Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems

API 570
FIFTH EDITION, FEBRUARY 2024

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed. The use of API publications is voluntary. In some cases, third parties or authorities having jurisdiction may choose to incorporate API standards by reference and may mandate compliance.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to ensure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Classified areas may vary depending on the location, conditions, equipment, and substances involved in any given situation. Users of this Standard should consult with the appropriate authorities having jurisdiction.

Users of this standard should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

API is not undertaking to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations to comply with authorities having jurisdiction.

Information concerning safety and health risks and proper precautions with respect to materials and conditions should be obtained from the employer, the manufacturer or supplier of that material, or the material safety data sheet.

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The verbal forms used to express the provisions in this document are as follows.

Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the standard.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the standard.

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

Can: As used in a standard, “can” denotes a statement of possibility or capability.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, Suite 1100, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, Suite 1100, Washington, DC 20001.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, Suite 1100, Washington, DC 20001, standards@api.org.

Contents

Figures

Tables

Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems

1 Scope

1.1 General Application

1.1.1 Coverage

API 570 covers inspection, rating, repair, and alteration procedures for metallic piping systems and their associated pressure-relieving devices (PRDs) that have been placed in-service. This inspection code applies to all hydrocarbon and chemical process piping covered in 1.2.1 that have been placed in-service unless specifically designated as optional per 1.2.2. This publication does not cover inspection of specialty equipment including impulse tubing, sensory tubing or tubing associated with instrumentation, exchanger tubes, and control valves. However, this piping code could be used by owner-operators in other industries and other services at their discretion.

Process piping systems that have been decommissioned from service and abandoned in place are no longer covered by this in-service inspection code. However, abandoned in place piping may still need some amount of inspection and/or risk mitigation to ensure that it does not become a safety hazard due to continued deterioration. Process piping systems that are temporarily out of service or idled but have been mothballed (preserved for potential future use) are still covered by this code.

1.1.2 Intent

The intent of this code is to specify the in-service inspection and condition-monitoring program, as well as repair guidance that is needed to determine and maintain the ongoing integrity of piping systems. That program should provide reasonably accurate and timely assessments to determine if any changes in the condition of piping could possibly compromise continued safe operation. It is also the intent of this code that owner-operators shall respond to any inspection results that require corrective actions to ensure that the continued integrity of piping is consistent with appropriate risk analysis. API 570 is intended for use by organizations that maintain or have access to an authorized inspection agency, a repair organization, and piping engineers, inspectors, and examiners, all as defined in Section 3.

This code does not cover source inspection of newly fabricated pressure piping. Refer to API 588 for guidance on the surveillance of supplier vendors fabricating and/or repairing pressure piping that will be installed on-site. Owner-operators may engage the services of individuals qualified and certified in accordance with API 588 or this code.

However, inspections after new piping systems arrive on-site may still be needed at owner-operator option depending upon quality of shop inspection services and owner-operator specifications during fabrication.

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. If the requirements of this code are more stringent than the regulatory requirements, then the requirements of this code shall govern.

1.2 Special Applications

1.2.1 Included Fluid Services

Except as provided in 1.2.2, API 570 applies to piping systems for process fluids that are hazardous to personnel, such as hydrocarbons, and similar flammable or toxic fluid services and processes.

The following are processes, services, and product state that are applicable:

a) catalyst lines;

b) hydrogen, natural gas, fuel gas, and flare systems;

c) sour water and hazardous waste streams;

d) hazardous fluid services;

e) cryogenic fluids, such as liquid N_2, H_2, O_2, and air;

f) gaseous He, H_2, O_2, and N_2 at pressures greater than 150 psig.

1.2.2 Optional Piping Systems and Fluid Services

The fluid services and classes of piping systems listed below are optional when applying requirements of API 570:

a) hazardous fluid services below designated threshold limits, as defined by jurisdictional regulations;

b) water (including fire protection systems), steam, steam-condensate, boiler feed water, and Category D fluid services as defined in ASME B31.3;

c) other classes of piping that are exempted from the applicable process piping code.

1.3 Fitness-For-Service and Risk-based Inspection

This inspection code recognizes Fitness-For-Service concepts for evaluating in-service damage of pressure-containing piping components. API 579-1/ASME FFS-1 provides detailed Fitness-For-Service assessment procedures for specific types of damage that are referenced in this code.

This inspection code also recognizes risk-based inspection (RBI) concepts for determining inspection intervals or due dates and strategies. API 580 provides the basic minimum and recommended elements for developing, implementing, and maintaining an RBI program for fixed equipment, including piping. API 581 provides a set of methodologies for assessing risk (both probability of failure and consequence of failure) and for developing inspection plans.

2 Normative References

The following documents are referred to in the text in such a way that some or all their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document, including any addenda, applies.

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 574, *Inspection Practices for Piping System Components*

API Recommended Practice 576, *Inspection of Pressure-relieving Devices*

API Recommended Practice 577, *Welding Processes, Inspection, and Metallurgy*

API Recommended Practice 578, *Material Verification Program for New and Existing Assets*

API Standard 579-1/ASME FFS-1 [1], *Fitness-For-Service*

API Recommended Practice 580, *Elements of a Risk-based Inspection Program*

API Recommended Practice 583, *Corrosion Under Insulation and Fireproofing*

API Recommended Practice 584, *Integrity Operating Windows*

API Recommended Practice 585, *Pressure Equipment Integrity Incident Investigation*

API Standard 598, *Valve Inspection and Testing*

API Recommended Practice 751, *Safe Operation of Hydrofluoric Acid Alkylation Units*

API Recommended Practice 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*

API Recommended Practice 2201, *Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries*

ASME B16.34, *Valves—Flanged, Threaded, and Welding End*

ASME B31.3, *Process Piping*

ASME *Boiler and Pressure Vessel Code, Section V: Nondestructive Examination*

ASME *Boiler and Pressure Vessel Code, Section IX: Welding, Brazing, and Fusing Qualifications*

ASME PCC-1, *Guidelines for Pressure Boundary Bolted Flange Joint Assembly*

ASME PCC-2, *Repair of Pressure Equipment and Piping*

ASNT CP-189 [2], *Standard for Qualification and Certification of Nondestructive Testing Personnel*

ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing*

NACE SP0472 [3], *Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments*

NACE MR0103, *Petroleum, Petrochemical and Natural Gas Industries—Metallic Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

NFPA 704 [4], *Standard System for the Identification of the Hazards of Materials for Emergency Response*

---

[1] American Society of Mechanical Engineers, Two Park Avenue, New York, New York 10016, www.asme.org.

[2] American Society for Nondestructive Testing, 1201 Dublin Road, Suite #G04, Columbus, Ohio 43215, www.asnt.org.

[3] NACE International (now Association for Materials Protection and Performance), 15835 Park Ten Place, Houston, Texas 77084, www.ampp.org.

[4] National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169, www.nfpa.org.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

NOTE Definitions for terms delineated with asterisks are maintained by API 570. If another document plans to reference, see API Bulletin 590 for reference.

3.1.1
abandoned-in-place
Piping system, circuit, or contiguous sections thereof meeting all the following: has been decommissioned with no intention for future use; has been completely deinventoried/purged of hydrocarbon/chemicals; and is physically disconnected (i.e. air-gapped) from all energy sources and/or other piping/equipment but remains in place.

3.1.2
alloy material*
Any metallic material (including welding filler materials) that contains alloying elements, such as chromium, nickel, or molybdenum, which are intentionally added to enhance mechanical or physical properties and/or corrosion resistance.

NOTE 1 Alloys may be ferrous or nonferrous based.

NOTE 2 Carbon steels are not considered alloys for purposes of this code.

3.1.3
alteration
A physical change in any component that has design implications that affect the pressure-containing capability of a piping system beyond the scope described in existing data reports.

NOTE The following are not considered alterations: comparable or duplicate replacements, replacements in-kind, and the addition of small-bore attachments that do not require reinforcement or additional support.

3.1.4
applicable construction code
The code, code section, or other recognized and generally accepted engineering standard or practice to which the piping system was built, or deemed by the owner-operator or the engineer to be most appropriate for the situation.

3.1.5
authorization
Approval/agreement to perform a specific activity (e.g. repair) prior to the activity being performed.

3.1.6
authorized inspection agency
Defined as any of the following:

— the inspection organization of the jurisdiction in which the piping system is used;

— the inspection organization of an insurance company licensed or registered to write insurance for piping systems;

— the inspection organization of an owner-operator of piping systems who maintains an inspection organization for their equipment only and not for piping systems intended for sale or resale;

— an independent inspection organization or individual under contract to and under the direction of an owner-operator and recognized or otherwise not prohibited by the jurisdiction in which the piping system is used; the owner-operator's inspection program shall provide the controls necessary when contract inspectors are used.

