Piping Inspection Code

Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems

API 570
Second Edition, October 1998

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Downstream Segment

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FOREWORD

It is the intent of API to keep this publication up to date. All piping system owners and operators are invited to report their experiences in the inspection and repair of piping systems whenever such experiences may suggest a need for revising or expanding the practices set forth in API 570.

This edition of API 570 supersedes all previous editions of API 570, Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems. Each edition, revision, or addenda to this API standard may be used beginning with the date of issuance shown on the cover page for that edition, revision, or addenda. Each edition, revision, or addenda, to this API standard becomes effective six months after the date of issuance for equipment that is rerated, reconstructed, relocated, repaired, modified (altered), inspected, and tested per this standard. During the six-month time between the date of issuance of the edition, revision, or addenda and the effective date, the user shall specify to which edition, revision, or addenda, the equipment is to be, rerated, reconstructed, relocated, repaired, modified (altered), inspected and tested.

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Suggested revisions are invited and should be submitted to the director of the Downstream Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

1 Scope

1.1 General Application

1.1.1 Coverage

API 570 covers inspection, repair, alteration, and rerating procedures for metallic piping systems that have been in-service.

1.1.2 Intent

API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. It is intended for use by organizations that maintain or have access to an authorized inspection agency, a repair organization, and technically qualified piping engineers, inspectors, and examiners, all as defined in Section 3.

1.1.3 Limitations

API 570 shall not be used as a substitute for the original construction requirements governing a piping system before it is placed in-service; nor shall it be used in conflict with any prevailing regulatory requirements.

1.2 Specific Applications

1.2.1 Included Fluid Services

Except as provided in 1.2.2, API 570 applies to piping systems for process fluids, hydrocarbons, and similar flammable or toxic fluid services, such as the following:

a. Raw, intermediate, and finished petroleum products.
b. Raw, intermediate, and finished chemical products.
c. Catalyst lines.
d. Hydrogen, natural gas, fuel gas, and flare systems.

e. Sour water and hazardous waste streams above threshold limits, as defined by jurisdictional regulations.
f. Hazardous chemicals above threshold limits, as defined by jurisdictional regulations.

1.2.2 Excluded and Optional Piping Systems

The fluid services and classes of piping systems listed below are excluded from the specific requirements of API 570 but may be included at the owner's or user's (owner/user's) option.

a. Fluid services that are excluded or optional include the following:
   1. Hazardous fluid services below threshold limits, as defined by jurisdictional regulations.
   2. Water (including fire protection systems), steam, steam-condensate, boiler feed water, and Category D fluid services, as defined in ASME B31.3.

b. Classes of piping systems that are excluded or optional are as follows:
   1. Piping systems on movable structures covered by jurisdictional regulations, including piping systems on trucks, ships, barges, and other mobile equipment.
   2. Piping systems that are an integral part or component of rotating or reciprocating mechanical devices, such as pumps, compressors, turbines, generators, engines, and hydraulic or pneumatic cylinders where the primary design considerations and/or stresses are derived from the functional requirements of the device.
   3. Internal piping or tubing of fired heaters and boilers, including tubes, tube headers, return bends, external crossovers, and manifolds.
   4. Pressure vessels, heaters, furnaces, heat exchangers, and other fluid handling or processing equipment, including internal piping and connections for external piping.
   5. Plumbing, sanitary sewers, process waste sewers, and storm sewers.
   6. Piping or tubing with an outside diameter not exceeding that of NPS ½.
   7. Nonmetallic piping and polymeric or glass-lined piping.

2 References

The most recent editions of the following standards, codes, and specifications are cited in this code.

API

510	Pressure Vessel Inspection Code
Publ 920	Prevention of Brittle Fracture of Pressure Vessels
Publ 2201	Procedures for Welding or Hot Tapping on Equipment Containing Flammables
RP 574	Inspection of Piping System Components
RP 651	Cathodic Protection of Aboveground Petroleum Storage Tanks
RP 750	Management of Process Hazards
Std 598	Valve Inspection and Testing

Guide for Inspection of Refinery Equipment, Chapter II (This document will be replaced by API RP 571, Conditions Causing Deterioration or Failures, currently under development.)
API 570 Inspector Certification Exam Body of Knowledge

ASME

B16.34	Valves-Flanged, Threaded, and Welding End
B31.3	Process Piping
B31G	Manual for Determining the Remaining Strength of Corroded Pipelines

Boiler and Pressure Vessel Code, Section VIII, Divisions 1 and 2; Section IX,

ASNT
SNT-TC-1A
CP-189 Standard for Qualification and Certification of Nondestructive Testing Personnel

ASTM

G57	Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method

NACE

RP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems
RP0170	Protection of Austenitic Stainless Steels from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment
RP0274	High-Voltage Electrical Inspection of Pipeline Coatings Prior to Installation
RP0275	Application of Organic Coatings to the External Surface of Steel Pipe for Underground Service

NFPA

704	Identification of the Fire Hazards of Materials

3 Definitions

For the purposes of this standard, the following definitions apply.

3.1 alteration: A physical change in any component that has design implications affecting the pressure containing capability or flexibility of a piping system beyond the scope of its design. The following are not considered alterations: comparable or duplicate replacement; the addition of any reinforced branch connection equal to or less than the size of existing reinforced branch connections; and the addition of branch connections not requiring reinforcement.

3.2 applicable code: The code, code section, or other recognized and generally accepted engineering standard or practice to which the piping system was built or which is deemed by the owner or user or the piping engineer to be most appropriate for the situation, including but not limited to the latest edition of ASME B31.3.

3.3 ASME B31.3: A shortened form of ASME B31.3, Process Piping, published by the American Society of Mechanical Engineers. ASME B31.3 is written for design and construction of piping systems. However, most of the technical requirements on design, welding, examination, and materials also can be applied in the inspection, rerating, repair, and alteration of operating piping systems. When ASME B31.3 cannot be followed because of its new construction coverage (such as revised or new material specifications, inspection requirements, certain heat treatments, and pressure tests), the piping engineer or inspector shall be guided by API 570 in lieu of strict conformity to ASME B31.3. As an example of intent, the phrase “principles of ASME B31.3” has been employed in API 570, rather than “in accordance with ASME B31.3.”

3.4 authorized inspection agency: Defined as any of the following:

a. The inspection organization of the jurisdiction in which the piping system is used.

b. The inspection organization of an insurance company that is licensed or registered to write insurance for piping systems.

c. An owner or user of piping systems who maintains an inspection organization for activities relating only to his equipment and not for piping systems intended for sale or resale.

d. An independent inspection organization employed by or under contract to the owner or user of piping systems that are used only by the owner or user and not for sale or resale.

e. An independent inspection organization licensed or recognized by the jurisdiction in which the piping system is used and employed by or under contract to the owner or user.

3.5 authorized piping inspector: An employee of an authorized inspection agency who is qualified and certified to perform the functions specified in API 570. A nondestructive (NDE) examiner is not required to be an authorized piping inspector. Whenever the term inspector is used in API 570, it refers to an authorized piping inspector.

3.6 auxiliary piping: Instrument and machinery piping, typically small-bore secondary process piping that can be isolated from primary piping systems. Examples include flush lines, seal oil lines, analyzer lines, balance lines, buffer gas lines, drains, and vents.

3.7 critical check valves: Valves that have been identified as vital to process safety and must operate reliably in order to avoid the potential for hazardous events or substantial consequences should a leak occur.

3.8 CUI: Corrosion under insulation, including stress corrosion cracking under insulation.

3.9 deadlegs: Components of a piping system that normally have no significant flow. Examples include the following: blanked branches, lines with normally closed block valves, lines with one end blanked, pressurized dummy support legs, stagnant control valve bypass piping, spare pump piping, level bridles, relief valve inlet and outlet header piping, pump trim bypass lines, high-point vents, sample points, drains, bleeders, and instrument connections.

3.10 defect: An imperfection of a type or magnitude exceeding the acceptable criteria.

3.11 design temperature of a piping system component: The temperature at which, under the coincident pressure, the greatest thickness or highest component rating is required. It is the same as the design temperature defined in ASME B31.3 and other code sections and is subject to the same rules relating to allowances for variations of pressure or temperature or both. Different components in the same piping system or circuit may have different design temperatures. In establishing the design temperature, consideration shall be given to process fluid temperatures, ambient temperatures, heating and cooling media temperatures, and insulation.

3.12 examiner: A person who assists the inspector by performing specific nondestructive examination (NDE) on piping system components but does not evaluate the results of those examinations in accordance with API 570, unless specifically trained and authorized to do so by the owner or user. The examiner need not be qualified in accordance with API 570 or be an employee of the owner or user but shall be trained and qualified in the applicable procedures in which the examiner is involved. In some cases, the examiner may be required to hold other certifications as necessary to satisfy owner or user requirements. Examples of other certification that may be required are SNT-TC-1A or CP-189; or AWS Welding Inspector certification. The examiner's employer shall maintain certification records of the examiners employed, including dates and results of personnel qualifications, and shall make them available to the inspector.

3.13 hold point: A point in the repair or alteration process beyond which work may not proceed until the required inspection has been performed and documented.

3.14 imperfections: Flaws or other discontinuities noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis.

3.15 indication: A response or evidence resulting from the application of a nondestructive evaluation technique.

3.16 injection point: Locations where relatively small quantities of materials are injected into process streams to control chemistry or other process variables. Injection points do not include locations where two process streams join (mixing tees). Examples of injection points include chlorine in reformers, water injection in overhead systems, polysulfide injection in catalytic cracking wet gas, antifoam injections, inhibitors, and neutralizers.

3.17 in-service: Refers to piping systems that have been placed in operation, as opposed to new construction prior to being placed in service.

3.18 inspector: An authorized piping inspector.

3.19 jurisdiction: A legally constituted government administration that may adopt rules relating to piping systems.

3.20 level bridle: A level gauge glass piping assembly attached to a vessel.

3.21 maximum allowable working pressure: (MAWP): The maximum internal pressure permitted in the piping system for continued operation at the most severe condition of coincident internal or external pressure and temperature (minimum or maximum) expected during service. It is the same as the design pressure, as defined in ASME B31.3 and other code sections, and is subject to the same rules relating to allowances for variations of pressure or temperature or both.

3.22 mixing tee: A piping component that combines two process streams of differing composition and/or temperature.

3.23 MT: Magnetic-particle testing.

3.24 NDE: Nondestructive examination.

3.25 NPS: Nominal pipe size (followed, when appropriate, by the specific size designation number without an inch symbol).

3.26 on-stream: Piping containing any amount of process fluid.

3.27 owner/user: An owner or user of piping systems who exercises control over the operation, engineering, inspection, repair, alteration, testing, and rerating of those piping systems.

3.28 owner/user inspector: An authorized inspector employed by an owner/user who has qualified either by written examination under the provisions of Section 4 and Appendix A of API 570 or has qualified under the provisions of A.2, and who meets the requirements of the jurisdiction.

3.29 PT: A liquid-penetrant testing.

3.30 pipe: A pressure-tight cylinder used to convey a fluid or to transmit a fluid pressure and is ordinarily designated "pipe" in applicable material specifications. (Materials designated "tube" or "tubing" in the specifications are treated as pipe when intended for pressure service.)

3.31 piping circuit: A section of piping that has all points exposed to an environment of similar corrosivity and that is of similar design conditions and construction material. Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and record keeping. When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for record keeping and performing field inspection.

3.32 piping engineer: One or more persons or organizations acceptable to the owner or user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics affecting the integrity and reliability of piping components and systems. The piping engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly address a technical requirement.

3.33 piping system: An assembly of interconnected piping that is subject to the same set or sets of design conditions and is used to convey, distribute, mix, separate, discharge, meter, control, or snub fluid flows. Piping system also includes pipe-supporting elements but does not include support structures, such as structural frames and foundations.

3.34 primary process piping: Process piping in normal, active service that cannot be valved off or, if it were valved off, would significantly affect unit operability. Primary process piping normally includes all process piping greater than NPS 2.

3.35 PWHT: postweld heat treatment.

3.36 renewal: Activity that discards an existing component and replaces it with new or existing spare materials of the same or better qualities as the original component.

3.37 repair: The work necessary to restore a piping system to a condition suitable for safe operation at the design conditions. If any of the restorative changes result in a change of design temperature or pressure, the requirements for rerating also shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair.

3.38 repair organization: Any of the following:

a. An owner or user of piping systems who repairs or alters his or her own equipment in accordance with API 570.

b. A contractor whose qualifications are acceptable to the owner or user of piping systems and who makes repairs or alterations in accordance with API 570.

c. One who is authorized by, acceptable to, or otherwise not prohibited by the jurisdiction and who makes repairs in accordance with API 570.

