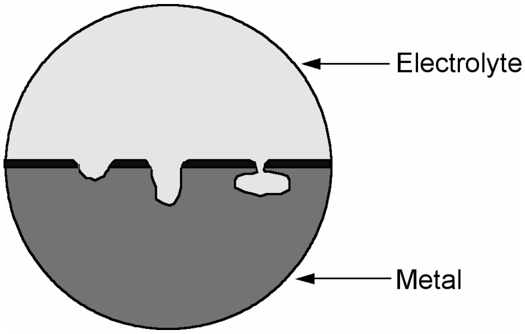

Figure 4-21
Schematic of Pitting

Precipitation of the insoluble metal hydroxide removes hydroxyl ions, producing an excess of hydrogen ions. That process, along with the chloride attracted from the bulk solution as described above, forms hydrochloric acid that further accelerates dissolution inside the pit. Solutions inside pits can be far more concentrated in anions such as chlorides and far more acidic and corrosive than the bulk water.

The preceding discussion is generally applicable to all metals. It applies very specifically to steels and stainless steels, as well as to copper and copper alloys. The interaction of copper alloys with chlorides, copper ions, and sulfides modifies the exact sequence of pit propagation, as those anions will have very specific effects on the formation and reformation of protective corrosion product films on the copper alloy.

Pits can vary from open, broad, and shallow pits (Figures 4-20, 4-22, and 4-23) to very high aspect ratio pits (Figure 4-24) to closed pits (Figure 4-25). Copper alloys in sulfate and chloride environments, or steels in sulfide solutions, will often produce the open pits of low aspect ratio shown in Figures 4-22 and 4-23. Steels in oxygenated waters, with or without chlorides, may exhibit small, deep pits. Closed pits (Figures 4-25 and 4-26) are often observed for stainless steel in oxidizing chloride solutions such as oxygenated seawater or in the presence of oxidizing species such as ferric or manganic chlorides or permanganate ion [4-12]. Such pits are also often observed when microbiologically influenced corrosion is responsible for the pitting of stainless steel [4-13]. Closed or undercutting pits can be very difficult to detect by visual inspection since the entrance and exit openings are very small. If such pits are aligned (for example, at circumferential welds), they can jeopardize the structural integrity of piping or other components.

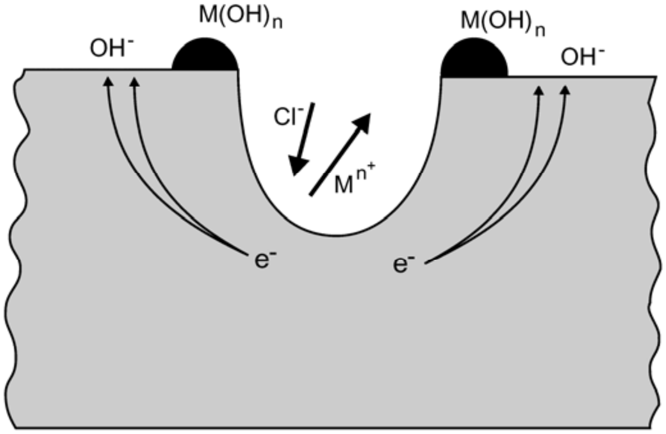

Figure 4-22
An Open Pit

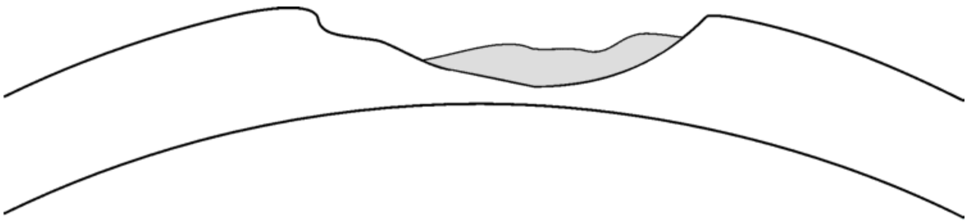

Figure 4-23
A Different View of an Open Pit

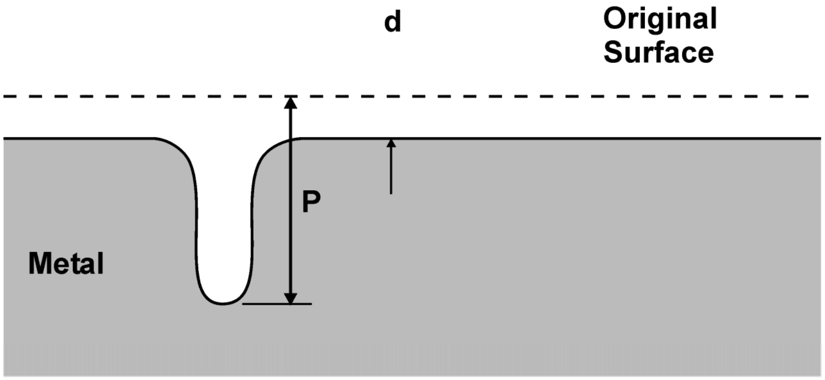

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Figure 4-24
A High-Aspect-Ratio Pit

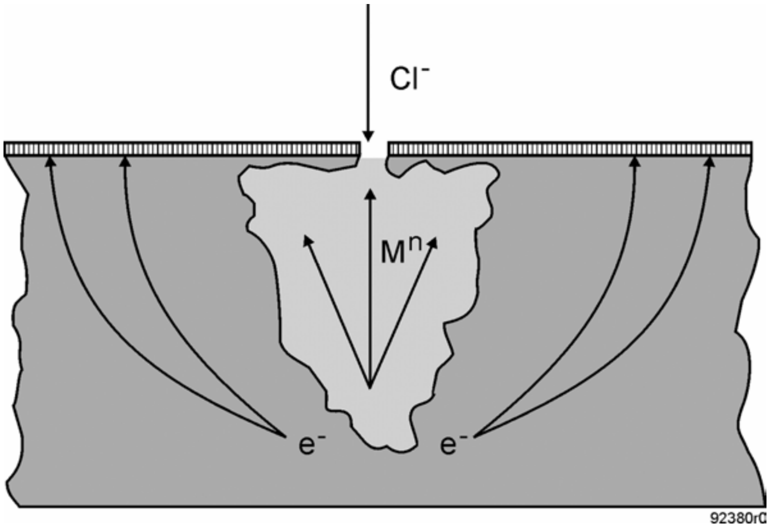


Figure 4-25
A Closed Pit

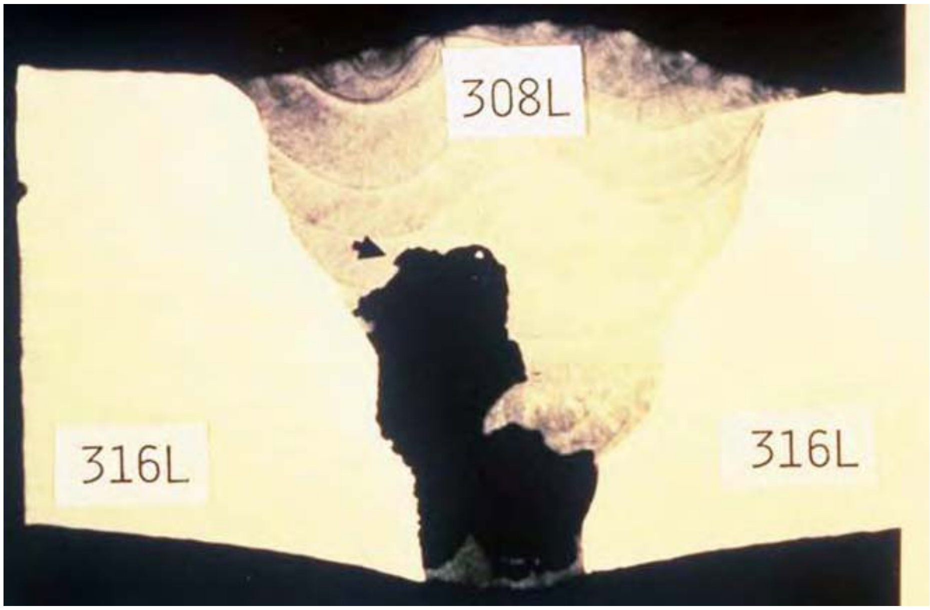
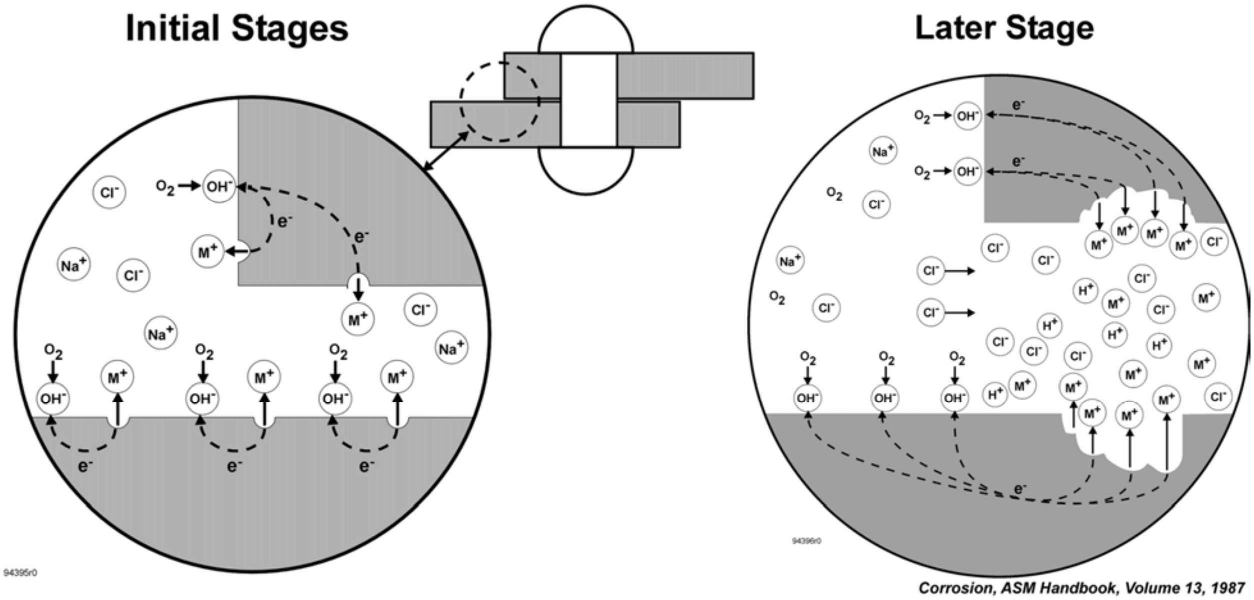


Figure 4-26
A Closed Pit (Stainless Steel Weldment)

Other oxidizing chemicals such as hypochlorite, which is often used as a biocide, can have similar effects on pitting. Species like hypochlorite can cause precipitation of ferrous or cuprous species by oxidizing particulate iron or copper or ferrous or cuprous ions producing the same situations as noted above. Further, reduction of hypochlorite ion can also serve as an alternative cathodic half-reaction to oxygen reduction.

Pit propagation usually takes place in the direction of gravity. That is, inner diameter pitting on pipes will most often be at the bottom of the pipes. Pits on the outer diameter of buried pipe will most often be at the top. The gravity effect results from the concentration effect described above. The heavier, more concentrated solution will tend to fall toward the bottom of pits (and will drip out of pits that might initiate on the top of the ID of piping). Aqueous solutions, concentrated or not, will fall out of OD pits in orientations other than those near the top of pipes.

Crevice corrosion, which is localized corrosion caused by a geometric discontinuity, produces a concentration cell that establishes and maintains local anodic areas by keeping the solution inside the crevice stagnant, thus impeding the movement of cations into and anions out of the crevice, as shown in Figure 4-27. Metal dissolution will occur both inside and outside of the crevice. Initially, the inside and outside of the crevice will behave identically. For cathodic half-reactions such as oxygen reduction, however, the limited communication between the metal surface and environment inside and outside of the crevice prevents cathodic processes from occurring inside the crevice as oxygen is quickly consumed. Corrosion inside and outside of the crevice will continue, much as it did prior to oxygen depletion inside the crevice; however, an excess of positively charged metal ions inside the crevice will attract mobile anions into the crevice. When aggressive anions such as chlorides migrate into the crevice, the anodic half-reaction inside the crevice will be accelerated. The solution inside the crevice may also become highly acidic as an insoluble metal hydroxide precipitates from the aqueous solution of metal chloride, as shown in Equation 4-3.



Corrosion, ASM Handbook, Volume 13, 1987

Figure 4-27
Crevice Corrosion (Reproduced Courtesy of ASM International)

Again, the corrosive effect will be aggravated because a small anodic area will be supported by a large cathodic area.

Oxygen concentration cells as described above and illustrated in Figure 4-28 are probably the most common type of concentration cell. They may be created by designed-in or built-in crevices, or may result from deposition of silt, precipitation of minerals, or biomass. Pits may initiate within the crevice (commonly the case for oxygen concentration cells in stainless steel and nickel-base alloys) or just outside the interface between the crevice and the remainder of the surface (typically the case for metal ion concentration cells as experienced with copper alloys).

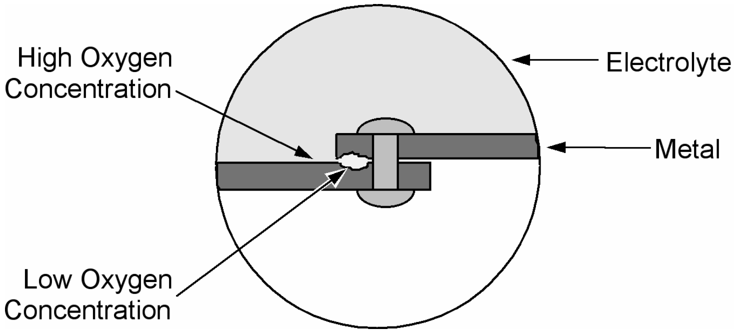


Figure 4-28
Schematic of Oxygen Concentration Cell at a Crevice

Crevices may result from improper design and construction or from operation. Crevices may be formed by other metallic members (as shown in Figure 4-29), at weld defects or tube-to-tubesheet joints, by nonmetallics (gaskets or nonmetallic bearing materials), by imperfections in films (cracked mill scale), or under deposits (silt, scale, biofilms). The dimensions of the crevice will influence the communication between the inside and outside of the crevice, hence the potential severity of the creviced environment. In general, tight, deep crevices produce more severe conditions than more open crevices. Many gasket materials act as a wick, transporting the environment to the surface and providing almost perfectly stagnant conditions at the metal surface.

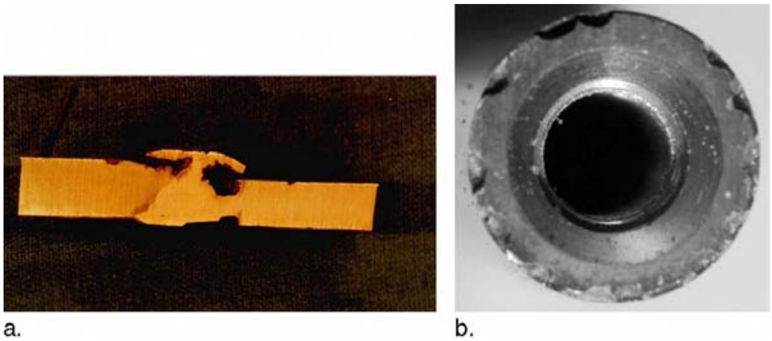


Figure 4-29
Crevice Corrosion Examples: (a) Under Backing Ring (Carbon Steel); (b) Stainless Steel Test Specimen

Initially, the corrosion potential and corrosion current will be determined by the intersection of the anodic half-reaction ($M \rightarrow M^+ + e^-$) and the cathodic half-reaction ($H_2O + \frac{1}{2} O_2 + 2e^- \rightarrow 2OH^-$), which are occurring over the same areas. However, once the oxygen inside the crevice is depleted, oxygen reduction can no longer occur there, but it can continue over the rest of the surface, which is usually much larger than the oxygen depleted area inside the crevice. The anodic process must occur over the small, creviced area at a rate that is balanced by reduction on a large cathode.

Underdeposit corrosion, in which the crevice results from deposits that form on the component surfaces as a result of corrosion product transport, silt, or microbiological influences, can form concentration cells just as readily. The service water systems of nuclear plants provide a number of conditions under which deposition and underdeposit corrosion may be expected: high-solids waters, long periods of stagnation or low flow that permit particulates to settle out, oxygenated environments (most service waters will be saturated with oxygen), and, often, the presence of oxidizing biocides such as hypochlorite.

As noted above, localized corrosion beneath deposits, biological or not, can proceed rapidly in oxygenated waters. If deposits produce a crevice that effectively isolates the underlying material from the bulk environment so that the area beneath the deposit becomes a fixed anodic site, the corrosion will be localized to the underdeposit location as the reduction of oxygen occurs all around it. Further, the continued dissolution of iron to the ferrous ion inside the crevice will produce a net positive charge inside the crevice. Negatively charged ions such as chlorides will be attracted to those areas, making the environment inside the crevice even more aggressive. Such “differential aeration” cells are common sites for localized failures in carbon steels and other structural alloys. A major difference between this type of underdeposit corrosion and MIC is that MIC can proceed much more rapidly because the metabolic activity of the microbes can produce a far greater enrichment in aggressive species such as chlorides, and the microbes can produce alternative reactions that cause the corrosion to proceed when nonbiological mechanisms would stall out—for example, in low-oxygen environments.

In cooling waters, where the reduction of oxygen provides the primary cathodic reaction, pitting under deposits will be a strong function of the dissolved oxygen content of the water because the electrochemical potential difference between the area under the deposit (where most or all of the dissolution is taking place) and the surfaces not covered by a deposit (where the reduction of oxygen occurs) will dictate the rate of dissolution under the crevice. In other words, if the oxidizing power of the bulk solution is increased, for example by the addition of an oxidizing biocide such as chlorine, the driving force for the underdeposit corrosion will increase dramatically.

Flow is often a key factor in determining whether localized corrosion will occur at a geometric crevice area. As noted above, the transport or communication of reductive species between the volume inside the crevice and the bulk fluid will dictate whether the areas inside the crevice will be sufficiently different from the area outside that cathodic events cannot occur inside the crevice, hence “fixing” the creviced location as an anodic site. For a given crevice size (opening and length), at high flows, mixing will occur between the areas inside and outside the crevice, while at lower flows, the local environments will communicate much less and the area inside the crevice is much more likely to become an occluded cell and the site of only dissolution.

For crevices that are produced by deposits, rather than by design or fabrication, the flow conditions will determine the transport rate of the crevice-forming material. The flow conditions will also dictate where deposits will form and how effectively the deposits will stick together to form crevices. Flow conditions also influence the transport of materials in and out of the crevice. The silt loading of the water and the general corrosion rate of pipe work upstream will also be important factors, as they impact the amount of deposit-forming material.

Localized corrosion often takes a long time to initiate, because the effects described above accumulate fairly slowly. Further, the development of more aggressive conditions inside the occluded cell also occurs over time. Once the necessary conditions have been established, however, localized corrosion rates are often high, reaching 100 mpy or more in extreme cases. The time to perforation, once the localized corrosion has initiated, can be very short.

MIC

Microbiologically influenced corrosion (MIC) involves the interaction between the metabolic processes of microorganisms and corrosion processes. MIC has been the subject of considerable research and scrutiny. Numerous reference volumes exist [4-13 through 4-19]. Figure 4-30 depicts MIC in stainless steel weld metal.

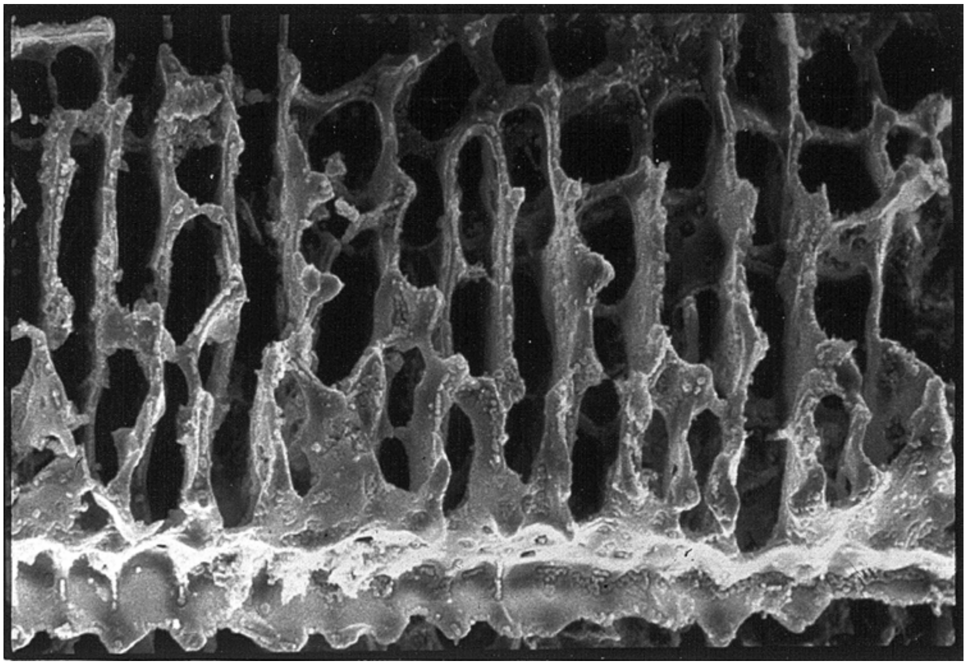


Figure 4-30
MIC in Stainless Steel Weld Metal

Microbes can excrete substances that accelerate corrosion (for example, sulfides, organic and mineral acids, and ammonia); they can fix the electrochemical potential of metals at levels that produce accelerated corrosion; they can actively participate in anodic and cathodic processes and effectively eliminate slow steps in the dissolution process that would tend to slow the corrosion down; or they can simply glue together silt, sand, scale, and corrosion products to make a "better crevice" that produces more occlusion of the local anodic site and a more damaging underdeposit environment.

Microbes are essentially everywhere, they are very small (on the order of 1 to 2 μm), they are mobile (at least on a scale comparable to their size), and they can tolerate a wide variety of conditions; however, they will typically flourish only within relatively narrow ranges of pH, temperature, and oxygen. Microbes will rapidly attach to surfaces and can develop consortia (interdependent groups) very quickly. Very specific microenvironments will be created within the biofilm such that the film can contain strict aerobes in a layer that is aerobic, while containing strict anaerobes where the oxygen concentration is essentially nil, often at the metal surface.

A major factor regulating microbiological growth and the influences that the microbes may have on the corrosion has to do with the level of aeration in the environment and the aeration history that the environment has experienced. Many of the microorganisms important to corrosion are strictly anaerobic (that is, they cannot flourish in environments where there is oxygen), others are strictly aerobic (that is, they only flourish in the presence of oxygen), and many others can both tolerate and grow over a wide variety of levels of oxygen. For example, long periods of stagnation can lead to anaerobic conditions, to the formation of a vigorous, anaerobic biofilm, and often, to the production of sulfides by sulfate-reducing bacteria (SRB). Without the biofilm, corrosion rates during the stagnation periods would be very low, because the kinetics of the cathodic reaction would be very slow. The presence of the SRB and sulfides provides an alternative to the reduction of oxygen that typically produces corrosion of carbon steels in cooling waters. Further, the production of sulfides serves to make the anaerobic environment more aggressive. The sulfides also produce a nonprotective iron sulfide film (in contrast to the much more protective iron oxide film that normally forms). When such a surface is then exposed to rapidly flowing, oxygenated water, the poorly protective film and some base metal will be removed. This leads to short periods of very rapid corrosion during periods of flow that follow long periods of stagnation. Hardy and Brown have described this phenomenon in detail [4-20]. The key element in the rapid corrosion is the dissolution of the nonprotective iron sulfide in an oxygenated environment.

The initial deposition of microbes will most often be at rates comparable to those for the deposition of silt. Both will be controlled by delivery of the foreign material to the system; settling will then be controlled by Brownian motion. A major difference between microbes and silt is that a single microbe can produce rapid colonization of metallic surfaces, limited only by the supply of nutrients and other factors required for growth. As shown in Figure 4-31, microbes from the bulk fluid will settle onto metal surfaces, often very rapidly, first forming an aerobic biofilm, and then, as those organisms utilize the available oxygen, an anaerobic layer will be formed and an anaerobic biofilm can form on the metal surface. As the biofilm grows, the differentiation between the aerobic and anaerobic layer becomes more pronounced as a consortium of bacteria forms (see the middle panel of Figure 4-31). This coexistence of the aerobes and anaerobes is vital to the survival of the anaerobes. Eventually, a thick and nearly impervious biofilm, which may also include entrapped silt, debris, or corrosion products, will form (see the far right panel of Figure 4-31). At this stage, biocidal treatments are nearly useless, because the outer layers of the biofilm and entrapped materials effectively shield the organisms below. Electrochemical differences between different portions of the biofilm may be sufficient to establish stand-alone anodic and cathodic areas and to fix the location of the sites producing localized corrosion. Note that for a patchy film, which is the most common type, electrochemical differences between areas under the film and areas that are in direct contact with the environment will be strongly influenced by effects that increase the oxidizing power of the solution, because the areas under the film will be relatively smaller and hence the area that is dissolving (that is, losing electrons) is being balanced by a more powerful and much larger area where those electrons can be gained.

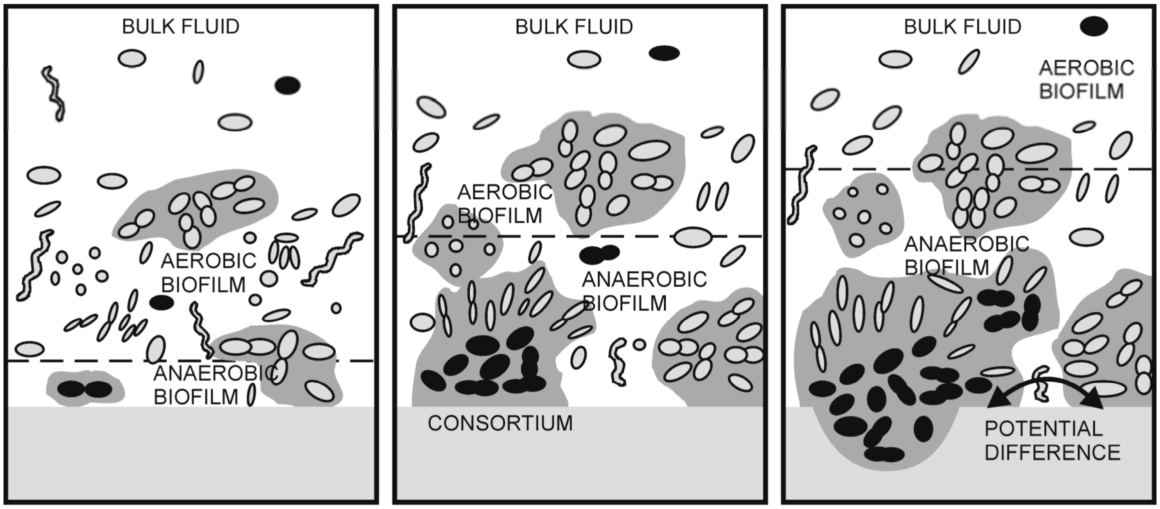
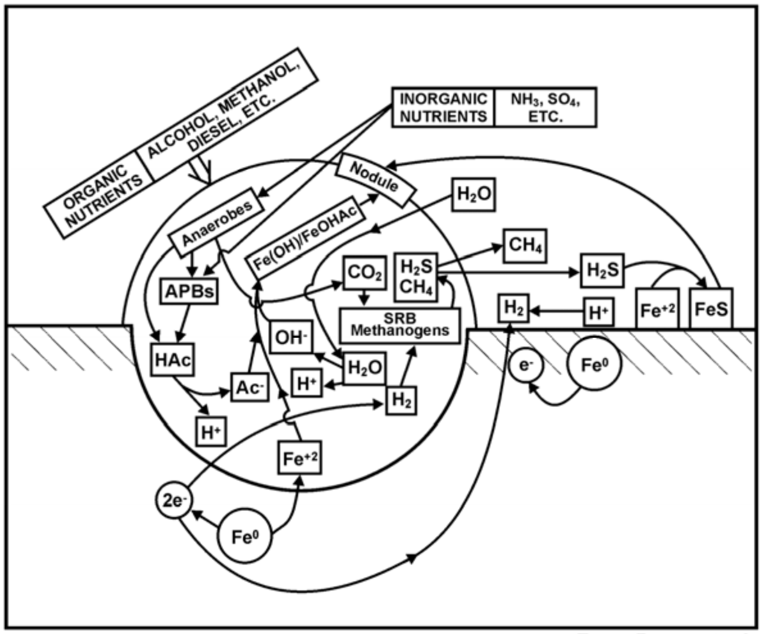


Figure 4-31
Progression of Biofilm Activity (from Costerton and Geesey [4-21]; Reproduced Courtesy of NACE International)

Two different models for MIC of carbon steels are illustrated in Figures 4-32 and 4-33. The critical point demonstrated by both of those models is that the interactions among the various microorganisms are critical to the viability of the biofilm and its influence on corrosion reactions. Those models also provide an excellent illustration of why MIC tends to produce localized attack.



From Pope, et. al, EPRI ER-6345

Figure 4-32
The Interdependencies Required for Microbes to Produce MIC (from Pope [4-15])

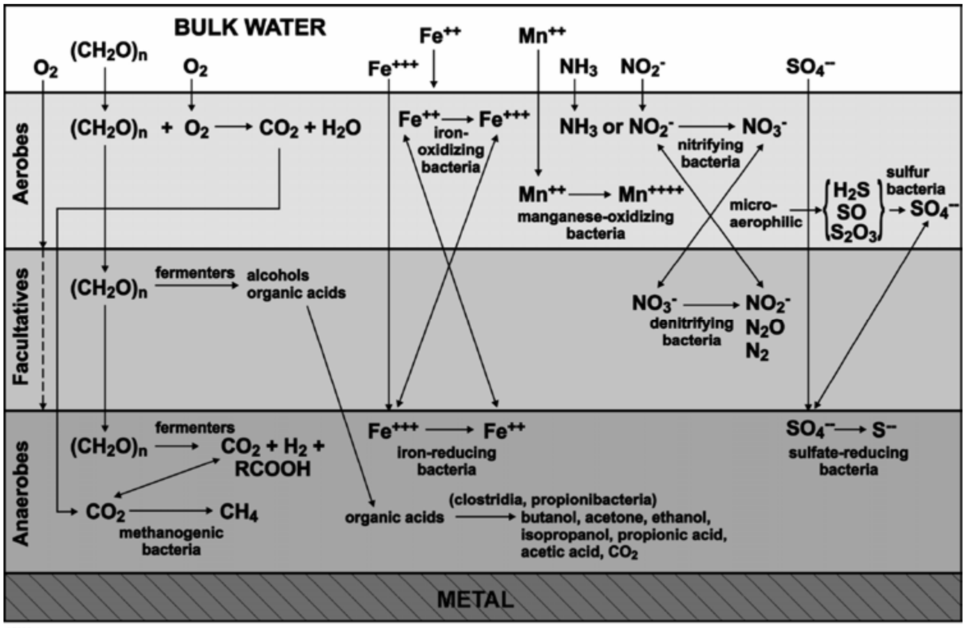


Figure 4-33
The Interdependencies of Microbes to Produce MIC (from Little [4-22])

Pope has shown that acid-producing bacteria, especially in consortia with SRB and slime formers, can produce rapid attack of carbon steels by the production of organic acids [4-23]. Highly acidic conditions can be formed in environments such as the insides of gas pipelines (typically anaerobic) or in cooling waters (aerobic or anaerobic). The resulting attack in the carbon steel is often highly localized, with pit propagation at rates up to 100 mpy (2.54 mm/y).

Microbial settlement will occur most readily under conditions of low flow or stagnation, where shear stresses in the fluid at the metal surface are low. Clean surfaces exposed to higher flows are relatively easy to keep clean. As fluid velocity decreases, microorganisms can settle onto surfaces. Their ability to adhere to the surface will be determined by the shear stresses between the fluid and the film. As the fluid velocity increases, the biofilm cannot sustain its bond to the surface, and it will slough off. However, once a mature biofilm is formed, increases in the fluid flow, and even chemical treatment, may not be able to penetrate the film sufficiently to dislodge it. Many microorganisms can also produce copious amounts of slime that help to preserve them and their neighbors under temporary adverse conditions. This slime can also foul heat exchangers and pipe work so that efficiency is compromised. Sufficiently high flow rates and shear stresses can prevent biofilm from forming, however once a biofilm becomes established, shear forces between the fluid and the biofilm are unlikely to dislodge the biofilm.

Under more or less steady, low-flow conditions, the environment has a continuous supply of both microbes and nutrients, hence microbial growth for both aerobic and anaerobic organisms will be optimum. No precise agreement exists regarding a “critical velocity” above which MIC will not occur; however, fluid velocities of 2 to 3 fps (0.6 to 0.9 m/s) have been shown to be sufficiently rapid to continuously replenish biofilms with nutrients, oxygen, and so forth, but sufficiently slow that biofilm is not stripped from the metal surface [4-14]. For extended periods of stagnation, the corrosion reactions and biological processes can change the bulk environment from the typical aerobic environment that supports fish and other higher life forms to an essentially anaerobic environment that favors the activity of the anaerobes on the metal surface. It also eliminates any contribution to corrosion from aerobic bacteria or from the reduction of oxygen.

Dead legs in communication with active legs often represent an environment that is much more conducive to MIC than the environment found in a truly stagnant leg. The frequency at which stagnant legs experience flow (for example, monthly vs. quarterly vs. annually) also has a significant impact on the propensity toward MIC. Failure statistics for many power plants suggest that systems that flow only once every 30 to 90 days are more susceptible to failures from MIC and other localized corrosion phenomena than systems that flow relatively frequently [4-14, 4-20, 4-24]. Dead legs are discussed more thoroughly later in this section.

The diverse and redundant design philosophy that is a design basis for nuclear plants is clearly a contributor to service water system problems with corrosion, fouling, and performance degradation. Since redundant loops sit idle for extended periods, the potential for deposition of organic and inorganic materials is significant. Further, since heat removal capabilities for those service water systems are based upon a loss of coolant accident, the piping and heat exchanger are oversized, often dramatically oversized, for their normal heat loads. As a result, flows under normal conditions, especially during colder weather, will be very low, leading to additional MIC and deposition. Key lessons that can be taken from nuclear service water system experience are that regular flow (for example, weekly or semiweekly flow) at appropriate rates (for example, a minimum of 5 feet per second [1.5 m/s]) and attention to system cleanliness are keys to avoiding piping or heat exchanger replacement.

It must also be noted that once a mature biofilm has formed and pitting initiates, the presence of an active biofilm may not be required for propagation of pitting. Although an active biofilm may accelerate corrosion, localized corrosion can proceed very rapidly under a dead or inactive biofilm. The only times that an active biofilm are required for corrosion to continue are times when the biofilm actively participates in the corrosion process (for example, under anaerobic conditions, as for SRB) or when a biologically produced chemical species (for example, an organic or mineral acid) provides the aggressive environment. These are the only conditions where killing or inactivating the biofilm will effectively control an established corrosion cell.

Galvanic Corrosion

Galvanic corrosion is defined as corrosion associated with the current resulting from the electrical coupling of dissimilar electrodes (which may include conductive nonmetals such as graphite) in an electrolyte. For a given environment, metals can be listed in order of their reactivity or tendency to oxidize in what is called a galvanic series. For instance, the galvanic series for selected alloys in flowing seawater is shown in Table 4-2.

Table 4-2
The Galvanic Series for Selected Alloys in Seawater Flowing at 8 to 13 ft/sec (2.4 to 4.0 m/sec) for 5 to 15 Days at 5 to 30°C (41 to 86°F) [4-25]

Most Active (Most Negative Potential)
Magnesium
Zinc
Aluminum alloys
Cadmium
Iron or mild steel
Low-alloy steel
Type 430 stainless steel (active)
Type 304 stainless steel (active)
Type 316 stainless steel (active)
Lead
Muntz metal
Naval brass
Admiralty brass
Aluminum bronze
Copper
90/10 copper-nickel
Type 430 stainless steel (passive)
70/30 copper-nickel
Monel Alloy 400
Type 304 stainless steel (passive)
Type 316 stainless steel (passive)
Alloy 20 stainless steel
Titanium
Graphite
Most Noble (Most Positive Potential)

If any two metals in the series are in electrical contact, the anodic reaction will be stimulated on the material appearing “higher” in the series as shown in Table 4-2 (that is, on the more active metal) and galvanic corrosion will occur. In a galvanic couple, the more active metal acts as the anode, while the more noble metal is the cathode. As a result, dissolution on the anode is accelerated by the galvanic coupling, while dissolution of the more noble member is reduced or eliminated. Galvanic corrosion is generally characterized by accelerated attack at and near the point of contact of the two members. A greater difference in potential between the two materials usually results in a more rapid attack.

Figures 4-34 and 4-35 are power plant examples. Figure 4-34 shows a seawater-cooled condenser, where galvanic corrosion of a Muntz metal or aluminum bronze tubesheet was stimulated when more noble AL-6X austenitic stainless steel tubes were installed. Figure 4-35 illustrates the preferential dissolution of carbon steel in a carbon steel/stainless steel couple in a nuclear plant’s service water piping (river water). On the other hand, the cathodic reaction will be stimulated on the material appearing lower in the series (that is, on the more noble material) resulting in partial or complete protection from corrosion. For instance, if a copper alloy and zinc are in electrical contact in seawater, the more active metal—zinc—corrodes much more quickly, and the more noble metal—copper—corrodes less rapidly than it would in isolation. This reduction in the corrosion rate of copper also provides an illustration of the principle of cathodic protection by a sacrificial anode (by zinc, in this example). Thus, galvanic corrosion of one material in a couple results in cathodic protection of the other.

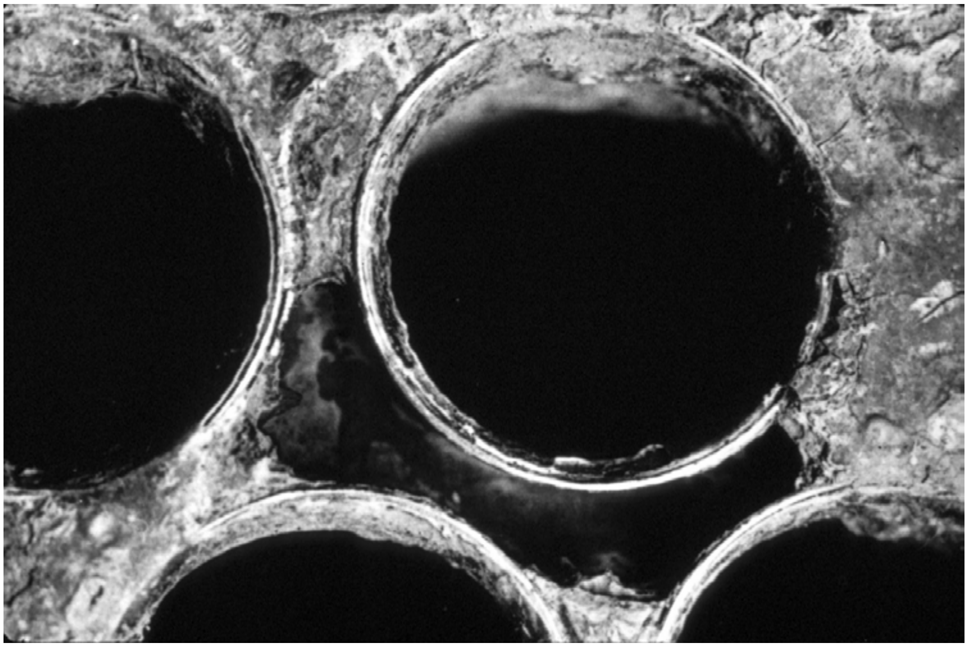


Figure 4-34
Galvanic Attack at Tube/Tubesheet Interface of a Condenser: AL-6X® Stainless Steel Tubes/Muntz Metal Tubesheet in Seawater Service (Photo Courtesy of Corrpro Companies, Inc.)

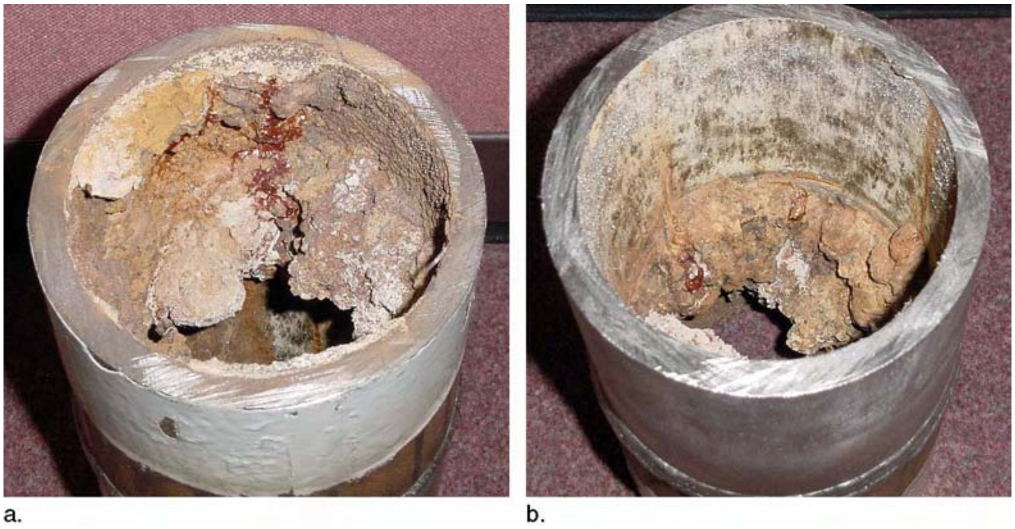


Figure 4-35
Galvanic Attack and Corrosion Product Buildup at Carbon Steel/Stainless Steel: (a) View from Carbon Steel Side; (b) View from Stainless Steel Side (Photos Courtesy of Dean Carstens)

As with any corrosion process, maintaining charge neutrality requires that the total current flowing from the more active member of the galvanic couple (the anode) must equal the total current flowing into the nobler member (the cathode) even if the surface areas of the two metals are not equal. Because corrosion rate is proportional to current **density**, the smaller the anode-to-cathode area ratio is, the greater the galvanic corrosion rate is.