3.1.7
authorized piping inspector*
An employee of an owner-operator organization or authorized inspection agency (see 3.1.6) who is qualified and certified by examination under the provisions of Section 4 and Annex A and can perform the functions specified in API 570 where contracted or directed to do so.

3.1.8
auxiliary piping*
Instrument and machinery piping, typically small-bore secondary process piping that can be isolated from primary piping systems but is normally not isolated.

NOTE Examples include flush lines, seal oil lines, analyzer lines, balance lines, buffer gas lines, drains, and vents.

3.1.9
condition monitoring location
CML
A designated area on piping systems where periodic examinations are conducted to directly assess and monitor the condition of the piping system using a variety of examination methods and techniques based on damage mechanism susceptibility.

NOTE 1 CMLs may contain one or more examination points and can be a single small area on a piping system [e.g. a 2 in. (50 mm) diameter spot] or plane through a section of a pipe where examination points exist in all four quadrants of the plane).

NOTE 2 CMLs now include, but are not limited to, what was previously called TML.

3.1.10
construction code
The code or standard to which the piping system was originally built (e.g. ASME B31.3).

3.1.11
contact point*
The locations at which a pipe or component rests on or against a support or other object that may increase its susceptibility to external corrosion, fretting, wear, or deformation especially because of moisture and/or solids collecting at the interface of the pipe and supporting member.

3.1.12
corrosion allowance
Additional material thickness available to allow for metal loss during the service life of the pipe component.

NOTE Corrosion allowance is not used in design strength calculations.

3.1.13
corrosion rate
The rate of metal loss due to erosion, erosion/corrosion, and/or the chemical reaction(s) with the environment, either internal and/or external.

3.1.14
corrosion specialist
A person acceptable to the owner-operator who is knowledgeable and experienced in the specific process chemistries, damage mechanisms, materials selection, corrosion mitigation methods, corrosion monitoring techniques, and their impact on piping systems.

3.1.15
corrosion under fireproofing
CUF
Corrosion of piping, pressure vessels, and structural components resulting from water trapped under fireproofing.

3.1.16
corrosion under insulation
CUI
External corrosion of piping, pressure vessels, and structural components resulting from water trapped under insulation.

NOTE External chloride stress corrosion cracking (ECSCC) of austenitic and duplex stainless steel under insulation is also classified as CUI damage.

3.1.17
critical check valves*
Check valves that need to operate reliably to avoid the potential for hazardous events or substantial consequences should reverse flow occur.

3.1.18
cyclic service
Refers to service conditions that may result in cyclic loading and produce fatigue damage or failure (e.g. cyclic loading from pressure, thermal, and/or mechanical loads).

NOTE 1 Other cyclic loads associated with vibration may arise from sources such as impact, turbulent flow vortices, resonance in compressors, and wind, or any combination thereof.

NOTE 2 API 579-1/ASME FFS-1—Section I.A.15 has a definition of cyclic service. A screening procedure to determine if a component is in cyclic service is provided in Part 14. A definition of “severe cyclic conditions” is in ASME B31.3—Section 300.2, Definitions.

3.1.19
damage mechanism
Any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of equipment.

EXAMPLE Corrosion, cracking, erosion, dents, and other mechanical, physical, or chemical impacts (see API 571 for a comprehensive list and description of damage mechanisms).

3.1.20
damage rate*
The rate of deterioration other than corrosion (i.e. rate of cracking, rate of HTHA, and creep rate).

3.1.21*
deadleg
Components of a piping system that normally have little or no significant flow.

3.1.22
decommissioned
Termination of pressure piping from its service; pressure piping at this stage of its life cycle is permanently removed from service and either removed from the process unit or abandoned-in-place.

3.1.23
defect
A discontinuity or discontinuities that by nature or accumulated effect render a part or product unable to meet minimum applicable acceptance standards or specifications (e.g. total crack length); the term designates rejectability.

3.1.24
deferral
An approved and documented postponement of an inspection, test, or examination (see 7.13 and 7.14).

3.1.25
design pressure*
The pressure at the most severe condition of coincident internal or external pressure and temperature

(minimum or maximum) expected during service.

NOTE It is the same as the design pressure 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.

3.1.26
design temperature
The temperature used for the design of the piping system per the applicable construction code.

NOTE 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 can have different design temperatures. In establishing this temperature, consideration should be given to process fluid temperatures, ambient temperatures, heating/cooling media temperatures, and insulation.

3.1.27
due date
The date established by the owner-operator and in accordance with this code, whereby an inspection, test, examination, or inspection recommendation falls due or is to be completed.

NOTE The date may be established by rule-based inspection methodologies (e.g. fixed intervals, retirement half-life interval, retirement date), risk-based methodologies (e.g. RBI target date), Fitness-For-Service analysis results, owner-operator inspection agency practices/procedures/guidelines, or any combination thereof.

3.1.28
examination point
recording point
measurement point
test point
A more specific location within a CML. CMLs may contain multiple examination points; for example, a piping component may be a CML and have multiple examination points (e.g. an examination point in all four quadrants of the CML of the piping component).

NOTE The term “test point” is no longer in use as “test” in this code refers to mechanical or physical tests, e.g. tensile tests or pressure tests.

3.1.29
examinations
A process by which an examiner or inspector investigates a component of the piping system using nondestructive examination (NDE) in accordance with approved NDE procedures (e.g. inspection of a CML and quality control of repair areas).

NOTE Examinations would be typically those actions conducted by NDE personnel, welding, or coating inspectors but may also be conducted by authorized piping inspectors.

3.1.30
examiner
A person who assists the inspector by performing specific NDE on piping system components and evaluates to the applicable acceptance criteria 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-operator.

3.1.31
external inspection
A visual inspection performed from the outside of a piping system to find conditions that could impact the piping systems’ ability to maintain pressure integrity or conditions that compromise the integrity of the supporting structures (e.g. stanchions, pipe supports, shoes, and hangers). The external inspection may be done while the piping is out of service and can be conducted at the same time as on on-stream inspection.

NOTE External inspections are also intended to find conditions that compromise the integrity of the coating and insulation covering and attachments (e.g. instrument and small branch connections).

3.1.32
Fitness-For-Service evaluation
An engineering methodology whereby flaws and other deterioration/damage contained within piping systems are assessed to determine the structural integrity of the piping for continued service (see API 579-1/ ASME FFS-1).

3.1.33
fitting*
A piping component usually associated with a branch connection, a change in direction, or change in piping diameter.

NOTE Flanges are not considered fittings.

3.1.34
flammable materials*
As used in this code, includes all fluids that will support combustion.

NOTE 1 Refer to NFPA 704 for guidance on classifying fluids in 6.3.4.

NOTE 2 Some regulatory documents include separate definitions of flammables and combustibles based on their flash point. In this document, flammable is used to describe both, and the flash point, boiling point, autoignition temperature, or other properties are used in addition to better describe the hazard.

3.1.35
flash point*
The lowest temperature at which a flammable product emits enough vapor to form an ignitable mixture in air.

NOTE 1 For example, gasoline's flash point is about −45 °F (−43 °C), diesel's flash point varies from about 125 °F to 200 °F (52 °C to 93 °C).

NOTE 2 An ignition source is required to cause ignition above the flash point, but below the autoignition temperature.

3.1.36
flaw*
An imperfection in a piping system detected by NDE that may or may not be a defect depending upon the applied acceptance criteria.

3.1.37
general corrosion
Corrosion distributed approximately uniform over the surface of the metal.

3.1.38
hold point
A point in the repair or alteration process beyond which work may not proceed until the required inspection or NDE has been performed.

3.1.39
idle
Piping system, circuit, or contiguous sections that are not currently operating but remain connected to pressure vessels, electrical, or instrumentation (may be blinded or blocked in).

3.1.40
imperfection
Flaws or other discontinuities noted during inspection or examination that may or may not exceed the applicable acceptance criteria.

3.1.41
indication
A response or evidence resulting from the application of NDE that may be nonrelevant, flawed, or defective upon further analysis.

3.1.42
industry-qualified ultrasonic angle beam examiner
A person who possesses an ultrasonic angle beam qualification from API (e.g. API QUTE/QUSE Detection and Sizing Tests) or an equivalent qualification approved by the owner-operator.

NOTE Rules for equivalency are defined in API 587.

3.1.43
injection point*
Injection points are locations where water, steam, chemicals, or process additives are introduced into a process stream at relatively low flow/volume rates as compared to the flow/volume rate of the parent stream.

NOTE 1 Corrosion inhibitors, neutralizers, process antifoulants, de-salter demulsifiers, oxygen scavengers, caustic, and water washes are most often recognized as requiring special attention in designing the point of injection. Process additives, chemicals, and water are injected into process streams to achieve specific process objectives.