3.39 rerating: A change in either or both the design temperature or the maximum allowable working pressure of a piping system. A rerating may consist of an increase, a decrease, or a combination of both. Derating below original design conditions is a means to provide increased corrosion allowance.

3.40 secondary process piping: Small-bore (less than or equal to NPS 2) process piping downstream of normally closed block valves.

3.41 small-bore piping (SBP): Piping that is less than or equal to NPS 2.

3.42 soil-to-air (S/A) interface: An area in which external corrosion may occur on partially buried pipe. The zone of the corrosion will vary depending on factors such as moisture, oxygen content of the soil, and operating temperature. The zone generally is considered to be from 12 inches (305 mm) below to 6 inches (150 mm) above the soil surface. Pipe running parallel with the soil surface that contacts the soil is included.

3.43 spool: A section of piping encompassed by flanges or other connecting fittings such as unions.

3.44 temper embrittlement: A loss of ductility and notch toughness in susceptible low-alloy steels, such as 11/4 Cr and 21/4 Cr, due to prolonged exposure to high-temperature service [700¡F -1070¡F (370¡C -575¡C)].

3.45 temporary repairs: Repairs made to piping systems in order to restore sufficient integrity to continue safe operation until permanent repairs can be scheduled and accomplished within a time period acceptable to the inspector or piping engineer.

3.46 test point: An area defined by a circle having a diameter not greater than 2 inches (50 mm) for a line diameter not exceeding 10 inches (250 mm), or not greater than 3 inches (75 mm) for larger lines. Thickness readings may be averaged within this area. A test point shall be within a thickness measurement location.

3.47 thickness measurement locations (TMLs): Designated areas on piping systems where periodic inspections and thickness measurements are conducted.

3.48 WFMT: Wet fluorescent magnetic-particle testing.

4 Owner/User Inspection Organization

4.1 General

An owner/user of piping systems shall exercise control of the piping system inspection program, inspection frequencies, and maintenance and is responsible for the function of an authorized inspection agency in accordance with the provisions of API 570. The owner/user inspection organization also shall control activities relating to the rerating, repair, and alteration of its piping systems.

4.2 api authorized piping inspector qualification and certification

Authorized piping inspectors shall have education and experience in accordance with Appendix A of this inspection code. Authorized piping inspectors shall be certified by the American Petroleum Institute in accordance with the provisions of Appendix A. Whenever the term inspector is used in this document, it refers to an authorized piping inspector.

4.3 Responsibilities

4.3.1 Owner/User

An owner/user organization is responsible for developing, documenting, implementing, executing, and assessing piping inspection systems and inspection procedures that will meet the requirements of this inspection code. These systems and procedures will be contained in a quality assurance inspection manual or written procedures and shall include:

a. Organization and reporting structure for inspection personnel.

b. Documenting and maintaining inspection and quality assurance procedures.
c. Documenting and reporting inspection and test results.
d. Corrective action for inspection and test results.
e. Internal auditing for compliance with the quality assurance inspection manual.
f. Review and approval of drawings, design calculations, and specifications for repairs, alterations, and reratings.
g. Ensuring that all jurisdictional requirements for piping inspection, repairs, alterations, and rerating are continuously met.
h. Reporting to the authorized piping inspector any process changes that could affect piping integrity.
i. Training requirements for inspection personnel regarding inspection tools, techniques, and technical knowledge base.
j. Controls necessary so that only qualified welders and procedures are used for all repairs and alterations.
k. Controls necessary so that only qualified nondestructive examination (NDE) personnel and procedures are utilized.
l. Controls necessary so that only materials conforming to the applicable section of the ASME Code are utilized for repairs and alterations.
m. Controls necessary so that all inspection measurement and test equipment are properly maintained and calibrated.
n. Controls necessary so that the work of contract inspection or repair organizations meet the same inspection requirements as the owner/user organization.
o. Internal auditing requirements for the quality control system for pressure-relieving devices.

4.3.2 Piping Engineer

The piping engineer is responsible to the owner/user for activities involving design, engineering review, analysis, or evaluation of piping systems covered by API 570.

4.3.3 Repair Organization

The repair organization shall be responsible to the owner/user and shall provide the materials, equipment, quality control, and workmanship necessary to maintain and repair the piping systems in accordance with the requirements of API 570.

4.3.4 Authorized Piping Inspector

When inspections, repairs, or alterations are being conducted on piping systems, an API-authorized piping inspector shall be responsible to the owner/user for determining that the requirements of API 570 on inspection, examination, and testing are met, and shall be directly involved in the inspection activities. The API-authorized piping inspector may be assisted in performing visual inspections by other properly trained and qualified individuals, who may or may not be certified piping inspectors. Personnel performing nondestructive examinations shall meet the qualifications identified in 3.12, but need not be API-authorized piping inspectors. However, all examination results must be evaluated and accepted by the API-authorized piping inspector.

4.3.5 Other Personnel

Operating, maintenance, or other personnel who have special knowledge or expertise related to particular piping systems shall be responsible for promptly making the inspector or piping engineer aware of any unusual conditions that may develop and for providing other assistance, where appropriate.

5 Inspection And Testing Practices

5.1 Risk-Based Inspection

Identifying and evaluating potential degradation mechanisms are important steps in an assessment of the likelihood of a piping failure. However, adjustments to inspection strategy and tactics to account for consequences of a failure should also be considered. Combining the assessment of likelihood of failure and the consequence of failure are essential elements of risk-based inspection (RBI).

When the owner/user chooses to conduct a RBI assessment it must include a systematic evaluation of both the likelihood of failure and the associated consequence of failure. The likelihood assessment must be based on all forms of degradation that could reasonably be expected to affect piping circuits in any particular service. Examples of those degradation mechanisms include: internal or external metal loss from an identified form of corrosion (localized or general), all forms of cracking including hydrogen assisted and stress corrosion cracking (from the inside or outside surfaces of piping), and any other forms of metallurgical, corrosion, or mechanical degradation, such as fatigue, embrittlement, creep, etc. Additionally, the effectiveness of the inspection practices, tools, and techniques utilized for finding the expected and potential degradation mechanisms must be evaluated. This likelihood of failure assessment should be repeated each time equipment or process changes are made that could significantly affect degradation rates or cause premature failure of the piping.

Other factors that should be considered in a RBI assessment include: appropriateness of the materials of construction; piping circuit design conditions, relative to operating conditions; appropriateness of the design codes and standards utilized; effectiveness of corrosion monitoring programs; and the quality of maintenance and inspection Quality Assurance/Quality Control programs. Equipment failure data and information will also be important information for this assessment. The consequence assessment must consider the potential incidents that may occur as a result of fluid release, including explosion, fire, toxic exposure, environmental impact, and other health effects associated with a failure of piping.

It is essential that all RBI assessments be thoroughly documented, clearly defining all the factors contributing to both the likelihood and consequence of a piping failure.

5.2 Preparation

Because of the products carried in piping systems, safety precautions are important when the system is inspected, particularly if it is opened for examining internal surfaces.

Procedures for segregating piping systems, installing blanks (blinds), and testing tightness should be an integral part of safety practices. Appropriate safety precautions shall be taken before any piping system is opened and before some types of external inspection are performed. In general, the section of piping to be opened should be isolated from all sources of harmful liquids, gases, or vapors and purged to remove all oil and toxic or flammable gases and vapors.

Before starting inspection, inspection personnel should obtain permission to work in the vicinity from operating personnel responsible for the piping system.

Protective equipment shall be worn when required by regulations or by the owner/user.

Nondestructive testing equipment used for inspection is subject to the operating facility's safety requirements for electrical equipment.

In general, inspectors should familiarize themselves with prior inspection results and repairs in the piping systems for which they are responsible. In particular, they should briefly review the history of individual piping systems before making any of the inspections required by API 570. (See Section 8 of API RP 574 for supplementary recommended practices.)

5.3 Inspection for Specific Types of Corrosion and Cracking

Note: For more thorough and complete information, see API IRE Chapter 11.

Each owner/user should provide specific attention to the need for inspection of piping systems that are susceptible to the following specific types and areas of deterioration:

a. Injection points.
b. Deadlegs.
c. Corrosion under insulation (CUI).
d. Soil-to-air (S/A) interfaces.
e. Service specific and localized corrosion.
f. Erosion and corrosion/erosion.
g. Environmental cracking.
h. Corrosion beneath linings and deposits.
i. Fatigue cracking.

j. Creep cracking.
k. Brittle fracture.
l. Freeze damage.

Other areas of concern are noted in IRE Chapter II, and Section 6 of API RP 574.

5.3.1 Injection Points

Injection points are sometimes subject to accelerated or localized corrosion from normal or abnormal operating conditions. Those that are may be treated as separate inspection circuits, and these areas need to be inspected thoroughly on a regular schedule.

Figure 5-1-Typical Injection Point Piping Circuit

When designating an injection point circuit for the purposes of inspection, the recommended upstream limit of the injection point circuit is a minimum of 12 inches (300 mm) or three pipe diameters upstream of the injection point, whichever is greater. The recommended downstream limit of the injection point circuit is the second change in flow direction past the injection point, or 25 feet (7.6 m) beyond the first change in flow direction, whichever is less. In some cases, it may be more appropriate to extend this circuit to the next piece of pressure equipment, as shown in Figure 5-1.

The selection of thickness measurement locations (TMLs) within injection point circuits subject to localized corrosion should be in accordance with the following guidelines:

a. Establish TMLs on appropriate fittings within the injection point circuit.
b. Establish TMLs on the pipe wall at the location of expected pipe wall impingement of injected fluid.
c. TMLs at intermediate locations along the longer straight piping within the injection point circuit may be required.
d. Establish TMLs at both the upstream and downstream limits of the injection point circuit.

The preferred methods of inspecting injection points are radiography and/or ultrasonics, as appropriate, to establish the minimum thickness at each TML. Close grid ultrasonic measurements or scanning may be used, as long as temperatures are appropriate.

For some applications, it is beneficial to remove piping spools to facilitate a visual inspection of the inside surface. However, thickness measurements will still be required to determine the remaining thickness.

During periodic scheduled inspections, more extensive inspection should be applied to an area beginning 12 inches (300 mm) upstream of the injection nozzle and continuing for at least ten pipe diameters downstream of the injection point. Additionally, measure and record the thickness at all TMLs within the injection point circuit.

5.3.2 Deadlegs

The corrosion rate in deadlegs can vary significantly from adjacent active piping. The inspector should monitor wall thickness on selected deadlegs, including both the stagnant end and at the connection to an active line. In hot piping systems, the high-point area may corrode due to convective currents set up in the deadleg. Consideration should be given to removing deadlegs that serve no further process purpose.

5.3.3 Corrosion Under Insulation

External inspection of insulated piping systems should include a review of the integrity of the insulation system for conditions that could lead to corrosion under insulation (CUI) and for signs of ongoing CUI. Sources of moisture may include rain, water leaks, condensation, and deluge systems. The most common forms of CUI are localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels.

This section provides guidelines for identifying potential CUI areas for inspection. The extent of a CUI inspection program may vary depending on the local climate-warmer marine locations may require a very active program; whereas cooler, drier, mid-continent locations may not need as extensive a program.

5.3.3.1 Insulated Piping Systems Susceptible to CUI

Certain areas and types of piping systems are potentially more susceptible to CUI, including the following:

a. Areas exposed to mist overspray from cooling water towers.
b. Areas exposed to steam vents.
c. Areas exposed to deluge systems.
d. Areas subject to process spills, ingress of moisture, or acid vapors.
e. Carbon steel piping systems, including those insulated for personnel protection, operating between 25¡F-250¡F (-4¡C-120¡C). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.
f. Carbon steel piping systems that normally operate in-service above 250¡F (120¡C) but are in intermittent service.
g. Deadlegs and attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line.
h. Austenitic stainless steel piping systems operating between 150¡F-400¡F (65¡C-204¡C). (These systems are susceptible to chloride stress corrosion cracking.)
i. Vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress.
j. Steam traced piping systems that may experience tracing leaks, especially at tubing fittings beneath the insulation.
k. Piping systems with deteriorated coatings and/or wrappings.

5.3.3.2 Common Locations on Piping Systems Susceptible to CUI

The areas of piping systems listed in 5.3.3.1 may have specific locations within them that are more susceptible to CUI, including the following:

a. All penetrations or breaches in the insulation jacketing systems, such as:
    1. Deadlegs (vents, drains, and other similar items).
    2. Pipe hangers and other supports.
    3. Valves and fittings (irregular insulation surfaces).
    4. Bolted-on pipe shoes.
    5. Steam tracer tubing penetrations.
b. Termination of insulation at flanges and other piping components.
c. Damaged or missing insulation jacketing.
d. Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing.
e. Termination of insulation in a vertical pipe.
f. Caulking that has hardened, has separated, or is missing.
g. Bulges or staining of the insulation or jacketing system or missing bands. (Bulges may indicate corrosion product buildup.)
h. Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs.
i. Carbon or low-alloy steel flanges, bolting, and other components under insulation in high-alloy piping systems.

Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed. Several types of removable plugs are commercially available that permit inspection and identification of inspection points for future reference.

5.3.4 Soil-to-Air Interface

Soil-to-air (S/A) interfaces for buried piping without adequate cathodic protection shall be included in scheduled external piping inspections. Inspection at grade should check for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is localized to the S/A interface or may be more pervasive to the buried system. Thickness readings at S/A interfaces may expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. If the buried piping has satisfactory cathodic protection as determined by monitoring in accordance with Section 9, excavation is required only if there is evidence of coating or wrapping damage. If the buried piping is uncoated at grade, consideration should be given to excavating 6 inches to 12 inches (150 mm to 300 mm) deep to assess the potential for hidden damage.

At concrete-to-air and asphalt-to-air interfaces of buried piping without cathodic protection, the inspector should look for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on piping systems over 10 years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint.

5.3.5 Service-Specific and Localized Corrosion

An effective inspection program includes the following three elements, which help identify the potential for service-specific and localized corrosion and select appropriate TMLs:

a. An inspector with knowledge of the service and where corrosion is likely to occur.
b. Extensive use of nondestructive examination (NDE).
c. Communication from operating personnel when process upsets occur that may affect corrosion rates.

A few examples of where this type of corrosion might be expected to occur include the following:

a. Downstream of injection points and upstream of product separators, such as in hydroprocess reactor effluent lines.
b. Dew-point corrosion in condensing streams, such as overhead fractionation.
c. Unanticipated acid or caustic carryover from processes into nonalloyed piping systems or caustic carryover into steel piping systems that are not postweld heat treated.
d. Ammonium salt condensation locations in hydroprocess streams.
e. Mixed-phase flow and turbulent areas in acidic systems.
f. Mixed grades of carbon steel piping in hot corrosive oil service [450¡F (230¡C) or higher temperature and sulfur content in the oil greater than 0.5 percent by weight]. Note that nonsilicon killed steel pipe, such as A-53 and API 5L, may corrode at higher rates than does silicon killed steel pipe, such as A-106, especially in high-temperature sulfidic environments.
g. Underdeposit corrosion in slurries, crystallizing solutions, or coke producing fluids.
h. Chloride carryover in catalytic reformer regeneration systems.
i. Hot-spot corrosion on piping with external heat tracing. In services that become much more corrosive to the piping with increased temperature, such as caustic in carbon steel, corrosion or stress corrosion cracking (SCC) can occur at hot spots that develop under low-flow conditions.

5.3.6 Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles. It can be characterized by grooves, rounded holes, waves, and valleys in a directional pattern. Erosion usually occurs in areas of turbulent flow, such as at changes of direction in a piping system or downstream of control valves where vaporization may take place. Erosion damage is usually increased in streams with large quantities of solid or liquid particles flowing at high velocities. A combination of corrosion and erosion (corrosion/erosion) results in significantly greater metal loss than can be expected from corrosion or erosion alone. This type of corrosion occurs at high-velocity and high-turbulence areas.

Examples of places to inspect include the following:

a. Downstream of control valves, especially when flashing is occurring.
b. Downstream of orifices.
c. Downstream of pump discharges.
d. At any point of flow direction change, such as the inside and outside radii of elbows.
e. Downstream of piping configurations (such as welds, thermowells, and flanges) that produce turbulence, particularly in velocity sensitive systems such as ammonium hydrosulfide and sulfuric acid systems.

Areas suspected of having localized corrosion/erosion should be inspected using appropriate NDE methods that will yield thickness data over a wide area, such as ultrasonic scanning, radiographic profile, or eddy current.

5.3.7 Environmental Cracking

Piping system construction materials are normally selected to resist the various forms of stress corrosion cracking (SCC). However, some piping systems may be susceptible to environmental cracking due to upset process conditions, CUI, unanticipated condensation, or exposure to wet hydrogen sulfide or carbonates.

Examples of environmental cracking include:

a. Chloride SCC of austenitic stainless steels due to moisture and chlorides under insulation, under deposits, under gaskets, or in crevices.
b. Polythionic acid SCC of sensitized austenitic alloy steels due to exposure to sulfide, moisture condensation, or oxygen.
c. Caustic SCC (sometimes known as caustic embrittlement).
d. Amine SCC in piping systems that are not stress relieved.
e. Carbonate SCC.
f. SCC in environments where wet hydrogen sulfide exists, such as systems containing sour water.
g. Hydrogen blistering and hydrogen induced cracking (HIC) damage.

When the inspector suspects or is advised that specific circuits may be susceptible to environmental cracking, the inspector should schedule supplemental inspections. Such inspections can take the form of surface NDE [liquid-penetrant testing (PT), or wet fluorescent magnetic-particle testing (WFMT)], or ultrasonics (UT). Where available, suspect spools may be removed from the piping system and split open for internal surface examination.

If environmental cracking is detected during internal inspection of pressure vessels and the piping is considered equally susceptible, the inspector should designate appropriate piping spools upstream and downstream of the pressure vessel for environmental cracking inspection. When the potential for environmental cracking is suspected in piping circuits, inspection of selected spools should be scheduled prior to an upcoming turnaround. Such inspection should provide information useful in forecasting turnaround maintenance.

5.3.8 Corrosion Beneath Linings and Deposits

If external or internal coatings, refractory linings, and corrosion-resistant linings are in good condition and there is no reason to suspect a deteriorated condition behind them, it is usually not necessary to remove them for inspection of the piping system.

The effectiveness of corrosion-resistant linings is greatly reduced due to breaks or holes in the lining. The linings should be inspected for separation, breaks, holes, and blisters. If any of these conditions are noted, it may be necessary to remove portions of the internal lining to investigate the effectiveness of the lining and the condition of the metal piping beneath the lining. Alternatively, ultrasonic inspection from the external surface can be used to measure wall thickness and detect separation, holes, and blisters.

Refractory linings may spill or crack in-service with or without causing any significant problems. Corrosion beneath refractory linings can result in separation and bulging of the refractory. If bulging or separation of the refractory lining is detected, portions of the refractory may be removed to permit inspection of the piping beneath the refractory. Otherwise, ultrasonic thickness measurements may be made from the external metal surface.

Where operating deposits, such as coke, are present on a pipe surface, it is particularly important to determine whether such deposits have active corrosion beneath them. This may require a thorough inspection in selected areas. Larger lines should have the deposits removed in selected critical areas for spot examination. Smaller lines may require that selected spools be removed or that NDE methods, such as radiography, be performed in selected areas.

5.3.9 Fatigue Cracking

Fatigue cracking of piping systems may result from excessive cyclic stresses that are often well below the static yield strength of the material. The cyclic stresses may be imposed by pressure, mechanical, or thermal means and may result in low-cycle or high-cycle fatigue. The onset of low-cycle fatigue cracking is often directly related to the number of heat-up and cool-down cycles experienced. Excessive piping system vibration (such as machine or flow-induced vibrations) also can cause high-cycle fatigue damage. (See 5.4.4 for vibrating piping surveillance requirements and 7.5 for design requirements associated with vibrating piping.)

Fatigue cracking can typically be first detected at points of high-stress intensification such as branch connections. Locations where metals having different coefficients of thermal expansion are joined by welding may be susceptible to thermal fatigue. (See 6.6.3 for fatigue considerations relative to threaded connections.) Preferred NDE methods of detecting fatigue cracking include liquid-penetrant testing (PT) or magnetic-particle testing (MT). Acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

It is important that the owner/user and the inspector understand that fatigue cracking is likely to cause piping failure before it is detected with any NDE methods. Of the total number of fatigue cycles required to produce a failure, the vast majority are required to initiate a crack and relatively fewer cycles are required to propagate the crack to failure. Therefore, proper design and installation in order to prevent the initiation of fatigue cracking are important.

5.3.10 Creep Cracking

Creep is dependent on time, temperature, and stress. Creep cracking may eventually occur at design conditions, since some piping code allowable stresses are in the creep range. Cracking is accelerated by creep and fatigue interaction when operating conditions in the creep range are cyclic. The inspector should pay particular attention to areas of high stress concentration. If excessive temperatures are encountered, mechanical property and microstructural changes in metals also may take place, which may permanently weaken equipment. Since creep is dependent on time, temperature, and stress, the actual or estimated levels of these parameters shall be used in any evaluations. An example of where creep cracking has been experienced in the industry is in 11/4 Cr steels above 900ºF (480ºC).

NDE methods of detecting creep cracking include liquid- penetrant testing, magnetic-particle testing, ultrasonic testing, radiographic testing, and in-situ metallography. Acoustic emission testing also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

5.3.11 Brittle Fracture

Carbon, low-alloy, and other ferritic steels may be susceptible to brittle failure at or below ambient temperatures. Brittle fracture usually is not a concern with relatively thinwall piping. Most brittle fractures have occurred on the first application of a particular stress level (that is, the first hydrotest or overload) unless critical defects are introduced during service. The potential for a brittle failure shall be considered when rehydrotesting or more carefully evaluated when testing equipment pneumatically or when adding any other additional loads. Special attention should be given to low-alloy steels (especially 21/4 Cr-1 Mo material), because they may be prone to temper embrittlement, and to ferritic stainless steels.

API Publ 920, which contains information on the prevention of brittle fracture in pressure vessels, may be useful in assessing brittle fracture potential in piping systems.

5.3.12 Freeze Damage

At subfreezing temperatures, water and aqueous solutions in piping systems may freeze and cause failure because of the expansion of these materials. After unexpectedly severe freezing weather, it is important to check for freeze damage to exposed piping components before the system thaws. If rupture has occurred, leakage may be temporarily prevented by the frozen fluid. Low points, driplegs, and deadlegs of piping systems containing water should be carefully examined for damage.

5.4 Types of Inspection and Surveillance

Different types of inspection and surveillance are appropriate depending on the circumstances and the piping system (see note). These include the following:

a. Internal visual inspection.
b. Thickness measurement inspection.
c. External visual inspection.
d. Vibrating piping inspection.
e. Supplemental inspection.

Note: See Section 6 for frequency and extent of inspection.

5.4.1 Internal Visual Inspection

Internal visual inspections are not normally performed on piping. When possible and practical, internal visual inspections may be scheduled for systems such as large-diameter transfer lines, ducts, catalyst lines, or other large-diameter piping systems. Such inspections are similar in nature to pressure vessel inspections and should be conducted with methods and procedures similar to those outlined in API 510. Remote visual inspection techniques can be helpful when inspecting piping too small to enter.

An additional opportunity for internal inspection is provided when piping flanges are disconnected, allowing visual inspection of internal surfaces with or without the use of NDE. Removing a section of piping and splitting it along its centerline also permits access to internal surfaces where there is need for such inspection.

5.4.2 Thickness Measurement Inspection

A thickness measurement inspection is performed to determine the internal condition and remaining thickness of the piping components. Thickness measurements may be obtained when the piping system is in or out of operation and shall be performed by the inspector or examiner.

5.4.3 External Visual Inspection

An external visual inspection is performed to determine the condition of the outside of the piping, insulation system, painting and coating systems, and associated hardware; and to check for signs of misalignment, vibration, and leakage. When corrosion product buildup is noted at pipe support contact areas, lifting off such supports may be required for inspection. When doing this, care should be exercised if the piping is in-service.

External piping inspections may be made when the piping system is in-service. Refer to API RP 574 for information helpful in conducting external inspections. A checklist to assist in conducting external piping inspections is provided in Appendix D.

External inspections shall include surveys for the condition of piping hangers and supports. Instances of cracked or broken hangers, “bottoming out” of spring supports, support shoes displaced from support members, or other improper restraint conditions shall be reported and corrected. Vertical support dummy legs also shall be checked to confirm that they have not filled with water that is causing external corrosion of the pressure piping or internal corrosion of the support leg. Horizontal support dummy legs also shall be checked to determine that slight displacements from horizontal are not causing moisture traps against the external surface of active piping components.

Bellows expansion joints should be inspected visually for unusual deformations, misalignment, or displacements that may exceed design.

The inspector should examine the piping system for the presence of any field modifications or temporary repairs not previously recorded on the piping drawings and/or records. The inspector also should be alert to the presence of any components in the service that may be unsuitable for long-term operation, such as improper flanges, temporary repairs (clamps), modifications (flexible hoses), or valves of improper specification. Threaded components that may be more easily removed and installed deserve particular attention because of their higher potential for installation of improper components.