The ratio of the surface area of the more active member to that of the more noble member in a galvanic couple can have a powerful influence (often the most powerful influence) on the degree of corrosion. A relatively large active member coupled to a smaller noble member will experience minimal galvanic attack. In this case, the total anodic current will be limited by the rate at which electrons can be accepted (that is, the cathodic current) on the cathodic area. As a result, cathodic half-reactions are nearly as likely to occur on the more active metal, rather than being constrained to the more noble metal. Thus, when the ratio of the area of the active metal member to the area of the noble metal member is large, the dissimilar materials will act independently in terms of corrosion.

The opposite situation—a small active member galvanically coupled to a large noble member—produces the worst possible area effect (Figure 4-36). In this case, the electrons lost (anodic current) from the small active metal area can be readily accepted and accommodated by reduction reactions occurring over the large cathodic area. The rate of reduction per unit area in this case is no longer limiting, because the total reduction rate (that is, the reduction per unit area times the cathodic area) will overpower even a slow reduction rate because of the much larger relative area of the cathode. When anodic and cathodic areas are roughly the same, or the area of more active member is much larger than that of the more noble member, galvanic attack is likely to occur; however, the specific limiting or accelerating factors noted above will not be operative.

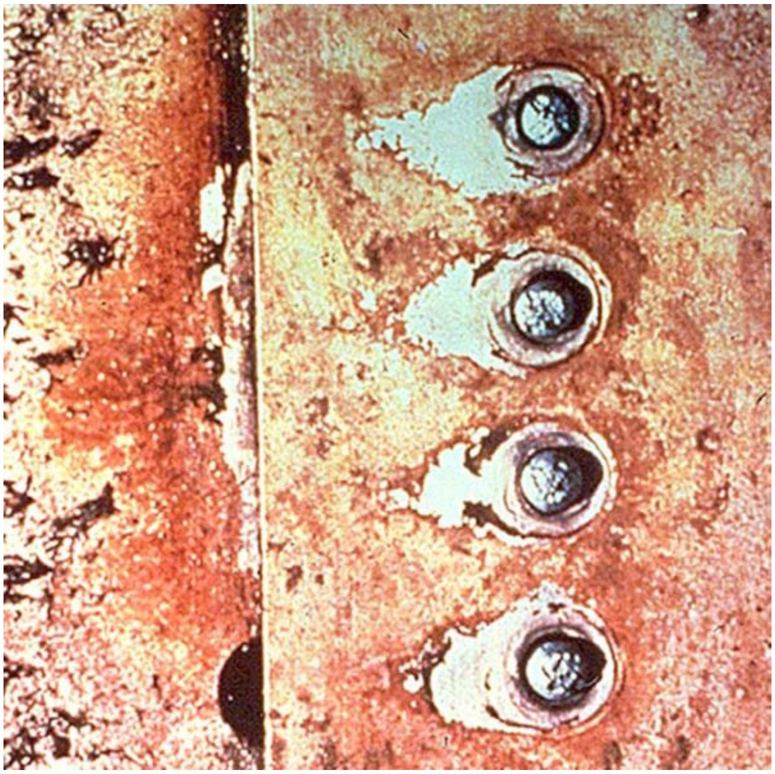


Figure 4-36
Galvanic Corrosion—Worst-Case Area Effect (Small Iron Rivets in Large Copper Plate)

Weld area corrosion is a special form of galvanic corrosion that may occur in welded structures. Compositional and metallurgical differences existing between the weld metal, heat-affected zone, and parent metal can lead to galvanic attack and preferential corrosion of one or more of these three zones.

The distance over which galvanic attack will occur is a strong function of the conductivity of the environment. In very aggressive, high-conductivity environments, corrosion on both members will generally be more severe. When an active and relatively noble metal are coupled, the extent of any accelerated attack on the more active metal will, naturally, be at the interface. However, the galvanic effect will also span greater distances, as the greater mobility of ions in the higher-conductivity environment increases the distance over which the electrical circuit will be operative (see the upper part of Figure 4-37).

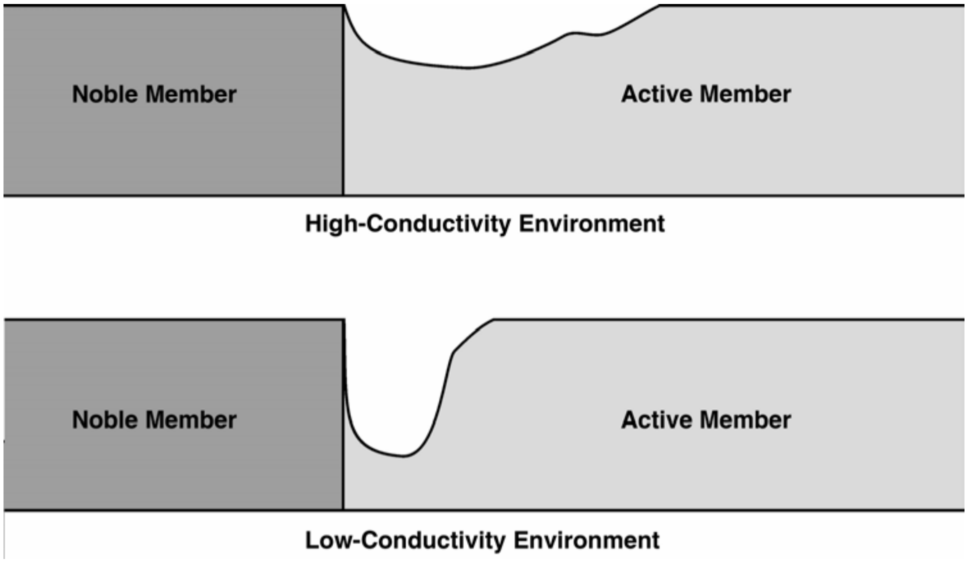


Figure 4-37
Effect of Conductivity of Solutions on Galvanic Corrosion

In low-conductivity solutions, galvanic effects will be most pronounced at the interface; however, the distance over which the effect of the coupling will be experienced will be far less (see the lower part of Figure 4-37). Galvanic corrosion in lower-conductivity environments can present a more serious concern than galvanic corrosion in higher-conductivity solutions. In the high-conductivity environment, galvanic corrosion is spread out over a greater area, thus approximating a general corrosion condition. The same galvanic couple in a lower-conductivity environment may produce a significantly greater proportion of the attack on the active member, to the point of producing a localized corrosion situation. When dissimilar metals separated by a large potential difference in a galvanic series must be used, the design can take advantage of the shorter distance over which the galvanic effects are operative in lower-conductivity environments. A section of a third material, intermediate in the galvanic series between the two metals of concern, can be installed between the two dissimilar metals. This practice produces two different galvanic couples. However, the severity of the attack at each interface will generally be less than if the intermediate material were not used.

“Isolation kits” are often used for flanged connections where dissimilar metals are used. Electrical isolation of the two materials eliminates the electron path so that preferential corrosion of the more active metal is avoided. Proper installation must be confirmed for all metallic surfaces (including flange faces and all connectors) to avoid any electrical continuity between the components to be isolated from each other.

Carbon steel and copper alloy galvanic couples may be expected in service water piping systems and other raw water systems such as fire protection systems. The most common carbon steel/copper alloy galvanic couples will be at pipe-to-valve connections, although pipe-to-pipe, pipe-to-fitting (for example, brass or bronze sprinkler heads), and flanged connections (including flange-to-bolt couples exposed to atmospheric conditions or leakage past gaskets) are also likely.

Some galvanic attack on the steel may be expected at such joints, with the most severe attack expected in more aggressive waters. High-conductivity fresh waters or very soft or highly acidic waters would be included in this definition of aggressive environments.

Both carbon steel and stainless steel are used for piping and vessels in service water systems. In saline waters (including seawater), virtually all of the carbon steel used will be coated or lined. Where coating holidays exist or where the environment can penetrate or slip past the lining (that is, in virtually all systems), the uncoated carbon steel will be coupled to stainless steel. That "coupling" may occur over a long distance, depending upon the location of the coating or lining failure. As a result of this coupling to stainless steel, the carbon steel components will be subject to galvanic attack. As in most cases of galvanic attack, the extent of corrosion will be greater in more aggressive environments.

In freshwater-cooled systems, a number of essential components and service water system piping with a critical or definite safety function will often be fabricated from stainless steel. Heat exchanger shells, tubesheets, and other less critical parts of the system will usually be fabricated from carbon steel. In these systems, dissimilar metal welds between stainless steel and carbon steel, flanged connections, and stainless steel tubes and tubesheets and carbon steel heat exchanger vessel contact areas will be subject to galvanic corrosion. Numerous specialty pipe fittings such as thermowells and instrument connections are only fabricated from stainless steel. Piping components can be susceptible to galvanic attack at connections between these fittings and the piping. Fortunately, the area ratio (large anode/small cathode) is favorable, which may help prevent severe corrosion.

A number of plants have replaced or are planning to replace small-bore carbon steel piping in service water systems with stainless steel. The small-diameter lines are a major source of iron ions to the system (which can result in underdeposit corrosion downstream). As noted in the section on tuberculation, small-bore lines will be much more sensitive to tuberculation and occlusion, because the same amount of iron that dissolves in a small-diameter line will have a much larger effect in terms of the fraction of the volume that the corrosion product takes up than would occur in a large diameter pipe. These lines are also subject to plugging due to silt and corrosion products and may be particularly susceptible to MIC [4-26 and 4-27]. Dissimilar metal joints connecting these new stainless steel lines to the larger bore carbon steel piping are susceptible to galvanic corrosion. In systems where the small-bore lines were replaced due to the generation of excessive corrosion products, the connections between the stainless steel and carbon steel should be inspected regularly to assure their integrity. For example, the inspection of galvanic couples between stainless steel and carbon steel may be part of license renewal commitments.

Bare carbon steel will be more active than the mill scale on its surface in virtually all environments. Consequently, pipe or other product forms that are purchased in the as-hot-rolled condition may be subject to attack of the bare carbon steel at cracks in the mill scale due to galvanic corrosion. Such attack, sometimes exacerbated by microbiological influences, has been observed in operating service water systems [4-28]. Thorough cleaning of existing surfaces to remove most of the mill scale may be effective for repair, because galvanic corrosion can be minimal with a very large anode and small cathode. If carbon steel piping must be replaced, a pickling operation performed by the pipe fabricator can eliminate the problem.

Dealloying

A detailed discussion of dealloying, also called *selective leaching* or *parting corrosion*, is provided in EPRI TR-103403 [4-6]. Parts of that discussion are repeated here.

Selective leaching or dealloying is a corrosion process in which one constituent of an alloy is preferentially dissolved by the environment. The more active constituent is always removed in preference to the more noble one. Dealloying may occur uniformly or locally (plug dealloying). In either case, the remaining metal structure will be weak and often porous. As a result, leaks in tubing or vessels may be initiated without a perceptible penetration. Structural integrity is often jeopardized, even when there is no change in cross section, if uniform dealloying or a large quantity of dealloyed plugs exist. Copper alloys and cast irons are susceptible to dealloying in aqueous environments used in service water systems. Both single-phase and multiphase alloys are susceptible. Numerous cases of dealloying of such materials in service water systems have been reported [4-29 through 4-33].

Dezincification of copper-zinc alloys is a classic and commonly cited example of dealloying. Zinc is removed preferentially from alloys with zinc contents of 15% or more in a variety of environments, including cooling waters such as those encountered in service water systems. When the zinc is removed, a weak and porous layer or plug of copper and copper oxide are left behind. Local failures of the water system result from leakage through the porous material. Larger failures resulting from weakened plugs blowing out under water pressure or, in the most serious situation, where the entire structure fails by overloading the dealloyed section are of greater concern. More aggressive aqueous environments (for example, stagnant or slowly flowing seawater and brackish waters, or mildly acidic waters) increase dezincification [4-29]. Waters high in oxygen or carbon dioxide are also more aggressive dealloying environments.

Other copper-base alloys (for example, tin bronzes, aluminum bronze, nickel aluminum bronze, and copper-nickel alloys) have been formulated for mechanical properties and corrosion resistance in specific environments. All are subject to dealloying under specific environmental conditions, many of which can be encountered in service water systems. The dealloying susceptibility of the more microstructurally complex alloys will also be sensitive to the effects of heat treatment.

The precise mechanism of dealloying is not well understood. In aqueous environments, dealloying occurs most often in solid solution or multiphase alloys where the constituent metals are widely separated in the galvanic series.

Dealloying of copper alloys may contribute to, or be a precursor to, stress corrosion cracking. Conversely, stress appears to increase an alloy’s susceptibility to dealloying [4-29].

Cast iron, which is used for piping and some components in service water systems, is also subject to a form of dealloying known as graphitic corrosion. Graphitic corrosion involves the dissolution of all or part of the iron matrix. Analogous to dealloying of copper alloys, the more active component (iron) is removed in preference to the more noble constituent (graphite). The result of graphitic corrosion is a very weak and porous structure composed mostly of graphite. ASM International's handbook volume on corrosion [4-30] states that only gray irons, where the graphite is in the form of flakes, are susceptible to graphitic corrosion. Experience with cast iron water distribution lines in the United Kingdom suggests that nodular iron (where the graphite exists as nearly spherical nodules) is also subject to graphitic corrosion, at least under the influence of microorganisms (that is, MIC) [4-34]. The UK researchers found that part of the reason that MIC of cast iron lines had not been reported many years earlier was that the older lines were fabricated from gray iron where leakage through the porous mesh of graphite flakes was the dominant failure mechanism. When the nodular iron pipes experienced a loss of the iron matrix, no network of graphite existed, and the leaks were much larger and readily noticeable. Figures 4-38 and 4-39 illustrate two types of dealloying.

Figure 4-38
Dealloying—Layer Type (Muntz Metal)

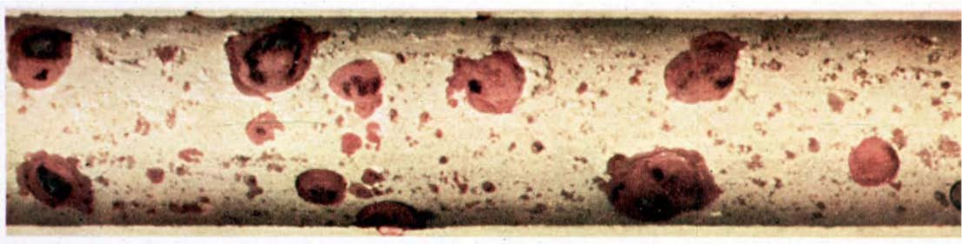


Figure 4-39
Dealloying—Plug Type (Aluminum Brass)

Several domestic nuclear plants have experienced dealloying of service water piping. They include South Texas Project and St. Lucie (aluminum bronze and nickel aluminum bronze). Some plants have also experienced graphitic corrosion of cast iron.

SCC

Stress corrosion cracking (SCC) involves the interaction between mechanical effects and a corrosion process. The interaction of those two effects can produce an extremely damaging process that effectively causes a tough and ductile alloy to behave in a brittle manner over a localized area. SCC requires a susceptible material to an environment in which it is susceptible to the highly localized corrosion/mechanical interaction, and the presence of a tensile stress.

As noted in EPRI TR-103403 [4-6], SCC tends to occur only within a limited range of strain rates and crack tip dissolution rates that are "compatible" with the strain rate, because the mechanical and corrosion effects must interact. For example, SCC is typically not observed in extremely aggressive environments (where the corrosion effects dominate) or at very high strain rates (where mechanical effects dominate). Unfortunately, the strain rate and dissolution rate limits to which many engineering components are subjected lie within the ranges where SCC can occur. The numerous failures in nuclear plant primary heat removal systems are evidence of this fact.

Figures 4-40 through 4-43 show examples of SCC in different alloy/environment systems.

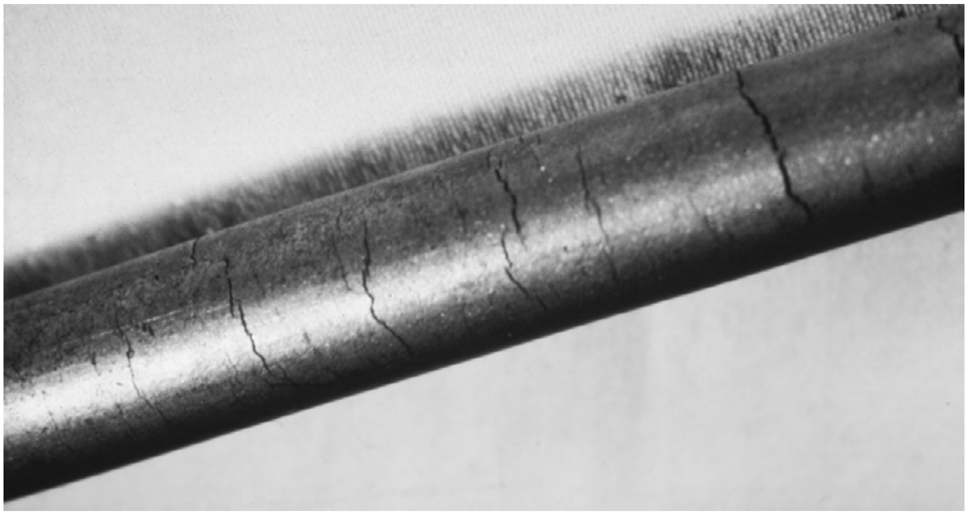


Figure 4-40
Stress Corrosion Cracking of Admiralty Brass in Ammonia (from [4-35])

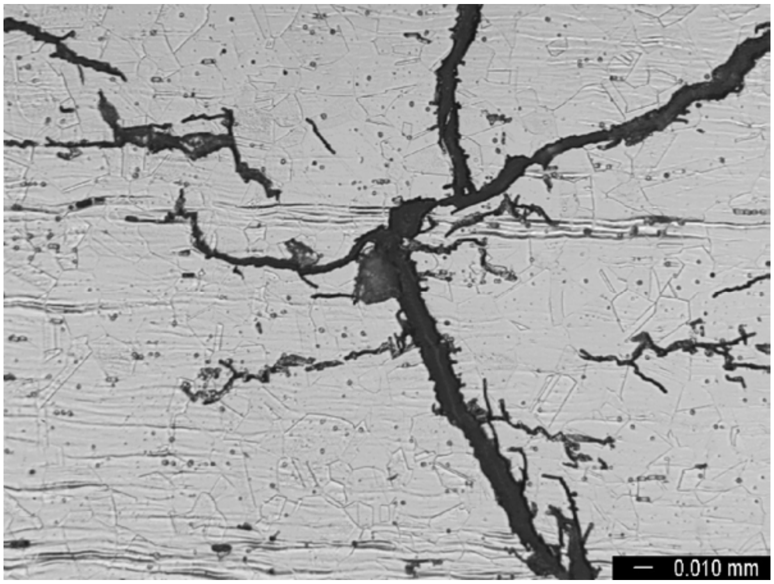


Figure 4-41
Transgranular Stress Corrosion Cracking of Stainless Steel

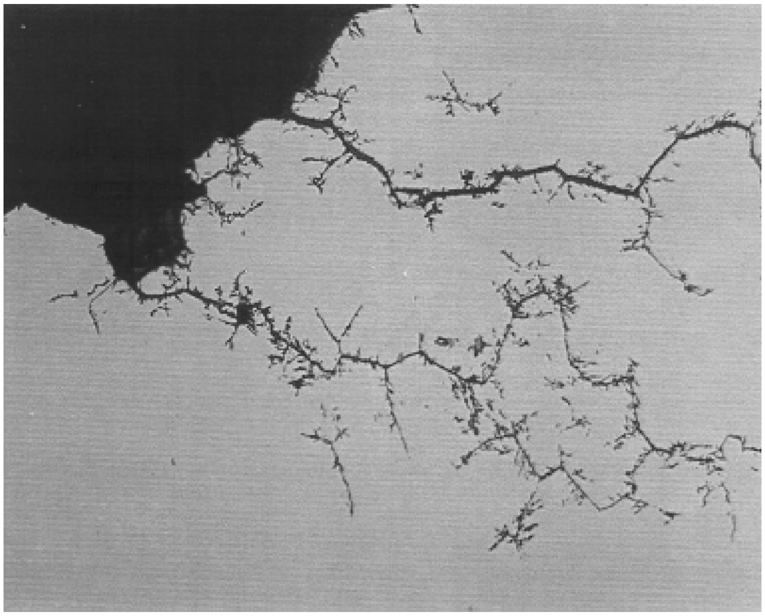


Figure 4-42
Intergranular Stress Corrosion Cracking of Stainless Steel

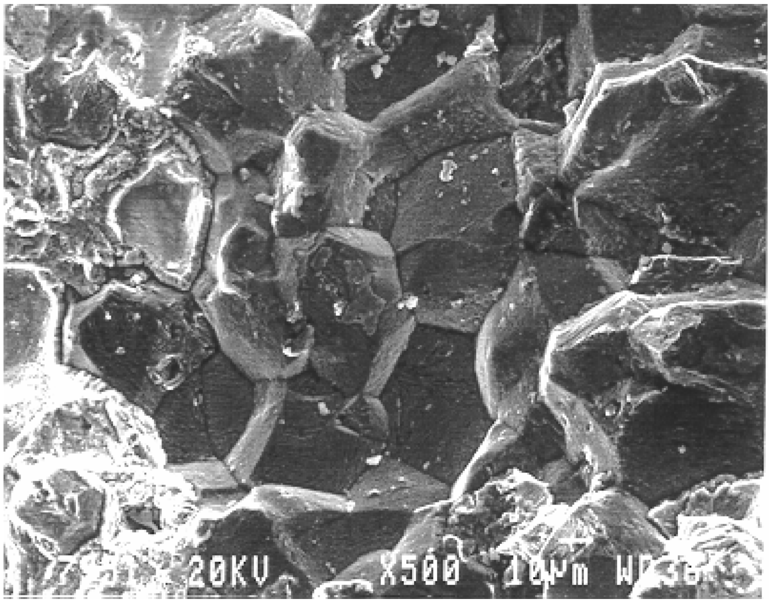


Figure 4-43
Another Example of Intergranular Stress Corrosion Cracking of Stainless Steel

For the materials of construction of most service water systems, other corrosion effects are far more significant than SCC. The primary SCC-susceptible material/environment pairs used in service water system operations are stainless steels exposed to waters high in chloride content and copper alloys exposed to ammonia. Carbon steels in high-nitrate environments can also be susceptible to SCC. In general, SCC of stainless steels in chlorides or carbon steel in high nitrates would only be considered probable if the temperature is high enough, usually at the extreme upper limit for service water systems.

Environments outside the normal operating envelope for service water systems (for example, chemical cleaning or extended operation at elevated temperatures) must be taken into account during the selection of processes or system control.

In general, SCC is not a major concern in service water piping.

Erosion-Corrosion

Erosion-corrosion is a major concern in power plant systems. Flow-accelerated corrosion (FAC), a term that is specific to erosion-corrosion in carbon steel systems such as the feedwater train in fossil-fired and nuclear power plants, can produce ruptures, with associated unplanned downtime and potentially even loss of life of plant personnel, in those high-energy lines.

In carbon steels, FAC results from the combination of highly turbulent flowing water, steam, or water/steam mixtures (for example, at elbows or tees or other changes of direction), exposure in a susceptible temperature range (of the order of 350°F [177°C]), and perhaps most importantly a nonprotective oxide film (often the result of an extremely low oxygen content).

FAC of carbon steel is not a concern for service water piping, because the temperature is far too low for the degradation mechanism to be operative, and most often oxygen concentrations are much too high to reduce the nonprotective corrosion product films that are striped from the surfaces by the high-velocity, turbulent flows. As shown in Figures 4-44 and 4-45, effects at temperatures typical of service water systems (that is, <<350°F [177°C]) are not a concern.

Copper alloys can be susceptible to degradation from erosion-corrosion under service water system conditions. The corrosion product films that form on copper alloys are readily removed by flowing waters. The maximum fluid velocity is often a critical parameter in the selection of one copper alloy over another.

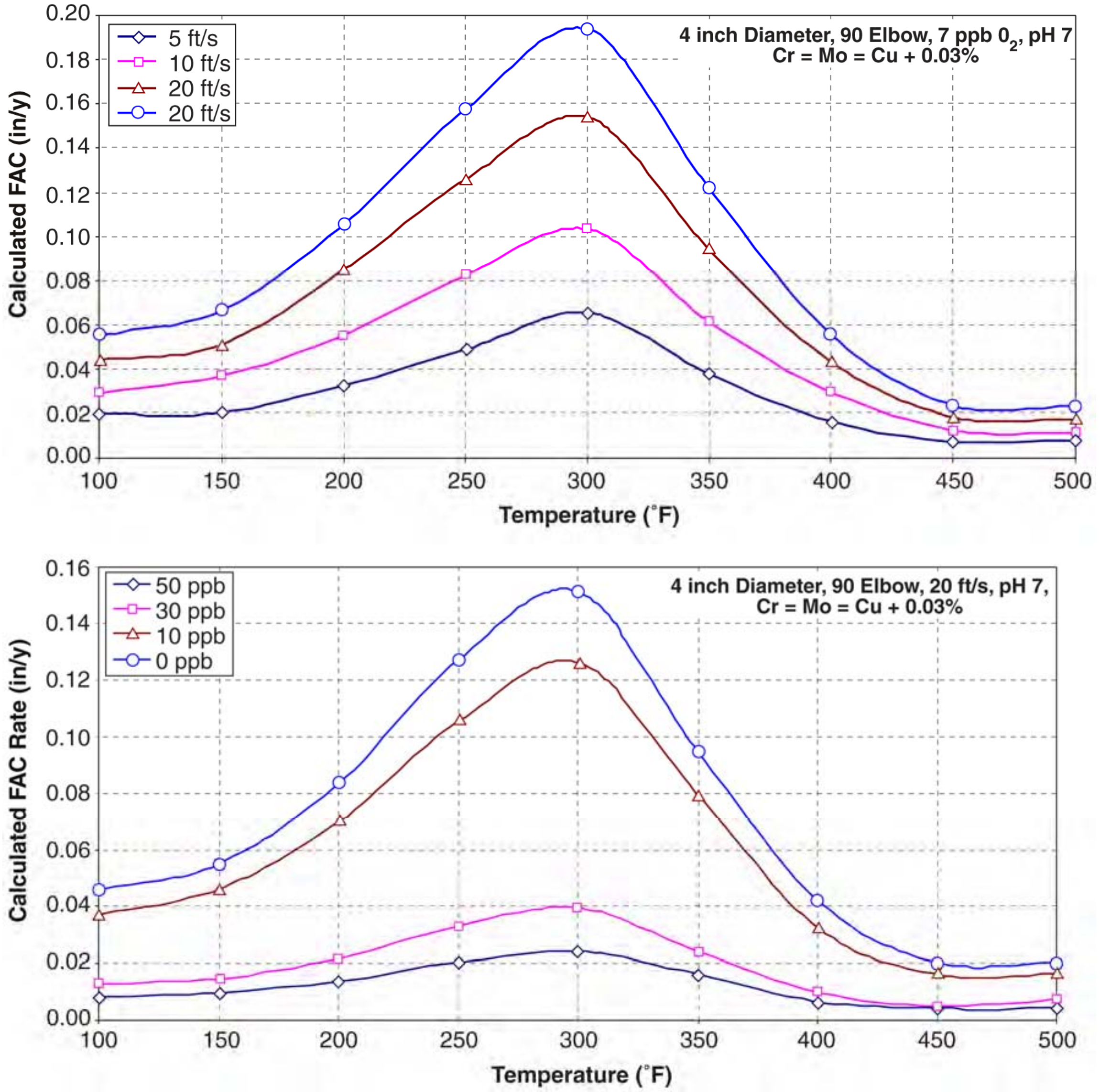


Figure 4-44
Temperature Dependence of FAC in Carbon Steel Systems: (a) Velocity Effects; (b) Oxygen Effects

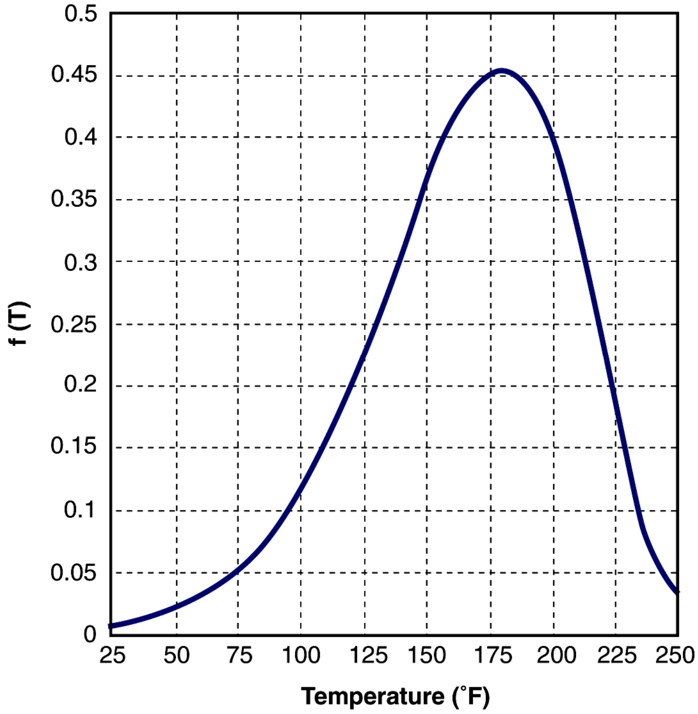


Figure 4-45
Another Illustration of the Extreme Temperature Dependence of FAC of Steels (from [4-29]; Reproduced Courtesy of ASM International)

Copper alloy heat exchanger tubes are often subject to conditions that produce erosion-corrosion, because corrosion product films are often soft and poorly protective. Turbulence is greatest at the inlet end of heat exchanger tubes. As might be expected, erosion-corrosion effects are most significant there (Figure 4-46). Minor blockages in heat exchanger tubes produce locally high fluid velocities that can remove corrosion product films very effectively. Partial blockage of the tube by stones, shells, or other debris anywhere along the tube length can have the same effect (Figure 4-47). Both higher copper contents and the presence of impurities such as sulfides tend to produce poorly protective corrosion product films and increase the susceptibility to erosion-corrosion. Dissolved iron in the water can improve resistance to impingement attack and other forms of FAC [4-36]. While service water piping constructed from copper alloys is less likely to be subject to the localized flow effects that occur at the inlet end of heat exchangers, the sensitivity of the copper alloys to high turbulence can also affect piping (Figure 4-48).

Figure 4-46
Flow-Accelerated Corrosion of Copper Alloy Tubes

Figure 4-47
Extreme Case of Flow-Accelerated Corrosion of Copper Alloy: Complete Perforation Downstream of a Pebble (Reproduced Courtesy of the Copper Development Association)

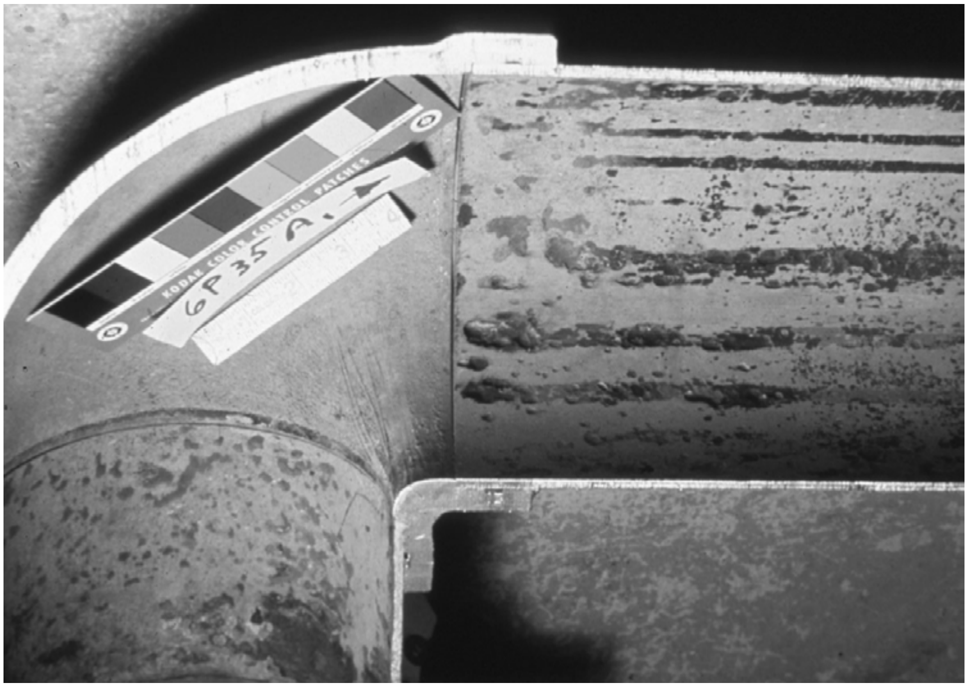


Figure 4-48
Sulfide Attack of 90-10 Cu-Ni Piping (Reproduced Courtesy of Naval Surface Warfare Center)

Effects of Flow on Corrosion

In addition to the wide variety of materials and water chemistries that service water piping will experience, operating conditions can also vary significantly with time, which means that the piping will experience numerous different flow regimes. The diverse and redundant design philosophy that pervades nuclear plant design certainly applies to service water systems. Systems will typically be designed for the most limiting condition (for example, a LOCA), however normal heat loads are generally minimal. As a result, duplicate or triplicate paths will exist for the cooling water such that one, two, or three legs of the system will be filled with cooling water, but in a standby mode, awaiting a need for cooling of equipment. All of those systems will have surveillance tests that are required on a regular basis. For many portions of a service water system, especially a safety-related service water system, periodic testing, interspersed with extended periods of wet layup, will be the most common condition of “operation.” The flow conditions in the piping can dramatically change the nature of the degradation that the piping will experience, producing local conditions that are significantly different from those that were considered in design.

Corrosion allowances for service water piping are based upon 40 years of operation at design flows and design temperature in the nominal water chemistry. Uncoated carbon steel or cast iron would be expected to degrade by general corrosion that produces a fairly protective oxide film. The key consideration relative to the form and rate of the corrosion is the protective nature of the oxide, which is a function of dissolved oxygen, temperature, flow, and water chemistry.

Normally Flowing Conditions

Normally flowing lines will usually form a relatively uniform and fairly protective oxide and may form some tubercles. In flowing environments, at temperatures and water chemistries typical of service water systems, the corrosion is usually general corrosion and is fairly predictable and bounding (that is, the greatest amount of general corrosion will occur in flowing pipes). The range of rates will have a distribution (a factor of 2 or so on the average).

The presence of the corrosion product would also be expected to produce a small loss of flow carrying capability, due to a slight reduction in cross-sectional area and an increase in roughness. These effects may or may not have been included in the design.

Normally Stagnant Conditions

In normally stagnant systems, oxygen (the primary constituent that controls corrosion) will be consumed relatively quickly by corrosion reactions and biological oxygen demand. As a result, general corrosion will proceed to a very limited extent, then decrease as the oxygen content of the water decreases, and eventually stop as the oxygen is consumed. However, MIC, driven by anaerobic organisms such as sulfate-reducing bacteria, can proceed, producing localized corrosion at rates that are greater than those of general corrosion under anaerobic conditions. In addition, the films that are established during periods of stagnation can produce accelerated corrosion if oxygen is introduced. The section below on intermittent flow conditions provides a more complete description.

Intermittent Flow Conditions

As discussed briefly in Section 3, intermittent flow conditions can produce degradation that is intermediate between that of the normally flowing legs and the normally stagnant legs (for example, time-averaged based upon the fraction of time flowing), or in some situations, producing corrosion of a form and at rates that are far worse than either flowing or stagnant conditions. When the nature of the environment and the time period of the stagnation are such that the stagnation periods can set up conditions that reinforce aggressive conditions during flow periods that follow the stagnation periods, extremely rapid degradation that has not been considered in design can occur.

For example, biofilms formed during extended periods of stagnation may have only minimal effects on corrosion during the stagnant periods but can establish conditions that will produce very rapid corrosion during the transition from stagnation to full flow such that the bulk of the corrosion will occur at high rates for minutes or hours during the transition from anaerobic and stagnant conditions to full flow in an aerated water. Hardy and Bown [4-20] have shown that corrosion rates during those transition periods can be much higher than corrosion rates during either the preceding stagnant period or under full flow after steady state environmental conditions have been established. In field tests, using a side stream at a lake-cooled power plant, the utility formerly known as Ontario Hydro also showed that corrosion activity on a corrosion-resistant alloy (Alloy 800) increased very dramatically following extended periods of stagnation, even before the oxygenated water flowed past the metal spools [4-36]. Those tests showed that after weeks or months of stagnation, corrosion activity increased when the inlet valve was opened, but before the outlet valve was opened. Presumably, reactions between the surface biofilm and oxygen that diffused into the test piece were very rapid, even without the need for any flow.

Dead Legs

Dead legs will exist where normally stagnant or intermittent flow legs are connected to normally flowing legs such as headers. As noted in Section 3, the degradation that occurs in dead legs can often be the worst in the service water piping system, depending upon the material of construction, the environment, the flow rate in the flowing section, the relative sizes of the piping in the flowing pipe and the dead leg, and the length and orientation of the dead leg (for example, a long or short length of pipe from the connection to the flowing branch, or a vertical dead leg at the bottom of the flowing line where sediments can accumulate, in contrast to other orientations).

The distance over which oxygen penetrates into the dead leg, the local flows, and the collection of other debris, including formation of biofilms on surfaces, can all influence the degree of localized attack.

The fluid flow in the lines running past the “stagnant” lines will cause some turbulence at the tee and mixing of the otherwise stagnant fluid in the dead leg section. To estimate the depth of penetration of the turbulent flow down the dead leg, correlations from an EPRI report on thermal stratification, cycling, and striping (TASCS) [4-37] were used. The following assumptions were used in the turbulent mixing analysis:

- Water flows in excess of 3 feet per second (0.9 meters per second) in each of the lines tied into the “stagnant” lines.
- The TASCS analysis successfully approximates the depth of penetration down the dead legs.
- The diameters of the flowing and dead-leg lines define the depth of penetration.

Figure 4-49 is a graph showing the depth of penetration versus flow velocity, from the EPRI report on TASCS [4-38].

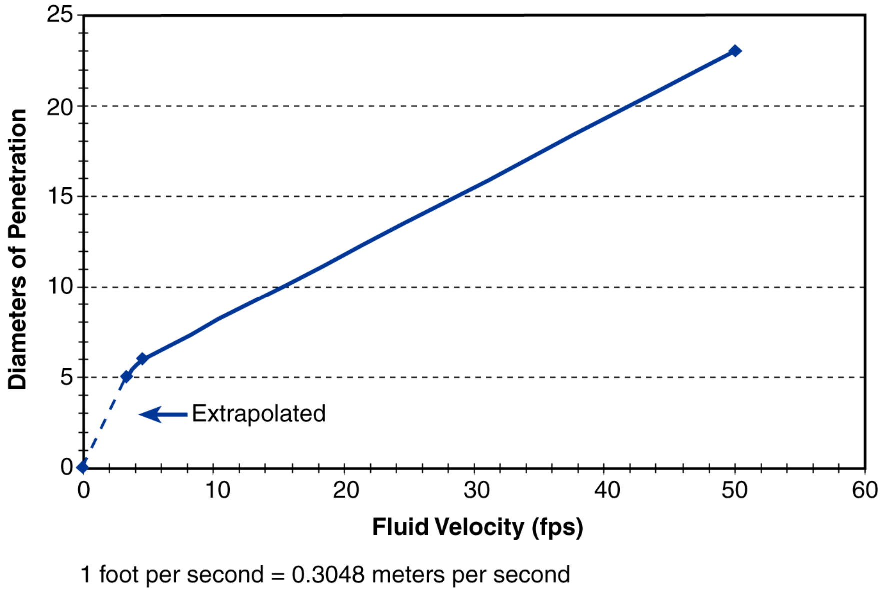


Figure 4-49
Depth of Turbulent Flow Penetration Versus Fluid Velocity

With the fluid velocity in the pipes flowing past the dead legs ranging from 3 to 10 feet per second (0.9 to 3 meters per second), Figure 4-49 estimates diameters of turbulent penetration down the dead leg. From Figure 4-49, 5 to 8 diameters of penetration can be expected down the dead leg lines. Therefore, on a 1-inch (25.4-mm) diameter line, 5 to 8 inches (127 to 203 mm) of turbulent penetration is expected, and on a 4-inch (102-mm) diameter line, 20 to 32 inches (508 to 813 mm) of penetration is expected. This first approximation may be extremely conservative—the distance of penetration of water with dissolved oxygen may be much larger.

In truly stagnant systems without water replenishment, the general corrosion reaction (which is essentially the oxidation of iron) and the biological oxygen demand (BOD) consume the available dissolved oxygen in a matter of days. Once oxygen is removed from the water, all nonbiologically driven corrosion stops; a truly "dead" system does not corrode. However, because of the turbulent flow of water into the dead leg sections during flow periods, dissolved oxygen will be replenished in the sections of pipe that would otherwise be considered as "stagnant." In fact, with relatively acquiescent flow of oxygen-rich water within the dead legs, MIC activity should be expected to increase without water flow scouring microbial colonies from piping walls, and pitting propensity should increase as well, with no heavy flow to wash out concentration cells.

When the dead legs are modeled this way, the same general corrosion rates are predicted as are observed in the continuous flow regime, because there is no dissolved oxygen restriction. Further, the pitting susceptibility will be greater, because the communication between anodic and cathodic areas will be limited by the lower flows. Finally, the MIC susceptibility will also be higher, because there is no scouring action of flow, but the cathodic reactions from oxygen reduction will not be decreased.