NOTE 2 Injection points do not include locations where two process streams join (see 3.1.64, “mixing points”).

EXAMPLE Chlorinating agents in reformers, water injection in overhead systems, polysulfide injection in catalytic cracking wet gas, antifoam injections, inhibitors, and neutralizers.

3.1.44
in-service
The life-cycle stage of a piping system that begins after initial installation (where typically initial commissioning or placing into active service follows) and ends at decommissioning.

NOTE 1 Piping systems that are idle in an operating site and piping systems that are not currently in operation because of a process outage are still considered in-service piping systems.

NOTE 2 Does not include piping systems that are still under construction or in transport to the site prior to being placed in service or piping systems that have been retired.

NOTE 3 Installed spare piping is also considered in service, whereas spare piping that is not installed is not considered in service.

3.1.45
in-service inspection
All inspection activities associated with in-service piping systems (after installation, but before it is decommissioned).

3.1.46
inspection
The external, internal, or on-stream evaluation (or any combination of the three) of the condition of a piping system conducted by the authorized inspector or the designee in accordance with this code.

3.1.47
inspection code
Shortened title for this code (API 570).

3.1.48
inspection plan
A strategy defining how and when a piece of pressure equipment and associated components will be inspected, examined, repaired, and/or maintained.

3.1.49
inspector
A shortened title for an authorized piping inspector qualified and certified in accordance with this code.

3.1.50
integrity operating window
IOW
Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined length of time (includes critical, standard, and informational IOWs).

3.1.51
intermittent service*
The condition of a piping system whereby it is not in continuous operating service (i.e. it operates at regular or irregular intervals rather than continuously).

NOTE Occasional turnarounds or other infrequent maintenance outages in an otherwise continuous process service does not constitute intermittent service.

3.1.52
internal inspection
An inspection performed from the inside of a piping system using visual and/or NDE techniques.

3.1.53
jurisdiction
A legally constituted governmental administration that may adopt rules relating to process piping systems.

3.1.54
level bridle*
The piping assembly associated with a level gauge attached to a vessel.

3.1.55
lining*
A nonmetallic or metallic material, installed on the interior of pipe, whose properties are better suited to resist damage from the process than the substrate material.

3.1.56
localized corrosion
Corrosion that is typically confined to a limited or isolated area(s) of the metal surface of a piping system.

3.1.57
lockout/tagout*
LOTO
A safety procedure used to ensure that piping is properly isolated and cannot be energized or put back in-service prior to the completion of inspection, maintenance, or servicing work.

3.1.58
major repair
Any work not considered an alteration that removes and replaces a major part of the pressure boundary. If any of the restorative work results in a change to the design temperature, minimum allowable temperature (MAT), or maximum allowable working pressure (MAWP), the work shall be considered an alteration and the requirements for rerating shall be satisfied.

EXAMPLE Removal and replacement of large sections of piping systems.

3.1.59
management of change
MOC
A documented management system for review and approval of changes (both physical and process) to

piping systems prior to implementation of the change.

NOTE The MOC process includes involvement of inspection personnel that may need to alter inspection plans because of the change.

3.1.60
material verification program*
A documented quality assurance procedure used to assess alloy materials (including weldments and attachments where specified) to verify conformance with the selected or specified alloy material designated by the owner-operator.

NOTE This program may include a description of methods for alloy material testing, physical component marking, and program recordkeeping (see API 578).

3.1.61
maximum allowable working pressure
MAWP
The maximum gauge pressure permitted for the piping system in its operating position for a designated temperature. This pressure is based on calculations using the minimum (or average pitted) thickness for all critical piping elements (exclusive of thickness designated for corrosion) and adjusted for applicable static head pressure ad nonpressure loads (e.g. wind and seismic). The MAWP may refer to either the original design or a rerated MAWP obtained through a Fitness-For-Service assessment.

NOTE MAWP 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.

3.1.62
minimum alert thickness*
flag thickness
A thickness greater than the required thickness that provides for early warning from which the future service life of the piping is managed through further inspection and remaining life assessment.

3.1.63
minimum design metal temperature/minimum allowable temperature
MDMT/MAT
The lowest permissible metal temperature for a given material at a specified thickness based on its resistance to brittle fracture.

NOTE In the case of MAT, it may be a single temperature, or an envelope of allowable operating temperatures as a function of pressure. It is generally the minimum temperature at which a significant load can be applied to a piping system as defined in the applicable construction code. It might be also obtained through a Fitness-For-Service evaluation.

3.1.64
minimum required thickness*
required thickness
t_{min}
The minimum thickness without corrosion allowance for each component of a piping system based on the appropriate design code calculations and code allowable stress that consider internal and external pressure, temperature, mechanical and structural loadings, including the effects of static head.

NOTE Minimum required thicknesses may also be reassessed using Fitness-For-Service analysis in accordance with API 579-1/ASME FFS-1.

3.1.65
mixing point*
Mixing points are locations in a process piping system where two or more streams meet.

NOTE The difference in streams may be composition, temperature, or any other parameter that may cause deterioration and may require additional design considerations, operating limits, inspection, and/or process monitoring.

3.1.66
non-conformance*
An aspect of quality of an item that is not in accordance with the requirements of this code and/or any other specified codes, standards, or other requirements.

NOTE A non-conformance does not necessarily mean that the item is defective or that the item is not suitable for continued service.

3.1.67
non-pressure boundary
Components and attachments of, or the portion of piping that does not contain the process pressure.

EXAMPLE Clips, shoes, repads, supports, wear plates, nonstiffening insulation support rings, etc.

3.1.68
off-site piping*
Piping systems not included within the plot boundary limits of a process unit, such as a hydrocracker, an ethylene cracker, or a crude unit.

EXAMPLE Tank farm piping and interconnecting piperack piping outside the limits of the process unit.

3.1.69
on-site piping*
Piping systems included within the plot limits of process units, such as a hydrocracker, an ethylene cracker, or a crude unit.

3.1.70
on-stream inspection
An inspection performed from the outside of piping systems while they are in-service using NDE procedures to establish the suitability of the pressure boundary for continued operation (see 5.5.3).

3.1.71
overdue inspection
Inspections for in-service piping that remain in operation and have not been performed by the due date documented in the inspection plan and have not been deferred by a documented deferral process (see 7.13).

3.1.72
overwater piping*
Piping located where leakage would result in discharge into streams, rivers, bays, etc., resulting in a potential environmental incident.

3.1.73
owner-operator
An owner or operator of piping systems who exercises control over the operation, engineering, inspection, repair, alteration, maintenance, pressure testing, and rerating of those piping systems.

3.1.74
pipe*
A pressure-tight cylinder used to convey, distribute, mix, separate, discharge, meter, control, or snub fluid flows,

or to transmit a fluid pressure and that is ordinarily designated "pipe" in applicable material specifications.

NOTE 1 Materials designated as "tube" or "tubing" in the specifications are treated as pipe in this code when intended for pressure service external to fired heaters.

NOTE 2 See API 530 for piping internal to fired heaters.

3.1.75
piperack piping*
Process piping supported by consecutive stanchions or sleepers (including straddle racks and extensions).

3.1.76
pipe spool*
A section of piping with a flange or other connecting fitting, such as a union, on both ends that allows the removal of the section from the system.

3.1.77
piping circuit*
A subsection of piping systems that includes piping and components that are exposed to a process environment of similar corrosivity and expected damage mechanisms and is of similar design conditions and construction material whereby the expected type and rate of damage can reasonably be expected to be the same.

NOTE 1 Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, data analysis, and recordkeeping.

NOTE 2 When establishing the boundary of a particular piping circuit, it may be sized to provide a practical package for recordkeeping and performing field inspection.

3.1.78
piping engineer*
One or more persons or organizations acceptable to the owner-operator 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.

NOTE The piping engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly address piping design requirements.

3.1.79
piping system*
An assembly of interconnected pipes that typically are subject to the same (or nearly the same) process fluid composition or operating conditions, or both.

NOTE Piping systems also include pipe-supporting elements (e.g. springs, hangers, guides, etc.) but do not include support structures, such as structural frames, vertical and horizontal structural members, and foundations.

3.1.80
pitting*
Localized corrosion of a metal surface in a small area that takes the form of cavities called pits, which can be highly localized as a single pit or widespread within a specific area on a metal surface.

NOTE Pitting can be highly localized (including a single pit) or widespread on a metal surface.

3.1.81
positive material identification
PMI
A physical evaluation or test of a material performed to confirm that the material, which has been or will be placed into service, is consistent with what is specified by the owner-operator.

NOTE These evaluations or tests can provide qualitative or quantitative information that is sufficient to verify the nominal alloy composition (see API 578).