The periodic external inspection called for in 6.4 should normally be conducted by the inspector, who also shall be responsible for record keeping and repair inspection. Qualified operating or maintenance personnel also may conduct external inspections, when acceptable to the inspector. In such cases, the persons conducting external piping inspections in accordance with API 570 shall be qualified through an appropriate amount of training.

In addition to these scheduled external inspections that are documented in inspection records, it is beneficial for personnel who frequent the area to report deterioration or changes to the inspector. (See Appendix D and Section 6.3 of API RP 574 for examples of such deterioration.)

5.4.4 Vibrating Piping and Line Movement Surveillance

Operating personnel should report vibrating or swaying piping to engineering or inspection personnel for assessment. Other significant line movements should be reported that may have resulted from liquid hammer, liquid slugging in vapor lines, or abnormal thermal expansion. At junctions where vibrating piping systems are restrained, periodic magnetic-particle testing or liquid-penetrant testing should be considered to check for the onset of fatigue cracking. Branch connections should receive special attention.

5.4.5 Supplemental Inspection

Other inspections may be scheduled as appropriate or necessary. Examples of such inspections include periodic use of radiography and/or thermography to check for fouling or internal plugging, thermography to check for hot spots in refractory lined systems, or inspection for environmental cracking. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Ultrasonics and/or radiography can be used for detecting localized corrosion.

5.5 Thickness Measurement Locations

5.5.1 General

Thickness measurement locations (TMLs) are specific areas along the piping circuit where inspections are to be made. The nature of the TML varies according to its location in the piping system. The selection of TMLs shall consider the potential for localized corrosion and service-specific corrosion as described in 5.3.

5.5.2 TML Monitoring

Each piping system shall be monitored by taking thickness measurements at TMLs. Piping circuits with high potential consequences if failure should occur and those subject to higher corrosion rates or localized corrosion will normally have more TMLs and be monitored more frequently (see 6.3). TMLs should be distributed appropriately throughout each piping circuit. TMLs may be eliminated or the number reduced under certain circumstances, such as olefin plant cold side piping, anhydrous ammonia piping, clean noncorrosive hydrocarbon product, or high-alloy piping for product purity. In circumstances where TMLs will be substantially reduced or eliminated, persons knowledgeable in corrosion should be consulted.

The minimum thickness at each TML can be located by ultrasonic scanning or radiography. Electromagnetic techniques also can be used to identify thin areas that may then be measured by ultrasonics or radiography. When accomplished with ultrasonics, scanning consists of taking several thickness measurements at the TML searching for localized thinning. The thinnest reading or an average of several measurement readings taken within the area of a test point shall be recorded and used to calculate corrosion rates, remaining life, and the next inspection date in accordance with Section 7.

Where appropriate, thickness measurements should include measurements at each of the four quadrants on pipe and fittings, with special attention to the inside and outside radius of elbows and tees where corrosion/erosion could increase corrosion rates. As a minimum, the thinnest reading and its location shall be recorded.

TMLs should be established for areas with continuing CUI, corrosion at S/A interfaces, or other locations of potential localized corrosion as well as for general, uniform corrosion.

TMLs should be marked on inspection drawings and on the piping system to allow repetitive measurements at the same TMLs. This recording procedure provides data for more accurate corrosion rate determination.

5.5.3 TML Selection

In selecting or adjusting the number and locations of TMLs, the inspector should take into account the patterns of corrosion that would be expected and have been experienced in the process unit. A number of corrosion processes common to refining and petrochemical units are relatively uniform in nature, resulting in a fairly constant rate of pipe wall reduction independent of location within the piping circuit, either axially or circumferentially. Examples of such corrosion phenomena include high-temperature sulfur corrosion and sour water corrosion (provided velocities are not so excessive as to cause local corrosion/erosion of elbows, tees, and other similar items). In these situations, the number of TMLs required to monitor a circuit will be fewer than those required to monitor circuits subject to more localized metal loss. In theory, a circuit subject to perfectly uniform corrosion could be adequately monitored with a single TML. In reality, corrosion is never truly uniform, so additional TMLs may be required. Inspectors must use their knowledge (and that of others) of the process unit to optimize the TML selection for each circuit, balancing the effort of collecting the data with the benefits provided by the data.

More TMLs should be selected for piping systems with any of the following characteristics:

a. Higher potential for creating a safety or environmental emergency in the event of a leak.
b. Higher expected or experienced corrosion rates.
c. Higher potential for localized corrosion.
d. More complexity in terms of fittings, branches, deadlegs, injection points, and other similar items.
e. Higher potential for CUI.

Fewer TMLs can be selected for piping systems with any of the following three characteristics:

a. Low potential for creating a safety or environmental emergency in the event of a leak.
b. Relatively noncorrosive piping systems.
c. Long, straight-run piping systems.

TMLs can be eliminated for piping systems with either of the following two characteristics:

a. Extremely low potential for creating a safety or environmental emergency in the event of a leak.
b. Noncorrosive systems, as demonstrated by history or similar service, and systems not subject to changes that could cause corrosion.

5.6 Thickness Measurement Methods

Ultrasonic thickness measuring instruments usually are the most accurate means for obtaining thickness measurements on installed pipe larger than NPS 1. Radiographic profile techniques are preferred for pipe diameters of NPS 1 and smaller. Radiographic profile techniques may be used for locating areas to be measured, particularly in insulated systems or where nonuniform or localized corrosion is suspected. Where practical, ultrasonics can then be used to obtain the actual thickness of the areas to be recorded. Following ultrasonic readings at TMLs, proper repair of insulation and insulation weather coating is recommended to reduce the potential for CUI. Radiographic profile techniques, which do not require removing insulation, may be considered as an alternative.

When corrosion in a piping system is nonuniform or the remaining thickness is approaching the minimum required thickness, additional thickness measuring may be required. Radiography or ultrasonic scanning are the preferred methods in such cases. Eddy current devices also may be used.

When ultrasonic measurements are taken above 150¡F (65¡C), instruments, couplants, and procedures should be used that will result in accurate measurements at the higher temperatures. Measurements should be adjusted by the appropriate temperature correction factor.

Inspectors should be aware of possible sources of measurement inaccuracies and make every effort to eliminate their occurrence. As a general rule, each of the NDE techniques will have practical limits with respect to accuracy. Factors that can contribute to reduced accuracy of ultrasonic measurements include the following:

a. Improper instrument calibration.
b. External coatings or scale.
c. Excessive surface roughness.
d. Excessive “rocking” of the probe (on the curved surface).
e. Subsurface material flaws, such as laminations.

f. Temperature effects [at temperatures above 150¡F (65¡C)].
g. Small flaw detector screens.
h. Thicknesses of less than 1/8 inch (3.2 mm) for typical digital thickness gauges.

In addition, it must be kept in mind that the pattern of corrosion can be nonuniform. For corrosion rate determinations to be valid, it is important that measurements on the thinnest point be repeated as closely as possible to the same location. Alternatively, the minimum reading or an average of several readings at a test point may be considered.

When piping systems are out of service, thickness measurements may be taken through openings using calipers. Calipers are useful in determining approximate thicknesses of castings, forgings, and valve bodies, as well as pit depth approximations from CUI on pipe.

Pit depth measuring devices also may be used to determine the depth of localized metal loss.

5.7 Pressure Testing of Piping Systems

Pressure tests are not normally conducted as part of a routine inspection. (See 8.2.6 for pressure testing requirements for repairs, alterations, and rerating.) Exceptions to this include requirements of the United States Coast Guard for overwater piping and requirements of local jurisdictions, after welded alterations or when specified by the inspector or piping engineer. When they are conducted, pressure tests shall be performed in accordance with the requirements of ASME B31.3. Additional considerations are provided in API RP 574 and API RP 920. Lower pressure tests, which are used only for tightness of piping systems, may be conducted at pressures designated by the owner/user.

The test fluid should be water unless there is the possibility of damage due to freezing or other adverse effects of water on the piping system or the process or unless the test water will become contaminated and its disposal will present environmental problems. In either case, another suitable nontoxic liquid may be used. If the liquid is flammable, its flash point shall be at least 120¡F (49¡C) or greater, and consideration shall be given to the effect of the test environment on the test fluid.

Piping fabricated of or having components of 300 series stainless steel should be hydrotested with a solution made up of potable water (see note) or steam condensate. After testing is completed, the piping should be thoroughly drained (all high-point vents should be open during draining), air blown, or otherwise dried. If potable water is not available or if immediate draining and drying is not possible, water having a very low chloride level, higher pH (>10), and inhibitor addition may be considered to reduce the risk of pitting and microbiologically induced corrosion.

Note: Potable water in this context follows U.S. practice, with 250 parts per million maximum chloride, sanitized with chlorine or ozone.

For sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking, consideration should be given to using an alkaline-water solution for pressure testing (see NACE RP0170).

If a pressure test is to be maintained for a period of time and the test fluid in the system is subject to thermal expansion, precautions shall be taken to avoid excessive pressure.

When a pressure test is required, it shall be conducted after any heat treatment.

Before applying a hydrostatic test to piping systems, consideration should be given to the supporting structure design.

A pneumatic pressure test may be used when it is impracticable to hydrostatically test due to temperature, structural, or process limitations. However, the potential risks to personnel and property of pneumatic testing shall be considered when carrying out such a test. As a minimum, the inspection precautions contained in ASME B31.3 shall be applied in any pneumatic testing.

During a pressure test, where the test pressure will exceed the set pressure of the safety valve on a piping system, the safety relief valve or valves should be removed or blanked for the duration of the test. As an alternative, each valve disk must be held down by a suitably designed test clamp. The application of an additional load to the valve spring by turning the adjusting screw is not recommended. Other appurtenances that are incapable of withstanding the test pressure, such as gage glasses, pressure gages, expansion joints, and rupture disks, should be removed or blanked. Lines containing expansion joints that cannot be removed or isolated may be tested at a reduced pressure in accordance with the principles of ASME B31.3. If block valves are used to isolate a piping system for a pressure test, caution should be used to not exceed the permissible seat pressure as described in ASME B16.34 or applicable valve manufacturer data.

Upon completion of the pressure test, pressure relief devices of the proper settings and other appurtenances removed or made inoperable during the pressure test shall be reinstalled or reactivated.

5.8 Material Verification and Traceability

During repairs or alterations of low- to high-alloy piping systems, the inspector shall verify the installation of the correct new materials. At the discretion of the owner/user or the inspector, this verification can be either by 100-percent checking or testing in certain critical situations or by sampling a percentage of the materials. Testing can be accomplished by the inspector or the examiner with the use of suitable portable methods, such as chemical spot testing, optical spectrographic analyzers, or X-ray fluorescent analyzers. Checking can involve verifying test reports on materials, markings on piping components and bolting, and key dimensions.

If a piping system component should fail because an incorrect material was inadvertently substituted for the proper piping material, the inspector shall consider the need for further verification of existing piping materials. The extent of further verification will depend upon circumstances such as the consequences of failure and the likelihood of further material errors.

5.9 Inspection of Valves

Normally, thickness measurements are not routinely taken on valves in piping circuits. The body of a valve is normally thicker than other piping components for design reasons. However, when valves are dismantled for servicing and repair, the shop should be attentive to any unusual corrosion patterns or thinning and, when noted, report that information to the inspector. Bodies of valves that are exposed to steep temperature cycling (for example, catalytic reforming unit regeneration and steam cleaning) should be examined periodically for thermal fatigue cracking.

If gate valves are known to be or are suspected of being exposed to corrosion/erosion, thickness readings should be taken between the seats, since this is an area of high turbulence and high stress.

Control valves or other throttling valves, particularly in high-pressure drop-and-slurry services, can be susceptible to localized corrosion/erosion of the body downstream of the orifice. If such metal loss is suspected, the valve should be removed from the line for internal inspection. The inside of the downstream mating flange and piping also should be inspected for local metal loss.

When valve body and/or closure pressure tests are performed after servicing, they should be conducted in accordance with API Std 598.

Critical check valves should be visually and internally inspected to ensure that they will stop flow reversals. An example of a critical check valve may be the check valve located on the outlet of a multistage, high head hydroprocessing charge pump. Failure of such a check valve to operate correctly could result in overpressuring the piping during a flow reversal. The normal visual inspection method should include:

a. Checking to insure that the flapper is free to move, as required, without excessive looseness from wear.
b. The flapper stop should not have excessive wear. This will minimize the likelihood that the flapper will move past the top dead central position and remain in an open position when the check valve is mounted in a vertical position.

c. The flapper nut should be secured to the flapper bolt to avoid backing off in service.

Leak checks of critical check valves are normally not required.

5.10 Inspection of Welds In-Service

Inspection for piping weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection. When preferential weld corrosion is noted, additional welds in the same circuit or system should be examined for corrosion.