In many respects, dead legs will behave similarly to intermittent flow legs that have an essentially infinite number of flow events where corrosion rates will be high, or similarly to continuously flowing legs that have no scouring action that removes microbes (that is, the potential for MIC will be greater) and where communication between anodic and cathodic locations will be poor, encouraging localized corrosion. As a result, localized corrosion effects are likely to be the worst at dead legs.

A number of utilities consider dead legs off normally flowing lines to be the locations of maximum corrosion susceptibility.

Further, such dead legs are often pipe segments that are isolated by valves that are not leak rate tested. Small leakage past those valves actually turns these "dead legs," where all flow is induced flow due to eddies or thermal effects from the flowing line nearby, into legs with continuous very low flow.

Fatigue

Fatigue is a phenomenon that leads to the fracture of material under repeated or fluctuating stresses that are less (often much less) than the tensile strength of the material. Higher alternating stresses cause failures in shorter times; at lower alternating stresses, fatigue life will be longer and can be essentially infinite, as shown in Figure 4-50. Steels will typically exhibit an "endurance limit," the alternating stress level below which fatigue life is essentially infinite. Many other materials, such as nonferrous materials, do not display the endurance limit behavior.

Fatigue curves, or "S-N" (Stress vs. Number of cycles) curves, are generally plotted on a semilogarithmic scale with alternating stress plotted linearly and the number of cycles plotted as the x-axis on a log scale. For high cycle fatigue (>1000 cycles), small decreases in alternating stress lead to dramatic increases in fatigue life. In the low cycle regime, the cycles to failure will decrease dramatically with a relatively small increase in stress.

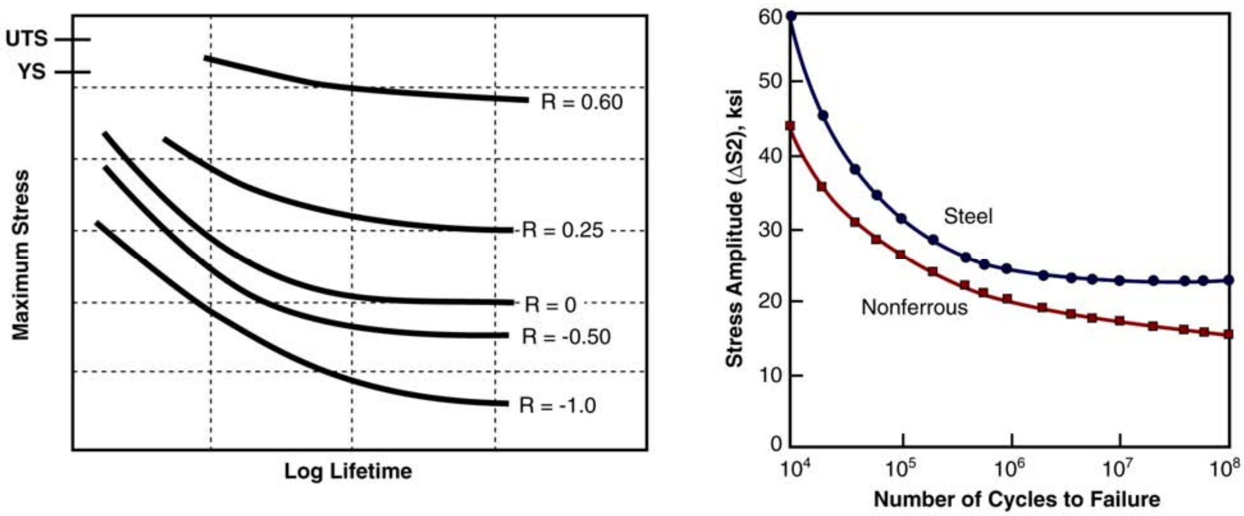


Figure 4-50
Examples of Fatigue Curves (from ASM Volume 19 [4-38]; Reproduced Courtesy of ASM International)

The most common sources of fatigue loadings in power plants are vibrational fatigue (which can affect rotating machinery, piping, heat exchanger tubes, and many other components) and thermal fatigue (which occurs as fluid streams of differing temperatures—often dramatically differing temperatures—produce fluctuations in skin temperature and results in alternating strains).

In a service water system, thermal fatigue effects will generally be minimal, because the maximum temperature differences will be small.

Piping, especially small-bore piping joined using socket welds, can be especially susceptible to fatigue failures.

Cavitation

As described in [4-39], cavitation damage of a material is associated with the repeated nucleation, growth, and violent collapse of cavities in the liquid at a solid/liquid interface. The damage may include loss of material, surface deformation, or changes in properties or appearance. The cavities are bubbles of water vapor or gas that form when the absolute pressure of the liquid stream is reduced to the vapor pressure of the liquid at the operating temperature. The collapse of the bubbles occurs in regions of locally high pressure and can generate enormous stresses in the surface layers of adjacent metals. Rapidly collapsing vapor bubbles produce shock waves that produce pressures as high as 60 ksi. Cavitation damage most often occurs in hydraulic turbines, on pump impellers, and on ship propellers, but can also occur on piping and other surfaces in contact with high-velocity liquids that are subject to changes in pressure. In piping, cavitation will most often occur downstream of a valve or orifice where pressure changes can occur rapidly.

Cavitation can occur in any liquid in which the pressure fluctuates due to flow patterns or from vibration in the system. Cavities form (only) if the local pressure falls below the vapor pressure of the liquid. Those nucleated cavities can then grow to a stable size and be transported downstream with the flow. When they reach a higher-pressure region, they become unstable and collapse, usually violently. The highly localized pressures produced by the collapse may cause localized deformation or removal of material (erosion) from the surface of any solid in the vicinity of the cavities.

Cavity radii for cavitation produced by flow effects are typically on the order of 10 to 40 mils (0.25 to 1 mm); smaller for cavitation produced by vibration (~2 mils [0.05 mm]). The cavity collapse velocity for a cavity with a radius of 40 mils, collapsing at approximately at 1 atmosphere in water, typically ranges from 300 ft/s (91 m/s) to nearly 500 ft/s (152 m/s).

When a cavity collapses within the body of the liquid, away from any solid boundary, it collapses symmetrically and (only) emits a shock wave into the surrounding liquid. However, when cavities are in contact with a solid surface or are very close to a solid surface, they will collapse asymmetrically, forming a microjet of liquid directed toward the solid, as shown in Figure 4-51. (In this figure, (a) is a solid surface showing the initial impact of a drop of liquid that produces circumferential cracks in the area of impact or produces shallow craters in very ductile materials. In (b), a high-velocity radial flow of liquid away from the impact area is arrested by a nearby surface asperity, which cracks at its base. In (c), subsequent impact by another drop of liquid breaks the asperity, and in (d) a direct hit on a deep pit results in accelerated damage, because shock waves bouncing off the sides of the pit cause the formation of a high-energy microjet within the pit.) More importantly, cavities do not act independently but instead collapse in clusters, which enhances the effects of the cavity collapse at the solid interface. Much of the energy generated by the collapse of the outer cavities is transferred to the cavities in the inner part of the cluster through an increased local hydrostatic pressure at the individual collapse, resulting in a more intense collapse of the central cavities.

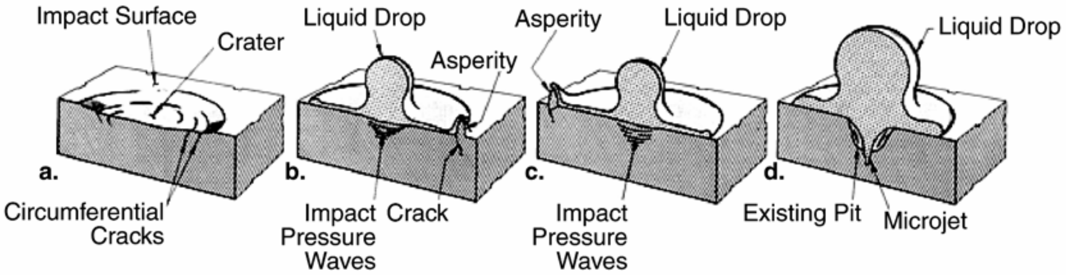


Figure 4-51
Processes by Which a Material Is Damaged by Liquid-Impingement Erosion (Reproduced Courtesy of ASM International)

In terms of appearance, cavitation (Figure 4-52) is similar to pitting except that surfaces in pits are usually much rougher.

Figure 4-52
Internal Surface of Carbon Steel Pipe Section Damaged by Cavitation (from [4-30]; Reproduced Courtesy of ASM International)

Cavitation usually manifests itself by another familiar characteristic—noise. The buildup and subsequent collapse of bubbles on the impeller create the familiar popcorn noise or a “sizzling” sound. Cavitation most commonly occurs downstream of throttle valves or orifices or in pumps (for example, on impellers).

Cavitation damage is not limited to low-pressure regions. In hydraulic components, the damaged area will rarely be associated with the region of lowest static pressure. If low static pressure is the cause of cavitation, damage will be downstream of the low-pressure region where vapor pockets cannot be sustained and bubbles implode. Cavitation damage often occurs in relatively high-pressure regions, particularly if sufficiently high flow velocity also occurs.

Components operating under nominally identical conditions can exhibit dramatically different results. For example, [4-40] notes that a bronze impeller from one of two water pumps, removed from service because of dramatically reduced output, exhibited considerable metal loss over interior and exterior surfaces, while several similar water pumps, operating under almost the same conditions, showed no observed damage.

Cavitation damage is most effectively avoided by reduction of either the flow velocity (for example, by adjusting the throttled position of a valve) or the temperature. Reduction of flow velocity is preferable. Other measures may include system redesign with orifices less likely to produce cavitation conditions, selection of more-cavitation-resistant material, or use of erosion-resistant welded overlays. Cavitation in service water piping is most common immediately downstream of throttling valves, and may be especially prone to occur downstream of valves that are not intended for throttling and orifices.

Cavitation corrosion, a special case, is the interaction of localized mechanical damage with corrosion processes. Collapsing vapor bubbles mechanically destroy protective surface films, exposing bare metal. Corrosion rates may be greatly increased because of the increased turbulence and associated high mass transfer rates. The mechanical removal of the protective films, exposing fresh surfaces to corrosion, leads to periods of high corrosion until the protective films have been reestablished.

Figures 4-53 through 4-55 illustrate an example of cavitation in an elbow immediately downstream of a butterfly valve in a service water system.

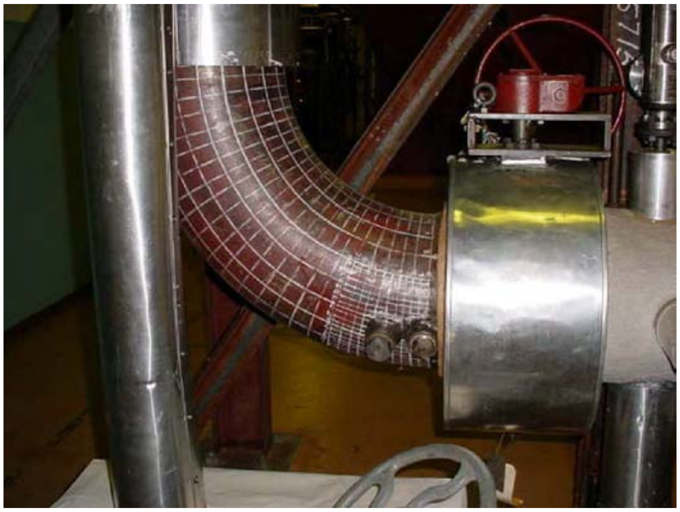


Figure 4-53
Elbow Downstream of Butterfly Valve. Half-couplings with plugs are locations of known through-wall leaks.

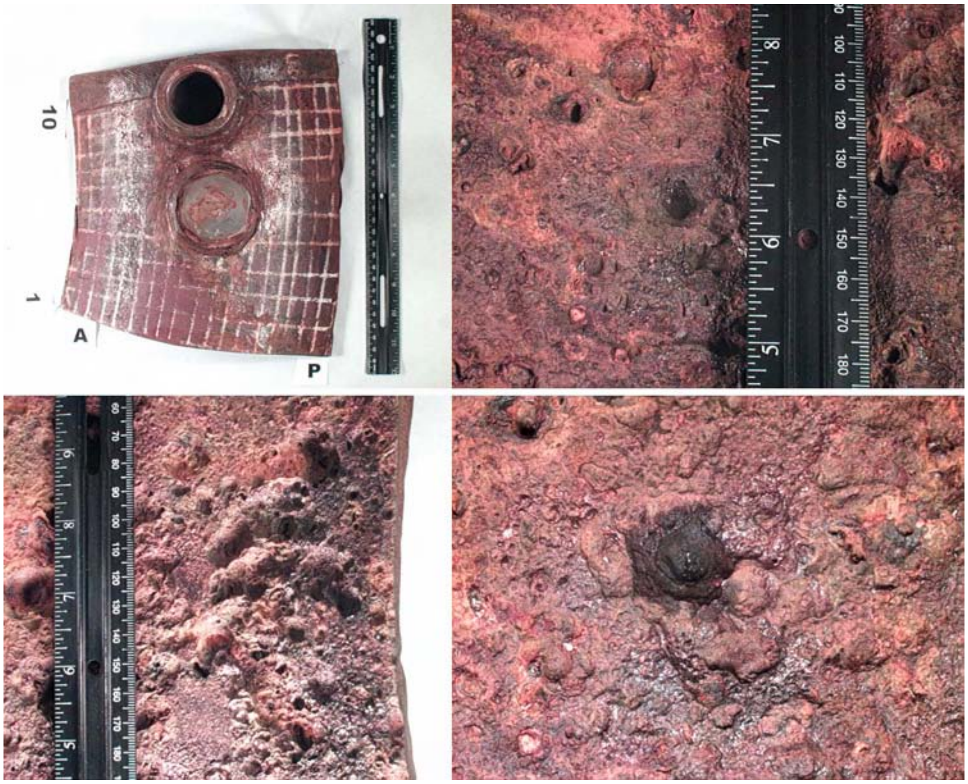


Figure 4-54
Surfaces of Service Water Elbow Subjected to Cavitation

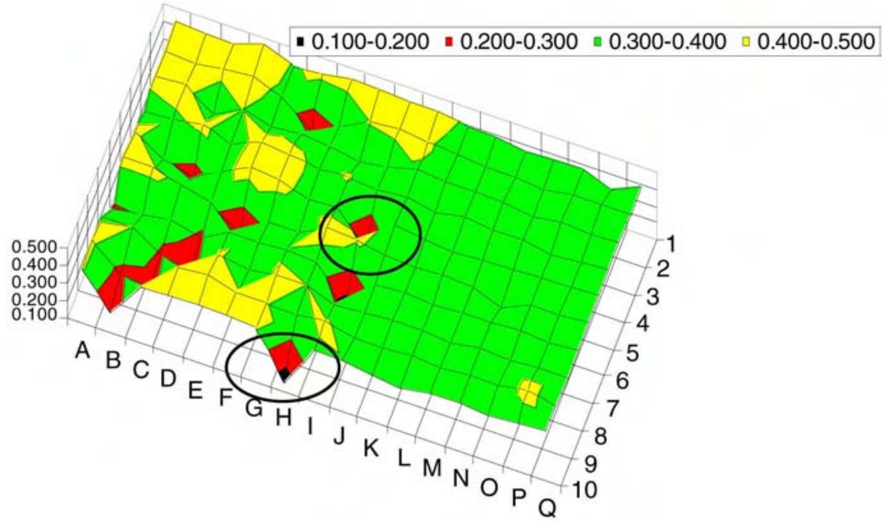


Figure 4-55
Thickness Profile for Surfaces from Elbow with Cavitation

Other Considerations

The most common approaches to mitigation of corrosion are the use of coatings (that is, providing a barrier between the environment and the metal), water treatment (forming a more protective corrosion product, eliminating aggressive bacteria, or scavenging an environmental component like oxygen that is key to the corrosion process), or cathodic protection (CP) where appropriate. These measures are described in greater detail in Section 6.

For buried lines, service water piping will be degraded from both the water side and the soil side. Coatings or water treatments may be used for corrosion control on the water side. Coatings and CP are commonly used to eliminate soil-side corrosion degradation. Degradation from the OD will be a strong function of the condition life of the coating. Under optimum conditions, coated and cathodically protected lines have provided lives of 50 years or more in immersion and buried service. However, failures of buried lines from the OD in 20 years or less have also been observed, including applications in nuclear plant cooling water piping.

Typical OD coatings for buried piping provide an inert and nearly impervious barrier that has very low moisture permeability and a high resistance to electrical currents (for example, stray current corrosion concerns). Coatings are considered the first line of defense against corrosion of buried piping; cathodic protection is the second. Buried pipes are usually coated and cathodically protected.

For example, coal tar enamel has been widely used for buried piping since the early 1900s and “has been applied to more miles of steel pipelines than any other coating in underground service” [4-40]. The coating may be applied in the shop or in the field. As with all coatings, surface preparation is key to the success of the coating system, hence the shop-applied coatings are preferred. Under optimum conditions, coal tar enamel has provided essentially failure-free service in buried and immersion service in some applications for periods of 50 years or more [4-41].

Munger [4-41] also shows an example of the coating performance of coal tar enamel with and without cathodic protection. A water tank with a 50-mil (1.27-mm) coal tar enamel coating, applied by a typical field application method, deteriorated after about ten years of service, requiring repair of the tank. The coating on a companion tank, which used the same coating plus continuous cathodic protection over the last 3 years of the 10-year exposure, was still sound with no evidence of corrosion of the underlying steel. This example indicates the known advantages of using cathodic protection in conjunction with a coating. It also suggests a conservative lower bound for coating life.

Corrosion failures in buried piping increase logarithmically with time (that is, the shape of the curve is the same as that shown in Figure 4-1) with galvanic couples and stray currents as the most common causes of corrosion [4-42].

Over time, coatings will degrade and the fraction of the protection provided by the cathodic protection system will have to increase. In the absence of CP, areas of degraded coating would be expected to experience active general corrosion, some level of localized corrosion, and possible MIC. Results of those degradation mechanisms would be expected to be leakage at low rates as has been observed for aboveground lines that have experienced leakage due to these same mechanisms but from the ID. Improper use of cathodic protection can be a major contributor to the destruction of protective coatings on buried pipes. “Overprotection,” the use of a potential that is too high, can cause the coating to blister and disbond, effectively destroying the coatings far more rapidly than the normal aging phenomena.

Stray currents can also be a significant contributor to the OD corrosion of buried lines. Plants can gain valuable information on the OD condition of their buried service water piping from assessments or known leaks in other buried lines on the plant property (for example, buried gas transmission lines) that have similar mitigation measures applied for OD degradation. Influences of other lines nearby (for example, buried gas transmission lines, buried lines owned by others, or the plant’s electrical grounding bed) can have an effect on OD corrosion due to stray currents that may influence the electrochemical potential of the buried service water and other lines. Any current leakage to the plant’s buried lines from other CP systems effectively makes the affected plant line locally anodic, because current will flow from the area of influence back to the source of the stray current [4-43]. The magnitude of stray current effects is often a major unknown relative to the OD corrosion of buried lines.

The adequacy of original design cathodic protection systems will also be compromised as more buried structures (piping, tank bottoms, and so forth) are added to the plant or as protective coatings on other buried structures degrade and expose additional metal. The original design cathodic protection system will not have been sized to protect the greater amount of buried but uncoated material.

Nuclear plants and owners of pipelines from other industries have also experienced the logarithmic time dependence of failures for buried pipes. Nuclear experience, based upon limited conversations with personnel from the U.S. nuclear fleet in general as well as from detailed analyses of the condition of buried piping in several other nuclear plants, has indicated that plants have experienced both ID- and OD-initiated perforation of buried pipe lines as a result of corrosion. Degradation of buried pipes has generally been discovered by examinations of the ID, during ID refurbishment, or, occasionally, from wet spots on the ground above the leaking pipe. Perforations have always manifested themselves as pinhole leaks, at least some of which are believed to have opened up as the result of ID surface cleaning done to facilitate inspection. Plants have undertaken actions or instituted plans to mitigate leaks in buried pipe to avoid more accelerated damage to the leaking pipe or adjacent pipes as a result of the leak. Those actions or plans have typically included more comprehensive inspections (remote and manned visual inspections, smart pigs with visual or UT equipment, or magnetic particle inspection), the use of cathodic protection, or the use of cured-in-place pipe liners.

Plant owners should always take care with any buried lines, because asbestos-containing wraps have historically been used along with coal tar for some buried lines.

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5
ASSESSMENTS

Priorities

As noted in Section 1, the priorities for a service water piping program are to do the following:

1. Assure that structural integrity of piping is maintained.
2. Assure that system function (for example, adequate flow of cooling water, per the design basis) is maintained.

   Both items 1 and 2 can be assured in the presence of one or more pinhole leaks, provided that the impact of the leak(s) on structural integrity and operation, including effects on adjacent equipment, have been evaluated.
3. Avoid surprises relative to degradation of the pipe wall thickness, leakage, or degradation of operation.
4. Anticipate and monitor degradation so that appropriate mitigation or remedial actions can be scheduled and implemented.
5. Provide input to the plant's long-range plan, especially if pipe replacements or other system modifications that require large expenditures are identified.
6. Protect the asset (that is, the service water system as a whole) by proactive or timely responses to degradation by adhering to items 1–5.

Criteria

As noted in Section 2, a successful program will meet the following criteria:

1. Completeness: The program considers the entire system and all potentially operative degradation mechanisms.
2. Degradation mechanisms: General thinning or other mechanisms that can jeopardize structural integrity have been accounted for adequately in design; degradation from those mechanisms is bounded by corrosion allowances,[1] materials selection (for example, corrosion-resistant alloys), or coatings; localized corrosion mechanisms are the only operative mechanisms that may jeopardize leak tightness; degradation is typically not in discrete areas (for example, only at welds); and the only result is leakage (structural integrity

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[1] A truly uniform loss of thickness of 40–120 mils would change the stiffness of the piping and necessitate a reevaluation of the piping system and its supports.

is not jeopardized). Prioritization of elements will be based upon the risks associated with a failure.

3. Complete documentation: Design and operating parameters relative to operative degradation mechanisms are documented, all inputs and assumptions for input values used in the evaluation are documented, and evaluation results are documented.
4. Element selection: Includes the most susceptible locations as determined from analysis and service history, and the highest risk locations. Typical locations or locations selected randomly are included, and the number of elements inspected assures that the condition of the system has been addressed.
5. Inspection and examination methods: Appropriate methods are used to accurately detect and characterize localized corrosion.
6. Internal validation: Validation has been performed based upon failure, repair, and examination history.
7. Benchmarking, peer reviews, and self assessments: These items have been incorporated.
8. Acceptance criteria: The acceptance criteria are defined such that the presence and extent of localized corrosion are reliably detected [5-1].
9. Sample expansion criteria: Sample criteria are defined. Additional examination locations will be based on inspection results [5-2].

Plant-Specific Scope Identification

Elements to be inspected are identified based upon failure history, susceptibility to degradation (taking into account all of the design and operating conditions that can contribute to that susceptibility), and the consequences of failure. In general, prioritization of elements to be inspected will be done on failure susceptibility, consequences of failure, and accessibility of the location for inspection. Element selection and prioritization must be consistent with the pertinent ASME Code Cases [5-3, 5-4, 5-5]. The EPRI methodology for risk-informed ISI [5-6] is one way to incorporate consequences of failure. For example, ANO and FitzPatrick have revised portions of their in-service inspection programs for service water piping to include evaluations of both susceptibility and consequences of failure to produce a risk-informed selection process. The pilot application for FitzPatrick [5-7] has demonstrated the benefits of the RI-ISI approach.

Probabilistic predictions (Figure 5-1) provide a useful way to quantitatively predict the number of pinhole leaks or other forms of degradation (for example, areas where structural integrity may be compromised) versus time. Once in place, these models can also be used to evaluate candidate options and the cost-effectiveness of each. These models can include considerations of the material, environment, flow, temperature, and water treatments and other mitigation approaches, as well as the statistical distribution of degradation rates to produce curves such as those developed in Figure 5-1 in order to include the various contributors to degradation quantitatively.

Characteristics of each system will dictate the approach to be used for the overall assessment.

For example, direct inspections of bare carbon steel or cast iron will rely upon volumetric methods, primarily radiography or ultrasonic thickness measurements, to determine generalized and localized thinning. For coated or lined steel or cast iron, visual methods to assess the condition of the coating may be the primary inspection tool. For corrosion-resistant alloys, visual inspections and some volumetric inspections to detect localized corrosion may be the most appropriate inspection methods. For buried pipe, remote visual or volumetric methods will typically be employed. The use of NDE methods that permit screening of large areas from a single inspection location may be used to define locations for subsequent more-detailed inspections. Further, for buried pipe, additional degradation modes will exist and often additional mitigation approaches will have been employed to combat OD corrosion. Assessments may rely more heavily on determinations that are specifically related to the condition of the mitigation measures as the key element to determine piping condition.

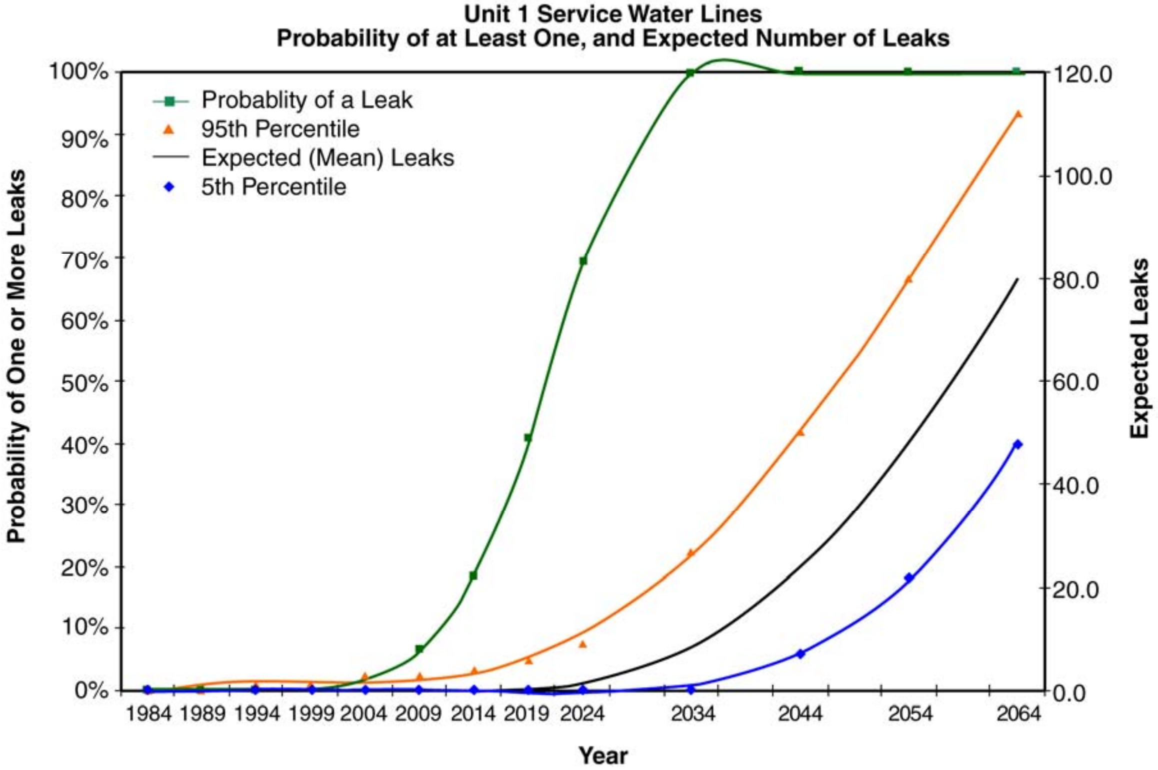

Figure 5-1
Example of Degradation of Service Water Piping: Pinhole Leaks

The direct assessment methodology that has successfully been employed for buried gas transmission and distribution pipelines and other pipelines that transport hazardous materials (for example, oil and gas) provides a useful model for assessments of service water piping. As noted in Section 2, direct assessment (for internal or external corrosion) includes the following steps:

1. **Preassessment:** Determine the feasibility of the direct assessment procedure based upon a collection of design and operating data, environmental information, and any corrosion protection measures. Separate the line into discrete segments based upon various design and operating characteristics.

2. **Indirect Inspection:** Determine the most susceptible locations from further details of the design and operating information, consistent with the ICDA/ECDA methodology.
3. **Direct Examination:** Develop predictions of corrosivity, corrosion monitoring results, and actual volumetric measurements and visual inspection results.
4. **Postassessment:** Perform analysis of the data from the first three steps to assess the overall effectiveness of the direct assessment process, and determine the reassessment interval (a key step).

Throughout the analysis, the approach involves estimating internal damage, which will be a function of the material, piping geometry, water chemistry, flow conditions, temperature, mitigation measures, and failure history, plus the estimated OD damage from soil corrosivity, coating condition (known and estimated), age, and cathodic protection.

Selection of Inspection Locations

The objectives of a service water piping program are to verify structural integrity and system functionality. A common approach is to select appropriate sample locations, perform inspections on the samples, evaluate system condition, and take appropriate actions.

The layout of a typical program is described below.

- Define a sample for evaluation. There are far more potentially susceptible locations than can be examined practically (in literally miles of pipe).
  - Identify the most susceptible locations or groupings based on design and operating characteristics.
  - Define risk. Define contingency actions as part of this.
  - Choose a limited sample of piping components with the greatest susceptibility.
  - Prioritize locations based upon the consequences of failure and upon accessibility of the locations for inspection (including possible radiological effects).
  - In the sample size, also consider the level of susceptibility for the system.
  - Consider historical degradation (replacements, repairs, and so forth), as well as similar areas in parallel trains or in sister plants with historical degradation or from the industry as a whole.
  - Consider components or locations known within the industry to be particularly susceptible.
- Evaluate the condition of the piping from the sample relative to the existence, extent, and rate of degradation.
  - Confirm that structural integrity of the piping has not been jeopardized.
  - Expand the sample as required.
  - Schedule repairs or replacements.

  - Define the reinspection interval.
  - Update the prediction methodology, including results from inspections and industry experience.
- Assess system condition.
  - Identify and inspect a sufficient number of appropriate locations to confirm system susceptibility and to establish the level of degradation present.
  - Define the existence of degradation by type.
  - Confirm structural integrity.
  - Characterize local conditions (for example, identify incipient leak locations).

The process of defining rates must be undertaken with caution, particularly when only a single inspection has been done. In all cases, sources of error in rate predictions will be associated with the actual time dependence of the phenomenon and the time over which the observed effect has actually occurred. For example, assigning a linear time dependence to a corrosion phenomenon will usually be conservative, often very conservative (most corrosion phenomena will have a time dependence less than 1). However, the observed metal loss may have occurred over a time that was significantly less than the time interval since the last inspection, so the operative rate is actually much larger than what would be calculated, assuming that corrosion began from the first day that the system was wet. In the latter case, the linear time dependence would be nonconservative, because the time used would be much too large. For single inspections, use of the nominal thickness as the "before" measurement can be a very dramatic source of error. Piping may be thicker, sometimes much thicker, than the nominal.

NDE tools that permit large sections of the system to be subjected to screening inspections offer the potential to augment the purely analytical (on paper) methods for selection of inspection locations. The interaction between the analytical and NDE screening tools can also be optimized.

Level of Susceptibility and Ranking Methodology

Known piping failures from the plant's service water system (or similar locations in other cooling water systems, or from service water system locations in other plants) will define a number of locations for inspection. The number of locations that are defined by known failures will, however, be relatively small and nonrepresentative of the system as a whole. Selection of an appropriate number of locations for inspection will rely more heavily upon NDE screening tools or a predictive methodology that considers all of the factors that can lead to piping degradation.

An appropriate predictive methodology will provide a quantitative or semiquantitative description of the susceptibility of different locations in the system. This can be used to define a ranking of locations for inspection.

Examples of several such methods are given below.

Example Methodologies

MICPro [5-8] is predictive software that evaluates material (including coatings and linings), water chemistry, flow, temperature, and water treatment to provide a relative ranking of MIC and corrosion due to all other sources. User inputs on system design and operation are evaluated against rules, many of which are based upon information in the EPRI *Sourcebook on Microbiologically Influenced Corrosion in Nuclear Power Plants* [5-9], to develop rankings of both MIC and other forms of corrosion on a scale from 1 to 10. Table 5-1 provides an example of a MICPro output summary.

Table 5-1
Typical MICPro Output: Supply Headers and Shutdown Cooling

Plant Information:								
Date Plant Began Operation:	3-26-80							
System/Segment	**Supply Headers (Note 1)**				**Shutdown Cooling (Note 4)**			
Period Evaluated	76-81	81-90	90-92	92-96	76-81	81-90	90-92	92-96
Date System Began Operation:	3/26/80	3/26/80	3/26/80	3/26/80	3/26/80	3/26/80	3/26/80	3/26/80
Date First Wet Out:	7/76	1/1/81	1/1/90	1/1/92	7/76	1/1/81	1/1/90	1/1/92
System Base Material								
Material-C-steel, S-Steel	CS	CS	CS	CS	CS	CS	CS	CS
Product Form: Pipe, Plate, Forging	Pipe	Pipe	Pipe	Pipe	Pipe	Pipe	Pipe	Pipe
Material Treatment Applied:	None	None	None	None	None	None	None	None
Operational Information:								
Average Temperature °F	72	72	72	72	72	72	72	72
Maximum Inlet Temperature °F:	Default	Default	Default	Default	Default	Default	Default	Default
Minimum Inlet Temperature °F:	Default	Default	Default	Default	Default	Default	Default	Default
Average ΔT °F	0	0	0	0	**10**	**10**	**10**	**10**
Maximum ΔT °F	0	0	0	0	Default	Default	Default	Default
Average Flow (ft/sec)	Default	Default	Default	Default	10.1	10.1	10.1	10.1
Minimum Non Zero Flow (ft/sec):	Default	Default	Default	Default	Default	Default	Default	Default
Normal System Operating Pressure:	110	110	110	110	70	70	70	70
Normal Stagnation Period (wks):	Default	Default	Default	Default	13	13	13	13
Longest Stagnation Period (wks):	13	13	13	13	52	52	52	52
# Stagnation Periods/year	Default	Default	Default	Default	4	4	4	4
Normal Restart flow (ft/sec)	Default	Default	Default	Default	10.1	10.1	10.1	10.1
Total Time at Min Flow (wks/yr)	Default	Default	Default	Default	Default	Default	Default	Default
Water Source:								
River, Lake, Pond, and so forth	Lake	Lake	Lake	Lake	Lake	Lake	Lake	Lake
Water Treatment:								
Biocide	None	Chlorine	NaOCl+NaBr	NaOCl+NaBr	None	Chlorine	NaOCl+NaBr	NaOCl+NaBr
Ppm		0.8	0.5	0.3		0.8	0.5	0.3
Freq		Cont's				Cont's		
Biodispersant								
Ppm								
Freq								
Inhibitor				Zinc + O'PO4				Zinc + O'PO4
Ppm				1				1
Freq								
Deposit Control				Polymer				Polymer
Ppm								
Freq								
Water Chemistry								
Conductivity (μS/cm)	500	500	500	500	500	500	500	500
Tot. Dis. Solids, TDS (ppm)	Default	Default	Default	Default	Default	Default	Default	Default
PH	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Turbidity (NTU)	Default	Default	Default	Default	Default	Default	Default	Default
Total Hardness ppm	Default	Default	Default	Default	Default	Default	Default	Default
Total Alkalinity ppm	75	75	75	75	75	75	75	75
Total Solids ppm	150	150	150	150	150	150	150	150
Sulfate ppm	50	50	50	50	50	50	50	50
Chloride ppm	100	100	100	100	100	100	100	100
Sulfide ppm	Default	Default	Default	Default	Default	Default	Default	Default
Oxygen ppm	Default	Default	Default	Default	Default	Default	Default	Default
Iron ppm	1	1	1	1	1	1	1	1
Manganese ppm	Default	Default	Default	Default	Default	Default	Default	Default
RESULTS	Note 2							
MIC	7.1	5	4.5	4.7	7.3	5.1	4.8	4.8
General/Pitting Corrosion	7.1	8.6	8.6	4.8	7.3	8.8	8	4.9
(for 300-series Stainless Steel):	Note 3							
MIC	6.8	4.8	4.3	4.6	7	4.9	4.6	4.6
General/Pitting Corrosion	2.8	3.5	3.5	1.9	2.8	3.5	3.1	1.9

Notes

1. Includes 2 HBC-32, -33, -34 and 2 HCC-33 & -34
2. MIC Index = 4.8 & Corrosion Index = 7.8 for 0.3 ppm TRO
3. MIC Index = 4.6 & Corrosion Index = 3.1 for 0.3 ppm TRO
4. Includes 2 HBC-35, -43, -59, -60 and 2 HCC-294 & -295
5. Includes 2 HBC-63, 64 (supply) & -75, -76 (return)
6. Includes 2HBC-68, -103, -69, -104, -105, -77, -106, -78 and HBB-2 , -3, -4, -5

MIC indices have been developed by several different organizations to assess the relative MIC susceptibility of different locations, based upon measured numbers of microorganisms that have been associated with MIC. In general, those methods evaluate predicted or measured microbiological activity from specific system, levels of siltation, and other deposits, and combine those predictions or observations into a more refined index for MIC, and only for MIC. Some of the MIC indices were developed for specific plants based upon the plant's experience in service water and other raw water systems, while other indices used results from multiple plants. Reference 5-11 provides a description of several MIC indices and compares their results for several plants to predictions from the CHECWorks Cooling Water Application [5-10].

Several utility-developed methods provide a predictive relative ranking methodology for susceptibility to MIC and other forms of corrosion for cooling water systems, based upon element configuration, material, temperature, and flow. The stated goals of those programs are to provide useful remaining life predictions and long-range planning, to generate long-term data for evaluating cost-benefit analyses of piping replacements, to generate information for repair/replace decisions, and to provide inputs to the water chemistry programs.

The Columbia Generating Station Plant Service Water (TSW) Corrosion Monitoring Program Plan [5-12] program was developed to monitor system corrosion rates, but does not attempt to predict or prevent through-wall leaks due to localized pitting. The program was created because TSW piping has experienced flow restriction and heat exchanger fouling since early in operation. During startup testing before commercial operation, many components were left with untreated stagnant water. Early failures included gross plugging and fouling of heat exchangers. Piping failures due to pitting were first observed in 1991. The predominant failure mode has been underdeposit, localized pitting, producing pinholes. MIC has been identified in many of the deposit analyses, but has not been a major concern for the plant.

The program is analogous to that used for FAC in high-energy lines. The approach divides the system into 31 individual zones, and zone flow velocity, temperature (inlet and outlet), previous failure information, and plant reliability risks have been determined for each zone. Zones are defined by areas or components that can be isolated by valves. System zone susceptibility is based on flow velocity and temperature. The zones are used to define where UT thickness monitoring will be done. UT and corrosion coupon data (from two corrosion coupon racks) are incorporated together. The goal of the program is to define uniform corrosion rate, not piping integrity or pitting. Therefore, only six individual points around the circumference are selected for UT inspections. No grids are used. Those six points per circumferential location are measured once per year to trend the average metal loss on an annual basis. Table 5-2 is an example of the ranking system.

Table 5-2
Example Corrosion Monitoring Program Weighting Factors

Flow Velocity	**Range Description**	**Assigned Points for Ranking**
Low	Settling out entrained solids, increased MIC susceptibility	50
Intermediate	Marginal	25
Design	Within design	0
High	Concerns with erosion	25
Temperature (Biofilm Effects)	**Range Description**	**Assigned Points for Ranking**
Hot	Impedes MIC	2
Warm	Optimum conditions for bacteria growth and MIC promotion	10
Moderate	Slow MIC growth	2
Temperature (Uniform Corrosion)	**Range Description**	**Assigned Points for Ranking**
Hot	Noticeable increase above 100	10
Warm		7
Moderate		4
Cooler		2
Cool		1

Detailed Example Application

MICPro was used as part of an element selection project performed for a service water system at a southern nuclear plant to define inspection locations. The software was used to define other actions required to modify the program to a risk-informed ISI (RI-ISI) program.

The first cut, binary evaluation of all potentially active degradation mechanisms indicated that the potential exists for localized corrosion (that is, microbiologically influenced corrosion and pitting) and flow sensitive attack (that is, erosion-cavitation) in the service water system. In accordance with the criteria given in EPRI report TR-106218 [5-13], the possibility of failure coupled with the consequence of failure determine the quantity of locations to be inspected. In the plant’s SWS, application of this approach would yield an inspection sampling of 10% to 25% of the susceptible locations. This approach is considered impractical for application to a very large system like service water, which is susceptible to localized corrosion mechanisms that can occur over large areas. Use of a “finer screen” than that used for the binary determination of all the potentially operative degradation mechanisms, however, permits the inspection to be focused on those portions of the system or subsystems where degradation is most likely. In this "finer screen" approach, other forms of corrosion that could potentially affect the SWS are evaluated in addition to MIC and pitting, which were determined to be operative for the SWS. This analysis required a determination of the temperature, flow, water chemistry, and water treatment variations throughout the system. Results from prior inspections or monitoring can also be factored into the selection process in this way so that system history becomes a key input into the determination of potential degradation. By selecting locations that are most likely to be degraded, and then performing a reasonable number of inspections at those areas, information can be obtained that should bound the entire system.

The objective of the element selection was to identify specific locations within the pilot plant SWS that are most susceptible to corrosion degradation based upon the system geometry (which influences local flow and deposition patterns), operating history (for example, the flow patterns for various subsystems in the SWS), any prior failure or repair history, seasonal variations in temperature and water chemistry, and variations of biocide concentrations around the system, with data from laboratory studies and prior experience at other plants also considered. Areas to be inspected could then be selected based upon accessibility, planned maintenance nearby, and so forth.