3.1.82
postweld heat treatment
PWHT
Treatment that consists of heating an entire weldment or section of fabricated piping to a specified elevated temperature after completion of welding in order to relieve the effects of welding heat, such as to reduce residual stresses, reduce hardness, stabilize chemistry, and/or slightly modify properties.

NOTE See ASME B31.3, paragraph 331.

3.1.83
pressure boundary
The portion of the piping that contains the pressure-retaining piping elements joined or assembled into pressure tight fluid-containing piping systems.

NOTE 1 Pressure boundary components include pipe, tubing, fittings, flanges, gaskets, bolting, valves, and other devices, such as expansion joints and flexible joints.

NOTE 2 Also see non-pressure boundary definition.

3.1.84
pressure design thickness*
Minimum allowed pipe wall thickness needed to hold the design pressure at the design temperature.

NOTE 1 Pressure design thickness is determined using the rating code formula, including needed reinforcement thickness.

NOTE 2 Pressure design thickness does not include thickness for structural loads, corrosion allowance, or mill tolerances and therefore should not be used as the sole determinant of structural integrity for typical process piping (see 7.6).

3.1.85
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.

NOTE Primary process piping typically does not include small-bore or auxiliary process piping (see also 3.1.96, "secondary process piping").

3.1.86
procedure
A document that specifies or describes how an activity is to be performed. A procedure may include methods to be employed, equipment or materials to be used, qualifications of personnel involved, and sequence of work.

3.1.87
process piping*
Hydrocarbon or chemical piping located at or associated with a refinery or manufacturing facility.

NOTE Process piping includes piperack, tank farm, and process unit piping but excludes utility piping (e.g. steam, water, air, nitrogen, etc.).

3.1.88
quality assurance
All planned, systematic, and preventative actions specified to determine if materials, equipment, or services will meet specified requirements so that the piping will perform satisfactorily in-service.

NOTE 1 Quality assurance plans will specify the necessary quality control activities and examinations.

NOTE 2 The contents of a quality assurance inspection management system for piping systems are outlined in 4.3.1.

3.1.89
quality control
Those physical activities that are conducted to check conformance with specifications in accordance with the quality assurance plan.

3.1.90
rating*
The work process of making calculations to establish pressures and temperatures appropriate for a piping system, including design pressure/temperature, MAWP, structural minimums, required thicknesses, etc.

3.1.91
renewal*
Activity that discards an existing component, fitting, or portion of a piping circuit and replaces it with new or existing spare materials of the same or better qualities as the original piping components.

3.1.92
repair
The work necessary to restore a piping system to a condition suitable for safe operation at the design conditions.

NOTE 1 Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair.

NOTE 2 Repairs can be temporary or permanent (see Section 8).

3.1.93
repair organization
An organization that is qualified to make the repair by meeting the criteria of 4.3.2 of API 570.

3.1.94
rerating
A change in either the design temperature rating, design pressure rating, or the MAWP of a piping system.

NOTE 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.

3.1.95
risk-based inspection
RBI
A risk assessment and management process that considers both the probability of failure and the consequence of failure due to material deterioration. See 5.2.

3.1.96
scanning nondestructive examination
Examination methods designed to find the thinnest spot or all flaws in a specified area of pressure piping, such as profile radiography (RT) of nozzles, scanning ultrasonic testing (UT) techniques, and/or other suitable NDE techniques that will reveal the scope and extent of localized corrosion or other deterioration.

3.1.97
secondary process piping*
Process piping located downstream of a block valve that can be valved off without significantly affecting the process unit operability.

NOTE Often, secondary process piping is small-bore piping (SBP).

3.1.98
small-bore piping*
SBP
Pipe or pipe components that are less than or equal to nominal pipe size (NPS) 2.

3.1.99
soil-to-air interface*
SAI
An area in which external corrosion may occur or be accelerated on partially buried pipe or buried pipe near where it egresses from the soil.

NOTE 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 at least 12 in. (305 mm) below to 6 in. (150 mm) above the soil surface. Pipe running parallel with the soil surface that contacts the soil is included.

3.1.100
structural minimum thickness*
Minimum required thickness without corrosion allowance based on the mechanical loads other than pressure that result in longitudinal stress (see 7.6).

NOTE The thickness is either determined from a standard chart or engineering calculations. It does not include thickness for corrosion allowance or mill tolerances.

3.1.101
tank farm piping*
Process piping inside tank farm dikes or directly associated with a tank farm.

3.1.102
temporary repair
Repairs made to piping systems to restore sufficient integrity to continue safe operation until permanent repairs are conducted.

NOTE Injection fittings on valves to seal fugitive [leak detection and repair (LDAR)] emissions from valve stem seal are not considered to be “temporary repairs” as described in 8.1.4.1 and 8.1.5 in this code.

3.1.103
testing
Within this document, testing generally refers to either pressure testing, whether performed hydrostatically, pneumatically, or a combination hydrostatic/pneumatic, or mechanical testing to determine data such as material hardness, strength, and notch toughness.

NOTE Testing does not refer to NDE using techniques such as liquid penetrant (PT), magnetic particle (MT), etc.

3.1.104
utility piping*
Non-process piping associated with a process unit (e.g. steam, air, water, nitrogen).

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

BPVC *Boiler and Pressure Vessel Code*

CCV critical check valve

CML condition monitoring location

CPD continuing professional development

CUF corrosion under fireproofing

CUI corrosion under insulation

EMAT electromagnetic acoustic transducer

ECSCC external chloride stress corrosion cracking

HF hydrofluoric

NOTE Generally referred to as HF acid.

ID inside diameter

IDMS Inspection Data Management System

IOW integrity operating window

ISO inspection isometric drawing

LDAR leak detection and repair (of fugitive emissions)

LT long term

MAT minimum allowable temperature

MAWP maximum allowable working pressure

MDMT minimum design metal temperature

MOC management of change

MT magnetic particle examination technique

NDE nondestructive examination

NPS nominal pipe size

NOTE The term is typically followed, when appropriate, by the specific size designation number without an inch unit.

EXAMPLE NPS 24 refers to a nominal pipe size of 24 in.

OD outside diameter

PEC pulsed eddy current

PMI positive material identification

PQR procedure qualification record

PRD pressure-relieving device

PT liquid penetrant examination technique

PWHT postweld heat treatment

RBI risk-based inspection

RT radiographic examination (method) or radiography

SAI soil-to-air interface

SBP small-bore piping

ST short term

SMYS specified minimum yield strength

TML thickness monitoring location

UT ultrasonic examination technique

WPS welding procedure specification

4 Owner-Operator Inspection Organization

4.1 General

An owner-operator of piping systems shall have a defined program for piping system inspections, 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-operator shall be responsible for the activities relating to the rating, repair, and alteration of its piping systems. See definition of "authorized inspection agency" in 3.1.6.

4.2 Authorized Piping Inspector Qualification and Certification

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

4.3 Responsibilities

4.3.1 Owner-Operator Organization

4.3.1.1 Systems and Procedures

An owner-operator 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/repair management system and shall include the following:

a) organization and reporting structure for inspection personnel;

b) documenting and maintaining inspection and quality control procedures;

c) documenting and reporting inspection and test results;

d) developing and documenting inspection plans;

e) developing and documenting risk-based assessments;

f) developing and documenting the appropriate inspection intervals;

g) corrective action for inspection and test results;

h) internal auditing for compliance with the quality assurance inspection manual;

i) review and approval of drawings, design calculations, and specifications for repairs, alterations, reratings, and Fitness-For-Service assessments;

j) ensuring that all jurisdictional requirements for piping inspection, repairs, alterations, and rerating are continuously met;

k) reporting to the authorized piping inspector any process changes that could affect piping integrity;

l) training requirements for inspection personnel regarding inspection tools, techniques, and technical knowledge base;

m) controls necessary so that only qualified welders and procedures are used for all repairs and alterations;

n) controls necessary so that only qualified NDE personnel and procedures are utilized;

o) controls necessary so that only materials conforming to the applicable construction code are utilized for repairs and alterations;

p) controls necessary so that all inspection measurement and test equipment are properly maintained and calibrated;

q) controls necessary so that the work of contract inspection or repair organizations meet the same inspection requirements as the owner-operator organization and this inspection code;

r) internal auditing requirements for the quality control system for PRDs;

s) requirements and work process to increase the confidence that inspectors have an annual vision test and are capable of reading standard J-1 letters on standard Jaeger test type charts for near vision;

t) controls necessary to prevent external covering or insulation of cold wall piping or headers that might cause overheating and rupture;

u) controls necessary to ensure that temporary facilities are managed and removed at the appropriate times.