On occasion, radiographic profile examinations may reveal what appears to be imperfections in the weld. If crack-like imperfections are detected while the piping system is in operation, further inspection with weld quality radiography and/or ultrasonics may be used to assess the magnitude of the imperfection. Additionally, an effort should be made to determine whether the crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

Environmental cracking shall be assessed by the piping engineer.

If the noted imperfections are a result of original weld fabrication, inspection and/or engineering analysis is required to assess the impact of the weld quality on piping integrity. This analysis may be one or more of the following:

a. Inspector judgment.
b. Certified welding inspector judgment.
c. Piping engineer judgment.
d. Engineering fitness-for-service analysis.

Issues to consider when assessing the quality of existing welds include the following:

a. Original fabrication inspection acceptance criteria.
b. Extent, magnitude, and orientation of imperfections.
c. Length of time in-service.
d. Operating versus design conditions.
e. Presence of secondary piping stresses (residual and thermal).
f. Potential for fatigue loads (mechanical and thermal).
g. Primary or secondary piping system.
h. Potential for impact or transient loads.
i. Potential for environmental cracking.
j. Weld hardness.

In many cases for in-service welds, it is not appropriate to use the random or spot radiography acceptance criteria for weld quality in ASME B31.3. These acceptance criteria are intended to apply to new construction on a sampling of welds, not just the welds examined, in order to assess the probable quality of all welds (or welders) in the system. Some welds may exist that will not meet these criteria but will still perform satisfactorily in-service after being hydrotested. This is especially true on small branch connections that are normally not examined during new construction.

5.11 Inspection of Flanged Joints

The markings on a representative sample of newly installed fasteners and gaskets should be examined to determine whether they meet the material specification. The markings are identified in the applicable ASME and ASTM standards. Questionable fasteners should be verified or renewed.

Fasteners should extend completely through their nuts. Any fastener failing to do so is considered acceptably engaged if the lack of complete engagement is not more than one thread.

If installed flanges are excessively bent, their markings and thicknesses should be checked against engineering requirements before taking corrective action.

Flange and valve bonnet fasteners should be examined visually for corrosion.

Flanged and valve bonnet joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange and bonnet fasteners may result in corrosion or environmental cracking. This examination should include those flanges enclosed with flange or splash-and-spray guards.

Flanged joints that have been clamped and pumped with sealant should be checked for leakage at the bolts. Fasteners subjected to such leakage may corrode or crack (caustic cracking, for example). If repumping is contemplated, affected fasteners should be renewed first.

Fasteners on instrumentation that are subject to process pressure and/or temperature should be included in the scope of these examinations.

See API RP 574 for recommended practices when flanged joints are opened.

6 Frequency and Extent of Inspection

6.1 General

The frequency and extent of inspection on piping circuits depend on the forms of degradation that can affect the piping and consequence of a piping failure. The various forms of degradation that can affect refinery piping circuits are described in 5.3, while a simplified classification of piping based on the consequence of failure is defined in 6.2. As described in 5.1, inspection strategy based on likelihood and consequence of failure, is referred to as risk-based inspection.

The simplified piping classification scheme in Section 6.2 is based on the consequence of a failure. The classification is used to establish frequency and extent of inspection. The owner/user may devise a more extensive classification scheme that more accurately assesses consequence for certain piping circuits. The consequence assessment would consider the potential for explosion, fire, toxicity, environmental impact, and other potential effects associated with a failure.

After an effective assessment is conducted, the results can be used to establish a piping circuit inspection strategy and more specifically better define the following:

a. The most appropriate inspection methods, scope, tools and techniques to be utilized based on the expected forms of degradation;
b. The appropriate inspection frequency;
c. The need for pressure testing after damage has been incurred or after repairs or modifications have been completed: and
d. The prevention and mitigation steps to reduce the likelihood and consequence of a piping failure.

A RBI assessment may be used to increase or decrease the inspection limits described in Table 6-1. Similarly, the extent of inspection may be increased or decreased beyond the targets in Table 6-2, by a RBI assessment. When used to increase inspection interval limits or the extent of inspection, RBI assessments shall be conducted at intervals not to exceed the respective limits in Table 6-1, or more often if warranted by process, equipment, or consequence changes. These RBI assessments shall be reviewed and approved by a piping engineer and authorized piping inspector at intervals not to exceed the respective limits in Table 6-1, or more often if warranted by process, equipment, or consequence changes.

6.2 Piping Service Classes

All process piping systems shall be categorized into different classes. Such a classification system allows extra inspection efforts to be focused on piping systems that may have the highest potential consequences if failure or loss of containment should occur. In general, the higher classified systems require more extensive inspection at shorter intervals in order to affirm their integrity for continued safe operation. Classifications should be based on potential safety and environmental effects should a leak occur.

Owner/users shall maintain a record of process piping fluids handled, including their classifications. API RP 750 and NFPA 704 provide information that may be helpful in classifying piping systems according to the potential hazards of the process fluids they contain.

The three classes listed below in 6.2.1 through 6.2.3 are recommended.

6.2.1 Class 1

Services with the highest potential of resulting in an immediate emergency if a leak were to occur are in Class 1. Such an emergency may be safety or environmental in nature. Examples of Class 1 piping include, but are not necessarily limited to, those containing the following:

a. Flammable services that may auto-refrigerate and lead to brittle fracture.
b. Pressurized services that may rapidly vaporize during release, creating vapors that may collect and form an explosive mixture, such as C2, C3, and C4 streams.
c. Hydrogen sulfide (greater than 3 percent weight) in a gaseous stream.
d. Anhydrous hydrogen chloride.
e. Hydrofluoric acid.
f. Piping over or adjacent to water and piping over public throughways. (Refer to Department of Transportation and U.S. Coast Guard regulations for inspection of overwater piping.)

6.2.2 Class 2

Services not included in other classes are in Class 2. This classification includes the majority of unit process piping and selected off-site piping. Typical examples of these services include those containing the following:

a. On-site hydrocarbons that will slowly vaporize during release.
b. Hydrogen, fuel gas, and natural gas.
c. On-site strong acids and caustics.

6.2.3 Class 3

Services that are flammable but do not significantly vaporize when they leak and are not located in high-activity areas are in Class 3. Services that are potentially harmful to human tissue but are located in remote areas may be included in this class. Examples of Class 3 service are as follows:

a. On-site hydrocarbons that will not significantly vaporize during release.
b. Distillate and product lines to and from storage and loading.
c. Off-site acids and caustics.

6.3 Inspection Intervals

The interval between piping inspections shall be established and maintained using the following criteria:

a. Corrosion rate and remaining life calculations.
b. Piping service classification.
c. Applicable jurisdictional requirements.
d. Judgment of the inspector, the piping engineer, the piping engineer supervisor, or a corrosion specialist, based on operating conditions, previous inspection history, current inspection results, and conditions that may warrant supplemental inspections covered in 5.4.5.

The owner/user or the inspector shall establish inspection intervals for thickness measurements and external visual inspections and, where applicable, for internal and supplemental inspections.

Thickness measurements should be scheduled based on the calculation of not more than half the remaining life determined from corrosion rates indicated in 7.1.1 or at the maximum intervals suggested in Table 6-1, whichever is shorter. Shorter intervals may be appropriate under certain circumstances. Prior to using Table 6-1, corrosion rates should be calculated in accordance with 7.1.3.

Table 6-1 contains recommended maximum inspection intervals for the three categories of piping services described in 6.2, as well as recommended intervals for injection points and S/A interfaces.

The inspection interval must be reviewed and adjusted as necessary after each inspection or significant change in operating conditions. General corrosion, localized corrosion, pitting, environmental cracking, and other forms of deterioration must be considered when establishing the various inspection intervals.

6.4 Extent of Visual External and CUI Inspections

External visual inspections, including inspections for corrosion under insulation (CUI), should be conducted at maximum intervals listed in Table 6-1 to evaluate items such as those in Appendix D. The external visual inspection on bare piping is to assess the condition of paint and coating systems, to check for external corrosion, and to check for other forms of deterioration. This external visual inspection for potential CUI is also to assess insulation condition and shall be conducted on all piping systems susceptible to CUI listed in 5.3.3.1.

Following the external visual inspection of susceptible systems, additional examination is required for the inspection of CUI. The extent and type of the additional CUI inspection are listed in Table 6-2. Damaged insulation at higher elevations may result in CUI in lower areas remote from the damage. NDE inspection for CUI should also be conducted as listed in Table 6-2 at suspect locations of 5.3.3.2 (excluding c) meeting the temperature criteria for 5.3.3.1 (e, f, h). Radiographic examination or insulation removal and visual inspection is normally required for this inspection at damaged or suspect locations. Other NDE assessment methods may be used where applicable. If the inspection of the damaged or suspect areas has located significant CUI, additional areas should be inspected and, where warranted, up to 100 percent of the circuit should be inspected.

The extent of the CUI program described in Table 6-2 should be considered as target levels for piping systems and locations with no CUI inspection experience. It is recognized that several factors may affect the likelihood of CUI to include:

a. Local climatic conditions (see 5.3.3).
b. Insulation design.
c. Coating quality.
d. Service conditions.

Facilities with CUI inspection experience may increase or reduce the CUI inspection targets of Table 6-2. An exact accounting of the CUI inspection targets is not required. The owner/user may confirm inspection targets with operational history or other documentation.

Piping systems that are known to have a remaining life of over 10 years or that are adequately protected against external corrosion need not be included for the NDE inspection recommended in Table 6-2. However, the condition of the insulating system or the outer jacketing, such as a cold-box shell, should be observed periodically by operating or other personnel. If deterioration is noted, it should be reported to the inspector. The following are examples of these systems:

a. Piping systems insulated effectively to preclude the entrance of moisture.

b. Jacketed cryogenic piping systems.

c. Piping systems installed in a cold box in which the atmosphere is purged with an inert gas.

d. Piping systems in which the temperature being maintained is sufficiently low or sufficiently high to preclude the presence of water.

6.5 Extent of Thickness Measurement Inspection

To satisfy inspection interval requirements, each thickness measurement inspection should obtain thickness readings on a representative sampling of TMLs on each circuit (see 5.5). This representative sampling should include data for all the various types of components and orientations (horizontal and vertical) found in each circuit. This sampling also must include TMLs with the earliest renewal date as of the previous inspection. The more TMLs measured for each circuit, the more accurately the next inspection date will be projected. Therefore, scheduled inspection of circuits should obtain as many measurements as necessary.

The extent of inspection for injection points is covered in 5.3.1.

6.6 Extent of Small-Bore, Auxiliary Piping, and Threaded-Connections Inspections

6.6.1 Small-Bore Piping Inspection

Small-bore piping (SBP) that is primary process piping should be inspected in accordance with all the requirements of this document.

SBP that is secondary process piping has different minimum requirements depending upon service classification. Class 1 secondary SBP shall be inspected to the same requirements as primary process piping. Inspection of Class 2 and Class 3 secondary SBP is optional. SBP deadlegs (such as level bridles) in Class 2 and Class 3 systems should be inspected where corrosion has been experienced or is anticipated.

6.6.2 Auxiliary Piping Inspection

Inspection of secondary, auxiliary SBP associated with instruments and machinery is optional. Criteria to consider in determining whether auxiliary SBP will need some form of inspection include the following:

a. Classification.

b. Potential for environmental or fatigue cracking.

c. Potential for corrosion based on experience with adjacent primary systems.

d. Potential for CUI.

6.6.3 Threaded-Connections Inspection

Inspection of threaded connections will be according to the requirements listed above for small-bore and auxiliary piping. When selecting TMLs on threaded connections, include only those that can be radiographed during scheduled inspections.

Threaded connections associated with machinery and subject to fatigue damage should be periodically assessed and considered for possible renewal with a thicker wall or upgrading to welded components. The schedule for such renewal will depend on several issues, including the following:

a. Classification of piping.

b. Magnitude and frequency of vibration.

c. Amount of unsupported weight.

d. Current piping wall thickness.

e. Whether or not the system can be maintained on-stream.

f. Corrosion rate.

g. Intermittent service.

Table 6-1-Recommended Maximum Inspection Intervals

Type of Circuit	Thickness Measurements	Visual External
Class 1	5 years	5 years
Class 2	10 years	5 years
Class 3	10 years	10 years
Injection points[a]	3 years	By Class
Soil-to-air interfaces[b]	-	By Class

Note: Thickness measurements apply to systems for which TMLs have been established in accordance with 5.5.

a See 5.3.1.
b See 5.3.4.