The first step in this process was a detailed review of all the piping and instrumentation diagrams, isometric drawings, and documents related to the typical operation of all of the subsystems within the SWS. These materials, supplied by the station, included information on typical system flows, temperatures, water chemistry, and water treatment. The information revealed that the SWS has operated under four clearly different control regimens:

- From prior to commercial operation to 1981, the system was untreated.
- From 1981 to 1990, gaseous chlorine at a target concentration of 0.8 ppm was added continuously (several times per day) in an attempt to control macrobiological fouling.
- From 1990 to 1992, the gaseous chlorine was replaced with a combination of sodium bromide and sodium hypochlorite at a target concentration of 0.5 ppm; again, this was for control of macrobiological activity.
- Since 1992, the sodium bromide plus sodium hypochlorite concentration was reduced to 0.3 ppm, and a corrosion inhibitor (zinc plus orthophosphate—zinc concentration in the SWS is believed to be on the order of 0.25 ppm) and a polymer (for deposit control) have been added.

The inputs were evaluated using **MICPro** [5-8] to determine the susceptibility of specific subsystems within the SWS to MIC and other forms of corrosion (including pitting, underdeposit corrosion, and general corrosion). **MICPro** evaluates susceptibility as a function of the material of construction, temperature, flow, water chemistry, and water treatment. Runs were performed for each subsystem for each of the time periods defined above.

The **MICPro** results for the different subsystems were compared and benchmarked against the system failure history. The majority of the failures or areas where degradation was detected by inspection were in good agreement with the **MICPro** rankings.

Water chemistry data and concentrations of water treatment chemicals used were nominal values for the entire system. All additions of water treatment chemicals are made at the SWS intake. The measured data for biocide residuals were made at the discharge of the closed component cooling water heat exchangers. The input data to this study did not include any measurements of the actual concentrations of critical chemical species around the system. For example, oxidizing biocides, such as chlorine or the bromine/hypochlorite mixture that is currently used, will be consumed in the system. As a result, the biocide concentration in some portions of the system, such as areas a long distance from the injection point or from the position where the residual values are measured, may be less than the target value. Oxidizing species also decay over time. Systems that have a biocide residual during periods when those systems experience flow will have a lower residual after the system has been stagnant for some time. Several elements were identified for selection to determine if consumption of water treatment chemicals through the system produced areas with more degradation than would be predicted from the nominal water treatment.

Conversely, areas very close to the biocide injection point may experience higher than nominal values (and possibly much higher than nominal values). Since those chemicals can exacerbate general and localized corrosion, several areas, such as the SWS supply headers, were also identified for inspection to ensure that the treatments themselves had not produced degradation.

The subsystems that showed the most severe MIC and other corrosion degradation in the **MICPro** runs were the primary focus for the element selection. The condition of those systems should bound the condition of all areas of the SWS. The majority of candidate locations selected for inspection were from the most susceptible systems.

Finally, some of the stainless steel piping in the SWS was identified for inclusion in the inspection matrix. Stainless steel has been shown to be susceptible to MIC, especially at weldments. Including a limited number of stainless steel welds provides comprehensive, bounding data to demonstrate that localized attack from MIC is well understood.

The redefined inspection program defined both typical and worst-case areas in the SWS so that all of the expected degradation mechanisms would be assessed. Areas were selected to provide a statistically significant number of locations and locations that are likely to experience worst-case conditions for localized corrosion (including pitting, crevice corrosion, and underdeposit corrosion).

Section changes, where fluid velocity can increase or decrease rapidly, or geometries where fluid changes direction abruptly are the areas most likely to experience erosion due to “scouring” by particulates. These areas are also susceptible to underdeposit corrosion or MIC where particulates and microbes settle.

Accessibility was another factor considered in the inspection recommendations. Since UT can be performed rapidly, with minimal disruption to system operations, its use was emphasized. Wall thickness determinations by UT will be used to evaluate the existing condition of the pipe relative to the minimum wall thickness, to provide an estimate of the general corrosion rate, and to define areas of localized attack.

Characterization of deposition effects can be performed using RT at locations that would be expected to demonstrate worst-case deposition. RT has also been shown to be a powerful tool in evaluating local thinning of carbon steels and other alloys where MIC or erosion effects are operative. Radiographic methods may also be used in areas where such effects might be suspected to be a concern. More likely, RT will be used to provide additional information in areas where UT has identified thinning.

Since access to most areas inside the SWS is limited, visual methods were to be used only where access was simple (available access ports and manholes, instrument taps that are being accessed for maintenance, threaded connections, and so forth) or where other techniques reveal that degradation is severe.

A summary of the results for the carbon steel SWS piping from the plant is shown below for the following systems:

- Supply headers
- Containment cooling coils
- Emergency diesel generators
- Shutdown cooling
- Emergency feedwater
- Fuel pool cooling
- Closed cooling water

Not surprisingly, the degradation for each of the subsystems was predicted to be fairly similar, because the materials, systemwide temperature, flow history, water chemistry, and water treatments had been essentially the same. The areas with the predicted worst degradation were:

Prior to commercial operation → 1981: Shutdown Cooling
Supply Headers

1981 → 1990: Shutdown Cooling
Fuel Pool Cooling

1990 → 1992: Supply Headers
Shutdown Cooling

After 1992: Shutdown Cooling

Reported failures or degradation detected include the following:

- Containment cooling (1989; localized corrosion)
- Emergency diesels—return line (1989 and 1995; localized corrosion)
- Supply header expansion joint (1990; localized corrosion)
- Shutdown cooling supply header (1991; localized corrosion)
- Emergency feedwater pump suction (1996 and 1997; localized corrosion)
- Spent fuel pool heat exchanger piping (two in 1997; localized corrosion)

A sampling of the specific locations included in the RI-ISI program within each system is given in Table 5-3. (Table 5-4 gives the single location selected for inspection of erosion-cavitation degradation.) These specific locations should provide typical areas of degradation for the system or worst-case degradation. In most cases, one or more 1-foot lengths in a spool piece or a specific fitting were identified for inspection. As noted previously, selection of these specific locations was based upon a change in flow (for example, the upstream or downstream end of a reducer or tee), or the locations were at the bottom of a long vertical run where deposition would be expected to be a maximum, immediately downstream of a heat exchanger (higher ΔT; greater microbiological activity), or in areas with extreme chlorine concentrations. High chlorine concentrations can accelerate damage beneath deposits. Such conditions may have existed in areas near the chlorine injection point (for example, supply headers), especially during the time periods when a relatively high chlorine residual (0.8 TRO) was measured at the CCW heat exchangers or at the system discharge. Other areas, such as any of the normally stagnant legs or the return headers, have probably experienced lower-than-nominal concentrations of water treatment chemicals and less protection against MIC or localized corrosion.

Table 5-3
Sample Element Selection

Iso Drawing No. Description	Risk Segment ID Inspection Location	Exam Method / Volume Reason for Selection
2HBC-68-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-06A / 16A Spool 2 - Long horizontal run	UT / One foot x 270° arc that includes bottom 60° Worst Case Section of Supply to Loop 1 Containment Cooling Coils
2HBC-68-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-16A / 17 Spool 3 or 4	UT / One foot x 270° arc that includes bottom 60° Typical Section of Supply to Loop 1 Containment Cooling Coils
2HBB-2-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-18A Spool 1	UT / One foot x 270° arc that includes bottom 60° Typical Section of Supply to Loop 1 Containment Cooling Coils
2HBB-2-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-18A Spool 2	UT / One foot x 270° arc that includes bottom 60° Typical Section of Supply to Loop 1 Containment Cooling Coils
2HBC-103-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-19A Spool 1 / 2 - Elbow (Item 11)	UT / One foot x 270° arc that includes bottom 60° Worst Case Section of Supply to Loop 1 Containment Cooling Coils
2HBC-103-1 Sh. 1 Supply Header #1 to Containment Cooling Coils	SWS-R-19A Spool 1 - Horizontal run	UT / One foot x 270° arc that includes bottom 60° Worst Case Section of Supply to Loop 1 Containment Cooling Coils
2HBC-59-1 Sh. 2 Return from Shutdown Cooling Heat Exchanger to Header #1	SWS-R-15A Spool 1 - Between heat exchanger nozzle and valve 2SW-11A	UT / One foot x 270° arc that includes bottom 60° At/near location of known failure and heat exchanger with microbiological fouling
2HBC-59-1 Sh. 2 Return from Shutdown Cooling Heat Exchanger to Header #1	SWS-R-15A Spool 2 - Riser from valve, horizontal run, and expansion loop (minimum of three areas)	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-59-1 Sh. 2 Return from Shutdown Cooling Heat Exchanger to Header #1	SWS-R-15A Spool 5 - Downstream of reducer (Item 86)	UT / One foot x 270° arc that includes bottom 60° Probable worst case location
2HBC-59-1 Sh. 2 Return from Shutdown Cooling Heat Exchanger to Header #1	SWS-R-15A Spool 3 - Horizontal run and expansion loop (two locations)	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-59-1 Sh. 2 Return from Shutdown Cooling Heat Exchanger to Header #1	SWS-R-15A Spool 4 - Long horizontal run and short vertical decline (minimum of two areas required)	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-60-1 Sh. 1 Return from Shutdown Cooling Heat Exchanger to Header #2	SWS-R-15B Spool 1 - At heat exchanger outlet and at bottom of short vertical run (two locations)	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-60-1 Sh. 1 Return from Shutdown Cooling Heat Exchanger to Header #2	SWS-R-15B Spool 1 - Dissimilar metal welds (carbon steel to stainless steel) at flow orifice 2FO-1456	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-60-1 Sh. 1 Return from Shutdown Cooling Heat Exchanger Header #2	SWS-R-15B Spools 3 and 4 One location – each spool	UT / One foot x 270° arc that includes bottom 60° Probable worst case locations
2HBC-60-1 Sh. 1 Return from Shutdown Cooling Heat Exchanger Header #2	SWS-R-15B Spool 5 - Downstream of reducer (Item 78)	UT / One foot x 270° arc that includes bottom 60° Probable worst case location
2HBC-50-1 Sh. 1 Return Header #1	SWS-R-12A Spool 7	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header
2HBC-50-1 Sh. 1 Return Header #1	SWS-R-12A Spool 5 or 6	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header

Table 5-3 (continued)
Sample Element Selection

Iso Drawing No. Description	Risk Segment ID Inspection Location	Exam Method / Volume Reason for Selection
2HBC-50-2 Sh. 1 Return Header #1	SWS-R-12A Spool 4 - Downstream of reducer (Item 21)	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header (with velocity change)
2HBC-50-2 Sh. 1 Return Header #1	SWS-R-12A Spool 2 or 3	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header
2HBC-51-1 Sh. 1 Return Header #2	SWS-R-12B Spool 1 (two locations required)	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header
2HBC-51-2 Sh. 1 Return Header #2	SWS-R-12B Spool 6	UT / One foot x 270° arc that includes bottom 60° Typical Section of Return Header
2HBC-83-81 Sh. 1 Return Headers #1 and #2 to Emergency Cooling Pond	SWS-R-32 Underground Section	Remote visual (when other activities provide access to any part of the line - piping is all underground) Return Header Location (Maximum distance from water treatment chemical injection point)
2HBC-83-2 Sh. 1 Return Headers #1 and #2 to Emergency Cooling Pond	SWS-R-32 Spool 2	UT / One foot x 270° arc that includes bottom 60° Typical Return Header Location (Minimum concentration of water treatment chemicals expected)
2HBC-83-1 Sh. 1 Return Headers #1 and #2 to Emergency Cooling Pond	SWS-R-32 Spool 1 - Downstream of reducer (Item 5) and at tee to 2HBC-51-18" (two locations)	UT / One foot x 270° arc that includes bottom 60° Probable worst case deposition/MIC locations in return header where water treatment chemical concentration is a minimum
2HBC-83-80 Sh. 1 Return Headers #1 and #2 to Emergency Cooling Pond	SWS-R-32 Underground Section	Remote visual (when other activities provide access to any part of the line - piping is all underground) Return Header Location (Maximum distance from water treatment chemical injection point)

Table 5-4
Single Location for Inspection of Erosion-Cavitation Degradation

Iso Drawing No. Description	Risk Segment ID Inspection Location	Exam Method / Volume Reason for Selection
2HBD-26-1 SW & ACW Return to Reservoir	SWS-R-13-2 Spool 1- Immediately downstream of valve 2CV-1460	UT / One foot x full 360°

Material (Including Coatings and Linings)

For uncoated materials, the key factor in corrosion protection is the protective nature of the oxide, which is a function of dissolved oxygen, temperature, flow, and water chemistry (see Section 4). For carbon steel and cast iron (the most commonly used service water piping materials), normally flowing lines will usually form a relatively uniform and somewhat protective oxide, and maybe some tubercles. In flowing environments, the corrosion is usually general corrosion and is fairly predictable and bounding (the worst general corrosion). The range of rates will have a distribution (a factor of 2 or so on the average).

Coatings and linings are applied to the ID or the OD of piping at the factory or in the field to provide a barrier between the corrosion-susceptible material and the environment. As long as the coating maintains its integrity, corrosion is effectively mitigated. However, all coatings have some level of permeability to water, and all coatings will degrade over time, so areas of the susceptible material will become uncovered. The approach for determining the condition of coated or lined piping systems will generally revolve around confirmation that the coating or lining is still in good condition.

Corrosion-resistant alloys rapidly form an extremely protective oxide film by exposure to air or water or to a specific pretreatment. The key to the protection that they provide is to keep that film integral and to permit the film to heal in the event that it is damaged.

For either coated or lined piping or for corrosion-resistant alloy piping, the number of points to be inspected is never zero. The number of inspected locations will probably be reduced and the inspection approach will typically be changed (for example, to verify that the protective nature of the coating or the corrosion-resistant alloy has been retained), in comparison to what is done for bare steel.

As noted previously, galvanic couples should receive particular attention, based upon the aggressiveness of the water and the coupled materials.

Temperature

Temperature will affect both general corrosion and localized corrosion (higher temperature is worse) and MIC (for which there is an optimum temperature; very high temperatures will have lower MIC susceptibility). In general, corrosion rates for carbon steel or cast iron will double for every 15°F (8.3°C) increase in temperature, at least up to approximately 160°F (71°C). Susceptibility to MIC will generally be optimum between about 80°F and 120°F (27°C and 49°C).

Flow Regime

In addition to the wide variety of materials and water chemistries that service water piping will experience, operating conditions can also vary significantly with time, so the piping will experience numerous different flow regimes. The flow conditions in the piping can dramatically change the nature of the degradation that the piping will experience, producing local conditions that are significantly different from those that were considered in design.

Normally Flowing

The pipe was designed for this condition. For fluid velocities from about 5 to 15 fps (that is, the flow regime that most of the pipe will experience per design), piping will experience general corrosion. Higher flows will produce higher general corrosion rates. Very high flows, particularly with entrained solids, can produce erosion. Cavitation downstream of valves can also occur. Lower flows can permit solids to settle onto surfaces, can encourage biofilm formation and MIC, and support localized corrosion. Continuous low flow (fluid velocities less than about 5 fps [1.5 m/s]) will be too slow to prevent biofilms from forming and attaching to surfaces but will still provide sufficient oxygen and nutrients to reach the surface so that corrosion, including localized corrosion and MIC, can proceed.

Normally Stagnant Conditions

In truly stagnant water systems, the corrosion process, which is essentially the oxidation of iron, and the biological oxygen demand will quickly consume the available dissolved oxygen. When the dissolved oxygen is gone, oxygen-driven corrosion effectively stops. However, in deoxygenated environments, anaerobic bacteria (for example, sulfate-reducing bacteria) can cause the corrosion process to continue, because alternative cathodic processes that are controlled by the metabolic activity of the anaerobic microorganisms will produce corrosion at finite rates.

Typically, it does not take long to consume the concentration of dissolved oxygen that is present in most ambient water (6 to 10 ppm in most waters; a function of temperature). The total time required to consume the oxygen will be dependent on the total quantity of dissolved oxygen, which is controlled by the concentration and volume of water, and by the oxidation of the iron, which will be directly proportional to the exposed surface area. Assuming a simple oxidation of iron reaction, where iron combines with dissolved oxygen ($\underline{O}$) to form one species of iron oxide, the following equation applies:

$$3Fe + 4\underline{O} = Fe_3O_4 \qquad \textbf{Eq. 5-1}$$

The basic effect will be the same if other oxides (for example, Fe_2O_3) are formed.[2] Only the rates will be slightly different.

Results of simple calculations of the time required to consume the total amount of dissolved oxygen in both a 6-inch (152-mm) pipe and an 8-inch (203-mm) pipe are shown in Figures 5-2 and 5-3. These figures include both the dissolved oxygen concentration and corrosion rates as a function of time in a stagnant 6-inch and 8-inch pipe, respectively.

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[2] In a service water system, the actual corrosion product will be a mixture of the two.

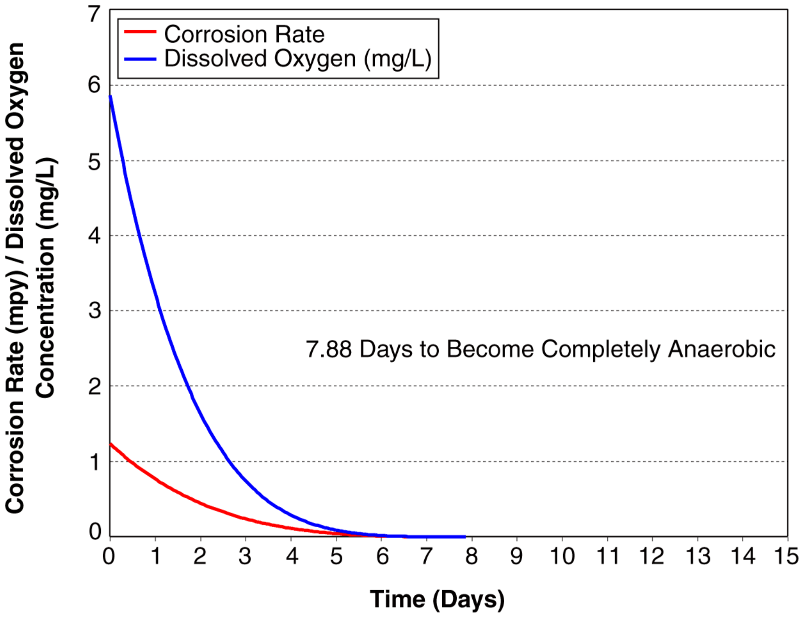


Figure 5-2
Consumption of Dissolved Oxygen in a Stagnant 6-Inch Line

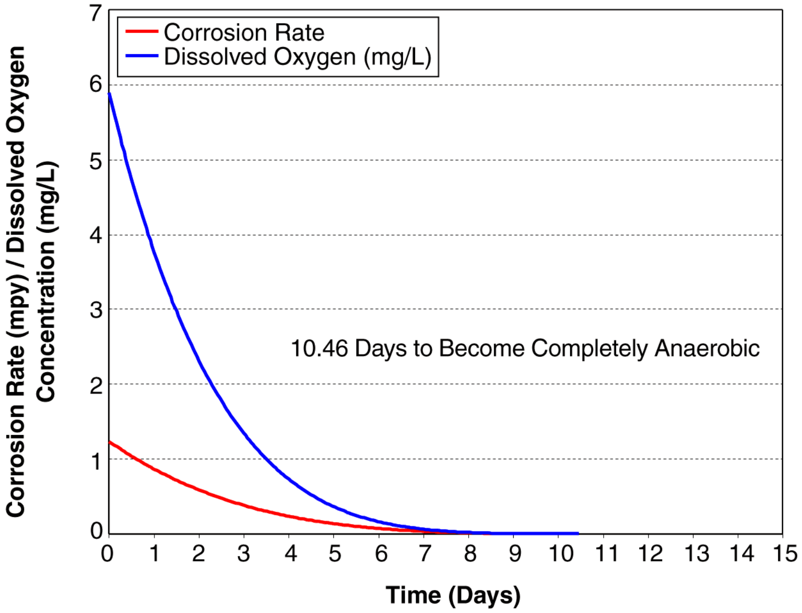


Figure 5-3
Consumption of Dissolved Oxygen Concentration in a Stagnant 8-Inch Line

Work from AECL [5-14] has shown that oxygen depletion is actually more rapid than shown in Figures 5-2 and 5-3. However, both the simplistic calculation used here and the measurements from AECL agree that the time required for a stagnant carbon steel line to go anaerobic is a few days, not weeks or months.

Using the oxygen concentration history generated in Figures 5-2 and 5-3, the total amount of corrosion occurring per oxygen batch was calculated at 0.006 mils (0.00015 mm) for the 6-inch pipe and 0.008 mils (0.0002 mm) for the 8-inch pipe. For 12 flow periods per year, the resulting metal loss would be 0.072 and 0.096 mils (0.0018 and 0.0024 mm), respectively, assuming that only dissolved oxygen effects influenced the corrosion. The resulting average corrosion rate over the one-year period would be very low, on the order of 0.1 mpy (0.00254 mm/y).

Intermittent Flow Conditions

Intermittent flow conditions can produce several different and somewhat conflicting effects on the form and rate of corrosion degradation. Corrosion degradation rates in intermittent flow regimes are typically higher, at least for localized corrosion, than in continuously flowing sections, for several reasons:

- Without the scouring action of continuously flowing water, microbial species have an easier time attaching themselves to piping walls and establishing active colonies.
- Without replenishing water flow to wash out crevices and pits, concentration cells that accelerate pitting rates can be established.
- Although corrosion during the stagnation period may not be great, microbial colonies can produce products such as sulfides that will produce rapid corrosion when flow is reinitiated.

Figures 5-2 and 5-3 predict that the total amount of dissolved oxygen will be consumed by the corrosion reaction specified within 8 days in the 6-inch stagnant pipe, and within 11 days in the 8-inch stagnant pipe. This estimation technique may overpredict the amount of time to completely consume the available dissolved oxygen, because it does not account for BOD. Therefore, with a once-monthly flow, the system described by those figures would be anaerobic for at least half of the month. Although the lack of available dissolved oxygen would have stopped nonbiological corrosion reactions, anaerobic microbes can continue the corrosion process in the absence of oxygen. Once bacterial organisms establish viable colonies on the surface of the pipe, a complex symbiotic structure can evolve where aerobic bacteria live on the surface exposed to the dissolved oxygen and shield the anaerobic bacteria from dissolved oxygen, allowing them to flourish below. Further, the aerobic bacteria will become inactive during periods of anaerobisis; however, those anaerobic periods may not kill them, but rather permit them to rebloom when oxygen is again supplied to the system.

In addition, during the relatively short periods of flow with oxygenated water, extremely high metal loss rates can occur, because nonprotective corrosion products that were formed during the anaerobic periods will dissolve rapidly during the initial stages of flow with aerated water.

A major factor in microbiological growth and the influences that the microbes may have on pipe corrosion has to do with the level of aeration in the environment and the aeration history that the environment has experienced. Many of the microorganisms important to corrosion are strictly anaerobic (that is, they cannot flourish in environments where there is oxygen), others are strictly aerobic (that is, they flourish only in the presence of oxygen), and many others can both tolerate and grow over a wide variety of levels of oxygen. For example, long periods of stagnation can lead to anaerobic conditions, the formation of a vigorous anaerobic biofilm, and, often, the production of sulfides by sulfate-reducing bacteria. Without the biofilm, corrosion rates during stagnation periods would be very low, because the kinetics of the cathodic reaction would be very slow. The presence of the SRB and sulfides provides an alternative to the reduction of oxygen that typically produces corrosion of carbon steels in cooling waters. Further, the production of sulfides serves to make the anaerobic environment more aggressive. Sulfides produce a nonprotective iron sulfide film (as opposed to the much more protective iron oxide film that normally forms). When a steel surface with an iron sulfide film is exposed to rapidly flowing oxygenated water, the poorly protective film and some base metal will be removed. This leads to short periods of very rapid corrosion during periods of flow that follow long periods of stagnation. Hardy and Bown have described this phenomenon in detail [5-15]. The key element in this form of rapid corrosion is the dissolution of the nonprotective iron sulfide film in an oxygenated environment.

Intermittent flow lines will be subject to some general corrosion (probably comparable to the time fraction of flow) plus some localized corrosion due to pitting, underdeposit corrosion, and MIC, where the MIC may be reinforced by the time of flow. The total metal loss will be a function of the time of flow, the number of flow periods that exist (for example, lines that flow once per month will have twelve times as many periods of accelerated corrosion during the transition from stagnation to full flow as lines that flow annually), and the specifics of the water chemistry, microbiology, and any mitigation measures that the specific line will experience.

Dead Legs

The fluid flow in the lines running past the stagnant portions of adjacent lateral lines will cause some turbulence at the tee and mixing of the otherwise stagnant fluid in the dead leg section. To estimate the depth of penetration of the turbulent flow down the dead leg, correlations from an EPRI report on thermal stratification, cycling and striping (TASCS) [5-16] were used. The following assumptions were used in the turbulent mixing analysis:

- Water flows in excess of 3 feet per second (0.9 meters per second) exist in each of the flowing lines tied into the “stagnant” lines.
- The TASCS analysis successfully approximates the depth of penetration down the dead legs.
- The diameter of the dead-leg line was assumed to be small, for example, 1 or 4 inches (25 or 102 mm). This is a conservative estimate since most dead leg lines are connected to lines that are 3 inches (76 mm) in diameter or greater.

Figure 5-4 is a graph showing the depth of penetration versus flow velocity, from [5-16].

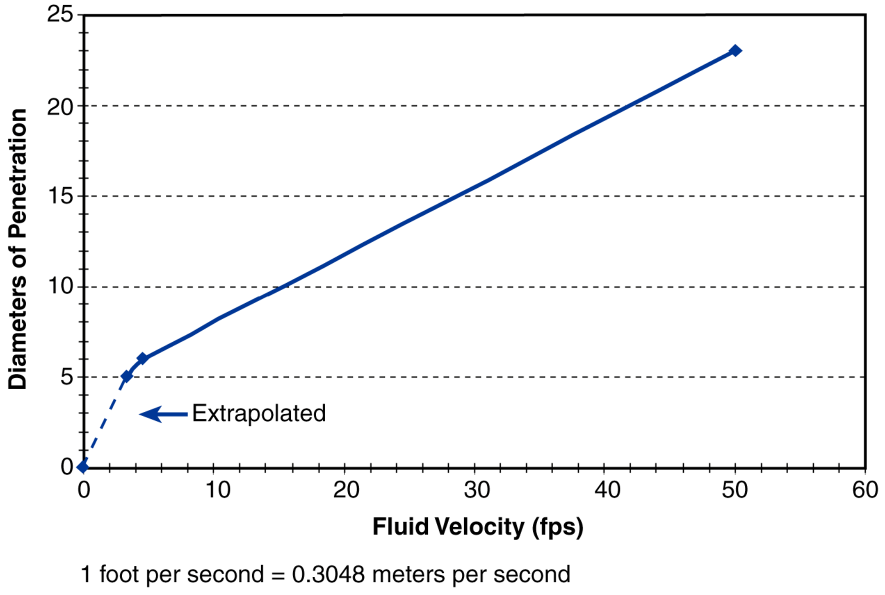


Figure 5-4
Depth of Turbulent Flow Penetration Versus Fluid Velocity

With the fluid velocity in the pipes flowing past the dead legs ranging from feet 3 to 10 feet per second (0.9 to 3 meters per second), the chart estimates diameters of turbulent penetration down the dead leg. From Figure 5-4, 5 to 8 diameters of penetration can be expected down the dead leg lines. Therefore, on a 1-inch (25.4-mm) diameter line, 5 to 8 inches (127 to 203 mm) of turbulent penetration is expected, and on a 4-inch (102-mm) diameter line, 20 to 32 inches (508 to 813 mm) of penetration is expected.

In truly stagnant systems (that is, without water replenishment), the general corrosion reaction and the BOD consume the available dissolved oxygen in a matter of days. Once oxygen is removed from the water, all nonbiologically driven corrosion stops. Hence, a truly "dead" system does not corrode. However, because of the turbulent flow of water into the dead leg sections during flow periods, dissolved oxygen will be replenished in the sections of pipe labeled as "stagnant" to a number of diameters, consistent with the example shown in Figure 5-4. In fact, with relatively acquiescent flow of oxygen-rich water within the dead legs, MIC activity will be expected to increase, since water flow will not scour microbial colonies from piping walls, and pitting propensity will as well with no heavy flow to wash out concentration cells.

When dead legs are modeled in this way, the same general corrosion rates will apply as for piping in the continuous flow regime, since there will be no dissolved oxygen limitation, at least to the depth of the turbulent penetration. Further, pitting susceptibility and MIC susceptibility will be increased over that for either continuously flowing or normally stagnant legs.

In many respects, dead legs offer the opportunity for general corrosion, other oxygen effects (for example, pitting due to oxygen concentration cells), and MIC all to be reinforced, even beyond the reinforcement that can occur under intermittent flow conditions. As a result, local corrosion effects may be worst in dead legs. Dead legs are a focal point for a number of utility service water piping inspection programs.

Configuration

For reasons noted above, dead legs are likely to be the most susceptible locations in a service water piping system.

Additionally, higher susceptibility piping configurations are:

- Horizontal runs, which are more susceptible than vertical runs
- Local low points and system low points, which can be more susceptible to corrosion damage
- The bottoms of long verticals or changes in section from smaller diameter to larger (that is, where fluid velocity will decrease rapidly and deposit suspended solids and microbes)
- Vertical dead legs at the intersection with flowing lines (that is, verticals that are at the bottom of the flowing line)
- Laterals where deposits can accumulate, which will be worse than straight runs or laterals that are at a higher elevation than the main run
- Locations downstream of heat exchangers, which can be more susceptible, especially at low points
- Locations downstream of valves that may be leaking, which should be treated as locations with continuous low flow, and hence may be more prone to localized corrosion and MIC
- Areas immediately downstream of throttling valves, butterfly valves, orifices, or downstream of pumps, which can be subject to cavitation

Other considerations:

- Give high priority for inspections to portions of the system that cannot be isolated (for pressure testing, for example).
- Give high priority to locations where a leak could disable safety-related equipment or generation-critical equipment.
- Take access and radiation safety considerations into account.
- For visual examinations, document condition (both as-found and after cleaning).

Water Chemistry

Within an untreated system, the water chemistry will generally be the same throughout the system; however, there can and will be effects of different chemistries contained by the service water piping at different times (for example, seasonal changes). For treated systems, the treatment chemicals may be consumed during their passage through the system. For example, water from the “normal” service water system may reside in safety-related service water lines a significant fraction of the time. Those waters may be from different sources (for example, a spray pond for the safety-related service water system vs. once-through for the normal service water) or receive dramatically different water treatments (for example, biocide, inhibitor, and dispersant vs. no treatment). Even in systems where only a single source of water ever resides in the piping, the consumption of constituents (for example, oxygen) may result from different flow conditions.

Plant-to-plant differences will also exist because of differences in water source. For example, corrosion rates for a brackish water plant will be much different from those for a fresh water plant.

The extensive discussion of how flow conditions affect oxygen concentration (and how corrosion will be influenced by oxygen content) provide an example of how water chemistry can vary within the system. Many of the same arguments apply to water treatments. Specifically, treatments can only be effective at surfaces that the treatments actually reach.

Treatments

The variety of treatments applied for scale and deposit control, corrosion control, and microbiological control will be even greater than differences in water chemistries as a result of the water source. Further, treatments will change over time. Many plants initially began operation with no treatment of their service water system, then changed that approach to include one or more biocides, corrosion inhibitors, or deposit control agents.

The selection of inspection locations within a system or a portion of a system will generally not be affected by water treatment. However, the number of points in the program may be reduced for an effectively treated system. For the initial inspection, “effective treatment” can be determined only from known satisfactory operation, especially as compared to system performance that may have preceded the treatment or performance dramatically superior to that of sister plants with similar water chemistry and operating conditions. It must be kept in mind that the effectiveness of many water treatment chemicals, particularly corrosion inhibitors and biocides, will be far less when applied to fouled surfaces as opposed to clean surfaces.

Historical Information

All plants have at least some knowledge of the overall condition of their system, based upon:

- Operating experience
- Historical inspections/failures
- Condition of coatings
- Input data from flow test results
- Chemistry/operating data
- Monitoring results (for example, heat transfer performance, pressure drop)

Historical information will be a key factor in defining where in the system to look further using inspection tools as well as in defining the magnitude of an inspection program. The number of inspection locations will be less for a service water system that has had minimal problems, few if any pinhole leaks, and so forth; however, since asset management is the key factor in defining the service water piping program, the value of the asset (the plant) will always enter into the cost of the program that is defined to assure continued safe and reliable operation of the asset.

Determination of Sample Size

For service water piping, the number of locations that will be inspected needs to be large enough to provide a meaningful result and should include a sampling of the locations with the highest susceptibility to degradation.

The sample size will not be a significant fraction of the enormous area presented by the service water piping, nor will it ever be intended to be. The number of sample inspection locations is less important than the nature of the degradation that has occurred (was likely to have occurred) at those locations, so the general condition of the system can be deduced by the samples that are inspected.

The use of NDE tools that permit a screening-level examination of the system and that provide that screening on a significant fraction of the system in order to select specific locations for more detailed examination can help the overall program tremendously.

Initial Inspection

The purpose and expected results from the initial inspection of the piping are basically to provide a screening of system condition and as the first point in trending. Unless degradation is severe, determining the amount of degradation or the degradation rate from the initial inspection is futile, because the initial condition (t_{init}) will be very poorly known.

The initial sampling should address the following points:

- Select a sample of the most susceptible components from the plant ranking analysis and from industry experience.
- Include highly stressed points.
- Include points where the risk associated with failure is highest.
- Incorporate plant history, including (new) components that have been replaced.
- Include some typical locations (and explain why).
- Select locations for inspection based upon their susceptibility. The highest susceptibility locations should be included. Engineering judgment should definitely be employed “to ensure that the most representative sample of the items with the highest probability of damage (will) be examined” (from [5-17]).
- Include similar locations in parallel trains.

- Include known and potential problem areas based on past plant experience and experience in sister plants.
- Consider other applicable locations from industry experience.
- Determine the measured degradation and update the predictive rankings and calculate rates and remaining life understanding that the calculated rates will contain significant uncertainty.
- Expand the sample if the results from any of the inspections present a challenge to structural integrity, indicate a potential problem with an excessive number of pinhole leaks, or indicate a much more aggressive condition than was predicted.

Inspection Methods

Inspection Philosophy

Inspection involves the examination of the plant service water piping, using visual or volumetric methods, to characterize the condition of the piping. Many plants currently have an aggressive program to characterize degradation in a variety of systems, including the various raw water systems in the plant. The primary objectives of those inspection activities are to assure structural integrity of the piping and to characterize the amount and rates of thinning in selected components, most often using ultrasonic testing methods to determine wall thickness. Typically, selected areas (for example, grids) are scanned with an ultrasonic transducer, and minimum thicknesses for that area are recorded. When the recorded minimum thickness is less than the nominal thickness, t_{nom}, the distribution of thicknesses around that minimum thickness point is also described in order to establish whether the metal loss is a more or less uniform thinning (general corrosion) or is more localized (from pitting, crevice corrosion, or MIC). Based upon the inspection results, assessments are then done to determine the types and degrees of degradation, to verify continued structural integrity of the pipe, to estimate the rates of degradation, and to plan repairs or replacements and subsequent inspections.

The locations selected for inspection in a service water piping monitoring program provide a regular assessment of the present condition of the plant, and through repeated measurements at the same locations provide a historical perspective on metal loss rates that can be used to determine the actual metal loss rates, to determine changes in the average rates of degradation, and to define locations that are outliers relative to the general metal loss that is expected. However, inspection is generally a poor way to track rates (it is slow, inaccurate, and has resolution limitations). Extrapolation of data from a single inspection is prone to the greatest inaccuracy.

The basic philosophy will be the same for coated lines or corrosion-resistant alloys and for buried lines. However, the techniques applied and numbers of areas inspected can be or will be much different.

Reiterating, the three purposes of the inspection are:

- To determine whether the component has experienced degradation and identify the location of maximum thinning
- To define the extent and depth of thinning for use in assessments of the level of damage and assessment of structural integrity
- To establish trends and estimate degradation rates

Piping Inspection Techniques

The most effective methods for inspecting service water piping to detect degradation from service involve volumetric NDE techniques. The most commonly used techniques are ultrasonic testing (UT) for thickness and radiographic testing (RT). For nonferrous materials, eddy current testing (ECT) may be used. Low-frequency eddy current testing (LFET) or pulsed eddy current testing are specialized methods that may also be used for screening inspections of ferrous metals.

Inspection Methods (Detailed)

The primary goals of service water piping evaluations should be determinations of the thickness of the piping and the distribution of thinning (pitting vs. general corrosion), both for defining the present condition of the piping relative to structural integrity and pinholes and for evaluating the existence and degree of localized corrosion. For both bare piping and coated piping, volumetric techniques such as ultrasonics and radiography provide the best methods for detailed assessments of thickness. Remote visual inspection may also be used for coated piping, to determine the condition of the coating. An intact coating should prevent all corrosion. Visual and remote visual inspections can also provide some insight regarding the presence and thickness of corrosion products, size and depth of metal loss (this may require removal of deposits or corrosion products), or other surface anomalies.

Ultrasonic testing (Figure 5-5) is a volumetric method (that is, the full volume is interrogated) that is extremely sensitive and can be used on all materials. For thickness measurements (as will most often be used in service water piping inspections), the required level of operator skill is not as great as is required for crack detection. The UT transducer must be coupled to the surface, so insulation must be removed to gain access. The primary feature of UT inspection is that it is very good at finding interfaces. Therefore, geometry effects can confound the inspection.

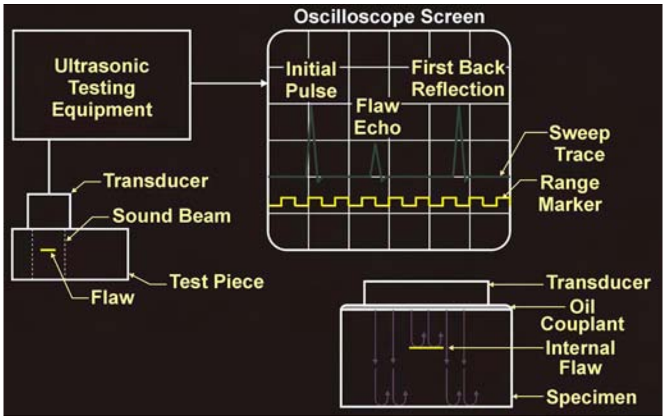


Figure 5-5
Ultrasonic Thickness Testing (Reproduced Courtesy of ASM International)

Radiography (Figure 5-6) is another volumetric method. It relies on the differential absorption of high-energy radiation to produce an image (including a digital read-out or image) based upon material density. Hence, pits, cracks, weld defects, or other areas of lesser density (for example, lesser thickness) will absorb less energy and will darken the radiographic film more. (A photographic print from that same film will show areas of lesser density as white rather than black; see Figure 5-7.) Radiography does not require contact with the surface, so insulation may not need to be removed. The standard “double-wall” RT shot can provide semiquantitative information on general or local thinning. The tangential shot (where the portion of the thickness that is parallel to the high-energy beam) is much more quantitative but requires more shots to image the entire pipe. RT can be very useful for imaging the magnitude, primarily the length and width rather than the depth, of closed, tunneling pits as have been observed in stainless steels, especially due to MIC at welds. Figure 5-7 is an example of an RT image of MIC in a stainless steel pipe.

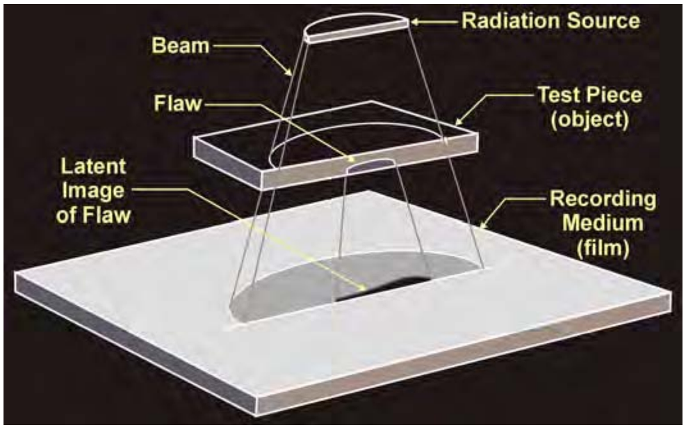


Figure 5-6
Radiography Basics (Reproduced Courtesy of ASM International)

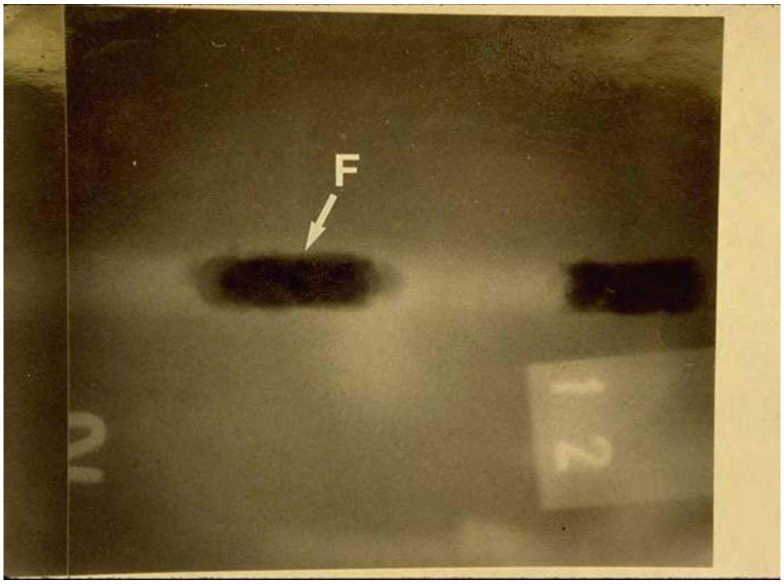


Figure 5-7
RT Image of Pitting in a Stainless Steel Weld (Original Film; Thinned Areas Will Be Black)

The most commonly used RT methods are double-wall and tangential radiography. The “steel equivalent thickness” will dictate the source to be used and the applicability of RT. For example, an iridium source will generally provide acceptable radiographs for water-filled piping up to about 8 inches diameter. Geometrical unsharpness and image magnification must be considered in the resolution capabilities. Most service water piping was not fabricated to radiographic quality standards, and some fabrication defects will be present. Prior to using a volumetric method that will show the presence of such defects (ones that have not obviously degraded system performance to date), the plant must define a plan for defining those defects and establish a plan for dispositioning those fabrication defects before the service water piping program is put in place. An example of one such program is provided in Reference [5-17].