4.3.1.2 Inspection Organization Audits

Each owner-operator organization shall be audited periodically to determine if they are meeting the requirements of an authorized inspection agency as defined in this inspection code. The audit team should consist of people experienced and competent in the application of this code. The audit team should typically be from another owner-operator plant site, company central office, or from a third-party organization experienced and competent in refining and/or petrochemical process plant inspection programs or a combination of third-party and other owner-operator sites.

The following key elements of an inspection program should be assessed by the audit team:

a) the requirements and principles of this inspection code are being met;

b) owner-operator responsibilities are being properly executed;

c) documented inspection plans are in place for covered piping systems;

d) intervals and extent of inspections are adequate for covered piping systems;

e) general types of inspections and surveillance are being adequately applied;

f) inspection data analysis, evaluation, and recording are adequate;

g) repairs, reratings, and alterations comply with this code.

The owner-operator shall receive a report of the audit team's scope and findings. After review of the report, non-conformances should be prioritized, and corrective actions implemented. Other suggestions for improvement are at the discretion of the owner-operator. Each organization should establish a system for tracking and completion of audit findings. This information should also be reviewed during subsequent audits.

4.3.1.3 MOC

The owner-operator is also responsible for implementing an effective MOC process that will review and control changes to the process and assets (e.g. piping and piping components). An effective MOC process is vital to the success of any piping integrity management program so the inspection group can:

a) address issues concerning the adequacy of the piping design and current condition of the proposed changes;

b) anticipate changes in corrosion or other types of damage and their effects on the adequacy on the pressure piping and update the inspection plan and records to account for those changes.

The MOC process shall include the appropriate materials/corrosion experience and expertise to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity. Changes to pipe components, supports, and the process shall be included in the MOC process to ensure its effectiveness.

4.3.1.4 IOWs

The owner-operator should implement and maintain an effective program for creating, establishing, and monitoring IOWs. IOWs are implemented to avoid process parameter exceedances that may have an unanticipated impact on pressure equipment integrity. Future inspection plans and intervals have historically been based on prior measured corrosion rates resulting from past operating conditions. Without an effective IOW and process control program, there often is no warning of changing operating conditions that could affect the integrity of equipment or validation of the current inspection plan. Deviations from and changes of trends within established IOW limits should be brought to the attention of inspection/engineering personnel so they may modify or create new inspection plans depending upon the seriousness of the exceedance.

IOWs should be established for process parameters (both physical and chemical) that could impact equipment integrity if not properly controlled. Examples of the process parameters include temperatures, pressures, fluid velocities, pH, flow rates, chemical or water injection rates, levels of corrosive constituents, chemical composition, etc. IOWs for key process parameters may have both upper and lower limits established, as needed. Particular attention to monitoring IOWs should also be provided during start-ups, shutdowns, and significant process upsets. See API 584 for more information on issues that may assist in the development of an IOW program.

4.3.1.5 Pressure Equipment Integrity Incident Investigations

The owner-operator should investigate pressure equipment integrity incidents and near-misses (near-leaks) to determine causes (root, contributing, and direct), which may result in updates to the associated inspection program, IOW, Corrosion Control Document, etc. If pressure equipment integrity incidents and near-misses are recognized and investigated, and the causes are identified, then future leaks and failures of pressure equipment can be minimized or prevented. API 585 covers pressure equipment integrity incident investigations and provides owner-operator with guidelines for developing, implementing, sustaining, and enhancing an investigation program for pressure equipment integrity incidents.

4.3.1.6 Corrosion Control Document

The owner-operator should assess piping systems, as identified in the owner-operator's piping inspection programs, for credible damage mechanisms. API 970 provides guidance to address this and may be used.

The Corrosion Control Documents or alternate document identifying all credible damage mechanisms should be available to all stakeholders (e.g. inspector, mechanical integrity engineering, and process engineers) who have a role in fixed equipment integrity.

4.3.2 Repair Organization

The repair organization is responsible to the owner-operator and shall provide the materials, equipment, quality control, and workmanship necessary to maintain and repair the piping or PRD in accordance with the requirements of this inspection code. The repair organization shall meet one of the following criteria:

a) the holder of a valid ASME Certificate of Authorization that authorizes the use of an appropriate ASME code symbol stamp;

b) the holder of another recognized code of construction certificate that authorizes the use of an appropriate construction code symbol stamp;

c) the holder of a valid R-stamp issued by the National Board for repair of pressure vessels;

d) the holder of a valid VR-stamp issued by the National Board for repair and servicing of relief valves;

e) an owner-operator of pressure piping and/or relief valves who repairs their own equipment in accordance with this code;

f) a repair contractor whose qualifications are acceptable to the pressure piping owner-operator;

g) an individual or organization authorized by the legal jurisdiction to repair pressure piping or service PRDs.

4.3.3 Personnel

4.3.3.1 Piping Engineer

The piping engineer is responsible to the owner-operator for activities involving design, engineering review, rating, analysis, or evaluation of piping systems and PRDs covered by API 570 as specified in this code.

4.3.3.2 Authorized Piping Inspector

When inspections, repairs, or alterations are being conducted on piping systems, the designated authorized piping inspector shall be responsible to the owner-operator for:

a) determining that the requirements of API 570 on inspection, examination, quality assurance, and testing are met;

b) being directly involved in the inspection activities, which in most cases will require field activities to ensure that procedures are followed;

c) extending the scope of the inspection (with appropriate consultation with engineers/specialists), where justified depending upon the findings of the inspection;

d) notifying the owner-operator in a timely manner and making appropriate repair or other mitigative recommendations, where non-conformances are discovered.

The inspector shall be knowledgeable with piping system damage mechanisms listed in API 571, as well as the content of API 574, API 576, API 577, API 578, API 583, API 584, API 585, and API 588, and be knowledgeable in API 580 where RBI is in use, where these are applicable or in use by the owner-operator. The inspector shall be able to use the guidance contained in these documents to meet the requirements and/or expectations in this code.

The 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 (e.g. examiners and operating personnel). Personnel performing NDE shall meet the qualifications identified in 4.3.3.3 but need not be authorized piping inspectors. However, all examination results shall be evaluated and accepted by the authorized piping inspector. See 3.1.7 for the definition of "authorized piping inspector."

4.3.3.3 Examiners

The examiner shall perform the specified NDE in accordance with job requirements. See 3.1.29 for the definition of "examiner."

The examiner is not required to be certified in accordance with Annex A and does not need to be an employee of the owner-operator. The examiner shall be trained and competent in the NDE procedures being used and hold industry or owner-operator certifications in those procedures. Examples of other certifications that may be required include ASNT SNT-TC-1A, ASNT CP-189, AWS CWI, API QUTE/QUSE, ASNT ISQ, and CGSB. Inspectors conducting their own examinations with NDE techniques shall also be appropriately qualified in accordance with owner-operator requirements and appropriate industry standards.

The examiner's employer shall maintain certification records of the examiners employed, including dates and results of personnel qualifications. These records shall be available to the inspector.

4.3.3.4 Inspection Supervisor

The owner-operator shall designate a role or position responsible for leading the mechanical integrity programs established under this code. The individual assigned to the role/position will ensure compliance and advise facility management on compliance with and non-conformance with any of the component activities required by this code. The job title may be variable and would be interchangeable with titles such as chief inspector and inspection authority.

4.3.3.5 Others

Operating, maintenance, engineering (process and mechanical), or other personnel who have special knowledge or expertise related to piping systems shall be responsible for timely notification to the inspector and/or engineer of issues that may affect piping integrity, such as the following:

a) any action that requires MOC or inspection activity because of an MOC;

b) operations outside defined IOWs;

c) changes in source of feedstock and other process fluids that could increase process-related corrosion rates or introduce new damage mechanisms;

d) piping failures, repair actions conducted, and failure analysis reports;

e) cleaning and decontamination methods used or other maintenance procedures that could affect piping and equipment integrity;

f) reports from other plants' experiences that have come to their attention regarding similar service piping and associated equipment failures;

g) any unusual conditions that may develop (e.g. noises, leaks, vibration, movement, insulation damage, external piping deterioration, support structure deterioration, and significant bolting corrosion);

h) any engineering evaluation, including Fitness-For-Service assessments, that might require current or future actions to maintain mechanical integrity until next inspection.

5 Inspection, Examination, and Pressure Testing Practices

5.1 Inspection Plans

5.1.1 Piping Systemization and Circuitization

To develop inspection plans (including scope, frequency, techniques, and location), facility piping should be broken down into piping systems and circuits. Piping systems (sometimes referred to as corrosion systems or loops) are a collection of piping circuits usually related to a common process intent/function and are typically defined at a process flow diagram level. Piping circuits are often defined at the process and instrumentation diagram (P&ID) level. Potential damage mechanisms are primarily a function of the process/operating conditions, the material of construction, and mechanical design. Defining systems and circuits based upon potential damage mechanisms is the first step in creating an effective inspection plan. Systemization is the first cut for defining the potential corrosion issues, and is a convenient reference to the general location of damage mechanisms within the process unit. Piping systems generally have common characteristics, such as one or more of the following:

a) process intent (e.g. overhead reflux system);

b) process control scheme (e.g. temperature/end point);

c) process stream composition;

d) design operating conditions;

e) similar or related set of IOWs.