Table 6-2-Recommended Extent of CUI Inspection
Following Visual Inspection

Approximate Amount of Follow-up Examination with NDE or Insulation Removal at Areas with Damaged Insulation
Approximate Amount of CUI Inspection by NDE at Suspect Areas (5.3.3.2) on Piping Systems within Susceptible Temperature Ranges (5.3.3.2,e,f,h)

Pipe Class

1	75%	50%
2	50%	33%
3	25%	10%

7 Inspection Data Evaluation, Analysis, and Recording

7.1 Corrosion Rate Determination

7.1.1 Remaining Life Calculations

The remaining life of the piping system shall be calculated from the following formula:

$$\text{Remaining life (years)} = \frac{t_{actual} - t_{minimum}}{\text{corrosion rate [inches (mm) per year]}}$$

where:

t_{actual} = the actual minimum thickness, in inches (mm), determined at the time of inspection as specified in 5.6.

$t_{minimum}$ = the minimum required thickness, in inches (mm), for the limiting section or zone.

The long term (L.T.) corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{corrosion rate (L.T.)} = \frac{t_{initial} - t_{last}}{\text{time (years) between last and initial inspections}}$$

The short term (S.T.) corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{corrosion rate (S.T.)} = \frac{t_{previous} - t_{last}}{\text{time (years) between last and previous inspections}}$$

Long-term and short-term corrosion rates should be compared to see which results in the shortest remaining life. (See 6.3 for inspection interval determination.)

7.1.2 Newly Installed Piping Systems or Changes in Service

For new piping systems and piping systems for which service conditions are being changed, one of the following methods shall be employed to determine the probable rate of corrosion from which the remaining wall thickness at the time of the next inspection can be estimated:

a. A corrosion rate for a piping circuit may be calculated from data collected by the owner/user on piping systems of similar material in comparable service.
b. If data for the same or similar service are not available, a corrosion rate for a piping circuit may be estimated from the owner/user's experience or from published data on piping systems in comparable service.
c. If the probable corrosion rate cannot be determined by either method listed in Item a or Item b, the initial thickness measurement determinations shall be made after no more than 3 months of service by using nondestructive thickness measurements of the piping system. Corrosion monitoring devices, such as corrosion coupons or corrosion probes, may be useful in establishing the timing of these thickness measurements. Subsequent measurements shall be made after appropriate intervals until the corrosion rate is established.

7.1.3 Existing Piping Systems

Corrosion rates shall be calculated on either a short-term or a long-term basis. For the short-term calculation, readings from the two most recent inspections shall be used. For the long-term calculation, wall thicknesses from the most recent and initial (or nominal) inspections shall be used. In most cases, the higher of these two rates should be used to estimate remaining life and to set the next inspection interval.

If calculations indicate that an inaccurate rate of corrosion has been assumed, the rate to be used for the next period shall be adjusted to agree with the actual rate found.

7.2 Maximum Allowable Working Pressure Determination

The maximum allowable working pressure (MAWP) for the continued use of piping systems shall be established using the applicable code. Computations may be made for known materials if all the following essential details are known to comply with the principles of the applicable code:

a. Upper and/or lower temperature limits for specific materials.
b. Quality of materials and workmanship.
c. Inspection requirements.
d. Reinforcement of openings.
e. Any cyclical service requirements.

For unknown materials, computations may be made assuming the lowest grade material and joint efficiency in the applicable code. When the MAWP is recalculated, the wall thickness used in these computations shall be the actual thickness as determined by inspection (see 5.6 for definition) minus twice the estimated corrosion loss before the date of the next inspection (see 6.3). Allowance shall be made for the other loadings in accordance with the applicable code. The applicable code allowances for pressure and temperature variations from the MAWP are permitted provided all of the associated code criteria are satisfied.

Table 7-1 contains two examples of calculations of MAWP illustrating the use of the corrosion half-life concept.

Table 7-1-Two Examples of the Calculation of Maximum Allowable Working Pressure (MAWP)

Illustrating the Use of the Corrosion Half-Life Concept

Example 1:

Design pressure/temperature 500 psig/400¡F (3447 kPA/204¡C)
Pipe description NPS 16, standard weight, A 106-B
Outside diameter of pipe, D 16 in. (406 mm)
Allowable stress 20,000 psi (137,900 kPa)
Longitudinal weld
efficiency, E 1.0
Thickness determined from inspection 0.32 in. (8.13 mm)
Observed corrosion rate
(see 7.1.1) 0.01 in./yr. (0.254 mm/yr.)
Next planned inspection 5 yrs.
Estimated corrosion loss by date of next inspection = 5 X 0.01 = 0.05 in. (5 X 0.254 = 1.27mm)

MAWP

In U.S. units = 2SEt/D

= 550 psig

In S.I units

= 3747 kPa

Conclusion: OK

Example 2:

Next planned inspection 7 yrs.
Estimated corrosion loss by date of next inspection = 7 X 0.01 = 0.07 in. (7 x 0.254 = 1.78mm)

MAWP

In U.S. units = 2SEt/D

= 450 psig

In S.I units

= 3104 kPa

Conclusion: Must reduce inspection interval or determine that normal operating pressure will not exceed this new MAWP during the seventh year, or renew the piping before the seventh year.

Notes:

1. psig = pounds per square inch gauge; psi = pounds per square inch.
2. The formula for MAWP is from ASME B31.3, Equation 3b, where t = corroded thickness.

7.3 Minimum Required Thickness Determination

The minimum required pipe wall thickness, or retirement thickness, shall be based on pressure, mechanical, and structural considerations using the appropriate design formulae and code allowable stress. Consideration of both general and localized corrosion shall be included. For services with high potential consequences if failure were to occur, the piping engineer should consider increasing the required minimum thickness above the calculated minimum thickness to provide for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse.

7.4 Evaluation of Locally Thinned Areas

Locally thinned areas may be evaluated by the piping engineer using one of the following methods:

a. In accordance with the latest edition of ASME B31G.
b. Detailed numerical stress analysis (such as finite element analysis) of the area to determine adequacy for continued service. The results of this analysis shall be evaluated as described in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, Appendix 4, Article 4-1. The basic allowable stress from the applicable code shall be used in place of Sm in Division 2, but in no case shall the allowable stress used in this evaluation be greater than two-thirds of the specified minimum yield strength (SMYS) at temperature. At design temperatures in the creep range of the material, additional considerations beyond the scope of Division 2 are necessary, such as the effects of creep-fatigue interaction.
c. An independent calculation using the appropriate weld joint factor when a longitudinal weld having a joint factor of less than 1.0 is corroded as well as surfaces remote from the weld. This calculation must be made to determine if the thickness at the weld, or remote from the weld, governs the allowable working pressure. For the purpose of this calculation, the surface at a weld includes 1 inch (2.5 centimeters) of parent metal on either side of the weld or twice the minimum measured thickness on either side of the weld, whichever is greater. Alternatively, the weld joint factor may be increased by radiographic examination in accordance with the principles of ASME B31.3.
d. Corroded areas of pipe caps may be evaluated in accordance with paragraph 5.7, item h, of API 510.

7.5 Piping Stress Analysis

Piping must be supported and guided so that (a) its weight is carried safely, (b) it has sufficient flexibility for thermal expansion or contraction, and (c) it does not vibrate excessively. Piping flexibility is of increasing concern the larger the diameter of the piping and the greater the difference between ambient and operating temperature conditions.

Piping stress analysis to assess system flexibility and support adequacy is not normally performed as part of a piping inspection. However, many existing piping systems were analyzed as part of their original design or as part of a rerating or modification, and the results of these analyses can be useful in developing inspection plans. When unexpected movement of a piping system is observed, such as during an external visual inspection (see 5.4.3), the inspector should discuss these observations with the piping engineer and evaluate the need for conducting a piping stress analysis.

Piping stress analysis can identify the most highly stressed components in a piping system and predict the thermal movement of the system when it is placed in operation. This information can be used to concentrate inspection efforts at the locations most prone to fatigue damage from thermal expansion (heat-up and cool-down) cycles and/or creep damage in high-temperature piping. Comparing predicted thermal movements with observed movements can help identify the occurrence of unexpected operating conditions and deterioration of guides and supports. Consultation with the piping engineer may be necessary to explain observed deviations from the analysis predictions, particularly for complicated systems involving multiple supports and guides between end points.

Piping stress analysis also can be employed to help solve observed piping vibration problems. The natural frequencies in which a piping system will vibrate can be predicted by analysis. The effects of additional guiding can be evaluated to assess its ability to control vibration by increasing the system's natural frequencies beyond the frequency of exciting forces, such as machine rotational speed. It is important to determine that guides added to control vibration do not adversely restrict thermal expansion.

7.6 Reporting and Records for Piping System Inspection

Any significant increase in corrosion rates shall be reported to the owner/user for appropriate action.

The owner/user shall maintain appropriate permanent and progressive records of each piping system covered by API 570. These records shall contain pertinent data such as piping system service; classification; identification numbers; inspection intervals; and documents necessary to record the name of the individual performing the testing, the date, the types of testing, the results of thickness measurements and other tests, inspections, repairs (temporary and permanent), alterations, or rerating. Design information and piping drawings may be included. Information on maintenance activities and events affecting piping system integrity also should be included. The date and results of required external inspections shall be recorded. (See API RP 574 for guidance on piping inspection records.)

The use of a computer-based system for storing, calculating, and analyzing data should be considered in view of the volume of data that will be generated as part of a piping test- point program. Computer programs are particularly useful for the following:

a. Storing the actual thickness readings.
b. Calculating short- and long-term corrosion rates, retirement dates, MAWP, and reinspection intervals on a test-point by test-point basis.
c. Highlighting areas of high corrosion rates, circuits overdue for inspection, circuits close to retirement thickness, and other information.

Algorithms for the analysis of data from entire circuits also may be included in the program. Care should be taken to ensure that the statistical treatment of circuit data results in predictions that accurately reflect the actual condition of the piping circuit.

8 Repairs, Alterations, And Rerating Of Piping Systems

8.1 Repairs and Alterations

The principles of ASME B31.3 or the code to which the piping system was built shall be followed.

8.1.1 Authorization

All repair and alteration work must be done by a repair organization as defined in Section 3 and must be authorized by the inspector prior to its commencement. Authorization for alteration work to a piping system may not be given without prior consultation with, and approval by, the piping engineer. The inspector will designate any inspection hold points required during the repair or alteration sequence. The inspector may give prior general authorization for limited or routine repairs and procedures, provided the inspector is satisfied with the competency of the repair organization.

8.1.2 Approval

All proposed methods of design, execution, materials, welding procedures, examination, and testing must be approved by the inspector or by the piping engineer, as appropriate. Owner/user approval of on-stream welding is required.

Welding repairs of cracks that occurred in-service should not be attempted without prior consultation with the piping engineer in order to identify and correct the cause of the cracking. Examples are cracks suspected of being caused by vibration, thermal cycling, thermal expansion problems, and environmental cracking.

The inspector shall approve all repair and alteration work at designated hold points and after the repairs and alterations have been satisfactorily completed in accordance with the requirements of API 570.

8.1.3 Welding Repairs (Including On-Stream)

8.1.3.1 Temporary Repairs

For temporary repairs, including on-stream, a full encirclement welded split sleeve or box-type enclosure designed by the piping engineer may be applied over the damaged or corroded area. Longitudinal cracks shall not be repaired in this manner unless the piping engineer has determined that cracks would not be expected to propagate from under the sleeve. In some cases, the piping engineer will need to consult with a fracture analyst.

If the repair area is localized (for example, pitting or pinholes) and the specified minimum yield strength (SMYS) of the pipe is not more than 40,000 psig (275,800 kPa), a temporary repair may be made by fillet welding a properly designed split coupling or plate patch over the pitted area. (See 8.2.3 for design considerations and Appendix C for an example.) The material for the repair shall match the base metal unless approved by the piping engineer.

For minor leaks, properly designed enclosures may be welded over the leak while the piping system is in-service, provided the inspector is satisfied that adequate thickness remains in the vicinity of the weld and the piping component can withstand welding without the likelihood of further material damage, such as from caustic service.

Temporary repairs should be removed and replaced with a suitable permanent repair at the next available maintenance opportunity. Temporary repairs may remain in place for a longer period of time only if approved and documented by the piping engineer.

8.1.3.2 Permanent Repairs

Repairs to defects found in piping components may be made by preparing a welding groove that completely removes the defect and then filling the groove with weld metal deposited in accordance with 8.2.

Corroded areas may be restored with weld metal deposited in accordance with 8.2. Surface irregularities and contamination shall be removed before welding. Appropriate NDE methods shall be applied after completion of the weld.

If it is feasible to take the piping system out of service, the defective area may be removed by cutting out a cylindrical section and replacing it with a piping component that meets the applicable code.