The most common methods for evaluating thinning, both generalized and localized, use volumetric methods, particularly UT and RT, and some specialized ECT in special cases.

EPRI TR-102063 [5-18] lists the commonly used techniques for assessment of service water system condition with an emphasis on safety-related service water systems. Table 2-1 from that document is imported here as Table 5-5. The methods include flow tests (for example, occlusion), pressure tests and leak tests (system leakage), radiography (tangential and double wall, sampling of material condition), ultrasonic thickness determinations (sampling of material condition), and visual methods (occlusion, fouling coating condition).

Table 5-5
General Applicability of Testing and Examination Methods (Table 2-1 from TR-102063)

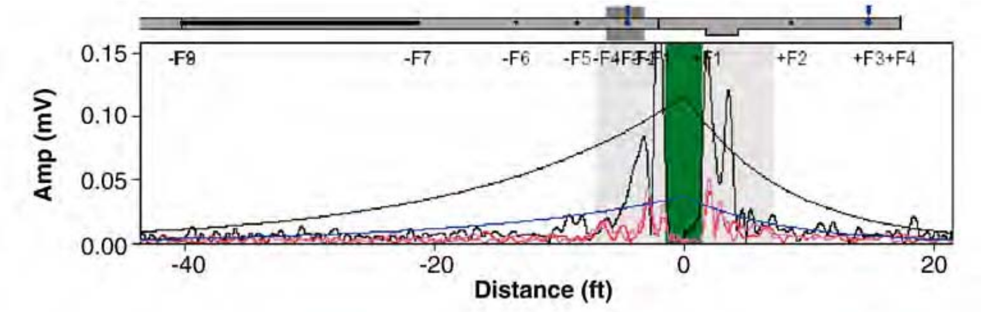
Method	Applicability
Pressure Test Systems	Assure the basic integrity of the piping. Visual inspection while the system is pressurized is conducted in conjunction with this test
Leak Test	Performed in conjunction with pressure test on buried or inaccessible lines provides evidence of structural integrity
Flow Test Capability	Provides evidence of system's performance
Tangent Radiography: Fouling and Erosion	Performed on a sampling basis, provides quantitative information on the extent of sedimentation and corrosion product deposition as well as pitting erosion
Double Wall Radiography	Performed on a sampling basis, provides qualitative information on the extent of fouling, pitting, and erosion; is the preferred method for quantitative evaluation of MIC attack in welds
Ultrasonic	Performed on a sampling basis, provides quantitative thickness information on the extent of wall thinning
Ultrasonic	Performed on a sampling basis, provides quantitative thickness information on the depth and extent of pitting corrosion
Visual	Performed locally on disassembly or system wide using remotely guided vehicles, provides qualitative data on the extent of fouling and identification of fouling and degradation mechanisms

The most common approach for service water piping inspection involves selection of inspections to be performed, as described above. The actual inspection sequence then involves construction of scaffolding, removal of insulation, UT thickness determinations performed using a grid or by continuously scanning over the area of interest then reinstalling the insulation, and removal of the scaffolding. This approach will inspect a very small fraction of the system.

Inspection Methods (Screening)

The analysis methods used to select locations for detailed inspection will be based upon plant design and operational history, histories of prior failures or known degradation, and other engineering judgment applied to the service water piping. For a service water system, the fraction of the piping that will actually be inspected will be extremely small, typically <<1%. Inspection tools that permit significant fractions of the system to be inspected using a screening tool can provide an additional key input to the selection of locations. Another potential advantage of the screening tools is that they can permit inspection of components with poor accessibility.

Specialized volumetric methods have also been developed that are useful for screening [5-19]. Those methods include long-range guided-wave UT that inspects the pipe up to several hundred feet in each direction with a single set-up; low-frequency and pulsed eddy current examinations, or broadband electromagnetic methods (BEM) that can also perform screening measurements locally but without the need for insulation removal; and digital radiography. The screening methods can be extremely useful in sampling a significant fraction (>10%) of the system, and to reinforce or replace locations selected for detailed examination by direct assessment. Figure 5-8 is an example of the output from a long-range guided-wave UT inspection of a service water pipe. It shows that the scan interrogated more than a 60-foot length of the pipe, including three welds, a penetration through a wall, with more than 30 feet of the pipe buried. That scan showed that the pipe was generally in good condition, but that several areas exhibited localized metal loss of up to 25% of the wall thickness.



Feature	Location	ECL	Class	Notes
+F1	1'9"	-	Y	
+F2	8'7"	13	Minor	70% Circulation Affected Estimated 19% Wall Loss
+F3	14'9"	12	Medium	50% Circulation Affected Estimated 24% Wall Loss
+F4	17'3"	-	Flange	
-F1	-2'1"	-	Weld	
-F2	-3'3"	-	Entrance	Concrete Wall Starts
-F3	-4'6"	18	Medium	70% Circulation Affected Estimated 25% Wall Loss
-F4	-6'3"	-	Exit	Concrete Wall Ends
-F5	-8'7"	11	Minor	60% Circulation Affected Estimated 18% Wall Loss

Figure 5-8
Screening Inspection of a 30-Inch Diameter Service Water Pipe Using Long-Range Guided-Wave UT

Visual Inspection

Assessments of coating condition can rely on visual examinations to a great extent. For ID-coated pipes, the condition of the coating is the key attribute to define, because an integral coating is what is keeping the material from corroding. Inspection should evaluate the condition of the coating in terms of its integrity, surface condition, and so forth. The presence of any corrosion products that appear to “pop through” the coating is a clear indicator of coating failure and corrosion of the underlying metal.

Any visual evidence of corrosion or the presence of corrosion products on coated piping indicates a failure of the coating. That visual inspection should be followed up by a volumetric (for example, UT thickness or RT) examination of the pipe from the OD.

Visual examination (including remote visual examination) is also recommended for assessing the condition of the coating in order to plan more detailed (for example, volumetric) examinations or to plan remedial activities. An example of visual criteria for cement liner degradation of lined carbon steel pipe is provided in the Indian Point-3 SWS Corrosion Monitoring Program Implementation Procedure [5-20] (with emphasis added):

None	The cement liner appears smooth and regular, without any indications of cracks or missing pieces. The carbon steel piping has no signs of corrosion or wall thinning. **No evaluation required**.
Minor	One or more cracks in liner, there are no pieces missing, the surface is smooth and regular. The carbon steel piping has no signs of corrosion or wall thinning. **No evaluation required**.
Moderate	One or more cracks in liner, surface is rough and shows signs of breaking down. Minor corrosion or scalloping is in evidence on the inside surface of the carbon steel piping. No evaluation required; future inspections should be conducted at this location during the next inspection interval to assess rate of degradation.
Significant	One or more cracks in liner, rough surface condition and evidence of missing pieces with widespread scalloping corrosion of inside surface of carbon steel piping. An evaluation is required to assess this condition and determine long-term monitoring needs.

Similar criteria applied to the specific characteristics of other coating or lining systems can follow this model.

Remote visual methods have the same goals and should have the same acceptance criteria applied as are used for visual methods.

Visual inspection of the inside surfaces should be used as the primary method for assessments of coated or lined piping to ascertain the condition of the coating over the breadth of the system. Satisfactory visual results should be supplemented by selected volumetric inspections to confirm the visual assessment of the coating and that the coating is continuing to provide corrosion protection. Fitness for continued service should be assessed in accordance with industry-accepted standards (for example, ASME B31G). Article 4.3 in ASME PCC-2 may be utilized to formulate a repair strategy. Four representative photographs from Crystal River Unit 3, presented as Figures 5-9 through 5-12, illustrate the coating condition in service water piping.

Figure 5-9
Crystal River Unit 3 Service Water Piping, Photograph 1 (Courtesy of Wes Rowley)

Figure 5-10
Crystal River Unit 3 Service Water Piping, Photograph 2 (Courtesy of Wes Rowley)

Figure 5-11
Crystal River Unit 3 Service Water Piping, Photograph 3 (Courtesy of Wes Rowley)

Figure 5-12
Crystal River Unit 3 Service Water Piping, Photograph 4 (Courtesy of Wes Rowley)

Visual inspection of the ID should also be used extensively for corrosion-resistant alloys. However, selected volumetric inspections, with emphasis on RT at welds, should be used on an appropriate number of locations determined to have the highest susceptibility to degradation or the highest risk.

Other NDE

NDE interrogation for cracking (for example, angle beam UT) is not recommended for service water piping except in cases where there is a strong suspicion that cracking may be present.

Destructive examination of selected sections of service water piping may be done to determine the root cause of damage. Root cause determinations can assist with selection of mitigation, repair, or replacement strategies.

Grid Size

The most common approach in service water piping inspection programs is to determine piping thickness using UT from the OD at numerous points in or along a grid pattern along the pipe to create a map of pipe thickness.

Inspection has three real objectives:

1. Determine the present condition of pipe—specifically, the condition of the system based upon the results from the sample, with respect to

   (a) structural integrity and
   (b) potential pinhole leaks

2. Determine the extent of localized corrosion
3. Estimate an average corrosion rate

UT transducers are of a finite size. As such, all UT thickness measurement will be at discrete points, either on a macro scale (for example, at grid intersection points), within the grid (via manual "scanning," searching for and reporting the minimum value within the grid), or by automated scanning with high resolution (for example, every 0.050 inch [12.7 mm]). A high-resolution scan as noted above (for example, discrete measurements made and recorded at intervals such as 0.050 inch) provides a detailed record of thinning, its spatial distribution, and its depth that are consistent with the objectives of a service water piping program.

Grids should be complete (that is, they should encompass a sufficiently large area to be meaningful and significant) and the grid size should be sufficiently small so as not to miss degraded areas.

The keys are to define the extent, both the depth and the area, of the thinning as described in the guidelines of Code Case N-597 [5-21]. There are definite pluses and minuses for a coarse grid ($\geq$1 in. [25.4 mm]) vs. a fine grid (<1/2 in. [12.7 mm]) vs. continuous scanning. Inspection costs for a coarse grid will be less than those for a finer grid. Inspection results from a fine grid or continuous scanning will provide better resolution but at higher inspection costs. For #1a, the real concern is the effect of thinning. For #2, a coarse grid is essentially useless. Note that for most service water piping inspections, a significant portion of the overall inspection process is associated with scaffolding and insulation removal to gain access to the piping surface.

Figures 5-13 through 5-15 present three separate C-scan type representations of the data from a 3-inch (76-mm) pipe with a pinhole leak and several thinned locations. (The actual data are given in Tables 5-6 through 5-8.) Figure 5-16 is a photograph of the section of pipe that was scanned. For the 1-inch grid (the actual data), there are 7 fairly small thin spots (total area probably less than 10% of the area interrogated) and 8 or 9 areas where the reported thickness is greater than 0.200 inch (5 mm) (Figure 5-13). For the 2-inch (51-mm) grid (Figure 5-14), derived from the same data, there are 4 areas with reported thickness less than 0.150 inch (3.8 mm) but they cover approximately 25% of the area. For the 1/2-inch (12.7-mm) grid (Figure 5-15), the results are very similar to those of the 1-inch (25.4-mm) grid.

Table 5-6
Raw Data from 3-Inch Pipe, Collected Using a 1-Inch Grid

3 Inch NPS with Pinhole Leak

t_{nom} = 0.216 t_{min} = 0.189 t_{acc} = 0.150

	A	B	C	D	E	F	G	H	I	J	K	L	Strip Min	Strip Avg	
1	0.190	0.176	0.178	0.198	0.198	0.164	0.197	0.190	0.165	0.191	0.147	0.190	0.147	0.182	Top
2	0.189	0.193	0.193	0.181	0.195	0.184	0.193	0.190	0.184	0.194	0.200	0.200	0.181	0.191	
3	0.187	0.184	0.171	0.175	0.134	0.177	0.182	0.183	0.157	0.173	0.177	0.194	0.134	0.175	
4	0.165	0.137	0.197	0.180	0.154	0.187	0.199	0.190	0.205	0.207	0.197	0.196	0.137	0.185	
5	0.190	0.164	0.177	0.178	0.206	0.209	0.201	0.195	0.162	0.180	0.187	0.192	0.162	0.187	
6	0.190	0.202	0.207	0.200	0.177	0.130	0.165	0.196	0.182	0.196	0.164	0.150	0.130	0.180	Bottom
7	0.165	0.174	0.140	0.192	0.174	0.188	0.207	0.201	0.191	0.176	0.156	0.168	0.140	0.178	
8	0.187	0.192	0.176	0.190	0.189	0.151	0.146	0.164	0.190	0.194	0.206	0.180	0.146	0.180	
9	0.198	0.208	0.199	0.201	0.189	0.146	0.206	0.209	0.169	0.200	0.163	0.205	0.146	0.191	
10	0.197	0.189	0.165	0.193	0.175	0.158	0.168	0.149	0.197	0.176	0.178	0.142	0.142	0.174	
11	0.206	0.206	0.192	0.194	0.199	0.196	0.183	0.184	0.170	0.172	0.177	0.178	0.170	0.188	
Band Min	0.165	0.137	0.140	0.175	0.134	0.130	0.146	0.149	0.157	0.172	0.147	0.142	0.130		
Band Avg	0.188	0.184	0.181	0.189	0.181	0.172	0.186	0.186	0.179	0.187	0.177	0.181	0.183		
												Std Dev=	0.018		
												Mean-S.D.	0.165		

Table 5-7
Same Raw Data as for Table 5-6 but Recorded on a 2-Inch Grid

3 Inch NPS with Pinhole Leak

t_{nom} = 0.216 t_{min} = 0.189 t_{acc} = 0.150

	A-B	C-D	E-F	G-H	I-J	K-L	Strip Min	Strip Avg	
1-2	0.176	0.178	0.164	0.190	0.165	0.147	0.147	0.170	Top
3-4	0.137	0.171	0.134	0.182	0.157	0.177	0.134	0.160	
5-6	0.164	0.177	0.130	0.165	0.162	0.150	0.130	0.158	Bottom
7-8	0.165	0.140	0.151	0.146	0.176	0.156	0.140	0.156	
9-10	0.189	0.165	0.146	0.149	0.169	0.142	0.142	0.160	
10-11	0.189	0.165	0.158	0.149	0.170	0.142	0.142	0.162	
Band Min	0.137	0.140	0.130	0.146	0.157	0.142	0.130		
Band Avg	0.170	0.166	0.147	0.164	0.167	0.152	0.161		
						Std Dev=	0.016		
						Mean-S.D.	0.145		

Table 5-8
Same Raw Data as for Table 5-7 but Recorded on a 1/2-Inch Grid

									3 Inch NPS with Pinhole Leak																	
								t_{nom} =	**0.216**			**t_{min} =**	**0.189**	**t_{acc} =**	**0.150**											
	A	A*	B	B*	C	C*	D	D*	E	E*	F	F*	G	G*	H	H*	I	I*	J	J*	K	K*	L	L*	Strip Min	Strip Avg
1A	0.190	**0.183**	**0.176**	**0.177**	**0.178**	**0.188**	0.198	0.198	0.198	**0.181**	**0.164**	**0.181**	0.197	0.194	0.190	**0.178**	**0.165**	**0.178**	0.191	**0.169**	**0.147**	**0.169**	0.190	0.190	**0.147**	**0.182** Top
1B	0.190	**0.187**	**0.185**	**0.185**	**0.186**	**0.188**	0.190	0.193	0.197	**0.185**	**0.174**	**0.185**	0.195	0.193	0.190	**0.182**	**0.175**	**0.184**	0.193	**0.183**	**0.174**	**0.184**	0.195	0.192	**0.174**	**0.187**
2A	0.189	0.191	0.193	0.193	0.193	**0.187**	**0.181**	**0.188**	0.195	0.190	**0.184**	**0.189**	0.193	0.192	0.190	**0.187**	**0.184**	0.189	0.194	0.197	0.200	0.200	0.200	0.195	**0.181**	0.191
2B	**0.188**	**0.188**	**0.189**	**0.185**	**0.182**	**0.180**	**0.178**	**0.171**	**0.165**	**0.173**	**0.181**	**0.184**	**0.188**	**0.187**	**0.187**	**0.179**	**0.171**	**0.177**	**0.184**	**0.186**	**0.189**	0.193	0.197	0.193	**0.165**	**0.183**
3A	**0.187**	**0.186**	**0.184**	**0.178**	**0.171**	**0.173**	**0.175**	**0.155**	**0.134**	**0.156**	**0.177**	**0.180**	**0.182**	**0.183**	**0.183**	**0.170**	**0.157**	**0.165**	**0.173**	**0.175**	**0.177**	**0.186**	0.194	0.191	**0.134**	**0.175**
3B	**0.176**	**0.168**	**0.161**	**0.172**	**0.184**	**0.181**	**0.178**	**0.161**	**0.144**	**0.163**	**0.182**	**0.186**	0.191	**0.189**	**0.187**	**0.184**	**0.181**	**0.186**	0.190	**0.189**	**0.187**	0.191	0.195	**0.186**	**0.144**	**0.180**
4A	**0.165**	**0.151**	**0.137**	**0.167**	0.197	**0.189**	**0.180**	**0.167**	**0.154**	**0.171**	**0.187**	0.193	0.199	0.195	0.190	0.198	0.205	0.206	0.207	0.202	0.197	0.197	0.196	**0.181**	**0.137**	**0.185**
4B	**0.178**	**0.164**	**0.151**	**0.169**	**0.187**	**0.183**	**0.179**	**0.180**	**0.180**	0.189	0.198	0.199	0.200	0.196	0.193	**0.188**	**0.184**	**0.189**	0.194	0.193	0.192	0.193	0.194	**0.186**	**0.151**	**0.186**
5A	0.190	**0.177**	**0.164**	**0.171**	**0.177**	**0.178**	**0.178**	0.192	0.206	0.208	0.209	0.205	0.201	0.198	0.195	**0.179**	**0.162**	**0.171**	**0.180**	**0.184**	**0.187**	0.190	0.192	0.191	**0.162**	**0.187**
5B	0.190	**0.187**	**0.183**	**0.188**	0.192	0.191	0.189	0.190	0.192	**0.181**	**0.170**	**0.176**	**0.183**	0.189	0.196	**0.184**	**0.172**	**0.180**	**0.188**	**0.182**	**0.176**	**0.173**	**0.171**	**0.181**	**0.170**	**0.183**
6A	0.190	0.196	0.202	0.205	0.207	0.204	0.200	**0.189**	**0.177**	**0.154**	**0.130**	**0.148**	**0.165**	**0.181**	0.196	0.189	**0.182**	0.189	0.196	**0.180**	**0.164**	**0.157**	**0.150**	**0.170**	**0.130**	**0.180** Bottom
6B	**0.178**	**0.183**	**0.188**	**0.181**	**0.174**	**0.185**	0.196	**0.186**	**0.176**	**0.167**	**0.159**	**0.173**	**0.186**	0.192	0.199	0.193	**0.187**	**0.186**	**0.186**	**0.173**	**0.160**	**0.160**	**0.159**	**0.168**	**0.159**	**0.179**
7A	**0.165**	**0.170**	**0.174**	**0.157**	**0.140**	**0.166**	0.192	**0.183**	**0.174**	**0.181**	**0.188**	0.198	0.207	0.204	0.201	0.196	0.191	**0.184**	**0.176**	**0.166**	**0.156**	**0.162**	**0.168**	**0.167**	**0.140**	**0.178**
7B	**0.176**	**0.180**	**0.183**	**0.171**	**0.158**	**0.175**	0.191	**0.186**	**0.182**	**0.176**	**0.170**	**0.173**	**0.177**	**0.180**	**0.183**	**0.187**	0.191	**0.188**	**0.185**	**0.183**	**0.181**	**0.178**	**0.174**	**0.175**	**0.158**	**0.179**
8A	**0.187**	0.190	0.192	**0.184**	**0.176**	**0.183**	0.190	0.190	0.189	**0.170**	**0.151**	**0.149**	**0.146**	**0.155**	**0.164**	**0.177**	0.190	0.192	0.194	0.200	0.206	0.193	**0.180**	**0.184**	**0.146**	**0.180**
8B	0.193	0.196	0.200	0.194	**0.188**	0.192	0.196	0.192	0.189	**0.169**	**0.149**	**0.162**	**0.176**	**0.181**	**0.187**	**0.183**	**0.180**	**0.188**	0.197	0.191	**0.185**	**0.189**	0.193	0.193	**0.149**	**0.186**
9A	0.198	0.203	0.208	0.204	0.199	0.200	0.201	0.195	0.189	**0.168**	**0.146**	**0.176**	0.206	0.208	0.209	0.189	**0.169**	**0.185**	0.200	**0.182**	**0.163**	**0.184**	0.205	0.202	**0.146**	0.191
9B	0.198	0.198	0.199	0.190	**0.182**	0.190	0.197	0.190	**0.182**	**0.167**	**0.152**	**0.170**	**0.187**	**0.183**	**0.179**	**0.181**	**0.183**	**0.186**	**0.188**	**0.179**	**0.171**	**0.172**	**0.174**	**0.186**	**0.152**	**0.183**
10A	0.197	0.193	0.189	**0.177**	**0.165**	**0.179**	0.193	**0.184**	**0.175**	**0.167**	**0.158**	**0.163**	**0.168**	**0.159**	**0.149**	**0.173**	0.197	**0.187**	**0.176**	**0.177**	**0.178**	**0.160**	**0.142**	**0.170**	**0.142**	**0.174**
10B	0.202	0.200	0.198	**0.188**	**0.179**	**0.186**	0.194	0.190	**0.187**	**0.182**	**0.177**	**0.176**	**0.176**	**0.171**	**0.167**	**0.175**	**0.184**	**0.179**	**0.174**	**0.176**	**0.178**	**0.169**	**0.160**	**0.181**	**0.160**	**0.181**
11A	0.206	0.206	0.206	0.199	0.192	0.193	0.194	0.197	0.199	0.198	0.196	0.190	**0.183**	**0.184**	**0.184**	**0.177**	**0.170**	**0.171**	**0.172**	**0.175**	**0.177**	**0.178**	**0.178**	0.192	**0.170**	**0.188**
11B	0.198	0.195	0.191	**0.188**	**0.185**	0.191	0.196	0.197	0.199	0.189	**0.180**	**0.185**	0.190	**0.189**	**0.187**	**0.177**	**0.168**	**0.175**	**0.182**	**0.172**	**0.162**	**0.173**	**0.184**	0.191	**0.162**	**0.185**
Band Min	**0.165**	**0.151**	**0.137**	**0.157**	**0.140**	**0.166**	**0.175**	**0.155**	**0.134**	**0.154**	**0.130**	**0.148**	**0.146**	**0.155**	**0.149**	**0.170**	**0.157**	**0.165**	**0.172**	**0.166**	**0.147**	**0.157**	**0.142**	**0.167**	**0.130**	
Band Avg	**0.187**	**0.185**	**0.184**	**0.182**	**0.181**	**0.185**	**0.189**	**0.185**	**0.180**	**0.176**	**0.171**	**0.179**	**0.186**	**0.186**	**0.186**	**0.183**	**0.180**	**0.184**	**0.187**	**0.183**	**0.178**	**0.180**	**0.181**	**0.184**	**0.183**	
																								Std Dev=	0.013	
Band Min$_{(l)}$	**0.165**		**0.137**		**0.140**		**0.175**		**0.134**		**0.130**		**0.146**		**0.149**		**0.157**		**0.172**		**0.147**		**0.142**	Mean-S.D.	0.169	
Band Avg$_{(l)}$	**0.188**		**0.184**		**0.181**		**0.189**		**0.181**		**0.172**		**0.186**		**0.186**		**0.179**		**0.187**		**0.177**		**0.181**			

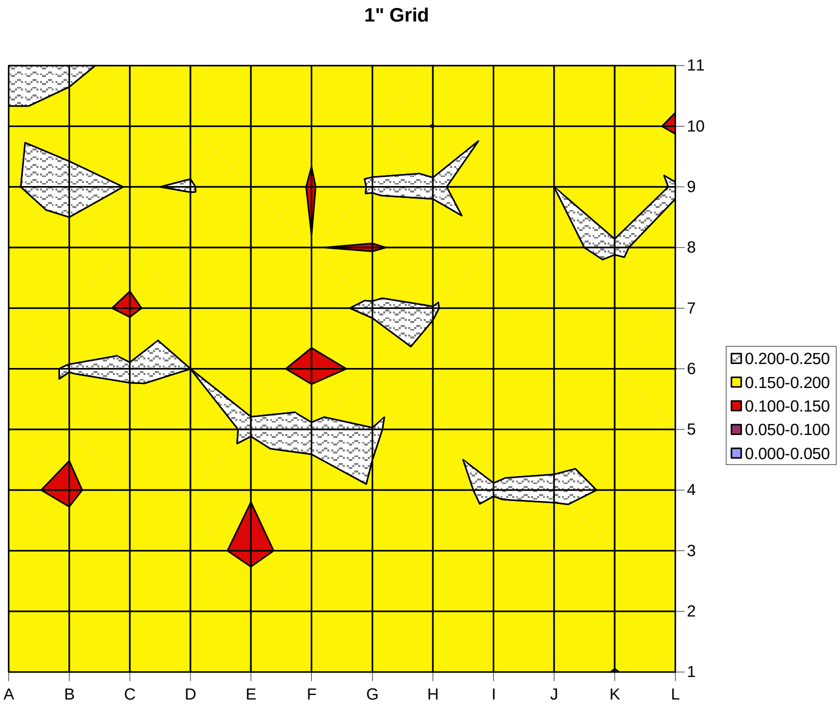


Figure 5-13
C-Scan Representation of Data from 1-Inch Grid (Actual Data)

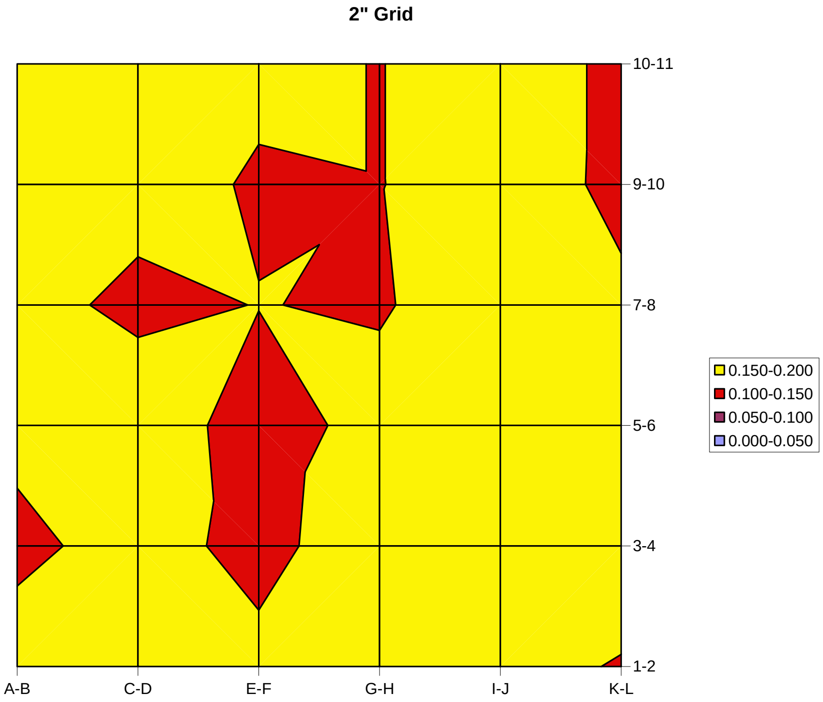


Figure 5-14
C-Scan Representation from 2-Inch Grid (Same Data and Initial Grid Positions as for Figure 5-13)

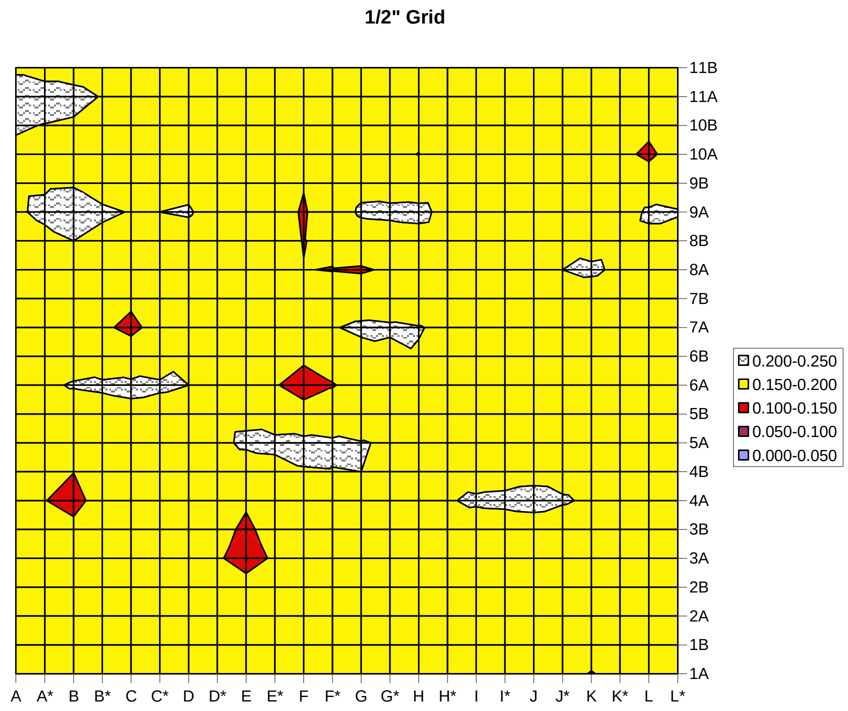


Figure 5-15
C-Scan Representation of Data from 1/2-Inch Grid (Same Data and Initial Grid Positions as for Figure 5-13; Thickness Values Interpolated from Actual Data)

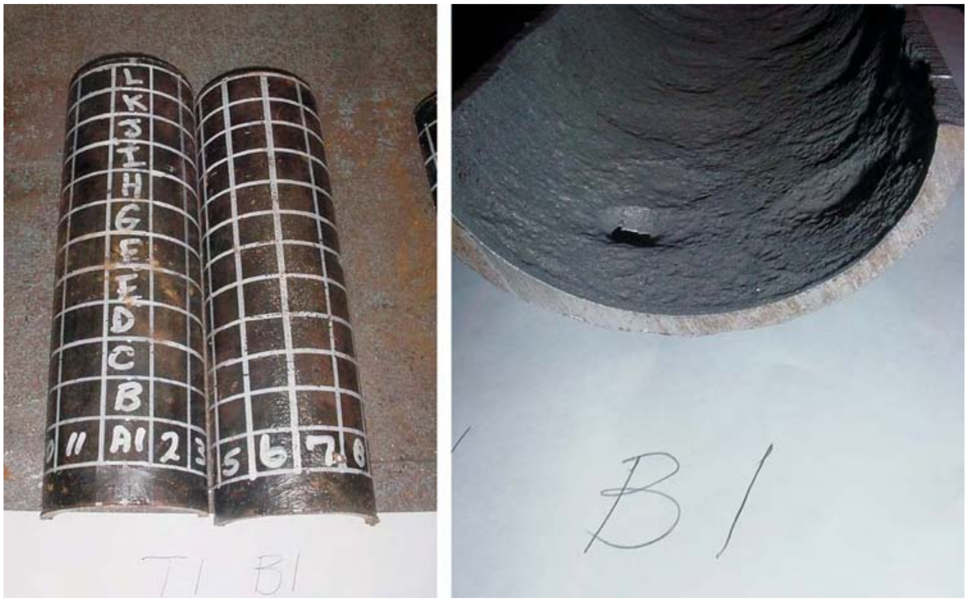


Figure 5-16
3-Inch Pipe Scanned by UT for Thickness Along 1-Inch and 2-Inch Grids

Using the example for a 3-inch (76.2-mm) pipe with a pinhole, the data acquired using a 1-inch (25.4-mm) grid (circumference of about 11 inches [280 mm], 12 inches [305 mm] long) showed a minimum thickness of 0.130 inch (3.3 mm) and a grand mean of 0.183 inch (3.5 mm). The minimum band average (that is, the thinnest average band) was 0.172 inch (4.37 mm) (the band with the thinnest spot in it). When these same data were evaluated using a 2-inch (50.8-mm) grid, and reporting the minimum value as "the" value for any grid, the minimum thickness reported was still 0.130 inch (3.3 mm). However, the grand mean decreased to 0.161 inch (4.1 mm). When a probable or possible data set using a 1/2-inch (12.7-mm) grid for those same data (values between the 1-inch [25.4-mm] grid points were determined by the average of the adjacent measured points), the minimum thickness and grand mean were identical to those from the initial data set. Also note that the UT thickness did not show a zero thickness location, even in the grid where that occurred. This is a limitation of this UT approach to finding and sizing pits.

Further, for the 1-inch grid, 0/12 band averages are less than (an arbitrarily assigned) $t_{acc} = 0.150$ with a grand mean of 0.183 inch (4.65 mm), as opposed to the case for the 2-inch (50.8-mm) grid where 1/6 band averages are less than t_{acc} and the grand mean is 0.161 inch (4.09 mm). Results for 1/2-inch (12.7-mm) grid are essentially the same as for the 1-inch (25.4-mm) grid, which is probably the result of the way that the unknown values (that is, those between the measurements) were derived.

When they are possible, full high-resolution scans at selected locations will give the best and most useful data. With automated equipment, total time and cost will probably be very comparable to those for manual data collection and recording. Because most of the cost of UT thickness profiles is scaffolding, insulation removal, and reinstallation, the cost of the scans themselves, whether done manually with a coarse grid, manually with a fine grid, or using a high-resolution scan, will be a minor portion of the inspection cost.

As shown in the comparison of different grid sizes, the "best" answer in terms of providing the most accurate description of the depth and extent of degradation will also provide the most accurate representation of the structural capabilities of the piping, even if the inspection is slightly more expensive (for example, a finer grid or continuous scanning).

The recommended best practice is to consider the purposes of the inspection and to use an appropriate method for inspection and subsequent evaluation. As shown in the example above, the use of a fine grid (1/2 inch maximum) or continuous scanning is definitely preferred in terms of the resolution and subsequent use of the results. While a coarse grid (for example, >1 inch) may have a slightly lower inspection cost, the poorer resolution will give a distorted picture of the piping degradation and can generate an overly conservative thickness distribution that will be used in evaluations of structural integrity.

Data Evaluation

Determination of Structural Integrity

Since one of the primary design bases for service water piping is that it must maintain its structural integrity, the assessment program, including inspections, must provide sufficient information to assure the structural integrity of the system.

The requirement for maintaining structural integrity is the real key in terms of how to inspect, where to inspect, the number of inspection locations, the grid size, and so forth. The first step in the process is to define a contingency plan for actions to be taken if locations with $t<t_{min}$ are found.

Evaluating inspection data requires comparisons to design information (for example, t_{init}, design pressure and temperature, and other loadings as applicable) and requires data management to include prior inspections and develop trends, identify data that are considered to be in error (reinspect or eliminate), and compare data among inspections for trends. The measured data are compared to the required general or local minimum thickness (for example, t_{min}). Most programs report average data that are less than some screening limit, usually 87.5% of the nominal wall thickness and require a structural evaluation of any "locations" that are less than $0.875 \cdot t_{nom}$. Locations that are evaluated for structural integrity are based upon one of several methods:

- Generalized top-level screening criteria. For example, if thickness is greater than X, file the inspection report and do nothing further with respect to structural integrity.
- Band method (circumferential bands of one grid width).
- Strip method (same as band method except that the average in a longitudinal vs. circumferential band/strip is used).
- Area method, which is more of a local (x,y) for the observed thinning, similar to the images illustrated in Figures 5-13 through 5-15.
- Point-to-point method, which provides a comparison of thicknesses at the same grid locations for multiple inspections.

In all cases, the predicted wall thickness (for example, at the next inspection) must be greater than the acceptable t_{min} per the Code of Record (original code of construction or "higher"—for example, N-513 [5-22]—as it applies to Code Case N-597 [5-21][3]. In the event that thinning beyond the screening limit is determined, the sample to be inspected is expanded, generally to a minimum of the next two most susceptible areas (for example, same line, similar flow characteristics, and so forth), corresponding areas in each other train (if any), with further expansion if there are positive findings of excessive thinning from the expanded sample.

Code Case N-597 provides guidance on **generalized thinning**:

> ... t_p at any location shall not be less than 90% of the minimum wall thickness of the piping item, t_{min}, required for design pressure, defined in the Construction Code used in the evaluation, exclusive of any additional corrosion allowance.

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[3] The criteria in Code Case N-597 and the evaluation methodology provided in this guideline are recommended even for non-ASME Code pipe.

and **localized thinning** should be evaluated based upon the depth and extent of the thinning:

> ... consider the depth and extent of the affected area and require that the wall thickness exceed t_{min} for a distance that is the greater of $2.5\sqrt{R_{nom} \bullet t_{nom}}$ or $2L_{m.avg}$ (thinning of limited transverse extent) or where the length of the thickness is predicted to be less than t_{min} is less than or equal to $2.65\sqrt{R_{nom} \bullet t_{nom}}$ and t_{nom} is greater than $1.13t_{min}$, t_{aloc} shall be determined by
>
> $$\frac{t_{aloc}}{t_{min}} \geq \frac{0.353L_m}{\sqrt{R_{m\,ln} t_{min}}}$$

or there is a surrounding reinforcement zone with predicted thickness of at least t_{nom} for a minimum dimension of L/2 in all directions and

$$\frac{t_{aloc}}{t_{min}} \geq \left(\frac{1.5\sqrt{R_{m\,ln} t_{min}}}{L}\right)\left(\frac{t_{nom}}{t_{min}} - 1\right)$$

where

t_{min} = minimum wall thickness of the Construction Code to sustain pressure

t_{nom} = nomimal wall thickness

t_{aloc} = allowable local thickness

R_{nom} = mean radius based upon the nominal outside radius and the minimum wall thickness

L = maximum extent of a local thinned area with wall thickness less than t_{nom}

$L_{m.avg.}$ = average of the extents of thickness less than t_{min} for two adjacent thinned areas

Code Case N-513 (and N-513-1[4]) provides requirements for acceptance of flaws, including through-wall flaws, in Class 3 moderate energy ($P \leq 275$ psi and $T \leq 200°F$) piping. The Code Case applies only to piping and does not include degraded socket welds. The Code Case provides methods for both planar flaws (basically, cracks) and nonplanar flaws (for example, corrosion). The key features of the Code Case are:

- Evaluation of the allowable flaw size, consistent with ASME Section XI methodology
- Estimation of flaw growth
- Determination of a safe operating period (that is, no longer than until the next outage)

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[4] N-513-1 has not been approved by NRC. Its use requires an approved Relief Request.

- Sample expansion (to determine the extent of damage throughout the system)
- Implementation of augmented inspections to assure that the initial evaluation is still valid

For a leak, a temporary leak repair (which may be a weld or a mechanical clamp) can be used. The primary advantage of the Code Case is that operation is permitted with degraded piping, including piping with a leak, until the next outage, when a welded Code repair must be done. Figure 5-17 is a flow chart that describes the methodology to be applied.

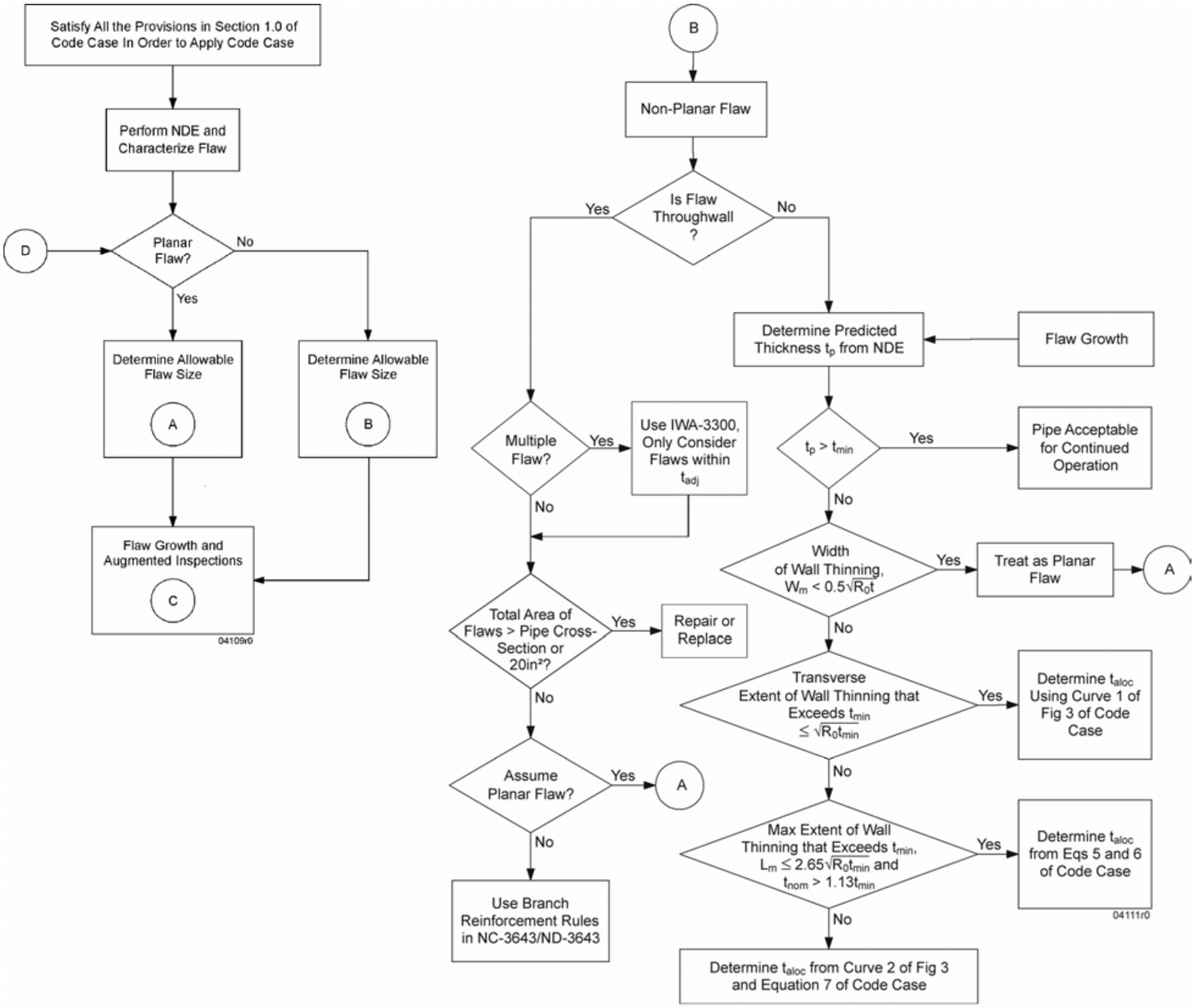

Figure 5-17
Flow Chart for Application of Code Case N-513 Criteria

Guidance on Sample Expansion

The total internal surface area of the service water system may be considered one area for the purposes of creating sample locations (for example, same host pipe, same cooling water). For a statistically significant sampling program, approximately 30 locations throughout the system (different flow regimes, different piping diameters) will generally be indicative of the condition of the pipe. Initially, the sampling program could be annual. If little pipe wall thinning is found, then the sampling program frequency could be lengthened.