Piping systems may contain (or pass through) one or more equipment items (e.g. exchangers and pumps) and will typically contain one or multiple piping circuits. Piping systems and circuits developed from expected/identified damage mechanisms enable the development of concise inspection plans and form the basis for improved data analysis. Piping circuitization is a further breakdown of piping systems into sections of piping and/or individual pipe components, which have common damage mechanisms and same material of construction and have similar damage rates and modes.

Refer to API 574 for more information on development of piping systems and circuits.

5.1.2 Development of an Inspection Plan

An inspection plan shall be established for all piping systems and/or circuits and associated PRDs within the scope of this code. The inspection plan shall be developed by the inspector and/or engineer.

A corrosion specialist shall be consulted to identify susceptibilities to credible damage mechanisms and potential locations. Some examples include the following:

a) localized corrosion;

b) cracking;

c) CUF;

d) metallurgical damage;

e) piping systems that operate at elevated temperatures [above 750 °F (400 °C)];

f) piping systems that operate below the ductile-to-brittle transition temperature.

Special attention in the inspection plan should be given to any types of deterioration or issues listed in 5.4.2.

The inspection plan is developed from the analysis of several sources of data, including the piping inspection records. Piping systems shall be evaluated based on present or possible types of damage mechanisms. The method and extent of the NDE technique shall be based off of the ability for it to detect the damage mechanism. Subdividing piping systems into circuits subject to common damage mechanisms facilitates the development of an inspection strategy and plan and selecting the inspection techniques best suited to find the damage that is most likely to occur in the piping circuit. Examinations shall be scheduled at intervals that consider the following:

a) damage mechanisms (see API 571);

b) rate of damage progression;

c) tolerance of the equipment to the type of damage;

d) capability of the NDE method to identify the damage;

e) maximum intervals as defined in codes and standards;

f) extent of examination;

g) recent operating history, including IOW exceedances;

h) MOC records that may impact inspection plans;

i) RBI assessments or piping classification.

The inspection plan should be developed using the most appropriate sources of information, including those references listed in Section 2. Inspection plans shall be reviewed and amended as needed when variables are identified that could impact damage mechanisms and/or deterioration rates (as defined by the owner-operator). See API 574 for more information on the development of inspection plans.

5.1.3 Contents of an Inspection Plan

The inspection plan shall contain the inspection tasks and schedule required to monitor identified damage mechanisms and ensure the mechanical integrity of the piping systems. The plan should:

a) define the type(s) of inspection needed (e.g. internal, external, on-stream, and nonintrusive);

b) identify the next inspection date for each inspection type;

c) describe the inspection methods and NDE techniques;

d) describe the extent and locations of inspection and NDE at CMLs;

e) describe the surface cleaning requirements needed for inspection and examinations for each type of inspection;

f) describe the requirements of any needed pressure test (e.g. type of test, test pressure, test temperature, and duration);

g) describe any required repairs if known or previously planned before the upcoming inspection;

h) describe the types of damage anticipated or experienced in the piping systems;

i) define the location of the expected damage;

j) define any special access and preparation needed.

Generic inspection plans based on industry standards and practices may be used as a starting point in developing specific equipment inspection plans. The inspection plan may or may not exist in a single document; however, the contents of the plan should be readily accessible from inspection data systems.

5.2 RBI

5.2.1 General

An RBI evaluation may be used to determine inspection intervals or due dates and the type and extent of future inspection/examinations. An RBI assessment determines risk by combining the probability and the consequence of piping system failure. When an owner-operator chooses to conduct an RBI assessment, it shall include the minimum program requirements as established by API 580. API 581 provides a set of semi-quantitative methodologies for assessing risk (both probability of failure and consequence of failure) and for developing inspection plans that are consistent with key elements defined in API 580.

Key steps evaluate both the probability and consequence of a failure. Identifying and evaluating credible damage mechanisms, current piping condition, and the effectiveness of the past inspections are important steps in assessing the probability of piping failure. Identifying and evaluating the process fluid(s), potential injuries, environmental damage, piping system damage, and piping system downtime are important steps in assessing the consequence of piping failure. Identifying and implementing IOWs for key process variables is an important adjunct to RBI (see 4.3.1.4), as well as any other method of planning and scheduling inspections.

5.2.2 Documentation

It is essential that all RBI assessments be thoroughly documented in accordance with the requirements in API 580 clearly defining all the factors contributing to both the probability and consequence of a failure of the equipment.

After an RBI assessment is conducted, the results can be used to establish the equipment inspection plan and better define the following:

a) the most appropriate inspection and NDE methods, tools, and techniques;

b) the extent of NDE (e.g. percentage of equipment to examine);

c) the interval or due date for internal (where applicable), external, and on-stream inspections;

d) the need for pressure testing after damage has occurred or after repairs/alterations have been completed;

e) the prevention or mitigation steps to reduce the probability or consequence of equipment failure when necessary to reduce risk to an acceptable level (e.g. repairs, process changes, and inhibitors).

5.2.3 Frequency of RBI Assessments

When RBI assessments are used to set equipment inspection intervals or due dates, the assessment shall be updated after each equipment inspection as defined in API 580. The RBI assessment shall be updated each time process or piping component/support changes are made that could significantly affect damage rates or damage mechanisms and anytime an unanticipated failure or inspection discovery occurs. The RBI assessment shall be reviewed, updated as necessary, and approved by the engineer and inspector at intervals not to exceed 10 years.

5.3 Preparation for Inspection

5.3.1 General

Safety precautions shall be included when preparing piping systems for inspection and maintenance activities to eliminate exposure to hazardous fluids, energy sources, and physical hazards. Regulations govern many aspects of piping systems inspection and shall be followed where applicable. See API 574 for more information on the safety aspects of piping inspection.

Procedures for segregating piping systems, installing blinds (blanks), and testing tightness should be an integral part of safety practices for flanged connections. Appropriate safety precautions shall be taken before any piping system is opened. 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. See API 574 for more information on the equipment preparation and entry aspects of piping inspection.

5.3.2 Records Review

Before performing any of the required inspections, inspectors shall familiarize themselves with prior history of the piping system for which they are responsible. They should review the piping system's prior inspection results, prior repairs, current inspection plan, and/or other similar service inspections. Additionally, it is advisable to ascertain recent operating history that may affect the inspection plan. The types of damage and failure modes experienced by piping systems are provided in API 571 and API 579-1/ASME FFS-1.

5.4 Inspection for Types and Locations of Damage Modes of Deterioration and Failure

5.4.1 Piping System Damage Types

The presence or potential of damage in piping systems is dependent upon its material of construction, design, construction, and operating conditions. The inspector should be familiar with these items and with the causes and characteristics of potential flaws and damage mechanisms associated with the equipment being inspected.

Information concerning common damage mechanisms (critical factors, appearance, and typical inspection and monitoring techniques) is found in API 571 and other sources of information on damage mechanisms included in the Bibliography. Additional recommended inspection practices for specific types of damage mechanisms are described in API 574. API 571 describes common damage mechanisms and inspection techniques to identify them.

5.4.2 Areas of Deterioration for Piping Systems

Each owner-operator shall provide specific attention to the need for inspection of piping systems that are susceptible to the following credible types and areas of deterioration:

a) injection points and mixing points;

b) deadlegs;

c) CUI, including ECSCC inspection;

d) soil-to-air interfaces (SAIs) and soil corrosion of buried piping;

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) freeze damage;

l) contact point corrosion.

NOTE For different reasons, brittle fracture and fatigue are not normally proactively managed or mitigated by inspection activities. The owner-operators should be aware of the potential for brittle fracture or fatigue and manage the risk appropriately (e.g. changing the mechanical design, or operation, adding process controls, etc.).

Refer to API 571 and API 574 for more detailed information about the above-noted types and areas of deterioration.

5.5 General Types of Inspection and Surveillance

5.5.1 General

Different types of inspection and surveillance are appropriate depending on the circumstances and the piping system. These include the following types of inspections and inspection focus areas that are covered in more detail in the following subsections:

a) Internal Visual Inspection;

b) On-stream Inspection;

c) Thickness Measurement Inspection and Various NDE Examinations;

d) External Visual Inspection;

e) Vibrating Piping and Line Movement Surveillance;

f) Supplemental Inspection.