Insert patches (flush patches) may be used to repair damaged or corroded areas if the following requirements are met:

a. Full-penetration groove welds are provided.
b. For Class 1 and Class 2 piping systems, the welds shall be 100 percent radiographed or ultrasonically tested using NDE procedures that are approved by the inspector.
c. Patches may be any shape but shall have rounded corners [1 inch (25 mm) minimum radius].

8.1.4 Nonwelding Repairs (On-Stream)

Temporary repairs of locally thinned sections or circumferential linear defects may be made on-stream by installing a properly designed and fabricated bolted leak clamp. The design shall include control of axial thrust loads if the piping component being clamped is (or may become) insufficient to control pressure thrust. The effect of clamping (crushing) forces on the component also shall be considered.

During turnarounds or other appropriate opportunities, temporary leak sealing and leak dissipating devices, including valves, shall be removed and appropriate actions taken to restore the original integrity of the piping system. The inspector and/or piping engineer shall be involved in determining repair methods and procedures.

Procedures that include leak sealing fluids (“pumping”) for process piping should be reviewed for acceptance by the inspector or piping engineer. The review should take into consideration the compatibility of the sealant with the leaking material; the pumping pressure on the clamp (especially when repumping); the risk of sealant affecting downstream flow meters, relief valves, or machinery; the risk of subsequent leakage at bolt threads causing corrosion or stress corrosion cracking of bolts; and the number of times the seal area is repumped.

8.2 Welding and Hot Tapping

All repair and alteration welding shall be done in accordance with the principles of ASME B31.3 or the code to which the piping system was built.

Any welding conducted on piping components in operation must be done in accordance with API Publ 2201. The inspector shall use as a minimum the "Suggested Hot Tap Checklist" contained in API Publication 2201 for hot tapping performed on piping components.

8.2.1 Procedures, Qualifications, and Records

The repair organization shall use welders and welding procedures qualified in accordance with ASME B31.3 or the code to which the piping was built.

The repair organization shall maintain records of welding procedures and welder performance qualifications. These records shall be available to the inspector prior to the start of welding.

8.2.2 Preheating and Postweld Heat Treatment

8.2.2.1 Preheating

Preheat temperature used in making welding repairs shall be in accordance with the applicable code and qualified welding procedure. Exceptions for temporary repairs must be approved by the piping engineer.

Preheating to not less than 300¡F (150¡C) may be considered as an alternative to postweld heat treatment (PWHT) for alterations or repairs of piping systems initially postweld heat treated as a code requirement (see note). This applies to piping constructed of the P-1 steels listed in ASME B31.3. P-3 steels, with the exception of Mn-Mo steels, also may receive the 300¡F (150¡C) minimum preheat alternative when the piping system operating temperature is high enough to provide reasonable toughness and when there is no identifiable hazard associated with pressure testing, shutdown, and startup. The inspector should determine that the minimum preheat temperature is measured and maintained. After welding, the joint should immediately be covered with insulation to slow the cooling rate.

Note: Preheating may not be considered as an alternative to environmental cracking prevention.

Piping systems constructed of other steels initially requiring PWHT normally are postweld heat treated if alterations or repairs involving pressure retaining welding are performed. The use of the preheat alternative requires consultation with the piping engineer who should consider the potential for environmental cracking and whether the welding procedure will provide adequate toughness. Examples of situations where this alternative could be considered include seal welds, weld metal buildup of thin areas, and welding support clips.

8.2.2.2 Postweld Heat Treatment

PWHT of piping system repairs or alterations should be made using the applicable requirements of ASME B31.3 or the code to which the piping was built. See 8.2.2.1 for an alternative preheat procedure for some PWHT requirements. Exceptions for temporary repairs must be approved by the piping engineer.

Local PWHT may be substituted for 360-degree banding on local repairs on all materials, provided the following precautions and requirements are applied:

a. The application is reviewed, and a procedure is developed by the piping engineer.
b. In evaluating the suitability of a procedure, consideration shall be given to applicable factors, such as base metal thickness, thermal gradients, material properties, changes resulting from PWHT, the need for full-penetration welds, and surface and volumetric examinations after PWHT. Additionally, the overall and local strains and distortions resulting from the heating of a local restrained area of the piping wall shall be considered in developing and evaluating PWHT procedures.

c. A preheat of 300¡F (150¡C), or higher as specified by specific welding procedures, is maintained while welding.
d. The required PWHT temperature shall be maintained for a distance of not less than two times the base metal thickness measured from the weld. The PWHT temperature shall be monitored by a suitable number of thermocouples (a minimum of two) based on the size and shape of the area being heat treated.
e. Controlled heat also shall be applied to any branch connection or other attachment within the PWHT area.
f. The PWHT is performed for code compliance and not for environmental cracking resistance.

8.2.3 Design

Butt joints shall be full-penetration groove welds.

Piping components shall be replaced when repair is likely to be inadequate. New connections and replacements shall be designed and fabricated according to the principles of the applicable code. The design of temporary enclosures and repairs shall be approved by the piping engineer.

New connections may be installed on piping systems provided the design, location, and method of attachment conform to the principles of the applicable code.

Fillet-welded patches require special design considerations, especially relating to weld-joint efficiency and crevice corrosion. Fillet-welded patches shall be designed by the piping engineer. A patch may be applied to the external surfaces of piping, provided it is in accordance with 8.1.3 and meets either of the following requirements:

a. The proposed patch provides design strength equivalent to a reinforced opening designed according to the applicable code.
b. The proposed patch is designed to absorb the membrane strain of the part in a manner that is in accordance with the principles of the applicable code, if the following criteria are met:
    1. The allowable membrane stress is not exceeded in the piping part or the patch.
    2. The strain in the patch does not result in fillet weld stresses exceeding allowable stresses for such welds.
    3. An overlay patch shall have rounded corners (see Appendix C).

8.2.4 Materials

The materials used in making repairs or alterations shall be of known weldable quality, shall conform to the applicable code, and shall be compatible with the original material. For material verification requirements, see 5.8.

8.2.5 Nondestructive Examination

Acceptance of a welded repair or alteration shall include NDE in accordance with the applicable code and the owner/user's specification, unless otherwise specified in API 570.

8.2.6 Pressure Testing

After welding is completed, a pressure test in accordance with 5.7 shall be performed if practical and deemed necessary by the inspector. Pressure tests are normally required after alterations and major repairs. When a pressure test is not necessary or practical, NDE shall be utilized in lieu of a pressure test. Substituting special procedures for a pressure test after an alteration or repair may be done only after consultation with the inspector and the piping engineer.

When it is not practical to perform a pressure test of a final closure weld that joins a new or replacement section of piping to an existing system, all of the following requirements shall be satisfied:

a. The new or replacement piping is pressure tested.
b. The closure weld is a full-penetration butt-weld between a weld neck flange and standard piping component or straight sections of pipe of equal diameter and thickness, axially aligned (not miter cut), and of equivalent materials. Acceptable alternatives are: (1) slip-on flanges for design cases up to Class 150 and 500¡F, (260¡C) and (2) socket welded flanges or socket welded unions for sizes NPS 2 or less and design cases up to Class 150 and 500¡F (260¡C). A spacer designed for socket welding or some other means shall be used to establish a minimum 1/16 inch (1.6 mm) gap. Socket welds shall be per ASME B31.3 and shall be a minimum of two passes.
c. Any final closure butt-weld shall be of 100-percent radiographic quality; or angle-beam ultrasonics flaw detection may be used, provided the appropriate acceptance criteria have been established.

d. MT or PT shall be performed on the root pass and the completed weld for butt-welds and on the completed weld for fillet-welds.

8.3 Rerating

Rerating piping systems by changing the temperature rating or the MAWP may be done only after all of the following requirements have been met:

a. Calculations are performed by the piping engineer or the inspector.
b. All reratings shall be established in accordance with the requirements of the code to which the piping system was built or by computation using the appropriate methods in the latest edition of the applicable code.
c. Current inspection records verify that the piping system is satisfactory for the proposed service conditions and that the appropriate corrosion allowance is provided.
d. Rerated piping systems shall be leak tested in accordance with the code to which the piping system was built or the latest edition of the applicable code for the new service conditions, unless documented records indicate a previous leak test was performed at greater than or equal to the test pressure for the new condition. An increase in the rating temperature that does not affect allowable tensile stress does not require a leak test.
e. The piping system is checked to affirm that the required pressure relieving devices are present, are set at the appropriate pressure, and have the appropriate capacity at set pressure.
f. The piping system rerating is acceptable to the inspector or piping engineer.
g. All piping components in the system (such as valves, flanges, bolts, gaskets, packing, and expansion joints) are adequate for the new combination of pressure and temperature.
h. Piping flexibility is adequate for design temperature changes.
i. Appropriate engineering records are updated.
j. A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code.

9 Inspection of Buried Piping

Inspection of buried process piping (not regulated by the Department of Transportation) is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions. Since the inspection is hindered by the inaccessibility of the affected areas of the piping, the inspection of buried piping is treated in a separate section of API 570. Important, nonmandatory references for underground piping inspection are the following NACE documents: RP0169, RP0274, and RP0275; and Section 11 of API RP 651.

9.1 Types and Methods of Inspection

9.1.1 Above-Grade Visual Surveillance

Indications of leaks in buried piping may include a change in the surface contour of the ground, discoloration of the soil, softening of paving asphalt, pool formation, bubbling water puddles, or noticeable odor. Surveying the route of buried piping is one method of identifying problem areas.

9.1.2 Close-Interval Potential Survey

The close-interval potential survey performed at ground level over the buried pipe can be used to locate active corrosion points on the pipe's surface.

Corrosion cells can form on both bare and coated pipe where the bare steel contacts the soil. Since the potential at the area of corrosion will be measurably different from an adjacent area on the pipe, the location of the corrosion activity can be determined by this survey technique.

9.1.3 Pipe Coating Holiday Survey

The pipe coating holiday survey can be used to locate coating defects on buried coated pipes, and it can be used on newly constructed pipe systems to ensure that the coating is intact and holiday-free. More often it is used to evaluate coating serviceability for buried piping that has been in-service for an extended period of time.

From survey data, the coating effectiveness and rate of coating deterioration can be determined. This information is used both for predicting corrosion activity in a specific area and for forecasting replacement of the coating for corrosion control.

9.1.4 Soil Resistivity

Corrosion of bare or poorly coated piping is often caused by a mixture of different soils in contact with the pipe surface. The corrosiveness of the soils can be determined by a measurement of the soil resistivity. Lower levels of resistivity are relatively more corrosive than higher levels, especially in areas where the pipe is exposed to significant changes in soil resistivity.

Measurements of soil resistivity should be performed using the Wenner Four-Pin Method in accordance with ASTM G57. In cases of parallel pipes or in areas of intersecting pipelines, it may be necessary to use the Single-Pin Method to accurately measure the soil resistivity. For measuring resistivity of soil samples from auger holes or excavations, a soil box serves as a convenient means for obtaining accurate results.

The depth of the piping shall be considered in selecting the method to be used and the location of samples. The testing and evaluation of results should be performed by personnel trained and experienced in soil resistivity testing.

9.1.5 Cathodic Protection Monitoring

Cathodically protected buried piping should be monitored regularly to assure adequate levels of protection. Monitoring should include periodic measurement and analysis of pipe-to-soil potentials by personnel trained and experienced in cathodic protection system operation. More frequent monitoring of critical cathodic protection components, such as impressed current rectifiers, is required to ensure reliable system operation.

Refer to NACE RP0169 and Section 11 of API RP 651 for guidance applicable to inspecting and maintaining cathodic protection systems for buried piping.

9.1.6 Inspection Methods

Several inspection methods are available. Some methods can indicate the external or wall condition of the piping, whereas other methods indicate only the internal condition. Examples are as follows:

a. Intelligent pigging. This method involves the movement of a device (pig) through the piping either while it is in-service or after it has been removed from service. Several types of devices are available employing different methods of inspection. The line to be evaluated must be free from restrictions that would cause the device to stick within the line. Five diameter bends are usually required since standard 90-degree pipe ells may not pass a pig. The line must also have facilities for launching and recovering the pigs.
b. Video cameras. Television cameras are available that can be inserted into the piping. These cameras may provide visual inspection information on the internal condition of the line.
c. Excavation. In many cases, the only available inspection method that can be performed is unearthing the piping in order to visually inspect the external condition of the piping and to evaluate its thickness and internal condition using the methods discussed in 5.4.2. Care should be exercised in removing soil from above and around the piping to prevent damaging the line or line coating. The last few inches (mm) of soil should be removed manually to avoid this possibility. If the excavation is sufficiently deep, the sides of the trench should be properly shored to prevent their collapse, in accordance with OSHA regulations, where applicable. If the coating or wrapping is deteriorated or damaged, it should be removed in that area to inspect the condition of the underlying metal.