If pipe wall thinning is occurring (for example, approaching minimum wall for pressure integrity at a rate not acceptable for remaining service life of the system), then a better perspective on what portions of the system are at risk is appropriate. The service water system could be divided into portions, based on combinations of the following:

- Flow regime
- Pipe size
- Vertical vs. horizontal piping segments

Then a statistically significant sampling program could be developed for each portion. The sampling program could initially be annual. If substantial degradation occurs, then the sample size could be doubled. If the increased sample size finds more substantial degradation, then double again the sample size (and again, and again … may be sampling so much that it is clear that corrective action is needed). If virtually no degradation occurs, then lengthen the frequency of the sampling program in that portion of the service water system.

Frequency of Inspections

The inspection locations should be selected and the first and second inspections performed as the initial phase of the service water piping program. Subsequent inspections, both in terms of locations (expansion, contraction, or other modifications) and subsequent scheduling will be dictated in part by the results from the initial and second inspections.

For example, the timing of the second inspection can be defined from the “rates” that are estimated from the results of the initial inspection. However, a reasonable interval for the second inspection can and should be defined prior to the initial inspection. A conservative (that is, relatively short, 3–5 years) interval between the initial inspection and the second inspection is recommended. However, that interval should be sufficiently long that subsequent inspection results and the rates that are derived from them can be meaningful. That interval should consider the time to additional thinning as defined per the predictive model used to define the initial inspection locations and, to a lesser extent, results from the initial inspection. As noted above, the uncertainties in both the initial thickness value (used to determine what the Δt was) and the operative time of the degradation will be large. However, the interval until the second inspection may be decreased if the projected thickness at the scheduled second inspection is very low.

The second inspection is intended primarily to confirm results from the first inspection, to establish the first real and believable trending information (that is, a realistic Δt can be determined), and to confirm service life of components with a (predicted) short remaining life.

Subsequent inspection intervals should be determined from plant requirements (for example, Generic Letter 89-13 commitments) and from results from the prior inspections, and should also factor in changes in plant operating conditions (for example, mitigation approaches such as water chemistry); different service water system usage; or power uprates that necessitate changes in service water system operation).

All of the follow-on inspections should be scheduled as necessary to monitor susceptibility to degradation and to update the need for repairs or replacements, considering budget, design, and procurement times. Other factors to be incorporated into the subsequent inspection intervals are to define a representative sample for inspection at each inspection, use of the minimum thickness from the highest degradation wear component from the previous inspection(s), to include assessments of problem areas at other plants since the prior inspection, and for components with high predicted or measured degradation.

Degradation rate is based on a linear time dependence, which, as discussed in Section 4, will be conservative, particularly after the second inspection, when the actual time interval over which the degradation has occurred will be better characterized. Any rates derived from the initial inspection will typically exhibit the greatest error, since t_{init} is poorly known and time is not well known. Predictions of rates will be much better once data from more than one inspection are available.

Corrosion coupons or other corrosion rate determinations can also provide useful feedback to the ranking methodology and to updating of the inspection interval.

Data Collection and Documentation Requirements

The complete documentation package for a service water piping program should include the inspection locations and the bases for their selection, as well the data. Tables 5-7 through 5-9 provide a complete representation of the data, showing minimum thickness for each grid. For high-resolution continuous scans, the complete data sets will be much larger. For example, at 0.050-inch (1.27-mm) points along the scan line and scan lines 0.200 inch (5 mm) apart, a 12-inch by 12-inch (305-mm by 305-mm) scanned area will contain approximately 14,000 individual thickness measurements. These data can be further summarized into band (circumferential), strip (longitudinal), area, or point-to-point averages in the same way that data collected from manual scans at grids are summarized.

Data packages should be revised after each new inspection. Data from at least two inspections for each inspection location should be retained. Since results from monitoring are likely to become available much more often than data from piping inspection, a regular schedule should be defined to coordinate monitoring activities with inspection activities.

Monitoring

Monitoring involves the controlled measurement of an effect, such as corrosion or heat transfer, on a part that is included in the system being monitored but that may or may not be a part of the system *per se*. Corrosion coupons, evaluated for both weight loss and the presence of pitting, or pipe spools that have been installed and regularly examined on a regular basis for corrosion determinations are examples of corrosion monitoring activities. Similarly, regular heat transfer measurements performed on system heat exchangers or model heat exchangers are also examples of monitoring.

One major advantage of monitoring is that carefully controlled on-line or destructive measurements can be performed on inexpensive samples that are exposed to the service water system environment. These samples are intended to simulate the system materials and components. They represent the most cost-effective method for tracking degradation, since the monitor itself can be considered disposable, unlike the system it intends to mock up.

As an assessment of the present condition of the equipment, monitoring is much less accurate than what is provided by an inspection, since the monitoring activity provides only a snapshot of the present condition of material that is as much like the piping as possible. Monitoring provides a much better method for tracking the future condition of the piping, since the monitor can be evaluated inexpensively, with superior resolution, and can be assessed much more often than an inspection of the piping.

Many of the available monitoring tools can be configured to permit accelerated testing of the effect that is being monitored, so the future condition of the system hardware can be predicted reliably. There will be trade-offs in sensitivity and reproducibility vs. prototypicality. For example, most corrosion monitors will use carefully ground surfaces to improve the reproducibility of the measured effect from one sample to another. That ground surface is rarely typical of the condition of system surfaces. The location of the monitoring tool(s) will always be a critical factor in the value of the information that is obtained. The key to evaluating the results from any monitoring tool is to correlate the effect that is being measured for the location, surface condition, and so forth, of the monitor to that of the component being simulated. The trends determined from the monitoring tools are the key components of a monitoring program.

Monitoring, used in addition to inspection, can provide a method by which the monitoring activity can be used to replace some inspection activities.

The greatest advantage offered by monitoring tools is that they can be used for control of processes that are intended to mitigate degradation.

Probably most importantly, continuous monitors provide very detailed information on exactly when the degradation is taking place. For example, in many systems, the bulk of the corrosion occurs only during transients, such as during the first few minutes of flow following an extended period of stagnation. An on-line monitor can provide sufficient detail to identify and quantify such effects. Further, a wide variety of materials, geometries, surface conditions, and so forth can be monitored at one time.

A corrosion monitoring program should contain corrosion coupons and one or more on-line electrically based monitors.

Corrosion coupons (Figure 5-18) are most commonly used as an inexpensive method for tracking weight loss. An average corrosion rate can be determined from the weight loss divided by the time of exposure. Unfortunately, weight loss is often the only way that such coupons are used. Detailed visual examination of coupons for the presence and size of localized corrosion, flow effects, crevice corrosion at coupon holders, or sampling of coupon surfaces for deposits, including microbiological deposits, can provide an extremely powerful tool in assessing various effects that are occurring on surfaces exposed to the system environment. Special coupons that are stressed, that include crevices, or that are electrically coupled to dissimilar metals to produce a galvanic effect may also be used.

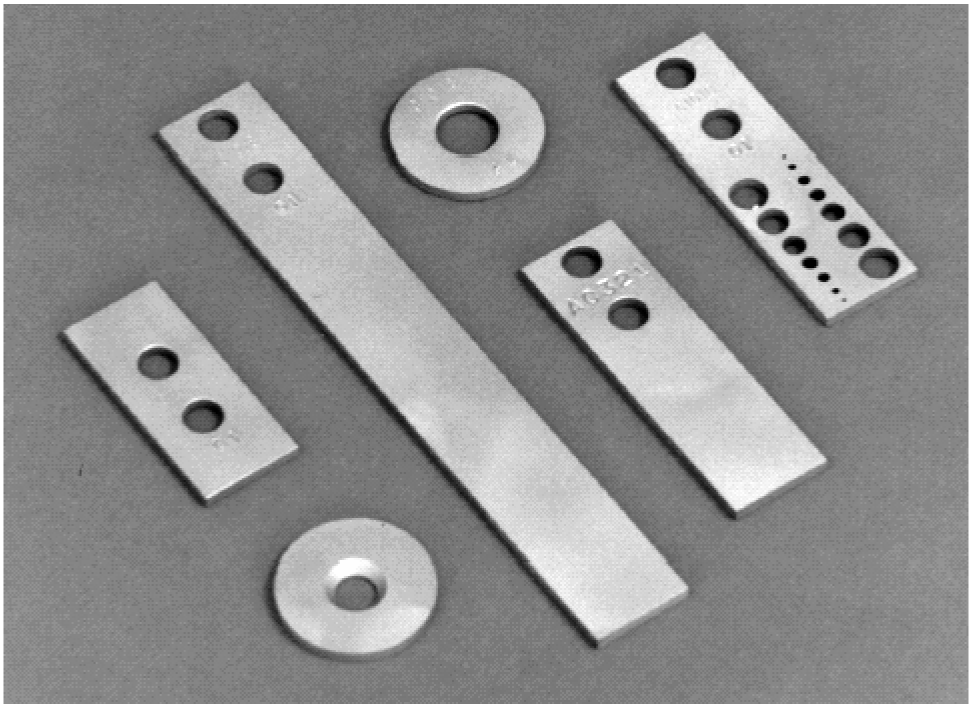

Figure 5-18
Corrosion Coupons (Photo Courtesy of Metal Samples)

Electrically based methods include electrical resistance (ER) probes, linear polarization resistance (LPR) probes, and special methods such as the BIOGEORGE probe for on-line monitoring of biofilm activity on metal surfaces.

ER probes (Figure 5-19) are based upon the principle that the resistance of an electrical conductor is inversely proportional to its cross-sectional area. By regularly measuring the electrical resistance of a tube, wire, or other shape that is fabricated from a material similar to that of the piping, and that is exposed to the same environment as the piping, the total metal loss can be determined continuously. The information collected is the same as that for a corrosion coupon. That is, metal loss is determined over a period of time. The major advantage of ER probes over coupons is that the probes need not be removed in order to determine the metal loss. Further, the average corrosion rate over a particular time period can be obtained with a single ER probe element.

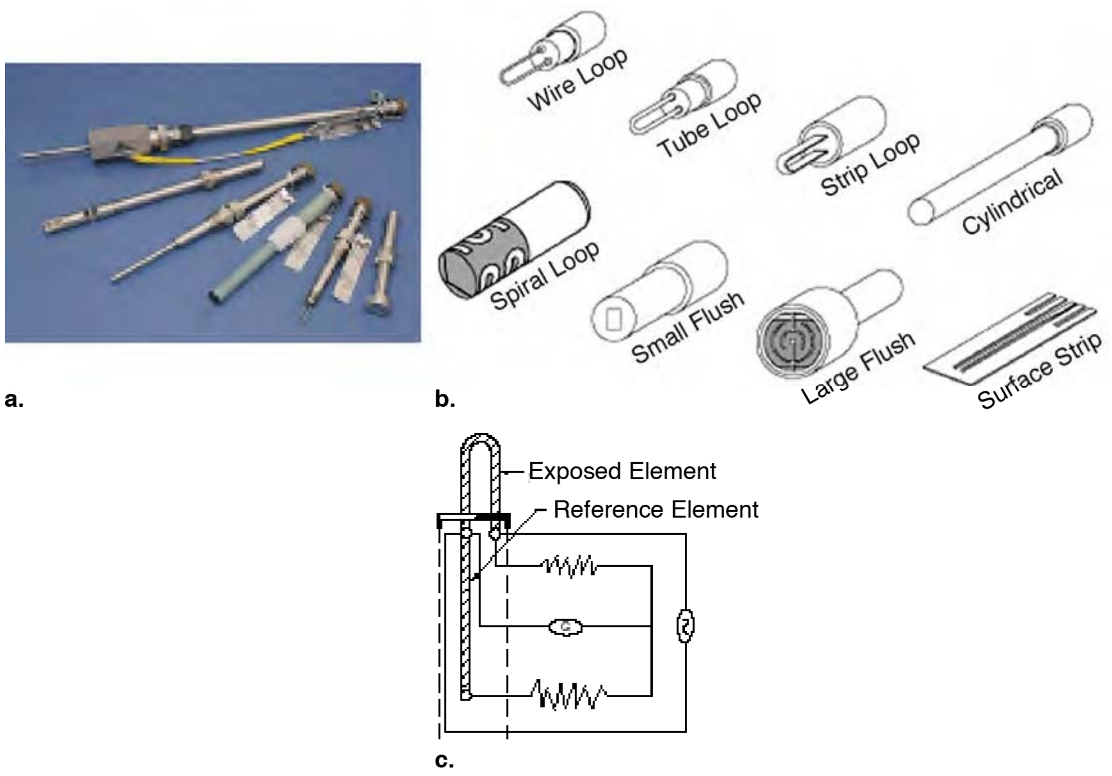

Figure 5-19
Electrical Resistance Probes: (a) Probes; (b) Resistance Elements; (c) Principle of Operation (Courtesy of Metal Samples)

LPR probes (Figure 5-20) use two or three electrodes of the material of interest. A small polarization potential is applied to the electrodes from an external power source. The *polarization resistance* is determined from the ratio of the applied potential to the measured current. The polarization resistance has been shown to be inversely proportional to the corrosion rate. This technique provides a method for continuously monitoring corrosion rates with a high resolution (compared to other methods such as coupons) and without the need for removing a sample from the system. LPR techniques are particularly useful for monitoring exactly when corrosion occurs (for example, during water chemistry upsets in closed systems or upon the initiation of flow following an extended period of stagnation in a service water system).

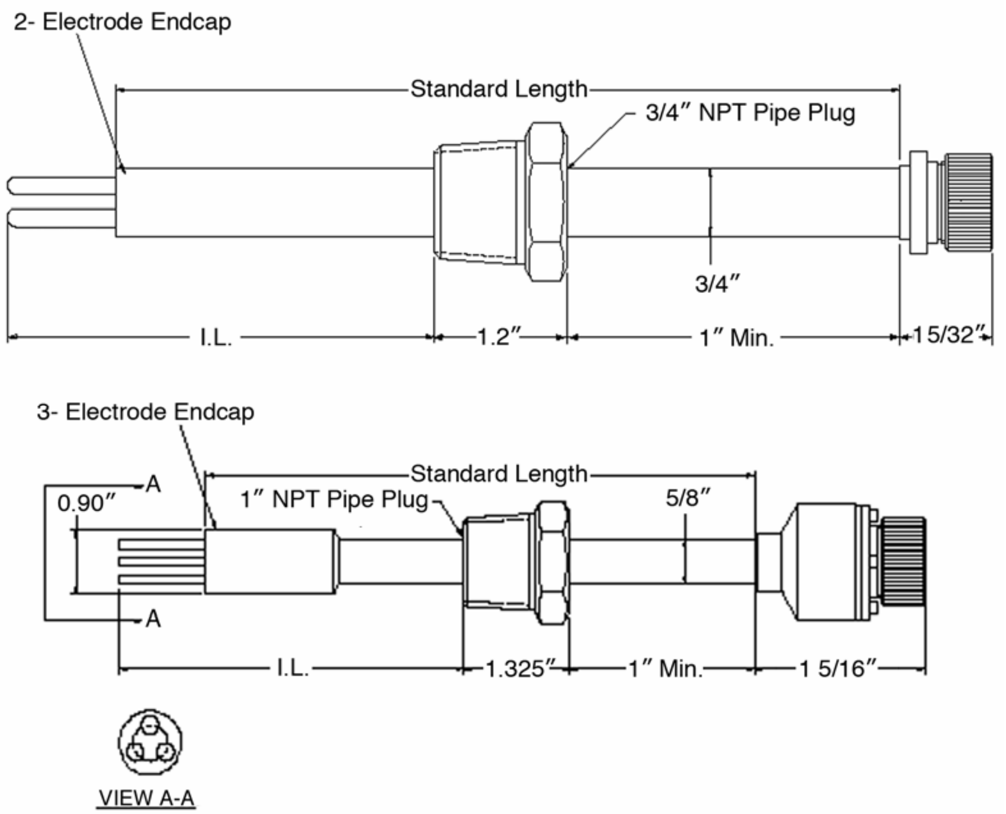

Figure 5-20
Linear Polarization Resistance Probes: (a) 2-Electrode Probe; (b) 3-Electrode Probe (Courtesy of Metal Samples)

ER and LPR probes are commercially available from a number of vendors and are easily installed into threaded pipe fittings in the piping system, into the water boxes of heat exchangers, or in a sidestream that is either reconnected to a lower-pressure section of the system or flows to a sump. The active elements of the probe are available in a variety of configurations including flush-mounted designs that should experience essentially the same shear forces from the fluid flow as the piping. Those probes are most often connected to a dedicated computer or to a remote controller and data acquisition device. The remote devices can be battery powered and are configured to download data or upload operating instructions through a hand-held device or phone line that provides the communication link between an engineer’s computer and the remote device(s).

ER and LPR probes are also available in configurations for use in “hot tap” fittings (fittings that permit coupons, probes, and so forth to be inserted or withdrawn with the system in operation). Some plants have chosen to install such fittings as piping “repairs” when localized thinning has dictated that a design repair was required. The ASME Code and Generic Letter 90-05 permit the addition of engineered repairs such as these fittings, which are basically a weld-o-let with special fittings to permit the insertion and withdrawal procedures, to effectively replace small areas of thinned piping.

Corrosion monitors, whether in the system or in sidestreams that experience the same flow history as the system they are intended to monitor, will provide a definite enhancement in terms of evaluating degradation in real life and real time. That information will be especially important in guiding mitigation programs. Sidestream test racks should contain corrosion monitors (coupons, LPR, ER, and so forth) and biofilm monitors, and expose different racks to conditions that typify systems of interest. The biofilm monitors may be batch-type devices (Robbins devices, sessile monitoring devices provided by water treatment companies, or normal corrosion coupons that are removed and swabbed for biofilms) or on-line devices such as the BIOGEORGE biofilm activity monitoring system [5-23]. These results can be tracked by the plant or by contractors. The plant should be aware that the early performance of the monitors will be different than longer-term performance. Initial corrosion rates of 20 mpy and greater are to be expected on bare steel. The plant piping has already experienced those rates and has "settled down" to steady state rates in most locations. Corrosion monitoring tools will be most useful for demonstrating trends in corrosivity, material responses to environmental changes, and effects of treatments. The trends are much more useful than the actual corrosion rates.

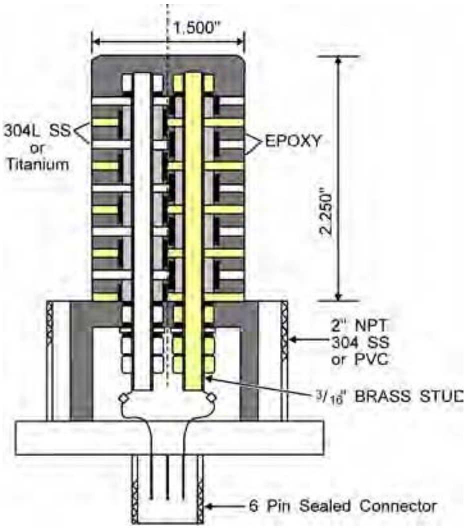

Figure 5-21
BIOGEORGE Electrochemical Biofilm Activity Monitoring Probe

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5-21. Requirements for Analytical Evaluation of Pipe Wall Thinning, Section XI, Division 1, ASME Code Case N-597, March 2, 1998.

5-22. Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping, Section XI, Division 1, ASME Code Case N-513-1, March 28, 2001.

5-23. G.J. Licina, L.B. Peterson, P.G. Kutzora, "Monitoring Biofilms on Cooling Water System Surfaces," EPRI Service Water System Reliability Improvement Seminar, San Diego, CA, 2002.

6

MITIGATION, REPAIR, AND REPLACEMENT

The service water system is a key part of the plant infrastructure and is crucial to achieving a 40-year life. Further, the service water system is a key for life extension. During original construction, the plant was built over it or around it, and the piping was not intended to be replaced or even worked on very much. Service water piping is likely to achieve 25 to 40 years of life without much special attention; however, for longer life, some repair or replacement should be expected. The key to repairs or replacements is to perform a given repair or replacement once and no more.

Corrosion damage, whether generalized or localized, will be cumulative. Figure 6-1 shows an example of the predicted history of the number of through-wall failures and the probability of at least one leak vs. time. Figure 6-1 shows that for much of the plant life, the probabilities of any leaks and the number of leaks vs. time are very low. For example, Figure 6-1 shows that for the first 20 years or more of system operation (much of which may significantly predate commercial operation of the plant), the number of leaks may be zero or nearly zero. However, over longer time, as corrosion continues, low failure rates (for example, 1–2 leaks/year) may begin to appear. If no corrective actions are taken, the number of leaks per year will continue to increase, eventually reaching a rate that may cause the reliability of the system or the plant to be compromised. In any case, as the number of leaks per year increases, the economic effects associated with disposition and repair of the leaks will become significant.

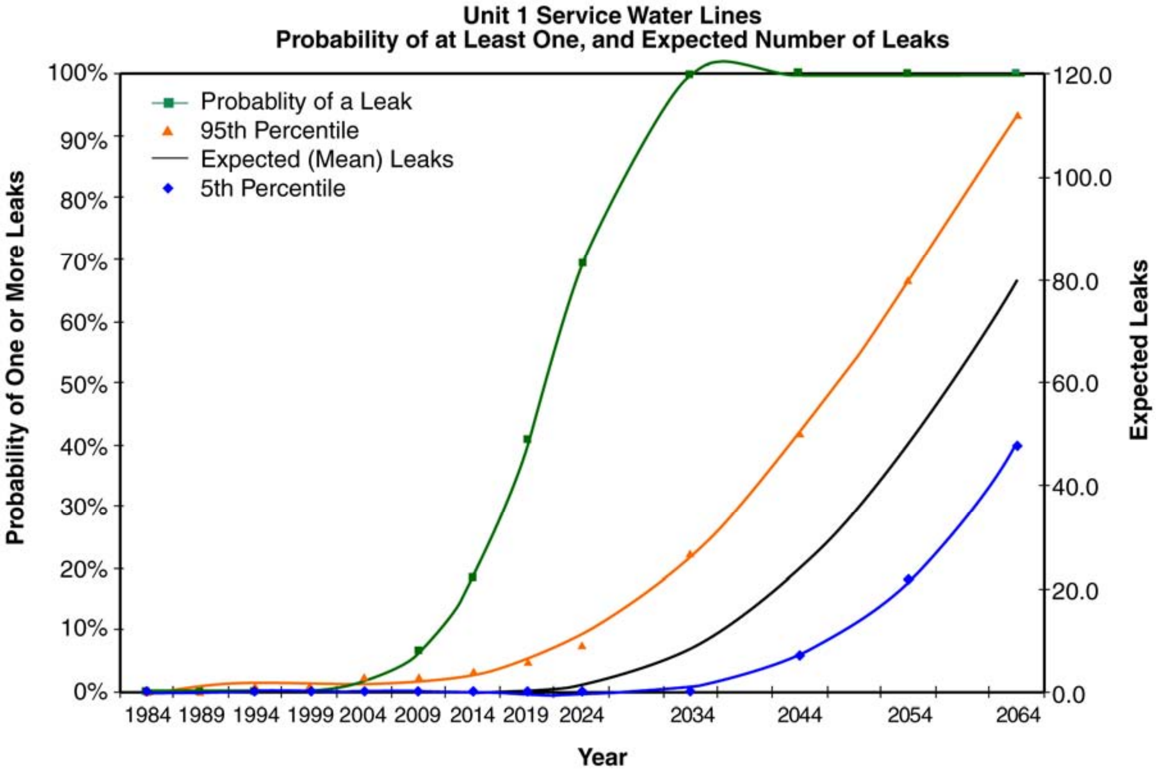

Figure 6-1
Probability of At Least One Leak and Predicted Number of Leaks Versus Time

For the specific example shown in Figure 6-1, the probability of one or more leaks is essentially zero for the first 15 years of service (1984–1999), increasing to a probability of about 10% at 25 years, about 50% at 35 years, and 100% at 45 years. The cumulative total number of leaks predicted is very low (0 or 1) for the first 20 years of service; a total of 1–5 leaks is predicted after 40 years of service; but 20–35 leaks are predicted after 60 years of service.

Mitigation, Repair, and Replacement Considerations

The most appropriate long-term strategy for management of service water piping life should focus on reducing "risk" by reducing susceptibility to degradation and, to a lesser extent, on focusing inspections. Time is a key parameter. As shown in Figure 6-1, the probability of experiencing a leak will increase as operating time increases. Further, the number of leaks that may be expected will increase at an increasing rate with system age as degradation accumulates over time, eventually reaching the point where the system begins to exhibit one or two pinhole leaks, then more leaks, and finally reaching the point where the most economical approach changes from leak repair to a more global and more expensive action. Structural integrity concerns will also follow the same basic time dependence but will typically lag the leakage curve significantly. Instituting mitigating actions can change the time dependence for leak formation by decreasing the rate of degradation and effectively topping the accumulation of through-wall damage. Figure 6-2 identifies a methodology for combining degradation susceptibility (for example, as shown in Figure 6-1) with the consequences that degradation can have on plant operation as a means to prioritize inspections and influence run/repair/replacement decisions for the system.

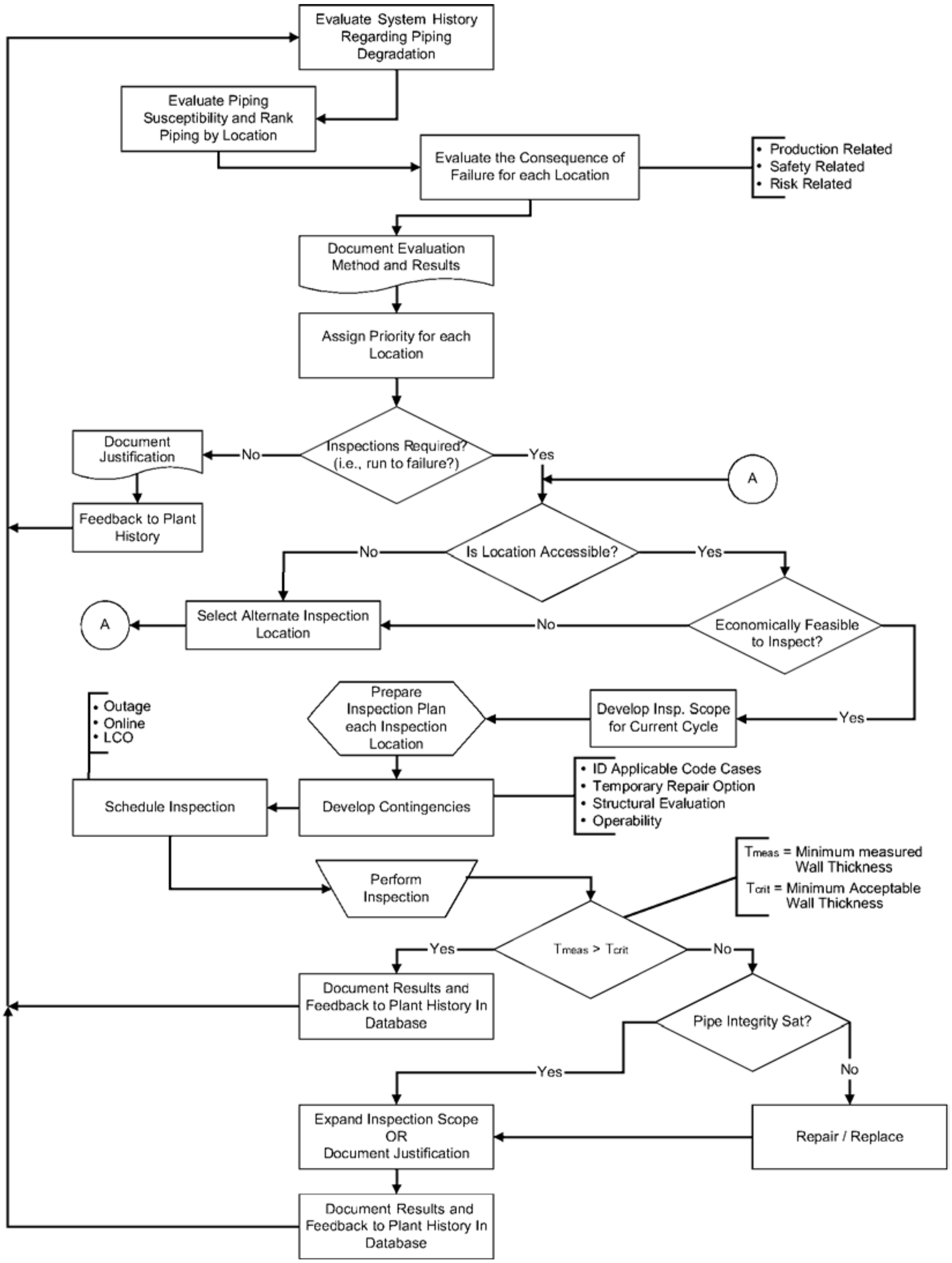

Figure 6-2
Example Methodology for Inspection, Repair, and Replacement of Service Water Piping (Courtesy of Greg Lupia, CSI Technologies, Inc.)[1]

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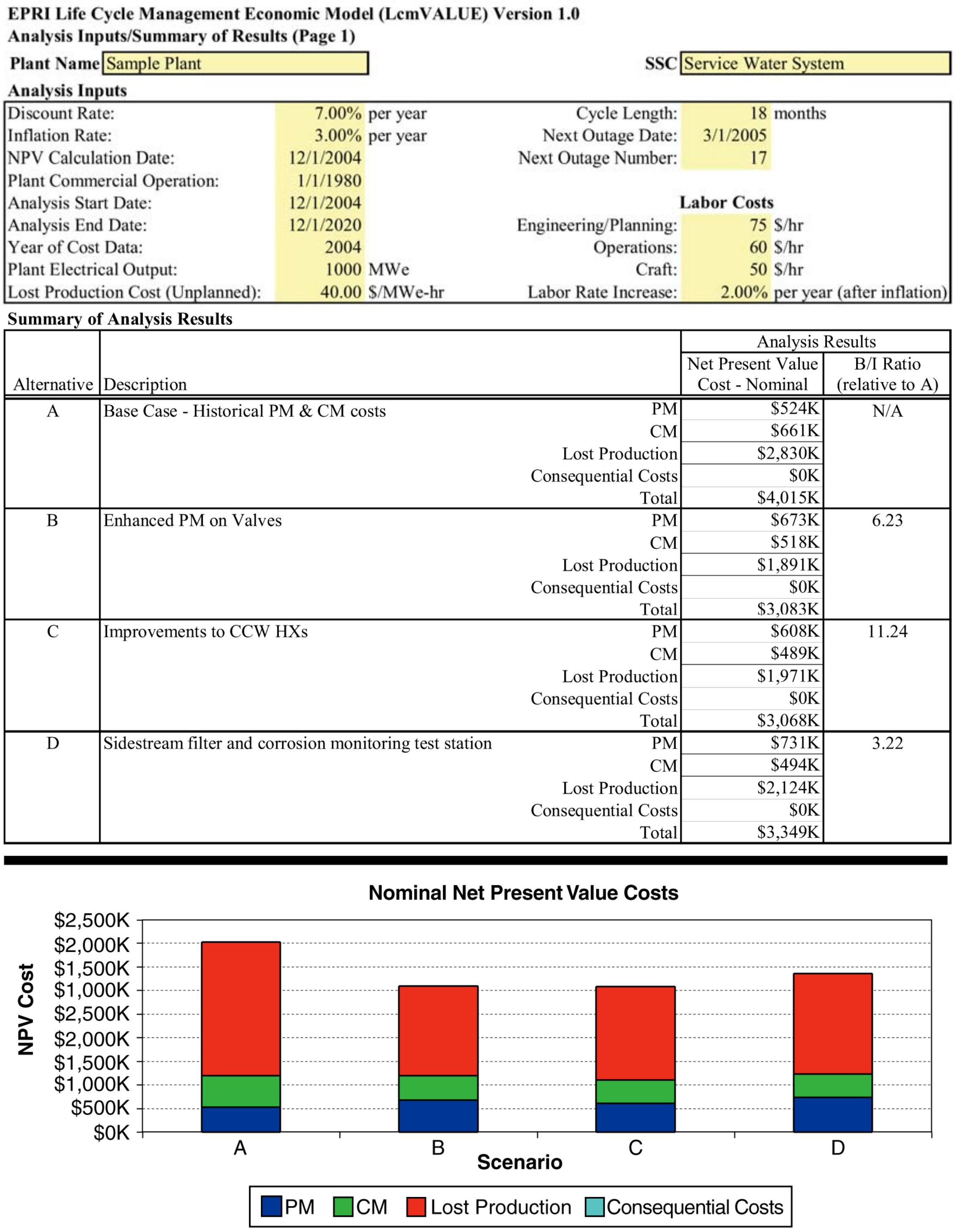
[1] The logic in the flowchart can and should be applied to “failures,” where failure is defined as the loss of function of a section of piping or where “pinhole leak” is substituted for “failure” in the flowchart.

Selection of the most appropriate strategy will be plant specific as well as system specific. Factors to consider include as-installed costs vs. lifetime cost, costs of repairs, personnel safety considerations, radiological exposure, impacts of piping system degradation on plant safety, impacts of piping system degradation on power curtailments, and timing. For example, in general, piece-by-piece replacement that may be cheaper in the short run will usually not be economical over the long run. Nonetheless, extending an outage to "do the right thing" relative to the service water piping may come at an inopportune time, which can necessitate making a short-term repair or replacement that is less economically sound when considered over the plant life, but is the correct approach at the particular window in time when some action is required.

For some non-safety-related systems, reacting to leaks or flow reductions may be the most reasonable alternative.

EPRI report TR-102204, *Service (Salt) Water System Life Cycle Management* [6-1], provides an example of a methodology that was applied to the evaluation of candidate service water piping, both aboveground and buried, and heat exchanger replacements. That LCM evaluation compared material costs, installation costs, and the required O&M costs, including inspections, associated with each candidate. The total cost was compared over the original license period and for license extension. The most economical piping replacement will be a function of material costs, installation costs, time period required to install replacements (or refurbishments as were offered for the case of the buried piping), subsequent inspections, water treatments and effluent considerations, inspections, and projected lifetime of the replacement piping. The material with the lowest as-installed cost will not necessarily have the lowest lifetime cost. Conversely, although the lower initial cost materials will typically require more attention to corrosion and microbiological controls than the higher initial cost materials, careful attention during installation and optimization of O&M procedures can produce a replacement piping system that has a long life at a low lifetime cost.

Timing is a key parameter due to inflation, cost of money, and performance of inspection or mitigation activities on critical path or not. A variety of financial risk optimization tools exist to compare various candidate approaches by including preventive maintenance costs, corrective maintenance, inspections, capital investments, and the potential for repairs or plant downtime associated with specific system or component failures. Figure 6-3 is an example of an analysis performed using EPRI's LcmVALUE tool.



EPRI Life Cycle Management Economic Model (LcmVALUE) Version 1.0
Analysis Inputs/Summary of Results (Page 1)

Plant Name Sample Plant **SSC** Service Water System

Analysis Inputs

Discount Rate:	7.00%	per year	Cycle Length:	18	months
Inflation Rate:	3.00%	per year	Next Outage Date:	3/1/2005	
NPV Calculation Date:	12/1/2004		Next Outage Number:	17	
Plant Commercial Operation:	1/1/1980				
Analysis Start Date:	12/1/2004		**Labor Costs**		
Analysis End Date:	12/1/2020		Engineering/Planning:	75	$/hr
Year of Cost Data:	2004		Operations:	60	$/hr
Plant Electrical Output:	1000	MWe	Craft:	50	$/hr
Lost Production Cost (Unplanned):	40.00	$/MWe-hr	Labor Rate Increase:	2.00%	per year (after inflation)

Summary of Analysis Results

			Analysis Results	
Alternative	Description		Net Present Value Cost - Nominal	B/I Ratio (relative to A)
A	Base Case - Historical PM & CM costs	PM	$524K	N/A
		CM	$661K	
		Lost Production	$2,830K	
		Consequential Costs	$0K	
		Total	$4,015K	
B	Enhanced PM on Valves	PM	$673K	6.23
		CM	$518K	
		Lost Production	$1,891K	
		Consequential Costs	$0K	
		Total	$3,083K	
C	Improvements to CCW HXs	PM	$608K	11.24
		CM	$489K	
		Lost Production	$1,971K	
		Consequential Costs	$0K	
		Total	$3,068K	
D	Sidestream filter and corrosion monitoring test station	PM	$731K	3.22
		CM	$494K	
		Lost Production	$2,124K	
		Consequential Costs	$0K	
		Total	$3,349K	

Figure 6-3
Example of an Analysis Performed Using LcmVALUE

Candidate **mitigation** approaches include cleaning, chemical treatments, operational modifications (for example, flows and temperatures), and corrosion control backfits such as cathodic protection for buried lines. Mechanical or chemical cleaning may be used to remove deposits, which can be massive and have an effect on flows and the localized environment that is underneath the deposit. Cleaning procedures alone may mitigate damage, or the cleaning may be used in preparation for a chemical treatment or application of a protective coating or lining. Typical solutions for corrosion problems in service water system piping may also include the addition or modification of water treatments for control of corrosion, microbiological fouling and MIC, or deposits.

In the event that mitigation approaches are not effective or not economical, more aggressive and costly **refurbishment** activities may be required. Refurbishments include nonstructural repairs, the addition of coatings or linings over already degraded piping to simply stop the degradation, and the repair or upgrade of existing corrosion control features (for example, improved cathodic protection).

If mitigation or refurbishment are inadequate for operation of the piping system for the desired design life, **repairs** or **replacements** may be in order. Repairs encompass local repairs to reclaim material lost to corrosion or to stop leaks, partial replacements, or complete piping replacement. Selection of the appropriate approach must consider cost and availability, applicability of temporary clamps (a temporary repair), considerations for weld build-ups (for example, Code Cases N-561-1 and N-562-1; a long- or short-term repair), weld procedures and welder qualification (repairs or replacements), pre- and postweld heat treatments as required, and revised stress analysis when the alloy class changes. For many non-safety-related service water piping systems, there is no stress analysis on record.

Finally, if mitigation approaches, refurbishments, repairs, or replacements will not suffice, a **design change**, for example, converting a once-through system to a closed system, may be required.

Mitigation Strategies

Mitigation of service water piping degradation will stop degradation completely or slow it down sufficiently that an existing system will reach its end of life without experiencing unacceptable degradation. Multiple degradation mechanisms may need to be treated individually. For example, a carbon steel line that is experiencing MIC, general corrosion, and nonmicrobiologically driven pitting will not benefit from the addition of high concentrations of oxidizing biocide. Such a line will need to be cleaned (chemically or mechanically; on-line or off-line), then treated with appropriate water treatment chemicals (biocides or inhibitors that have access to the surface) or the application of passive approaches such as a coating. In effect, a mitigation approach effectively applied to an existing system will dramatically change the slopes of the curves that describe the probability of one or more leaks vs. time and the number of leaks vs. time plots. Figure 6-4 is an example of effective mitigation program applied to the base case shown in Figure 6-1.

Figure 6-4 illustrates that by effectively changing the rate of damage, even after damage has accumulated for 25 years, the probability of one or more leaks and the number of leaks vs. time can be decreased dramatically at a 40-year or 60-year plant life. In the example shown in Figure 6-4, where the only change in operation was the addition of a corrosion inhibition program that was always from 50% to 90% effective (note that other steps like through-system cleaning would be required to attain that level of effectiveness), the probability of one or more leaks does not exceed 50%, even after 60 years of system operation (vs. 100% at the 45-year mark with no mitigation measures applied). Further, the predicted mean number of leaks is only one after 80 years; even for the worse-case predictions the number is between three and four leaks at 80 years.