Inspections shall be conducted in accordance with the inspection plan for each piping circuit or system. Refer to Section 6 for the interval/frequency and extent of inspection. Corrosion and other damage identified during inspections and examinations shall be characterized, sized, and evaluated per Section 7. Revisions to the inspection plan shall be approved by the inspector and/or piping engineer.

5.5.2 Internal Visual Inspection

Internal visual inspections are not normally performed on piping. When it is 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 such as those outlined in API 510 and API 572. Remote visual inspection techniques can be helpful when inspecting piping, which is 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. When piping flanges are disconnected, the gasket surface, studs, and nuts should be examined for any signs of deterioration. Removing a section of piping and splitting it along its centerline also permits access to internal surfaces where there is need for such inspection.

5.5.3 On-stream Inspection

The on-stream inspection may be required by the inspection plan. All on-stream inspections should be conducted by either an inspector or examiner. All on-stream inspection work performed by an examiner shall be authorized and approved by the inspector. When on-stream inspections of the pressure boundary are specified, they shall be designed to detect the damage mechanisms identified in the inspection plan.

The inspection may include several NDE techniques to check for various types of damage that pertain to the circuit as identified during inspection planning. Techniques used in on-stream inspections are chosen for their ability to identify specific damage mechanisms from the exterior and their capabilities to perform at the on-stream conditions of the piping system (e.g. metal temperatures). The external thickness measurement inspection described in 5.6.3 may be a part of an on-stream inspection.

There are inherent limitations when applying external NDE techniques trying to locate damage on the inside of piping components. Issues that can affect those limitations include the following:

a) type of material of construction (alloy);

b) weldments;

c) pipe junctions, nozzles, support saddles, and reinforcing plates;

d) internal lining or cladding;

e) physical access and equipment temperature;

f) limitations inherent to the selected NDE technique to detect the damage mechanism;

g) type of damage mechanism (e.g. pitting versus general wall thinning).

API 574 provides more information on piping system inspection and should be applied when performing on-stream inspections.

5.5.4 Thickness Measurement Inspection and Various NDE Examinations

Thickness measurements are obtained to verify the thickness of piping components. These data are used to calculate the corrosion rates and remaining life of the piping system. Thickness measurements shall be obtained by the inspector or the examiner at the direction of the inspector. The owner-operator shall ensure that all individuals conducting thickness measurements are trained and qualified in accordance with the applicable procedure used during the examination.

Typically, point thickness measurements are utilized to determine and track corrosion rates for damage mechanisms that produce uniform corrosion, whereas profile RT (if line size allows), UT scanning, or grids should be used where localized corrosion is expected/predicted.

Screening examination techniques [e.g. guided wave examination, electromagnetic acoustic transducer (EMAT), Lamb wave] are typically limited to the qualitative data results (i.e. volumetric percentage of wall loss, versus actual discrete thickness values). If used, screening examination techniques are considered to fulfill the requirements for thickness measurement inspection provided they are used complimentary to an inspection plan that also includes periodic quantitative examination techniques to establish actual baseline thickness data, or to prove up screening technique examination results conducted at appropriate intervals.

See API 574—Section 10.4, "Thickness Measurements," for additional guidance in conducting ultrasonic thickness measurements.

5.5.5 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 (see API 574). When corrosion product buildup or other debris is noted at pipe support contact areas, it may be necessary to lift the pipe off such supports for thorough inspection. When lifting piping that is in operation, extra care should be exercised and consultation with an engineer may be necessary. Based on the support type/configuration, screening techniques such as guided wave/EMAT or Lamb-wave inspections can be used to locate areas of interest for follow-up inspection using more quantitative NDE techniques. Users should understand the limitations of each of these techniques to minimize the potential for missing localized corrosion. External piping inspections may be made when the piping system is on-stream. Refer to API 574 for information concerning conducting external inspections. External piping inspections may include CUI inspections per 5.8.

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 shall be checked to confirm they have not filled with water 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.

Weep/drain holes should be installed at the lowest point of vertical and horizontal dummy legs and close to the process pipe weld for horizontal installations. Weep/drain holes should be always open and free of debris.

Several owner-operators have identified localized corrosion at the dummy leg to process pipe connection using profile RT. Corrosion was found in both open-ended and capped dummy legs.

Bellows expansion joints should be inspected visually for unusual deformations, misalignment, excessive angular rotation, and displacements that may exceed design. In some cases where two ply bellows have been utilized, the annular space between the inner and outer bellow should be pressure tested and/or monitored for leakage. Other nonstandard piping components (e.g. flex hoses) may have different degradation mechanisms (see API 574). Specialist engineers or manufacturer data sources may need to be consulted in developing valid inspection plans for these components. The inspector should examine the piping system for 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 that may be unsuitable for long-term (LT) operation, such as improper flanges, temporary repairs (clamps), modifications (flexible hoses), or valves of improper specification. Threaded components and other flanged spool pieces that may be easily removed and reinstalled deserve attention because of their higher potential for installation of incorrect construction materials.

The periodic external inspection called for in 6.4 should normally be conducted by the inspector. The inspector shall be responsible for recordkeeping and repair inspection. Qualified examiners and operating or maintenance personnel may also 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 acceptable to the owner-operator.

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 API 574 for examples of such deterioration).

During the external inspection, attention should be given to weldments of attachments (e.g. reinforcement plates and clips) looking for cracking, corrosion, or other flaws. Any signs of leakage should be investigated so that the sources can be established. Normally, weep holes in reinforcing plates (re-pads) should remain open to provide visual evidence of leakage. If weep holes are plugged to exclude moisture, they shall not be plugged with material capable of sustaining pressure behind the reinforcing plate unless Fitness-For-Service assessments and an approved MOC have demonstrated that the reinforcement plate can withstand the design pressure of the piping system.

5.5.6 Vibrating Piping and Line Movement Surveillance

Operating personnel should report vibrating or swaying piping to engineering or inspection personnel for assessment. Evidence of significant line movement that could have resulted from liquid hammer (e.g. piping shifted off pipe support’s normal/designed location), liquid slugging in vapor lines, abnormal thermal expansion, or from other sources, such as large reciprocating compressors, should be reported. At locations where vibrating piping systems are restrained to resist dynamic pipe stresses (such as at shoes, anchors, guides, struts, dampeners, and hangers), periodic MT or PT should be considered to check for the onset of fatigue cracking. Branch connections should receive special attention, particularly unbraced SBP connected to vibrating pipe. However, fatigue is generally considered to be a design-related mechanism.

Once a crack has been initiated, it can grow at unknown rates and inspection alone cannot be used to manage the risk of failure. Typically, at the point a fatigue crack is detectible, approximately 80 % of the life has been consumed and failure can occur prior to the next scheduled inspection cycle without careful engineering assessment/analysis.

5.5.7 Supplemental Inspection

Other inspections may be scheduled as appropriate or necessary. Examples of such inspections include periodic use of RT and/or thermography to check for fouling or internal plugging, thermography to check for hot spots in refractory lined systems, additional inspections after reported process unit upsets, verifying previously measured data for accuracy, inspection for environmental cracking, and any other piping-specific damage mechanism. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Areas susceptible to localized erosion or erosion-corrosion should be inspected using visual inspection internally if possible or by using other inspection approaches that provide visualization of the internal condition (i.e. RT or ultrasonic mapping). Scanning of the areas with UT is also a good technique and should be used if the line is larger than NPS 12.

5.6 CMLs

5.6.1 General

CMLs are specific areas along the piping circuit where inspections are conducted. The nature of the CML varies according to its location in the piping system. The allocation of CMLs shall be based on the potential for service-specific damage mechanisms (e.g. localized corrosion, as described in API 574 and API 571). The definitions of “condition monitoring location” (3.1.9) and “examination point” (3.1.27) are often a point of confusion at operating sites. A CML is usually an area (e.g. an elbow or other fitting) where multiple measurements may be conducted, whereas examination points are specific spots where individual readings are taken. Examples of different conditions to be monitored at CMLs include wall thickness, stress cracking, CUI, and high temperature hydrogen attack.

5.6.2 CML Allocation

In selecting, adjusting, or optimizing the number and locations of CMLs, the inspector should review the assigned credible damage mechanisms and the historical corrosion rate and patterns before making adjustments to the number and locations for CMLs (note that consultation from a corrosion specialist is advised). While low or no corrosion of assigned CMLs may be a consideration for elimination/archiving, in some cases, CMLs may have been selected to identify a problem from conditional or infrequent operation (e.g. CML at a spec break downstream from an exchanger bypass, or on a lower alloy warm-up line only used on start-up, etc.). A decision on the type, number, and location of the CMLs should consider results from previous inspections, the patterns of corrosion and damage that are expected and the potential consequence of loss of containment. CMLs should be distributed over the piping system to provide adequate monitoring coverage of all types of components and fittings. Thickness measurements at CMLs are intended to establish general and localized corrosion rates in different sections of the piping circuits.