9.2 Frequency and Extent of Inspection

9.2.1 Above-Grade Visual Surveillance

The owner/user should, at approximately 6-month intervals survey the surface conditions on and adjacent to each pipeline path (see 9.1.1).

9.2.2 Pipe-to-Soil Potential Survey

A close-interval potential survey on a cathodically protected line may be used to verify that the buried piping has a protective potential throughout its length. For poorly coated pipes where cathodic protection potentials are inconsistent, the survey may be conducted at 5-year intervals for verification of continuous corrosion control.

For piping with no cathodic protection or in areas where leaks have occurred due to external corrosion, a pipe-to-soil potential survey may be conducted along the pipe route. The pipe should be excavated at sites where active corrosion cells have been located to determine the extent of corrosion damage. A continuous potential profile or a close-interval survey may be required to locate active corrosion cells.

9.2.3 Pipe Coating Holiday Survey

The frequency of pipe coating holiday surveys is usually based on indications that other forms of corrosion control are ineffective. For example, on a coated pipe where there is gradual loss of cathodic protection potentials or an external corrosion leak occurs at a coating defect, a pipe coating holiday survey may be used to evaluate the coating.

9.2.4 Soil Corrosivity

For piping buried in lengths greater than 100 feet (30 m) and not cathodically protected, evaluations of soil corrosivity should be performed at 5-year intervals. Soil resistivity measurements may be used for relative classification of the soil corrosivity (see 9.1.4). Additional factors that may warrant consideration are changes in soil chemistry and analyses of the polarization resistance of the soil and piping interface.

9.2.5 Cathodic Protection

If the piping is cathodically protected, the system should be monitored at intervals in accordance with Section 10 of NACE RP0169 or Section 11 of API RP 651.

9.2.6 External and Internal Inspection Intervals

If internal corrosion of buried piping is expected as a result of inspection on the above-grade portion of the line, inspection intervals and methods for the buried portion should be adjusted accordingly. The inspector should be aware of and consider the possibility of accelerated internal corrosion in deadlegs.

The external condition of buried piping that is not cathodically protected should be determined by either pigging, which can measure wall thickness, or by excavating according to the frequency given in Table 9-1. Significant external corrosion detected by pigging or by other means may require excavation and evaluation even if the piping is cathodically protected.

Piping inspected periodically by excavation shall be inspected in lengths of 6 feet-8 feet (2.0 m-2.5 m) at one or more locations judged to be most susceptible to corrosion. Excavated piping should be inspected full circumference for the type and extent of corrosion (pitting or general) and the condition of the coating.

If inspection reveals damaged coating or corroded piping, additional piping shall be excavated until the extent of the condition is identified. If the average wall thickness is at or below retirement thickness, it shall be repaired or replaced.

If the piping is contained inside a casing pipe, the condition of the casing should be inspected to determine if water and/or soil has entered the casing. The inspector should verify the following: (a) both ends of the casing extend beyond the ground line; (b) the ends of the casing are sealed if the casing is not self-draining; and, (c) the pressure-carrying pipe is properly coated and wrapped.

9.2.7 Leak Testing Intervals

An alternative or supplement to inspection is leak testing with liquid at a pressure at least 10 percent greater than maximum operating pressure at intervals one-half the length of those shown in Table 9-1 for piping not cathodically protected and at the same intervals as shown in Table 9-1 for cathodically protected piping. The leak test should be maintained for a period of 8 hours. Four hours after the initial pressurization of the piping system, the pressure should be noted and, if necessary, the line repressurized to original test pressure and isolated from the pressure source. If, during the remainder of the test period, the pressure decreases more than 5 percent, the piping should be visually inspected externally and/or inspected internally to find the leak and assess the extent of corrosion. Sonic measurements may be helpful in locating leaks during leak testing.

Buried piping also may be surveyed for integrity by using temperature-corrected volumetric or pressure test methods. Other alternative leak test methods involve acoustic emission examination and the addition of a tracer fluid to the pressurized line (such as helium or sulfur hexafloride). If the tracer is added to the service fluid, the owner/user shall confirm suitability for process and product.

Table 9-1-Frequency of Inspection for Buried Piping Without Effective Cathodic Protection

Soil Resistivity (ohm-cm)	Inspection Interval (years)
< 2,000	5
2,000 to 10,000	10
• 10,000	15

9.3 Repairs to Buried Piping Systems

9.3.1 Repairs to Coatings

Any coating removed for inspection shall be renewed and inspected appropriately.

For coating repairs, the inspector should be assured that the coating meets the following criteria:

a. It has sufficient adhesion to the pipe to prevent underfilm migration of moisture.
b. It is sufficiently ductile to resist cracking.
c. It is free of voids and gaps in the coating (holidays).
d. It has sufficient strength to resist damage due to handling and soil stress.
e. It can support any supplemental cathodic protection.

In addition, coating repairs may be tested using a high- voltage holiday detector. The detector voltage shall be adjusted to the appropriate value for the coating material and thickness. Any holidays found shall be repaired and retested.

9.3.2 Clamp Repairs

If piping leaks are clamped and reburied, the location of the clamp shall be logged in the inspection record and may be surface marked. Both the marker and the record shall note the date of installation and the location of the clamp. All clamps shall be considered temporary. The piping should be permanently repaired at the first opportunity.

9.3.3 Welded Repairs

Welded repairs shall be made in accordance in 8.2.

9.4 Records

Record systems for buried piping should be maintained in accordance with 7.6. In addition, a record of the location and date of installation of temporary clamps shall be maintained

APPENDIX A-INSPECTOR CERTIFICATION

A.1 Examination

A written examination to certify inspectors within the scope of API 570, Piping Inspection Code, Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems, shall be administered by API or a third party designated by the API. The examination shall be based on the current API Body of Knowledge as published by API.

A.2 Certification

A.2.1 An API 570 authorized piping inspector certificate will be issued when an applicant has successfully passed the API certification exam and satisfies the criteria for experience and education. His/her education and experience, when combined, shall be equal to at least one of the following:

a. A Bachelor of Science degree in engineering or technology, plus one year of experience in supervision of inspection activities or performance of inspection activities as described in API 570.

b. A two year degree or certificate in engineering or technology, plus two years of experience in the design, construction, repair, inspection, or operation of piping systems, of which on year must be in supervision of inspection activities or performance of inspection activities as described in API 570.

c. A high school diploma or equivalent, plus three years of experience in the design, construction, repair, inspection, or operation of piping systems, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 570.

d. A minimum of five years of experience in the design, construction, repair, inspection, or operation of piping systems, of which on year must be in supervision of inspection activities or performance of inspection activities as described in API 570.

A.2.2 An API authorized piping inspector certificate is valid for three years from its date of issuance.

A.2.3 An API inspector certification will be valid in all jurisdictions and any other location that accepts or otherwise does not prohibit the use of API 570.

A.3 Certification Agency

The American Petroleum Institute shall be the certifying agency.

A.4 Retroactivity

The certification requirements of API 570 shall not be retroactive or interpreted as applying before twelve months after the date of publication of this edition or addendum to API 570. The recertification requirements of API 570 A.5.2 shall not be retroactive or interpreted as applying before 3 years after the date of publication of this edition or addendum to API 570.

A.5 Recertification

A.5.1 Recertification is required three years from the date of issuance of the API 570 authorized piping inspector certificate. Recertification by written test will be required for authorized piping inspectors who have not been actively engaged as authorized piping inspectors within the previous three years and for authorized piping inspectors who have not previously passed the exam. Exams will be in accordance with all provisions contained in API 570.

A.5.2 "Actively engaged as an authorized piping inspector" shall be defined as a minimum of 20% of time spent performing inspection activities or supervision inspection activities as described in the API 570 over the most recent three year certification period.

APPENDIX B-TECHNICAL INQUIRIES

B.1 Introduction

API will consider written requests for interpretations of API 570. API staff will make such interpretations in writing after consultation, if necessary, with the appropriate committee officers and the committee membership. The API committee responsible for maintaining API 570 meets regularly to consider written requests for interpretations and revisions, and to develop new criteria as dictated by technological development. The committee's activities in this regard are limited strictly to interpretations of the latest edition of API 570 or to the consideration of revisions to API 570 based on the new data or technology.

As a matter of policy, API does not approve, certify, rate, or endorse any item, construction, proprietary device, or activity; and accordingly, inquiries requiring such consideration will be returned. Moreover, API does not act as a consultant on specific engineering problems or on the general understanding or application of the rules. If, based on the inquiry information submitted, it is the opinion of the committee that the inquirer should seek engineering or technical assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

All inquiries that do not provide the information needed for full understanding will be returned.

B.2 Inquiry Format

Inquiries shall be limited strictly to requests for interpretation of the latest edition of API 570 or to the consideration of revisions to API 570 based on new data or technology. Inquiries shall be submitted in the following format:

a. Scope-The inquiry shall involve a single subject or closely related subjects. An inquiry letter concerning unrelated subjects will be returned.
b. Background-The inquiry letter shall state the purpose of the inquiry, which shall be either to obtain an interpretation of API 570 or to propose consideration of a revision to API 570. The letter shall provide concisely the information needed for complete understanding of the inquiry (with sketches, as necessary) and include references to the applicable edition, revision, paragraphs, figures, and tables.
c. Inquiry-The inquiry shall be stated in a condensed and precise question format, omitting superfluous background information and, where appropriate, composed in such a way that "yes" or "no" (perhaps with provisos) would be a suitable reply. This inquiry statement should be technically and editorially correct. The inquirer shall state what he or she believes API 570 requires. If in the opinion of the inquirer a revision to API 570 is needed, the inquirer shall provide recommended wording.

Submit the inquiry in typewritten form; however, legibly handwritten inquiries will be considered. Include the name and the mailing address of the inquirer. Submit the proposal to the following address: Downstream Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

APPENDIX C-EXAMPLES OF REPAIRS

C.1 Repairs

Manual welding utilizing the gas metal-arc or shielded metal-arc processes may be used.

When the temperature is below 50¡F (10¡C), low-hydrogen electrodes, AWS E-XX16 or E-XX18, shall be used when welding materials conforming to ASTM A-53, Grades A and B; A-106, Grades A and B; A-333; A-334; API 5L; and other similar material. These electrodes should also be used on lower grades of material when the temperature of the material is below 32¡F (0¡C). The piping engineer should be consulted for cases involving different materials.

When AWS E-XX16 or E-XX18 electrodes are used on weld numbers 2 and 3 (see Figure C-1 below), the beads shall be deposited by starting at the bottom of the assembly and welding upward. The diameter of these electrodes should not exceed 5/32 inch (4.0 mm). Electrodes larger that 5/32 inch (4.0 mm) may be used on weld number 1 (see Figure C-1), but the diameter should not exceed 3/16 inch (4.8 mm).

The longitudinal welds (number 1, Figure C-1) on the reinforcing sleeve shall be fitted with a suitable tape or mild steel backing strip (see note) to avoid fusing the weld to the side wall of the pipe.

Note: If the original pipe along weld number 1 has been checked thoroughly by ultrasonic methods and it is of sufficient thickness for welding, a backing strip is not necessary.

All repair and welding procedures for on-stream lines must conform to API Publ 2201.

C.2 Small Repair Patches

The diameter of electrodes should not exceed 5/32 inch (4.0 mm). When the temperature of the base material is below 32¡F (0¡C), low-hydrogen electrodes shall be used. Weaving of weld beads deposited with low-hydrogen electrodes should be avoided.

All repair and welding procedures for on-stream lines must conform to API Publication 2201.

Examples of small repair patches are shown below in Figure C-2.

Figure C-1-Encirclement Repair Sleeve

Figure C-2-Small Repair Patches

APPENDIX D-External Inspection CheckList for Process Piping
D.1 External Inspection Checklist for Process Piping
Publication Title #
Date Inspected
Item Inspected By Status
a. Leaks.
1. Process.
2. Steam Tracing.
3. Existing Clamps.
b. Misalignment.
1. Piping misalignment/restricted movement.
2. Expansion joint misalignment.
c. Vibration.
1. Excessive overhung weight.
2. Inadequate support.
3. Thin, small-bore, or alloy piping.
4. Threaded connections.
5. Loose supports causing metal wear.
d. Supports.
1. Shoes off support.
2. Hanger distortion or breakage.
3. Bottomed-out springs.
4. Brace distortion/breakage.
5. Loose brackets.
6. Slide plates/rollers.
7. Counter balance condition.
8. Support corrosion.
e. Corrosion.
1. Bolting support points under clamps.
2. Coating/Painting deterioration.
3. Soil-to-air interface.
4. Insulation interfaces.
5. Biological growth.
f. Insulation.
1. Damage/penetrations.
2. Missing jacketing/insulation.

3. Sealing deterioration.
4. Bulging.
5. Banding (broken/missing).