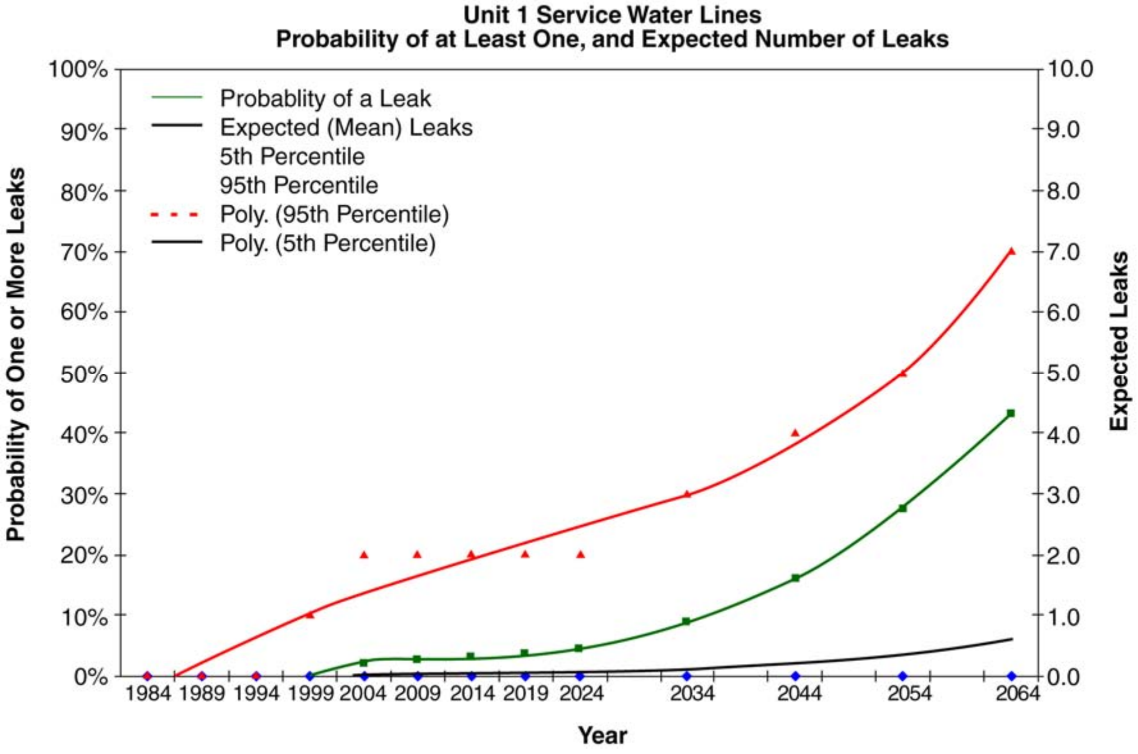


Figure 6-4
Probability of At Least One Leak and Predicted Number of Leaks Versus Time. (This is the same case as shown in Figure 6-1, except that application of corrosion inhibitor to a properly cleaned surface, with effectiveness range from 50% to 90%, is begun in 2009.)

Cleaning

The primary objectives of cleaning will often be to remove macrofouling, silt, and other deposits to restore flows and to remove deposits that may produce localized corrosion. More aggressive cleaning procedures may be used to remove all deposits and clean the surface down to bare metal in preparation for the initiation of a water treatment program or for the application of a coating. Cleaning is usually necessary to modify conditions that produce localized corrosion and return the system surfaces to a situation where general corrosion, the condition that has been accounted for in the design, is the operative degradation mechanism.

EPRI's *Recommended Cleaning Practices for Service Water Systems* provides guidance on appropriate approaches to cleaning of service water piping, heat exchangers, and other components [6-2].

References 6-3 through 6-12 provide guidance and case histories on mechanical cleaning with brushes, scrapers, solid abrasive particles, and high-pressure water jets, as well as via chemical methods including inhibited acids and chelating agents. Those methods have been applied successfully to piping, heat exchanger tubes, and other service water system components.

Mechanical Cleaning

Mechanical methods that can be applied to service water piping systems include air bumping or “rumbling” (introduction of air-induced pressure pulses to the fluid, similar to a plumber’s helper), abrasive blasting (both sand blasting, where the particle stream is perpendicular to the surface and Sandjetting, which uses a very shallow angle of incidence and repeated contacts with the surface), high pressure water jets, and metal or foam “pigs.” Pigging requires that launching and catching stations are provided.

High-pressure water jets (hydrolazing) are the most commonly used mechanical cleaning method for service water piping. Hydrolazing has been shown to be an effective off-line cleaning method. Hydrolazing can effectively remove scale, foulants, and corrosion products so that flow area is restored and treatment chemicals can reach bare metal surfaces and work effectively.

Where the system design permits, the use of pigs and other scrapers can effectively remove corrosion products and permit new surfaces to be treated, or can at least modify conditions from those where some localized corrosion conditions exist to those where general corrosion can be maintained.

Chemical Cleaning

Chemical cleaning, with inhibited mineral acids or organic acids or chelates, can also be used to completely remove corrosion products and expose bare metal surfaces. Chemical cleaning, which is often done after mechanical cleaning, provides an even more thorough cleaning of pipe walls down to base metal. As noted in [6-2], chemical cleaning can remove 100% of the corrosion products, exposing bare metal to treated water so that water treatments such as corrosion inhibitors can be applied at a high level of effectiveness.

All chemical cleaning operations will be costly, will use chemicals that can be dangerous and may be corrosive if not properly inhibited, and will generate waste, often very large quantities of waste. Even with all of those side effects, when the condition of the piping and the materials to be removed are well characterized, a properly executed chemical cleaning process can enable plant operations to improve dramatically.

References 6-7 and 6-12 provide case histories of chemical cleaning methods and application of those methods to power plant systems. References 6-8 and 6-10 describe specific plant experiences with chemical cleaning. The chemical cleaning project at River Bend [6-10] collected hundreds of pounds of corrosion products and cleaned piping and heat exchanger surfaces down to base metal with a chelate-based approach in anticipation for modification of the service water system from a once-through river water system to a closed system that relies on corrosion inhibitors to control corrosion to very low rates.

Chemical Treatments

Chemical treatments are the most frequently used method for mitigation of MIC and other forms of corrosion in cooling water systems, including service water systems. Water treatments may include biocides to control macrofouling, microfouling, and MIC; scale inhibitors to prevent the formation of calcium carbonate or other dissolved minerals; silt dispersants to prevent the accumulation of deposits; pH control agents and oxygen scavengers for microbiological and corrosion control; penetrants and dispersants to soften and help remove deposits of various sorts, and corrosion inhibitors for steels and copper alloys.

A brief discussion of the classes of water treatment chemicals that have been used in service water systems is provided below. The EPRI *Service Water System Chemical Addition Guideline* [6-13] provides a comprehensive discussion of chemical treatments that are used to treat microbiological and macrobiological growth, deposits (both fouling and scaling), and corrosion in nuclear service water systems.

Corrosion Inhibitors

Corrosion inhibitors minimize corrosion by a variety of mechanisms. Corrosion inhibitors may modify the nature of the corrosion product film to be a more protective film by further oxidation of the corrosion products to produce a film with fewer pores or imperfections or by incorporating other elements into the film (for example, molybdenum) that produce a more protective corrosion product. Other inhibitors produce a barrier film that blocks transport of metal ions away from the surface or stops cathodic reductants like oxygen from being reduced at the surface. Other chemicals provide corrosion inhibition by effectively scavenging chemical species in the environment (for example, oxygen) that control the rate of corrosion.

As noted in [6-13], most corrosion inhibitors can be classified as anodic or cathodic, depending upon whether the inhibitor slows the flow of electrons at the anodic sites or the cathodic sites. This differentiation provides a useful general guideline because of the potential danger for initiation of localized corrosion effects. An anodic inhibitor that protects 90% of the surface can produce localized corrosion at the unprotected 10% of the surface, because cathodic reactions can still occur over the entire surface. Those cathodic reactions will support corrosion (localized corrosion at accelerated rates) at the unprotected areas. The result is that some locations may experience worse corrosion than they would have with no inhibitor addition. On the other hand, a cathodic inhibitor that protects 90% of the surface will be 90% effective, since anodic events, wherever they occur, will be balanced by 10% of the amount of cathodic reactions that would have occurred with no inhibitor. Filming inhibitors, the third category identified in [6-13], will provide a barrier to anodic or cathodic reactions as long as the film covers the surface completely and is intact. Filming inhibitors generally produce much less tenacious films than anodic or cathodic inhibitors. Table 6-1, based upon information from [6-13], lists corrosion inhibitors commonly used for carbon steels and copper alloys.

Table 6-1
Common Corrosion Inhibitors by Category

Cathodic	Anodic	Filming
Polyphosphate	Chromate[2]	Azoles[3]
Zinc salts	Orthophosphate	
Polysilicate	Nitrite	
	Orthosilicate	
	Molybdate[4]	

All corrosion inhibitors provide protection by a very specific action. Therefore, the effectiveness of the corrosion inhibitor will be a function of the alloy, and will be effective only over specific ranges of pH, temperature, flow, and so forth. Corrosion inhibitors, like all water treatment chemicals, may also interact with other chemicals that occur naturally or are added to the system, a factor that can further complicate treatment. Some corrosion inhibitors can serve as nutrients for bacteria and can lead to microbiological fouling and may lead to MIC. The EPRI *Closed Cooling Water System Chemical Addition Guidelines* [6-14] provide guidance on those concerns and monitoring methods to track such effects. The plant owner must also be aware of the decomposition products of corrosion inhibitors. Those decomposition products can produce corrosive species or provide nutrients for bacteria.

Plant personnel must be aware that the addition of corrosion inhibitors to a fouled or significantly corroded system is rarely effective. Most chemical corrosion controls will only be effective when applied to clean metal surfaces. Removal of deposits, including corrosion products, biofilms, scale, and other inorganic deposits by mechanical or chemical cleaning, will make most corrosion inhibition treatments far more viable.

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[2] No longer used widely due to toxicity and environmental considerations.

[3] Corrosion inhibitor for copper alloys.

[4] Less likely to produce pitting than other anodic inhibitors.

Biocides

Biocides may be added for the control of macroscopic organisms (for example, clams, mussels, or barnacles) or microorganisms (for example, bacteria, algae, or fungi). Biocides are generally classified as oxidizing or nonoxidizing biocides. Table 6-2 is a listing of commonly used biocides.

Table 6-2
Commonly Used Biocides

Oxidizing	Nonoxidizing
Chlorine and chlorine compounds	Quaternary amines
Bromine compounds	Aldehydes
Chlorine dioxide	Heavy metals
Hydrogen peroxide	Isothiazalone
Ozone	

The toxicity of oxidizing biocides derives from their ability to oxidize living tissues and essentially “burn” organics. Examples of oxidizing biocides are chlorine, hypochlorite, bromine and chlorine/bromine compounds including hydantoins, chlorine dioxide, hydrogen peroxide, and ozone. The primary advantages of oxidizing biocides are that organisms do not develop a resistance to them, they can be effective at low concentrations, they are relatively inexpensive, and since they have been used for a long time their properties are well characterized. Their primary disadvantage is that they are oxidizers and are just as likely to oxidize metal (that is, cause it to corrode) as they are to provide the desired toxicity. Oxidizing biocides will be consumed in oxidation reactions throughout the pipework and may not persist at sufficiently high concentrations throughout the system to achieve the desired effects everywhere in the system.

Nonoxidizing biocides have much more specific toxic effects than oxidizing biocides. The nonoxidizing biocide may destroy cell membranes (which causes the life integrity of the cell to be lost) or block specific metabolic effects. Examples of nonoxidizing biocides are glutaraldehyde, quaternary amines, isothiazalone, and numerous other proprietary organics. In contrast to the oxidizing biocides, nonoxidizing biocides are more expensive and are used at higher concentrations. However, they generally do not cause corrosion of the metal to increase and they will not be consumed by reactions with the pipework. A key consideration with both oxidizing and nonoxidizing biocides is related to their ability to penetrate biofilms or layers of deposits where macro- or microorganisms are living. Persistence of the biocide is always a key consideration.

All of the biocides are toxic substances. Keys to their environmental compatibility and their discharge limits are their toxicity to fish and other higher life forms, including humans. Only approved biocides may be used.

Biocides have been shown to be effective in the control of fouling by clams, barnacles, mussels, and other macrofouling in many cases. The keys are to apply the biocide in adequate concentration for a sufficiently long time to kill the macrofouling organisms. Discharge limitations often enter into the biocide concentration and the duration of the addition. Those restrictions can limit biocide concentrations or additions sufficiently to render the chemical treatment ineffective.

Like other chemicals, biocides will only be effective against specific groups of macro- or microorganisms, and will only be effective over a particular range of parameters such as pH, temperature, and water chemistry (for example, scaling vs. non-scaling). There is no single all purpose biocide. The third panel of Figure 4-31 illustrates a key concern for control of microbiological fouling and MIC with biocides. As shown in Figure 4-31, once a mature biofilm is established, the addition of biocide is unlikely to be very effective for controlling microbes. In addition, in many circumstances, MIC will initiate a pit that will propagate with no further microbiological involvement. In such cases, the use of an oxidizing biocide (such as chlorine, sodium hypochlorite, or ozone) in systems where localized corrosion has been initiated, from MIC or other sources, can actually exacerbate the corrosion as the oxidizing power of the environment is increased, driving the existing corrosion cell in the pit or crevice at a greater rate.

The potential side effects of biocides must always be considered. In addition to the corrosion effects noted above, biocides must be evaluated for their potential interactions with other chemicals (for example, corrosion inhibitors). Biocides and other chemical additions can break down to produce aggressive species (for example, chlorides) or nutrients for macro- or microorganisms.

Deposit Control Agents

A variety of chemical agents have been developed to assist in the control of scale (precipitated dissolved solids), foulants (settled suspended solids, mud, and so forth), flocculants, surfactants, penetrants, and scale fluidizers. The prevention of deposits will eliminate crevices that form from the environment over time, thus minimizing concerns with localized attack beneath the deposits from normal crevice corrosion or from MIC.

Deposit control agents can also be applied to fouled surfaces to soften, penetrate, and remove existing deposits [6-13, 6-15]. Those agents typically work slowly. Surfactants and penetrants may also be added in conjunction with corrosion inhibitors or biocides to increase the effectiveness of the inhibitor or biocide by permitting those chemicals to reach the metal surface.

Cautions for Chemical Treatments

Most chemical corrosion controls will be effective only when applied to clean metal surfaces. The addition of corrosion inhibitors to a fouled system is rarely effective.

Factors that must be considered with any chemical treatment are:

- Surface conditions, as noted above.
- Startup vs. maintenance. The establishment of more protective corrosion product films on metal surfaces requires a much higher concentration of corrosion inhibitor than the maintenance level. Once a protective film has been formed, lower concentrations, sufficient to keep the film intact and to repair breaches in the film that may occur, can be used.
- Oxidizing power. Oxidizing biocides in particular are oxidizing agents that can be very powerful. Oxidizing biocides will serve to increase the oxidizing nature of the environment and drive corrosion (both general corrosion and localized corrosion).
- Toxicity. All biocides and many other water treatment chemicals are toxic to humans and other life forms. They should always be handled with care, in accordance with the manufacturer's guidelines.
- Effluent concerns. Because of toxicity and other environmental concerns, chemical treatments will be subject to federal or local discharge limitations.
- Concentration. The most common location for chemical additions will be at the pump house. Chemicals will be consumed during their trip(s) through the system. At high concentrations (for example, near the injection location), aggressive chemicals like oxidizing biocides can drive corrosion. At concentrations that are too low, as may occur at locations that are far removed from the injection point, chemical treatments can be ineffective. Supplemental injection locations be required

Coatings and Linings

Coatings and linings, previously discussed in Section 3, permit the use of inexpensive base materials, even in aggressive environments. All of the corrosion resistance is provided by coating. As long as the coating remains intact, corrosion is effectively mitigated. However, once the coating begins to degrade, corrosion will initiate at the location of the failure(s) in the coating. The corrosion can proceed rapidly, although the unfavorable area effect that can exacerbate galvanic couples won't be present. All coatings will degrade with time, and coating degradation may also be accelerated by the presence of particulates in the cooling water or by some water treatments. Some plant processes, like welding and cutting, can completely destroy coatings. Great care must be taken to assure that destructive processes are not applied to coated or lined piping without subsequent inspection of the coating, with repairs applied as necessary. Coating life is typically less than plant life. The degradation of the protective nature of the coating must be anticipated. Coating maintenance and repairs are a part of the management of any coated system.

Coated pipe, as purchased from the factory, will have a coating that has been applied and tested in the shop in accordance with the purchaser's requirements. Welds made in the field will have to be coated in the field. Field conditions will be less than optimum for application of the coatings, so the quality of field-applied coatings will be less than the quality of shop coatings. Careful testing for holidays or other defects should be done to ensure the best field coating possible.

Piping that was originally installed bare, or coated pipe that has experienced coating degradation in service may be coated in place via a variety of techniques (such as spray, trowel application, or wiper pigs). Keys to the success of those backfit coatings are proper selection of the coating type, thorough surface preparation to provide a clean ("white metal") surface that has a sufficient profile so that the coating will adhere tightly to the substrate, and curing under proper temperature and humidity conditions (including sufficient time for full curing of the coating).

Section 3 includes a brief overview of commonly used coatings.

Refurbishments

Cleaning

Commonly used mechanical and chemical cleaning methods have been discussed above. Cleaning alone can be used to eliminate deposits, remove biofilms and corrosion products, and enable the degradation processes to start over again—in effect, changing degradation from a local condition to a general (and more readily managed) process.

Visual inspection immediately after cleaning is the most common method to assess the effectiveness of the cleaning. Subsequent inspections or monitoring tools can be used to evaluate the long-term success of the cleaning process.

Coating

Coatings and coating methods are described in Section 3 and are also discussed above. This subsection includes discussion of local coatings and coating repairs as a refurbishment method.

Application of coating to previously uncoated piping can be used as part of a local repair or to enhance a temporary or permanent structural repair. A number of industries rely upon nonmetallic materials to reestablish the structural integrity of portions of the piping that has been degraded by corrosion on the interior or exterior or by other degradation mechanisms such as erosion.

Figure 6-5 provides an example of a line, eroded by cavitation, that was weld repaired and refurbished by a coating. The base metal continues to serve as the pressure boundary, with the coating acting as a barrier between the base metal and the aggressive environment. Although the coating has no structural function, it effectively prevents any further damage. Like all coatings, some level of inspection and maintenance must be anticipated for the coated pipe to provide a satisfactory life.

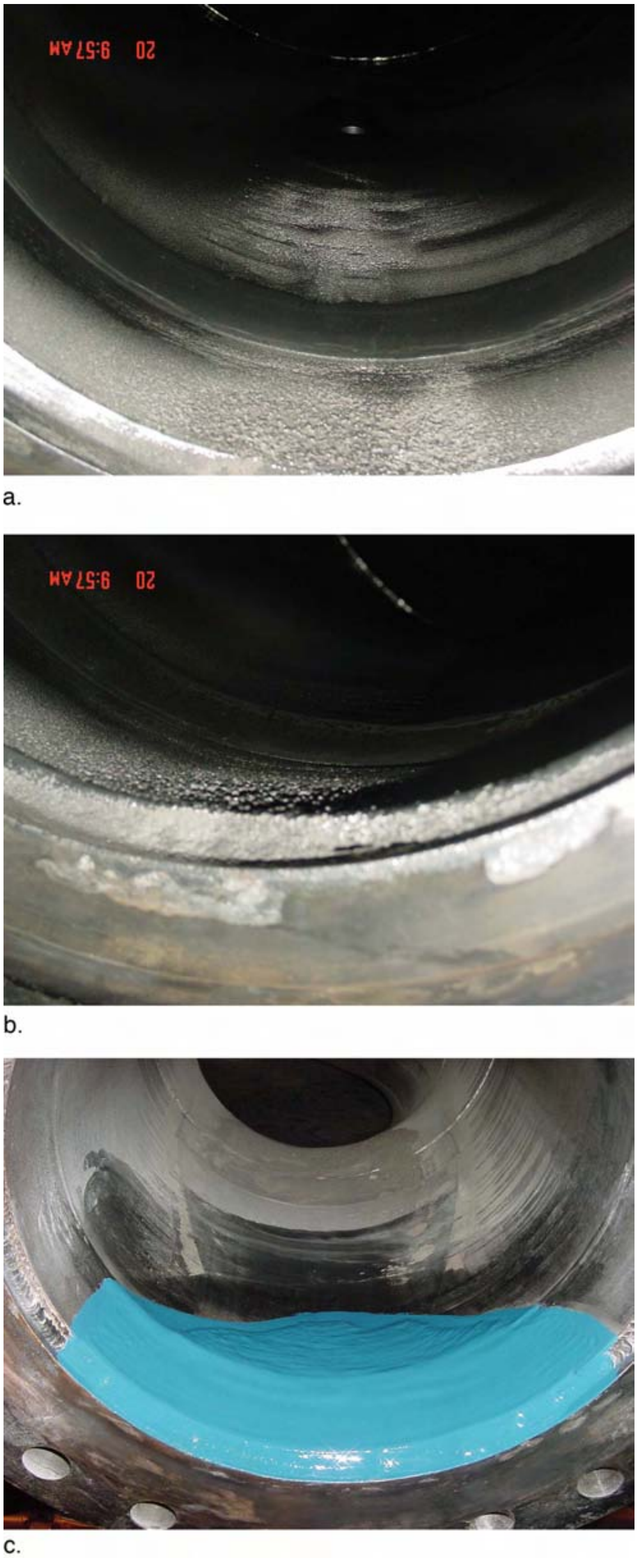


Figure 6-5
Degraded Piping, Refurbished by Weld Buildup and Coating: (a) Eroded AL6XN Piping at Slip-On Flange; (b) Close-Up of Eroded AL6XN Piping at Slip-On Flange; (c) Refurbished Piping Following Weld Buildup and Erosion-Resistant Epoxy Coating (Photos Courtesy of Jim Melchionna)

Linings

Retrofit linings, especially those that are not bonded to the pipe interior, have been used in some plants, including in buried pipe in nuclear plants. Cured-in-place piping (CIPP), such as Insituform and Master Liner, can be an effective method for refurbishment of degraded piping. CIPP is used extensively in the water and wastewater industries. The original concept for CIPP was that the epoxy-impregnated sleeve would be driven into and along the length of the original line. When the epoxy cured, the CIPP would become the pressure boundary, with the (degraded) original construction sewer line merely having served as the form for the cured-in-place pipe. These retrofit linings are always a custom application, sized specifically for the pipe to be refurbished.

In the initial nuclear applications, the CIPP was not considered as a stand-alone pipe but was defined only as a corrosion-resistant liner. That type of application requires that the initial construction material and the degraded pressure boundary must still be inspected periodically to ensure that the pressure boundary is still structurally sound.

In all applications, seals between the CIPP and lateral lines or other lengths of CIPP are critical to a successful installation.

Repairs

Welded Repairs

Welding, typically on the pipe OD, may be used to repair pinhole leaks or generalized or localized thinning. Code Case N-562 [6-16] provides guidance for the design of OD repairs for a variety of forms of corrosion damage on the pipe ID by applying a weld metal to the pipe OD. Those repairs are acceptable only when the “damage” on the ID is purely metal loss due to corrosion or wear. OD repairs are not permitted when the ID is damaged, for example, by cracking, without removing the cracking.

Full structural repairs, such as weld overlays that are applied on the pipe OD over the full 360° of the circumference, have been applied to carbon steel and stainless steel to create a new pressure boundary that bridges defected material as can exist when the pipe ID contains cracks. The design requirements for weld overlays must be consistent with Section XI of the ASME Code. It should also be noted that not all weld overlay repair approaches have been approved by the Nuclear Regulatory Commission. Although those repairs, including temporary repairs of ASME Code components described above, can be made in accordance with ASME Code rules, a relief request to the NRC is required.

The NRC recognized that there was a significant hardship related to providing Code-approved repair in nuclear plant piping systems, especially related to low-temperature, low-pressure Class 3 systems. To provide utility guidance for evaluating these systems, the NRC issued Generic Letter 90-05 [6-17]. The NRC staff position on Class 3 piping is summarized as follows:

1. For degraded Class 3 piping systems, licensees are required to make Code-approved repairs or to request NRC relief for temporary non-Code repairs on a case-by-case basis.
2. Provided that the piping is structurally acceptable (based on guidance in the Generic Letter) and augmented inspection is performed, temporary operation with through-wall flaws is acceptable for low-energy systems, provided that system interactions such as loss of flow and spray on adjacent equipment are considered.
3. For moderate-energy piping, nonwelded temporary repairs are acceptable.
4. For high-energy systems, temporary repairs must have load-bearing capability similar to that provided by engineered weld overlays or engineered mechanical clamps.
5. Evaluation criteria were provided in the Generic Letter for operation with no repairs to the piping system.

The intent of the repairs is to restore the piping to its nominal wall thickness and provide reinforcement of sufficient area that the local thinning has no effect on the load-carrying ability of the piping.

Code Case N-562 [6-16] was developed to provide rules for the restoration of wall thickness on low-energy or moderate-energy carbon steel piping that has experienced wall thinning on internal surfaces from FAC, MIC, or other forms of corrosion where localized removal of metal has occurred, without the production of cracks or crack-like defects. It would permit the application of weld metal on the pipe outside diameter in order to restore the pipe's wall thickness.

The evaluation of wall thinning must take into account the continuing degradation of the piping wall during the evaluation period. Therefore, an estimate must be made for the value of the minimum measured wall (t_{meas}) at the next inspection/repair outage. The rate of wall thinning will obviously depend upon the operative degradation mechanism. A reasonable upper bound for the penetration rate is 100 mils per year (mpy) where the thinning is due to MIC. This estimate is based on service experience, in-plant tests, or laboratory experiments. The actual rate for the specific applications may be augmented and updated by trending available inspection results.

For each grid location or measurement point, the predicted wall thickness at the end of the evaluation period (t_{pred}) is determined by starting with the measured wall thickness (t_{meas}) at that point and applying to it the rate of wall thinning, as follows:

$$t_{pred} = t_{meas} - (\rho \times \tau \times 10^{-3})$$

where

ρ = rate of wall thinning in mils per year

τ = evaluation period (time to next inspection/repair) in years

t_{pred} and t_{meas} are in inches

The size of the thinned area, defined by its axial and transverse (circumferential) dimensions, may be predicted in a number of different ways. The simplest approach is to assume that the shape of the flaw remains essentially constant. This approach assumes that the thickness of the existing thinned area and all contiguous areas will degrade at the same constant rate.

Temporary Repairs

Mechanical clamps can be used only as temporary repairs. For example, Code Case N-513 [6-18] permits the temporary operation of low-energy Class 2 and Class 3 piping, even in the presence of a through-wall leak. Structural evaluations must be performed that demonstrate that the leak does not jeopardize the structural integrity of the piping, and augmented inspections must be done regularly to assure that any growth of the defect has not compromised structural integrity. A full structural Code repair must be done at the next outage.

Nonmetallic repairs, including structural and nonstructural applications, can be applied on a case-by-case basis. Code Case N-589 and its revision N-589-1 [6-19], which has been approved by the ASME Code but not approved generically by the NRC, describes the design requirements for structural applications of nonmetallic repairs. This Code Case provides two alternative methods for structurally lining buried service water system header pipe, including design and installation requirements. The original Code Case N-589 is listed in NRC Regulatory Guide 1.193 with four objectives. The “inserted form” has been used at several light water reactors for safety-related buried headers for the service water system. Another LWR has used the “inserted from” extensively in its non-safety-related service water system buried headers. Currently this plant has an initiative to use Code Case N-589-1 for its safety-related service water system buried headers.

In addition, Article 4.3 of the ASME PCC-2 provides guidance on how to utilize the “sprayed form” structural liner for buried piping.

Replacements

Piping replacement is an option that can be used at any time, but becomes necessary when degradation cannot be economically recovered by mitigation or repair. References 6-20, 6-21, and 6-22 are EPRI documents that deal specifically with service water system repair and replacement, including welding issues.

In-Kind

Like all piping replacements, in-kind replacement enables the plant to start over again from zero degradation. A unique feature of the in-kind replacement is that the original piping design will still apply if the same piping thickness is again selected. The basis for in-kind replacement is that the plant successfully, although not easily, attained a significant number of years of adequate performance, often with minimal attention to corrosion control. Replacement with the same material, at the same nominal thickness or a slightly greater thickness, should provide performance that is at least as good, especially if greater attention is paid to maintenance and control for the replacement system. The keys for in-kind replacement to be successful for long-term use are to eliminate prior periods of poorly controlled operation that have dramatically influenced performance in a negative way and to maintain conditions so that corrosion will be general corrosion rather than localized corrosion (for example, eliminate deposits). Often a relatively minor modification to the materials specification, such as the addition of a pickling step to remove mill scale (thus avoiding preferential anodic sites at cracks in the mill scale), can produce a dramatic improvement in corrosion performance while still using the same nominal alloy.

The primary advantages of in-kind replacement are:

- Use of existing analyses and support arrangements
- Relatively low material costs
- Established fabrication procedures

Corrosion-Resistant Alloys

Corrosion-resistant alloys provide a margin against both general and localized corrosion, even during periods of poor control or in systems where chemical controls are impractical.

Concerns with welds and other fabrication issues, including procurement of rolled and welded pipe to ensure that the pipe is as corrosion resistant as the plate from which it is made, will be greater for corrosion-resistant alloys, because the corrosion resistance that results from alloying and careful controls of composition, surface oxides, and so forth at the mill are more readily undone by fabrication practices in the field. The end user needs to write an appropriate specification on properties of the as-received pipe, including corrosion testing, and should do the same with procedural controls (for example, plant welding, cleaning, and machining procedures). The use of corrosion-resistant alloys as a replacement for carbon steel will require new stress analyses (different physical and mechanical properties) as well as qualification of weld procedures and welders. For the highly alloyed materials like the 6% molybdenum stainless steels, the welder's qualification can be a major difficulty. At least one plant has reported that only one of four welders who were qualified for carbon steel and 300-series stainless steels was able to qualify for the 6% molybdenum stainless steel [6-23].

The replacement of carbon steel service water piping with 300 series stainless steel was unsuccessful for a number of plants. Generally, the bare carbon steel failed in untreated waters because of general corrosion and tuberculation that produced gross reductions in cross section and some leaks. The replacement systems exhibited failures, often by MIC at welds, in approximately the same time frame as that over which the carbon steel failed.

Selecting the Proper Stainless Steel for Service Water Piping Systems

When selecting stainless steel for service water piping, it is important to select an appropriate grade of stainless steel to match the aggressiveness of the water. When corrosion of stainless steels occurs, it is generally in the form of localized attack such as pitting and crevice corrosion.

As discussed in Section 4, the environmental factors that promote localized attack are higher chloride content, higher temperature, lower pH, and more noble corrosion potentials. More noble corrosion potentials can be produced by the addition of oxidizing species to the environment (for example, oxidizing biocides like chlorine). The presence of manganese deposits on stainless steel surfaces can also produce ennobled potentials and contribute to localized attack on stainless steel.

The resistance of a stainless steel to localized attack is strongly related to its alloying content. The primary elements that contribute to the pitting and crevice corrosion resistance of austenitic and duplex stainless steels are chromium, molybdenum, and nitrogen. An empirical relationship called the pitting resistance equivalent number or (PRE_N) has been developed to relate a stainless steel's composition to its relative pitting resistance.

The PRE_N relationship for austenitic and duplex stainless steels is usually given as follows:

$$PRE_N = \%Cr + 3.3(\%Mo) + 16(\%N)$$

Note: Factors other than 16 for nitrogen have been suggested. For example, 30 is another coefficient commonly used for nitrogen. Comparison of PRE_N values should only be made when the same N coefficient is used.

The PRE_N is a useful figure of merit that can be helpful in comparing different stainless steels and selecting the correct stainless steel for chloride-containing environments. Although this relationship has been developed to rank pitting resistance, it also provides a relative ranking of a stainless steel's crevice corrosion resistance. Comparisons made for resistance to crevice corrosion must also address the variations that can occur for different crevice materials and crevice geometries. For both pitting and crevice corrosion, the PRE_N number is related to the alloy's resistance under ideal conditions and does not address factors such as the presence of nonmetallic phases, the presence of intermetallic phases, improper heat treatments, or variations of surface condition. Because of these limitations, the PRE_N factor should only be used as an indicator of an alloy's potential performance. Table 6-3 lists stainless steels commonly used in water piping systems and their corresponding PRE_N using a nitrogen coefficient of 16.

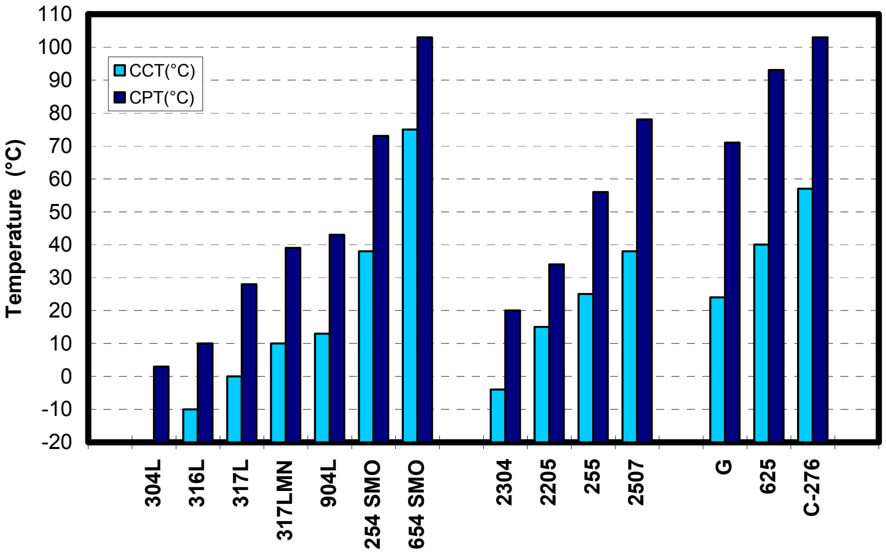
Table 6-3
Stainless Steels Commonly Used in Service Water Systems

Grade	UNS #	%C, max	%Cr	%Ni	%Mo	%N	Other	PRE_N
304	S30400	0.08	18	8	---	---	---	20
304L	S30403	0.03	18	8	---	---	---	20
316	S31600	0.08	16	11	2	---	---	23
316L	S31603	0.03	16	11	2	---	---	23
904L	N08904	0.02	20	25	4.5	---	Cu-1.5	34
2205	S32205	0.03	22	5	3	0.16	---	35
6%-Mo	S31254	0.02	20	18	6	0.20	Cu-0.75	41-43
	N08926	0.02	20	25	6	0.20	Cu -1.0	
	N08367	0.03	20.5	24	6	0.20	---	

In this table, the calculated PRE_N for the 304 and 304L grades includes the contribution from the residual levels of N and Mo for which there are no specified minimums. Likewise, the calculated PRE_N for the 316, 316L, and 904L grades includes the typical N residual.

The relative resistance of a stainless steel to localized corrosion can be quantified by testing using the concept of critical temperature required for initiating attack in standardized test solutions. The critical pitting temperature (CPT) or critical crevice corrosion temperature (CCT) is measured using either immersion test methods such as those outlined in ASTM G 48 [6-24] for coupon testing, or electrochemical methods such as the ASTM G 150 test method [6-25]. The higher the critical temperature required to initiate attack, the more resistant the stainless steel is to pitting and crevice corrosion in chloride-bearing environments.

Critical temperatures are usually measured in standard laboratory environments and are not directly transferable to practical operating environments. Without more detailed correlation data, the CPT and CCT measurements only provide a relative ranking of the grade's resistance to localized chloride attack, similar to the relative alloy ranking provide by the PRE_N. There have been a few cases where CPTs have been measured in actual service environments or in complex simulative environments with good correlation with service performance. In other cases, correlations have been made between the grade's measured CPT and CCT in standard test solutions and the performance in actual service environments. The CPT and CCT for various stainless steels and Ni-base alloys measured in a 6% ferric chloride test solution (10% $FeCl_3 \cdot 6H_2O$) are summarized in Figure 6-6.



Alloy	UNS #
304L	S30403
316L	S31603
317L	S31703
904L	N08904
254 SMO®	S31254
654 SMO®	S32654
2304	S32304
2205	S32205
255	S32550
2507	S32750
G	N06007
625	N06625
C276	N10276

Figure 6-6
The CPT and CCT for Various Stainless Steels Measured in 6% Ferric Chloride, $FeCl_3$ (10% $FeCl_3 \cdot 6H_2O$), from [6-32]. All of the alloys in the first group (304L-654SMO) are austenitic stainless steels. The second group (2304-2507) consists of duplex stainless steels. The third group (Alloy G-C276) is made up of nickel-base alloys. (Reproduced Courtesy of the Nickel Institute)

The end user must also be aware that castings with the same nominal composition as wrought products may not have corrosion resistance that is as good as that of the wrought products. The same caution regarding corrosion resistance of CRAs will also apply to welds. The procurement specification of castings, for shop welds, and for field welds should specify corrosion testing.

The CPT results are consistent with PRE_N rankings, as shown in Figure 6-7. The plot in Figure 6-7 shows a well-defined linear relationship between the CPT measured with the ASTM G 150 test method and the PRE_N of the stainless steel.

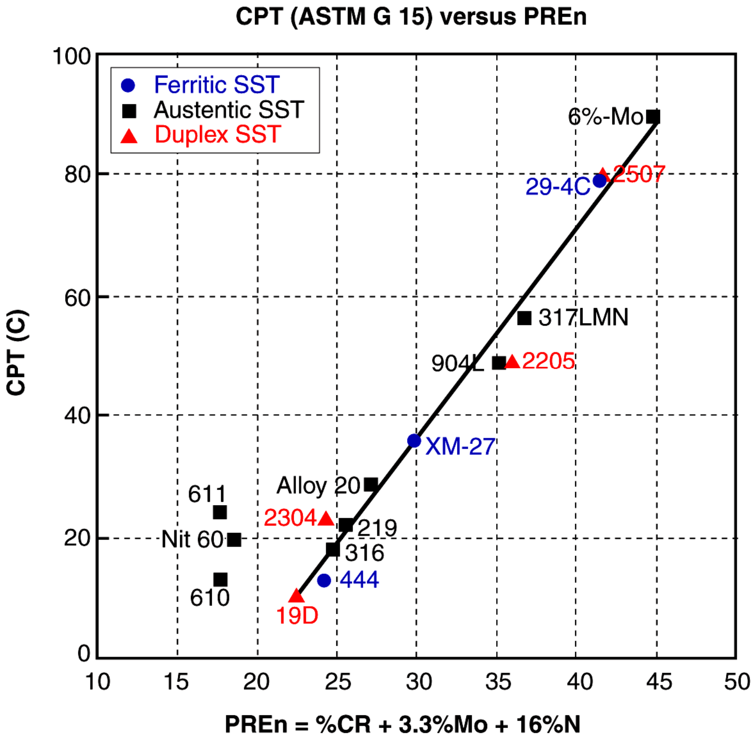


Figure 6-7
Plot of the Electrochemical CPT Measured in 1.0 M NaCl with the ASTM G 150 Test Method Versus the PRE_N Number of Various Austenitic, Ferritic, and Duplex Stainless Steels, from [6-33]

Natural Water Environments

Type 304 and Type 316 are the standard stainless steels specified for natural, raw, and potable water piping systems. Within limits, these standard grades perform well for the temperatures, chloride levels, the presence of crevices, microbial populations, flow rates, chlorination levels, and the presence of manganese that are experienced in those environments. When water environments are too demanding for standard grades, high-performance stainless steels with higher PRE_N values, as reflected in higher CPT and CCT values, are good alternatives.

For example, the recommended maximum chloride levels for the Types 304/304L and 316/316L in water systems are 200 ppm and 800 ppm, respectively. Those recommendations are based on laboratory trials and field experience in environments with neutral pH and water temperatures up to 30°C (85°F). Those recommendations do not include other factors that could make the environment more aggressive (for example, pH upsets, periodic high concentrations of oxidizing biocide, local environments that produce MIC). The increased pitting and crevice corrosion resistance of the austenitic 904L and the 2205 duplex stainless steel grades increase this maximum allowable chloride level to about 3000 ppm. The 6%-Mo stainless steels have sufficient alloying content to provide resistance in seawater environments where chloride levels are in the 20,000 ppm range.

Other factors that can increase the corrosivity of natural waters are:

Chlorination. Other factors, besides the level of chlorides, can have a substantial impact on the corrosion performance of stainless steel. For example, oxidizers such as chlorine raise the corrosion potential and make pitting and crevice corrosion more likely. Investigations with chlorinated water have shown that Types 304/304L and 316/316L are susceptible to crevice corrosion with chlorination levels in the 3–5 ppm range [6-26]. Alloys with higher Cr, Mo, and N levels provide increased resistance to high chlorination levels.

Manganese. In the presence of dissolved manganese, Types 304 and 316L have failed in waters that would have otherwise been considered to be noncorrosive based on their chloride content and temperature. When manganese contamination is present in the water, MnO_2 deposits **can** form. The presence of the MnO_2 deposits can contribute to pitting failures. Soluble Mn(II) can be oxidized to MnO_2 by either biological processes or chemically by commonly used biocides such as chlorine, peroxide, or ozone. When the biological or chemical conversion process is present in the environment, the level of manganese required for this corrosion mechanism is exceedingly small, well below the 1 ppm level. If Mn(II) is oxidized to manganic ion, resulting in the formation of MnO_2 deposits, Types 304 and 316 stainless steel could pit even if the chloride content is well below recommended limits. Selecting grades with higher chloride pitting resistance can solve the problem of Mn corrosion. High-performance stainless steels such as 6% Mo stainless steels have successfully replaced standard stainless grades in waters where manganese problems have been reported for other stainless steels.

MIC. There are circumstances where microbial activity can influence the corrosion process resulting in pitting of the stainless steel. MIC is discussed extensively in Section 4. Three kinds of bacteria are associated with pitting attack of stainless steel. They include aerobic iron and manganese-oxidizing bacteria, anaerobic sulfate-reducing bacteria, and aerobic iron and sulfur-oxidizing bacteria. MIC of stainless steel most frequently occurs on welds and heat-affected zones in stagnant or slowly moving waters. The morphology of attack is typically cavernous pitting that rapidly penetrates the stainless steel cross section.

In the presence of aggressive bacteria, Types 304 and 316 stainless steel can be very susceptible to MIC. The use of biocides can mitigate bacteria problems and will allow the use of standard grades such as Types 304 and 316. An alternative approach is to choose a stainless steel that has better MIC resistance. The important factor in avoiding MIC appears to be the increased pitting resistance that is provided by a grade with a higher PRE_N. The 6%-Mo grades with a PRE_N above 40 are immune to MIC failures. The intermediate grades such as 904L and 2205, although not immune, have had very few reports of MIC failures.

Seawater

Stainless steels such as Types 304, 316, and 2205 do not have sufficient corrosion resistance for use in seawater. It was not until the introduction of highly alloyed stainless steels that a truly seawater-resistant stainless steel became available. Testing has shown that stainless steels require a critical crevice corrosion temperature (CCT) measured with the ASTM G 48 Practice B ferric chloride crevice corrosion test of 35°C (95°F) or higher to resist seawater exposure (see Figure 6-8) [6-27]. This is consistent with Strandmyr and Hagerup [6-28] who reported adequate performance in offshore systems when the stainless steel has a PRE_N of 40 or greater.

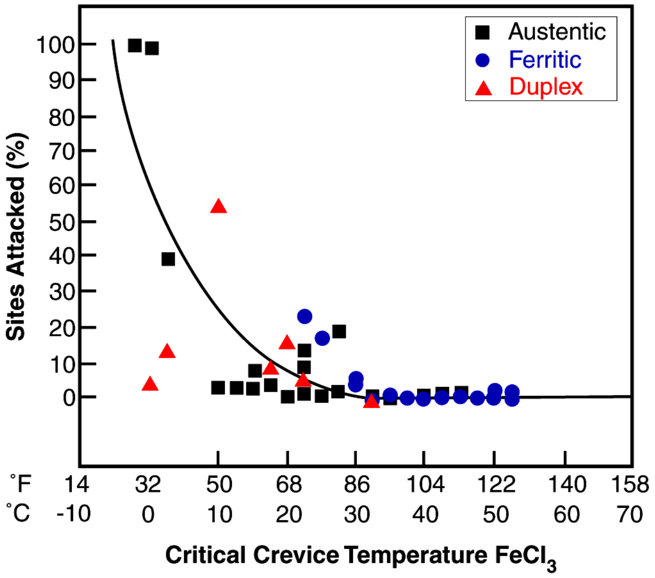


Figure 6-8
Crevice Corrosion Sites Attacked in Seawater Exposure at 35°C for Various Stainless Steels as a Function of ASTM G 48 Ferric Chloride CCT [6-27] (Reproduced Courtesy of the Nickel Institute)

The electrochemical potentials of stainless steels will shift in the noble direction in natural seawaters (and in fresh water), due to the presence of a microbial slime layer. Under such conditions the noble potentials, typically in the range of 300 to 350 mV (SCE), increase the risk of pitting and crevice corrosion. Living seawater is more aggressive than sterile solutions such as synthetic seawater and laboratory NaCl solutions where this ennoblement is absent.

In many applications, seawater is chlorinated to avoid fouling problems. Chlorine and hypochlorite will kill the biofilm, with the goals of avoiding both fouling and pit initiation due to MIC. The chlorine-based biocides are oxidants, which shift electrochemical potential of the stainless steel to more noble values, in the 500 to 600 mV SCE range. Consequently, chlorination can increase the risk of localized attack, and overchlorination can substantially increase that risk. However, because the chlorine will kill the biofilm, and, presumably, keep surfaces clean, localized attack from MIC is avoided. The balance between effects of biofilms and effects of the agents, like chlorine, that are used to control biofilms must be understood to achieve satisfactory corrosion performance. Both biocidal effectiveness and the probability of corrosive attack during chlorination will increase with chlorine concentration and temperature. The chlorine level required to prevent microbial activity on a stainless steel surface has commonly been reported to be 0.1 to 0.2 ppm [6-29, 6-30]. If intermittent chlorination is used, a residual level of 1 ppm of chlorine for 30 minutes per day seems to be sufficient to stop the microbial activity [6-30]. Based on practical experience, the offshore industry tends to restrict the use of 6% Mo austenitic stainless steels to a maximum of 85 to 95°F (30 to 35°C) and 1 ppm maximum residual chlorine [6-30].

The preceding discussion provides some basic guidelines for evaluating the aggressiveness of service water environments and selecting an appropriate stainless steel grade for piping systems. When properly selected, stainless steels provide outstanding service and have the potential to reduce downtime and lower maintenance costs. However, if an inappropriate grade is selected it can result in excessive leaks, high maintenance costs, and costly replacements. Because of this, it is wise to seek the advice of a specialist familiar with stainless steels and their limitations. The same basic discussion applies to other corrosion-resistant alloys.

Note that valve materials, especially the valve body, will often be forgings or castings. Where cast grades are used, the cautions noted previously will apply. For all product forms, corrosion testing of the final product form is strongly encouraged.

Welding Effects

Welding permits lengths of pipe, pipe fittings, different shapes (pipes to nozzles), or other components (for example, tube to tubesheet welds) to be metallurgically bonded at joints that will have strength properties that are equivalent to or superior to the properties of the base metals.

The welding process melts the base metals (and the filler metal if one is added, which it usually is) to produce an as-cast (cast-in-place) microstructure. The cast microstructure will have properties that are somewhat different than the properties of wrought material (plate, pipe, bare, and so forth) that has been cast, then forged or rolled or otherwise formed, and heat treated one or more times to refine the strength, ductility, and directionality of the wrought product.

Welding **can** degrade mechanical properties, especially toughness. All materials, even the best wrought products, have inherent flaws. The size of the inherent flaws in cast material, including welds, will generally be greater than in the wrought material. Since welds have solidified in place, directionality of the microstructure, due to the cooling, may also degrade properties slightly relative to those of wrought products.

Welding **will** degrade corrosion resistance. The nonuniform nature of the weldment will always produce one or more zones that are less corrosion resistant than the wrought product (Figure 6-9). The amount of the degradation depends upon the alloy, the process, and the welder.

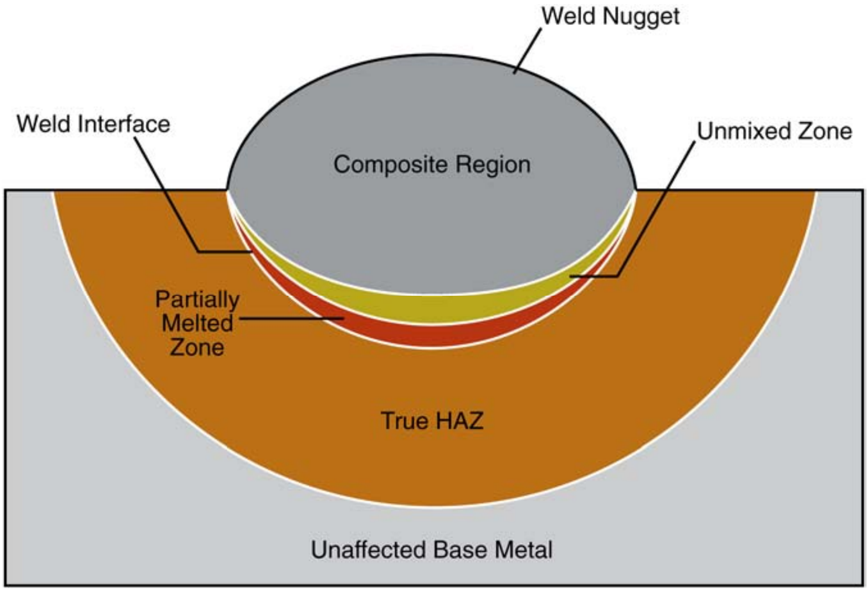


Figure 6-9
Schematic of Microstructural Zones in a Typical Weldment (Reproduced Courtesy of ASM International)

Under ideal conditions, all of the properties of welded structures are as good as those of the wrought products (or good enough). Years of positive experience with welded construction have given code authorities sufficient confidence to make the allowables for weld metals the same as for wrought products. Some design codes will assign an efficiency factor, or other factor, that must be applied to welds in order to complete the analysis. In addition, most codes identify welds as the locations where inservice inspections should be targeted. Shop welds, including longitudinal seam welds for piping, can be made under well-controlled conditions. Further, shop welds can often be postweld heat treated. Both factors can improve the corrosion resistance of the shop weld. Field welds will be made under less ideal conditions than the conditions that will exist in the shop. The detrimental effects of welding on corrosion resistance may greater for field welds. In both cases, when an alloy is being used for its high level of corrosion resistance, procurement specifications and plant procedure qualifications must address the minimal acceptable corrosion resistance provided by the welded microstructure.

A key factor in the reliability of welds is reliance on the welder's skill. For this reason, construction codes require that a weld procedure specification be qualified. That is, the procedure is not qualified until a number of welds have been made successfully with that procedure and destructive evaluation of the qualification pieces has demonstrated that weldments possess the required attributes. Then, all production welds must be done by qualified welders to the qualified procedure.

Inspection, either using surface or volumetric methods, is always performed as a check on weld quality. Inspection is a key.

Welded construction is used for the vast majority of aboveground piping fabricated from steel or corrosion-resistant alloys. Further, most buried steel and iron-based corrosion-resistant alloy piping will be welded. As noted in Section 1, inspection requirements imposed during fabrication of those welds were generally minimal. Volumetric techniques were generally not required. The most common weld configurations will be butt welds and socket welds. Butt welds, the most common configuration for large-bore (>2-in. [51-mm]) pipe may be made with or without backing rings. The presence of the backing ring can have a significant effect on corrosion damage in service, because the backing ring creates a crevice where impurities can collect or microbes can grow. Crevice corrosion can also initiate and propagate beneath the backing ring. Socket weld fittings also have a built-in crevice that can have corrosion ramifications. In addition, socket welded piping can be subject to failure by fatigue produced by vibration [6-31].

Proper machining and cleaning practices are also critical parameters that must be addressed in order to obtain the full benefit of the corrosion resistance of corrosion-resistant alloys. As discussed for welding, fabrication will impact corrosion resistance. Poor fabrication can dramatically reduce many of the properties of a corrosion-resistant alloy that was purchased at a premium price.

The higher material costs and installed costs for the highly alloyed corrosion-resistant alloys may be recouped over the life of the replacement system, because the corrosion-resistant materials offer the potential for reduced maintenance costs.

Design Changes

Design changes to eliminate or minimize the effect of dead legs can decrease localized corrosion significantly [5-14]. As discussed previously, degradation is much more readily controlled in a closed-loop system, where water chemistry can be carefully controlled and the use of corrosion inhibitors can permit unalloyed materials to be used successfully. In many plants with very aggressive cooling waters (for example, seawater or brackish water), the initial plant design had the majority of the equipment cooled by a closed system that transferred its heat to a relatively small, open service water system with the aggressive water source as the ultimate heat sink. At least one plant, River Bend, has successfully modified its plant design to change from an open river water system that was subject to high rates of general corrosion, pitting, and MIC to a closed loop. As noted in [6-10], chemical cleaning of the entire system was a precursor to the change-over.

The modification of an open loop to a closed loop provides an even more extreme modification of the leak history shown in Figures 6-1 and 6-4. For a closed system, the cumulative probability of one or more leaks effectively stays constant from the time that the change-over to a closed loop becomes operative, because degradation from corrosion is effectively stopped completely.

Other System Changes

Other modifications to the operation of the service water system can have significant positive effects on the piping. For example, changing the flow schedule for intermittent flow systems can significantly improve capabilities for control. More frequent flow can serve to prevent microbial attachment and will introduce water treatment chemicals to the nonflowing train more often to improve corrosion control. Modifications to the flow schedule need to consider the entire system, not just piping. For example, a bad flow frequency for carbon steel or stainless steel piping (see Section 4) relative to corrosion effects, including MIC, can be significantly different from a bad flow frequency for heat exchanger materials (for example, copper alloys).

Full flow or sidestream filtration can provide a surprisingly effective method for the removal of silt, other suspended solids, corrosion products, and macrofouling organisms. The elimination or reduction of constituents that can produce deposits and aggressive underdeposit conditions can produce a dramatic improvement in piping performance. The presence of a filter may also permit the plant to shock-dose the system with the intention of removing large quantities of foulants from piping surfaces. The filter provides a desirable location for the foulants to be collected, then removed. Without a filter, deposits that are removed from one location can collect in heat exchangers or other critical spots, where their presence can severely impact the system.

Many plants use thermal treatments for the control of macrofouling organisms. Typically, a few additional valves and small lines are provided that permit discharge side flows to be directed to inlet screens and piping. Thermal treatments can also be effective for microorganisms; however, the temperatures that must be used are higher than for macroorganism control, requiring external heat sources. In all cases, the kinetics of corrosion reactions will be increased during the thermal treatment. Since the thermal treatments are usually very short, the increased corrosion during the thermal treatment is not significant.

Cathodic Protection

Cathodic protection (CP) is commonly applied to protect buried pipe from soil corrosion. The basic approach is to pump electrons into the structure, making it the cathode in the corrosion circuit. Most buried pipe is coated, as the primary corrosion control method, with the CP system sized to protect areas where the coating has been damaged or deteriorates and loses its protective capabilities. Obviously, CP system design is important to successful protection of the piping. However, proper maintenance to either impressed current or sacrificial anode CP systems is probably equally important.

For buried pipe, coatings and effective cathodic protection provide the primary and secondary mitigation approaches for service water piping degradation from the OD. Coatings provide a physical barrier between the pipe and the corrosive environment, in effect delaying the onset of corrosion so that the cumulative damage does not start until the coating begins to fail. For buried pipe and in some other applications, cathodic protection provides an additional mitigation against corrosion by effectively making the pipe the cathode in the corrosion cell. Often, buried piping will be coated and cathodically protected, with the CP system sized to protect some area of failed coating rather than the much larger size CP system that would be required to provide corrosion protection by CP alone. As discussed in Section 4, the combination of an appropriate coating and CP can provide trouble-free service for 50 years or more.

Figure 6-10 [6-34] shows how a rectifier (which converts ac current to dc current) is used to impress current onto the pipe's surface. The rectifier supplies current to a series of buried anodes, which then distribute the current through the soil to the pipeline being protected.

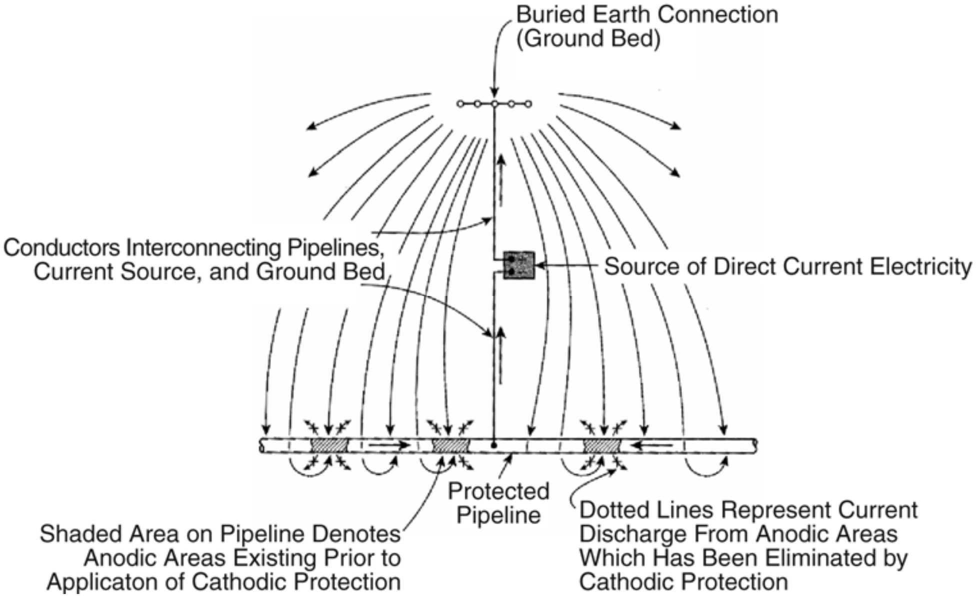


Figure 6-10
Diagram Showing How Impressed CP Current Protects Buried Piping (From [6-34]; Reproduced Courtesy of NACE International)

There are several practical considerations to take into account when actually applying cathodic protection to a buried pipeline. First, the amount of current required to polarize the pipe sufficiently to prevent corrosion is a strong function of the surface area exposed. Most buried steel pipelines are coated with a dielectric bitumastic coal tar or epoxy coating. The coating acts as an electrical insulator, preventing both corrosion current from being generated on the pipe and cathodic protection current from reaching the pipe. Therefore, cathodic protection current reaches the piping only at breaks (called *holidays*) in the coating where corrosion can occur; all coatings have holidays. Figure 6-11 is a schematic illustrating how CP current interacts with a coated pipe. The effect of the coating is to significantly reduce the amount of CP current required to protect the pipe by reducing the total surface area where corrosion can occur, as shown in Table 6-4.

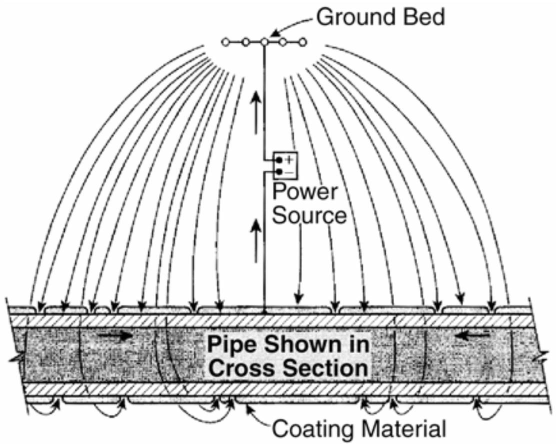


Figure 6-11
Schematic Showing the Interaction of Pipeline Coatings and CP Current (From [6-34]; Reproduced Courtesy of NACE International)

Table 6-4
Amount of CP Current Required, Based on Coating Resistance (from [6-34]; Reproduced Courtesy of NACE International)

Effective Coating Resistance, in Ohms, for One Average Square Foot	Current Required, in Amperes
Bare Pipe*	500
10,000	14.91
25,000	5.964
50,000	2.982
100,000	1.491
500,000	0.2982
1,000,000	0.1491
5,000,000	0.0298
Perfect Coating	0.000058

*Bare Pipe Assumed to Require a Minimum of 1 mA/ft^2

System Considerations

Finally, the plant owner must consider the overall system effects that produced the original problem. No single item causes a premature end of life, and no single action can result in infinite life.

Inspection and monitoring required to protect the current system or a repaired, refurbished, or replacement system should address:

- Corrosion
- Biofilm
- Chemical treatments
- Other mitigation approaches like coating

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A

SERVICE WATER PIPING GUIDELINE GLOSSARY

Acceptance Criteria	A preestablished range of values that define an acceptable outcome
Aerobic Bacteria	Bacteria that require free oxygen to survive
Anaerobic Bacteria	Bacteria that do not require free oxygen to survive
Anode	Positively charged electrode and location where the oxidation half-reaction occurs
Applied Load	A weight or other force applied onto the piping system or structure
Aspect Ratio	The depth to width ratio of the pit
Austenitic Stainless Steel	The most commonly used steel for stainless applications. The austenitic grades are not magnetic. The most common austenitic alloys are iron-chromium-nickel steels and are widely known as the 300 series. The austenitic stainless steels, because of their high chromium and nickel content, are the most corrosion resistant of the stainless group, providing unusually fine mechanical properties.
Autocatalytic	A catalytic reaction started by the products of a previous reaction that was itself catalytic / a chemical reaction in which a product also functions as catalyst. In such a reaction the observed rate of reaction is often found to increase with time from its initial value / a reaction requiring no further additions or changes of environment to continue to completion.
Backing Rings	Metallic rings sometimes inserted into a pipe joint during field installation to aid in performing butt welds to join two sections of piping together
Broadband Electromagnetic Method (BEM)	A type of NDE used as a screening technique to rapidly find piping defects
Biocide	A chemical added to raw water to kill macrobiological or microbiological fouling species

Biofilm	A complex aggregation of microorganisms growing on a solid substrate. Biofilms are characterized by structural heterogeneity, genetic diversity, complex community interactions, and an extracellular matrix of polymeric substances.
Biofouling	To cover or encumber with either macro or microbiological growth
Brackish Water	Water with high concentrations of dissolved solids (2,000–20,000 mg/l) and chloride (300–15,000 mg/l). The stability/scaling indices may range from 5.5 to 7.0. It has a low deposit tendency, but a high corrosivity resulting from the increased levels of dissolved solids and chloride.
Butt Weld	A piping weld performed to join two sections of pipe that have been essentially butted together end to end
Cathode	Negatively charged electrode where the reduction half-reaction takes place
Cathodic Disbondment	Buried pipe coating separation resulting from excessive amounts of cathodic protection current. It results from water and ion migration through the coating, generating increased pH at the pipe surface, which results in the coating separating from the pipe and forming defects called “blisters.”
Cathodic Protection (CP)	Equipment installed to impress a current onto piping to minimize corrosion. Cathodic protection can be provided with an impressed current system or sacrificial anode system.
Cavitation	Localized pipe, valve, or pump degradation caused by the formation and rapid collapse of water vapor due to changes in fluid pressure. Vapor cavities form (only) if the local pressure falls below the vapor pressure of the liquid. Those nucleated cavities can then grow to a stable size and be transported down-stream with the flow. When they reach a higher-pressure region, they become unstable and collapse, usually violently.
CFR	Code of Federal Regulations
Chelate	A heterocyclic compound having a metal ion attached by coordinate bonds to at least two nonmetal ions
Closed Cooling Water System	A fully recirculating cooling water system, normally chemically treated to control corrosion, that is “closed” to the atmosphere

Coal Tar	A coating material often used in service water applications, obtained by distillation of bituminous coal. It is very viscous and strong smelling.
Coating	A barrier less 100 mils thick (often less than 20 mils thick) applied between a corrosive environment and the underlying metal on the ID or OD of piping in order to prevent corrosion. Coatings permit materials like carbon steel and cast iron to be used in environments where they would otherwise corrode at unacceptably high rates.
Coating Life	The time period where the coating is nearly 100% effective at protecting the metal from corrosion
Code	A set of rules or regulation set forth by a governing body or professional society, such as ASME or USAS, that specifies the construction and testing requirements of piping, systems, or components
Code Repair	To restore a component to a sound condition in a manner which complies with all applicable codes of construction
Conductivity	A measure of the capacity of water to transmit electricity, as well as the relative purity of the water. The lower the conductivity the greater the purity, with 0.055 µmho/cm being the conductivity of theoretically pure water.
Containment	An enclosure around a nuclear reactor to confine fission products that otherwise might be released to the atmosphere in the event of an accident
Continuous Flow	Piping that is normally flowing while the unit is in operation
Corrosion Allowance	The quantity of pipe wall metal loss accounted for in the design of carbon steel or cast iron piping system that can be lost due to expected corrosion over the design life of the plant
Corrosion Products	Metal oxide by-products from the corrosion process
Corrosion-Resistant Alloys	Any material developed to resist degradation by corrosion, such as austenitic steel. Corrosion-resistant alloys provide a margin against both general and localized corrosion, even during periods of poor control or in systems where chemical controls are impractical.

Crevice Corrosion	Localized corrosion caused by a geometric discontinuity, where a concentration cell is produced that establishes and maintains local anodic areas by keeping the solution inside the crevice stagnant, thus impeding the movement of cations into and anions out of the crevice
Critical Crevice Corrosion Temperature (CCT)	The minimum temperature required for initiating crevice corrosion attack on a metal in standardized test solutions
Critical Pitting Temperature (CPT)	The minimum temperature required for initiating pitting attack on a metal in standardized test solutions
Dead Leg	A branch of pipe where normally stagnant or intermittent flow legs are connected to normally flowing pipe legs
Dealloying	A corrosion process in which one constituent of an alloy is preferentially dissolved by the environment. The more active constituent is always removed in preference to the more noble one. Dealloying may occur uniformly or locally (“plug dealloying”). In either case, the remaining metal structure will be weak and often porous. As a result, leaks in tubing or vessels may be initiated without a perceptible penetration.
Design Basis	10CFR50 defines the design basis for the service water system as being “to transfer heat from structures, systems, and components important to safety to an ultimate heat sink.”
Design Life	The length of time a component is designed to remain in service prior to replacement
Dezincification	Dealloying of copper-zinc alloys. This is a classic and commonly cited example of dealloying.
Duplex Stainless Steel	A combination of austenitic and ferritic material. This material typically has higher strength and superior resistance to stress corrosion cracking than the comparable austenitic grade and may also have superior pitting resistance to that of the comparable austenitic or ferritic grade.
Erosion or Erosion-Corrosion	Degradation caused by high velocity or turbulent fluids where the protective oxides are stripped away from the metal surface more rapidly than the protective oxide layer can reestablish itself
Eddy Current Testing (ET)	An NDE technique often used to find defects in heat exchanger tubes

Ferritic Stainless Steel	A group of stainless steels developed to resist corrosion and oxidation, while being highly resistant to stress corrosion cracking. These steels are magnetic but cannot be hardened or strengthened by heat treatment. They can be cold worked and softened by annealing. As a group, they are more corrosive resistant than the martensitic grades, but generally inferior to the austenitic grades. These are straight chromium steels with no nickel.
Flow-Accelerated Corrosion (FAC)	In carbon steels, FAC results from the combination of highly turbulent flowing water, steam, or water/steam mixtures (for example, at elbows or tees or other changes of direction), exposure in a susceptible temperature range (of the order of 350°F), and perhaps most importantly a nonprotective oxide film (often the result of an extremely low oxygen content). FAC of carbon steel is not a concern for service water piping.
Functionality	The ability of the piping system to perform its intended design function
Galvanic Corrosion	Corrosion associated with the current resulting from the electrical coupling of dissimilar electrodes, which may include conductive nonmetals such as graphite, in an electrolyte
General Thinning	Pipe wall thinning due to general corrosion, where corrosion attacks the entire surface in essentially uniform fashion
GL 89-13	NRC Generic Letter 89-13, applicable to safety-related SW systems
Half Reactions	The dissolution of metal and the reduction of oxygen
Hardness	A measure of the quantity of calcium carbonate and other “hard” minerals present in water. Waters with a total hardness of less than 60 ppm (measured as $CaCO_3$) are considered soft waters; those with more than 60 ppm total hardness are defined as hard.
Heat-Affected Zone (HAZ)	The part of a metal that is not melted during cutting, brazing, or welding, but whose microstructure and physical properties are altered by these processes
High-Energy Fluid	In the context of this report, fluid at higher temperatures and pressures than those normally experienced in service water systems
Holiday	A hole, crack, or other void in a coating or lining, exposing the base material to a concentrated corrosive environment

Hydrostatically Tested	A pressure test used to identify leakage in which the component being tested is filled completely with water or another liquid. Pressure, if required, is then applied to the liquid for the required time and the outside of the component is examined visually for leaks.
ID	Inside diameter or inside wall of a pipe
Intergranular Stress Corrosion Cracking (IGSCC)	A form of stress corrosion cracking in which cracks form between grain boundaries
In Kind Replacement	Replacement of system component(s) using the same materials as those contained in the original component
Intake Structure	The building or structure where inlet cooling water enters the cooling water piping system
Intermetallic Phases	A result of improper heat treat of duplex steels that can result in significantly diminished corrosion resistance and toughness
Intermittent Flow	Piping that is sometimes, but not always, experiencing flow
Isolation Kit	Used for flanged connections where dissimilar metals are used. Electrical isolation of the two materials eliminates the electron path so that preferential corrosion of the more active metal is avoided.
Larson Skold Index	A measure of the corrosivity of water
Life Cycle Management (LCM)	The management of the plant resource for the remainder of plant life
Low-Frequency Eddy Current Testing (LFET)	A type of NDE that can detect defects in piping
Lining	A barrier typically greater than or equal to 100 mils thick applied on the ID of a pipe between a corrosive environment and the underlying metal in order to prevent corrosion. Coatings permit materials like carbon steel and cast iron to be used in environments where they would otherwise corrode at unacceptably high rates.
Liquid Penetrant	NDE technique used to find minor cracks or other imperfections. A liquid solution of dye, either visible or fluorescent, capable of entering discontinuities open to the surface.

Localized Corrosion	Pitting, crevice corrosion, and underdeposit corrosion; occurs when anodic sites are fixed by geometric, environmental, or metallurgical conditions
Linear Polarization Resistance (LPR)	When a small polarization potential is applied to electrodes from an external power source, the *polarization resistance* is determined from the ratio of the applied potential to the measured current. The polarization resistance has been shown to be inversely proportional to the corrosion rate.
Langelier Saturation Index (LSI)	A quantitative measure of the scale-forming or scale-dissolving tendency of waters
Macrofouling	To cover or encumber with macrobiological growth
Magnetic Particle	A nondestructive test method utilizing magnetic leakage fields and suitable indicating materials to disclose surface and near-surface discontinuity indications
Microbiologically Induced Corrosion or Microbiologically Influenced Corrosion (MIC)	Specific types of microorganisms that can participate directly in an electrochemical reaction in a corrosion cell or furnish metabolic byproducts for such a reaction. Channels or closed pits are often formed rapidly (months) which can lead to pinhole leaks.
Microfouling	To cover or encumber with microbiological growth
MPY	Mils (0.001 in.) per year; a common measure of the rate of piping corrosion or other degradation
Nondestructive Examination (NDE)	Nondestructive examination, such as VT (visual), UT (ultrasonic), RT (radiographic), PT (penetrant), MT (magnetic particle), ET (eddy current)
Occlusion	The buildup of corrosion products or deposits that can decrease the flow-carrying capability of a service water pipe
O & M	Operation and maintenance
OD	Outside diameter or outside wall of a pipe
Open Pit	Localized corrosion sites on broadly exposed surfaces that has an uncovered or open mouth

Oxidation	Half-reaction that involves the loss of electrons to produce a positive metal ion and electrons
Oxygen Concentration Cell	An electrolytic cell whose electromotive force derives from a difference in oxygen concentration between the constantly oxygenated water flowing outside (cation) of a locally shielded region with a depleted oxygen concentration (anion)
Passive Alloy	Alloy where the anodic current does not change over a wide range of potential
pH	The logarithm of the reciprocal of hydrogen-ion concentration in gram atoms per liter; provides a measure on a scale from 0 to 14 of the acidity or alkalinity of a solution
Pickling	A chemical treatment applied to new metal, usually by the piping fabricator, to strip most of the mill scale and other impurities from heat treated surfaces.
Pinhole Leak	A leak occurring through a very small hole in the component; often starts as a stream about the diameter of a straight pin
Piping Failure	Piping wall loss or thinning in excess of that allowed by calculation as specified by the code of construction. Indication of a loss of structural integrity.
Pitting	Localized corrosion on boldly exposed surfaces, often in a passive alloy; requires a breakdown of the passive film, influenced by the material/environment pair
Planar Flaw	A continuous indication whose detected area of the flaw is oriented primarily in any single plane, other than parallel to the surface of the component, and any portion of the flaw penetrates a surface of the component
Pitting Resistance Equivalent Number (PRE_N)	The relationship of the various elements responsible for corrosion resistance is captured in an equation that has a number of different coefficients; the most commonly used form is: $PRE_N = \%Cr + 3.3(\%Mo) + 16(\%N)$
PRA	Probabilistic Risk Assessment

Preassessment	Consists of collection of design and operating data, as well as environmental information and any corrosion protection measures, to determine the feasibility of applying the direct assessment procedure to the pipeline in question. Preassessment also separates the line into discrete segments based upon various design and operating characteristics.
Puckorius or Practical Scaling Index (PSI)	A quantitative measure of the scale-forming or scale-dissolving tendency of waters
Radiography (RT)	Radiographic examination (NDE)
Reduction	Half-reaction that involves the acceptance of electrons to produce a negative ion (for example, OH^-) or a molecule with a valence of zero (for example, H^+ to H)
Risk	Defined as Susceptibility (probability of failure) multiplied by Consequence of Failure
Risk-Informed ISI (RI-ISI)	An enhancement to existing ASME Section XI, Div. 1 inspection requirements known as "Rules for Inservice Inspection of Nuclear Power Plant Components." The RI-ISI enhancements improve overall safety by focusing inspections on piping at highly risk significant and highly susceptible locations.
Ryznar Saturation Index (RSI)	A quantitative measure of the scale-forming or scale-dissolving tendency of waters
Stress Corrosion Cracking (SCC)	An interaction between mechanical effects and a corrosion process on metals. SSC effectively causes a tough and ductile alloy to behave in a brittle manner over a localized area. Requires a susceptible material to be in an environment in which it is susceptible to the highly localized corrosion/mechanical interaction, and the presence of a tensile stress.
Seawater	Ocean water, which has very high concentrations of chloride (>15,000 mg/l). This water is highly corrosive, resulting from high levels of dissolved solids and chloride.
Service Life	The length of time a component remains in service prior to replacement
Silting	Accumulation of silt or sand
Small-Bore Piping	Small diameter piping, usually 4 inches or less

Socket Weld	A method of welding two components (usually small bore) together where one component (usually a pipe) is inserted into an open recess inside the second component (usually a pipe coupling or valve body)
Stagnant Flow	Piping that very seldom or never experiences flow
Structural Integrity	For this document, the quality ability of piping or other component or structure to remain intact given the applicable stress and loading requirements specified by the code of construction. and to retain strength, not prone to catastrophic failure
Sulfate Reducing Bacteria (SRB)	A common anaerobic bacterium, commonly abbreviated SRB, that can convert sulfate ions, SO_4^{-2}, into S^{-2} and HS^-, with the oxidation of a carbon source
Total Dissolved Solids (TDS)	A measure of the quantity of soluble solids present in a sample
Temporary Repair	To restore a component to an acceptable tolerable condition for a limited period of time until a permanent repair can be implemented
Transgranular Stress Corrosion Cracking (TGSCC)	A form of stress corrosion cracking where cracks form across grain boundaries
Thermal Stratification	Natural separation of fluids, with warmer fluids usually migrating toward the top of a reservoir and cooler fluids toward the bottom
Thermal Treatments	Raising the temperature of a plants cooling water intake, usually in an effort to kill macrobiological or microbiological fouling species
Through-Wall Defect	A leak
Treated System	A water system that has been chemically treated, usually to minimize corrosion or biogrowth
Tubercle	A small rounded nodule on a wetted metal (usually carbon steel or cast iron) surface consisting predominantly of corrosion products and silt, under which localized pitting often occurs
Ultimate Heat Sink (UHS)	A body of water designed to remain available at all times to provide a source of cooling water for transfer and discharge of heat from the reactor core to the environment when the normal heat sink is unavailable

Underdeposit Corrosion	Localized pitting corrosion that occurs where a crevice results from deposits that form on component surfaces as a result of corrosion product transport, silt, or microbiological influences, and then form concentration cells. An oxygen depleted area is created under the deposit and becomes the anode where pitting occurs.
Ultrasonic Examination (UT)	A form of NDE able to accurately measure pipe wall thickness
Volumetric Techniques	A variety of NDE methods to determine subsurface indications such as ultrasonic testing and radiographic testing.
Weld Attack	Localized corrosion occurring in the weld metal or heat-affected zone of a weld

B

SERVICE WATER PIPING MATERIALS OF CONSTRUCTION

The survey of the participants in the Service Water Piping Task Group provided the following information on initial materials of construction:

- U.S. stations (aboveground, in-plant piping)
  - 28 with bare carbon steel
  - 13 with coated or lined CS
  - 1 with corrosion-resistant alloys (CRAs)
- U.S. stations (buried piping)
  - 24 with bare carbon steel
  - 15 with coated or lined piping
  - 1 with corrosion-resistant allots (CRAs)

All units with brackish or salt water used coated or lined pipe in original design.

- Three units with fresh water used ID coated or lined piping (in-plant piping and buried piping).
- Material replacements have been limited mainly to aboveground/in-plant piping.
- In most cases, piping replacement has been limited to piping ≤6 in. NPS.
- In many cases, piping replacement has been selective and limited.
- The number of units with bare carbon steel piping above ground is unchanged from the original design.
- Seven units have replaced some lined or coated piping with corrosion-resistant alloys (6% moly, titanium, and alloy 625).

The distribution of materials selections for original construction (buried and above ground) and for replacements are shown graphically in Figures B-1 through B-3.

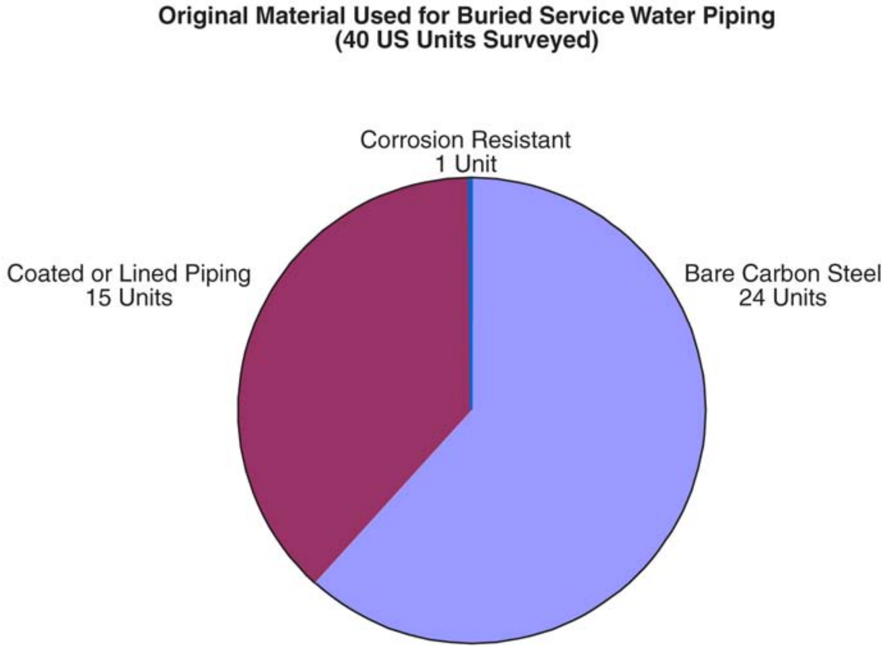

Figure B-1
Material Selection for Buried Piping—Original Construction[1]

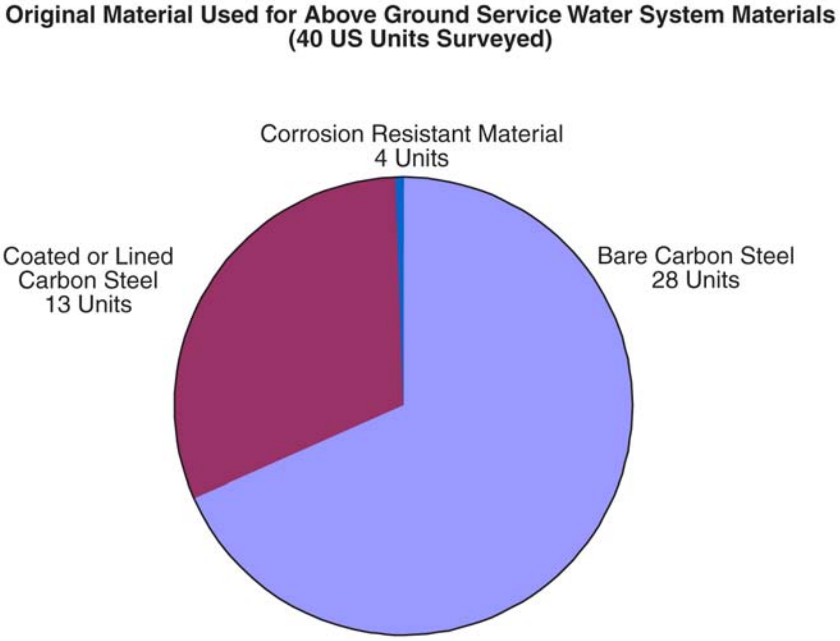

Figure B-2
Material Selection for Aboveground Piping—Original Construction[1]

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[1] Both bare carbon steel and coated or lined carbon steel piping are used in some plants; hence, the totals shown in the plots will not necessarily match the numbers in the text.

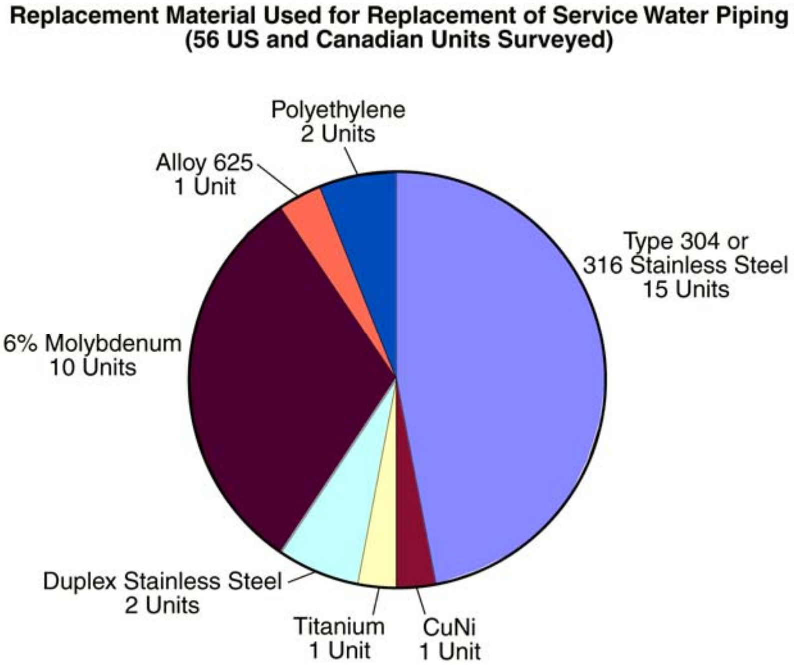

Figure B-3
Replacement Materials Selection for Service Water Piping

A separate compilation for 144 North American and 14 European and Japanese plants (nuclear and fossil) by the Nickel Development Institute indicated that the original service water system piping materials were:

- Carbon steel (most common, 51%)
- Cement-lined carbon steel (10%)
- Types 304 and 304L stainless steel (8%)
- Types 316 and 316L stainless steel (8%)
- Epoxy or coal tar lined carbon steel (6%)
- Unknown stainless steels (4%)
- 90-10 or 70-30 copper-nickel (3%)
- Concrete (2%)
- Fiberglass (1%)
- A lesser fraction of rubber lined carbon steel, cement-lined cast iron, copper-nickel clad carbon steel and aluminum bronze

Approximately 50% of those installations required repair or replacement due to corrosion. Systems using brackish or seawater were the most likely plants to have required replacements.

For replacements, the most common materials were:

- Carbon steel (27%)
- Type 316/316L stainless steel (21%)
- Type 304/304L stainless steel (13%)
- Epoxy or coal tar lined carbon steel (10%)
- 6% molybdenum stainless steel steels (10%)

For proposed replacements (that is, those replacements only in the planning stages as of 1993), the most commonly selected replacement material was the 6% molybdenum stainless steel.

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