CMLs may be eliminated, or the number reduced under certain circumstances when the expected damage mechanism will not result in a wall loss or other forms of deterioration, such as olefin plant cold side piping, anhydrous ammonia piping, clean noncorrosive hydrocarbon product, or high-alloy piping for product purity. In circumstances where CMLs will be substantially reduced or eliminated, a corrosion specialist should be consulted.

Several corrosive processes common to refining and petrochemical units are relatively uniform in nature, resulting in a constant rate of pipe wall reduction independent of location within the piping circuit, either axially or circumferentially. Examples of such corrosion phenomena include sulfidation corrosion (if it is a uniform liquid phase with no naphthenic acid or high/turbulent flow rates, and the piping circuit does not contain low silicon CS; see 5.12.2 and API 939-C) and hydrocarbon product lines. In these situations, the number of CMLs 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 CML. Corrosion is seldom truly uniform and in fact may be quite localized, so additional CMLs may be required. Where there is adequate historical thickness data for a circuit and data have been validated to ensure that they are representative for the expected corrosion environment, a statistical analysis may be useful to help determine the number of inspection points needed to establish the desired confidence in the calculated circuit average rate, limiting thickness, and/or remaining life.

More CMLs should be selected for corrosive 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;

f) higher corrosion rate (or thickness) variability;

g) higher short/long rate (or maximum/average) ratios;

h) higher degree of process variability (process parameters that will affect localized corrosion);

i) circuits with corrosion environments that have experienced unexpected failures in the facility or elsewhere in the industry.

Fewer CMLs 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 (by virtue of the piping alloy or service);

c) long, straight-run piping systems.

CMLs can be eliminated for piping systems with any of the following 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;

c) systems not subject to changes that could cause corrosion as demonstrated by history and/or periodic reviews.

Every CML should have at least one or more examination points identified. Examination points should be carefully identified to facilitate accurate examination during follow-up inspections. Examples include the following:

a) locations marked on uninsulated pipe using paint stencils, metal stencils, or stickers;

b) holes cut in the insulation and plugged with covers;

c) temporary insulation covers for fittings nozzles, etc.;

d) isometrics or documents showing CMLs;

e) radio frequency identification devices;

f) computerized monitoring buttons.

Careful identification of CMLs and examination points is necessary to enhance the accuracy and repeatability of the data.

Corrosion specialists should be consulted about the appropriate placement and number of CMLs for piping systems susceptible to localized corrosion or cracking, or in circumstances where CMLs will be substantially reduced or eliminated.

5.6.3 CML Monitoring

Piping circuits subject to higher corrosion rates or localized corrosion will normally be monitored more frequently. The minimum measured thickness at a CML can be located by ultrasonic scanning or profile RT. Electromagnetic techniques also can be used to identify thin areas that may then be measured by UT or RT. When accomplished with UT, scanning consists of taking several thickness measurements at the CML searching for localized thinning.

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. On large pipe (typically NPT 8 and larger), four quadrants may be insufficient and the number of CMLs needs to be increased or a grid scanning approach considered. The thinnest reading or an average of several measurement readings taken within the area of an examination point shall be recorded and used to calculate corrosion rates, remaining life, and the next inspection date in accordance with Section 7. When using a statistical approach for planning inspection, it is often desirable to record all readings taken on a CML. The rate of corrosion/damage shall be determined from successive measurements and the next inspection interval appropriately established. Corrosion rates, the remaining life, and next inspection intervals should be calculated to determine the limiting component of each piping circuit. For systemized/circuitized piping, the corrosion rates and remaining life may be determined statistically per 6.5.3.

CMLs should be established for areas with continuing CUI, corrosion at SAIs, immediately upstream and downstream of piping material changes (e.g. specification breaks), or other locations of potential localized corrosion, as well as for general, uniform corrosion.

CMLs should be marked on inspection or inspection isometric drawings (ISOs). The piping system may also be marked to allow repetitive measurements at the same locations. This recording procedure provides data for more accurate corrosion rate determination. The rate of corrosion/damage shall be determined from successive measurements and the next inspection interval appropriately established based on the remaining life or RBI analysis.

5.7 Condition Monitoring Methods

5.7.1 UT

ASME *BPVC*, Section V, Article 23, and Section SE-797 provide guidance for performing ultrasonic thickness measurements.

Ultrasonic thickness measurements taken on SBP may require specialized equipment (e.g. miniature transducers and/or curved shoes, as well as diameter-specific calibration blocks).

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. If the procedure does not compensate for 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. All 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) significant surface roughness;

d) transducer placement and orientation (e.g. curved surface placement, pitch/catch probe orientation);

e) subsurface material flaws, such as laminations;

f) temperature effects [at temperatures above 150 °F (65 °C)];

g) improper resolution on the detector screens;

h) thicknesses of less than $^1/_8$ in. (3.2 mm) for typical digital thickness gauges;

i) improper coupling of probe to the surface (too much or too little couplant);

j) piping diameter.

In addition, corrosion patterns 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 an examination point may be considered.

Following ultrasonic readings at CMLs, proper repair of insulation and insulation weather coating is recommended to reduce the potential for CUI (see API 583 for details on insulation repair).

5.7.2 RT

RT profile techniques are preferred for pipe diameters of NPS 1 and smaller. Profile RT is preferred for SBP where digital ultrasonic thickness gauging is not very reliable. Profile RT is very often the technique of choice on NPS 8 and under when localized corrosion is suspected.

RT profile techniques may be used for measuring thicknesses, particularly in insulated systems or where nonuniform or localized corrosion is suspected. However, the profile measurements may only be quantitative within error bounds along the tangent. The extent and magnitude of these error bounds may be equipment and technique specific so should be determined or documented as part of the inspection and/or NDE procedure.

Localized corrosion may vary around the pipe circumference and locating the thinnest location may require multiple profile orientation exposures or complimentary techniques (e.g. ultrasonic examination). Where practical, UT can then be used to obtain the actual thickness of the areas to be recorded.

RT profile techniques, which do not require removing insulation, are widely employed for detection and possible sizing of CUI.

See API 574 for additional information on thickness monitoring methods for piping. When corrosion in a piping system is nonuniform or the remaining thickness is approaching the required thickness, additional thickness measuring may be required. RT and ultrasonic scanning are the preferred methods in such cases.

5.7.3 Other Thickness Measurement Techniques

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, including lasers and structured white light scanners, also may be used to determine the depth of localized metal loss.

5.7.4 Other NDE Techniques for Piping Systems

In addition to thickness monitoring, other examination techniques may be appropriate to identify or monitor for other specific types of damage mechanisms. In selecting the technique(s) to use during piping inspection, the possible types of damage for each piping circuit should be taken into consideration. The inspector should consult with a corrosion specialist or an engineer to help define the type of damage, the NDE technique, and extent of examination. API 571 and API 577 also contain some general guidance on inspection techniques that are appropriate for different damage mechanisms. Examples of NDE techniques that may be of use include the following:

a) MT for cracks and other linear discontinuities that extend to the surface of the material in ferromagnetic materials; ASME *BPVC*, Section V, Article 7, provides guidance on performing MT;

b) PT for disclosing cracks, porosity, or pin holes that extend to the surface of the material and for outlining other surface imperfections, especially in nonmagnetic materials; ASME *BPVC*, Section V, Article 6, provides guidance on performing PT;

c) RT for detecting internal imperfections such as porosity, weld slag inclusions, cracks, and thickness of components; ASME *BPVC*, Section V, Article 2, provides guidance on performing RT;

d) Ultrasonic flaw detection for detecting internal and surface breaking cracks and other elongated discontinuities; ASME *BPVC*, Section V, Article 4, Article 5, and Article 23, provide guidance on performing UT;

e) alternating current flux leakage examination technique for detecting surface-breaking cracks and elongated discontinuities;

f) eddy current examination for detecting localized metal loss, cracks, and elongated discontinuities; ASME *BPVC*, Section V, Article 8, provides guidance on performing eddy current examination;

g) field metallographic replication for identifying metallurgical changes;

h) acoustic emission examination for detecting structurally significant flaws; ASME *BPVC*, Section V, Article 11 and Article 12, provide guidance on performing acoustic emission examination;

i) thermography for determining temperature of components, blockages, debris/sediment levels, and flow verification;

j) leak testing for detecting through-thickness defects; ASME *BPVC*, Section V, Article 10, provides guidance on performing leak testing;

k) guided wave examination for the detection of changes in cross-sectional area indicative of metal loss.

5.7.5 Surface Preparation for NDE

Adequate surface preparation is important for proper visual examination and for the satisfactory application of most examination methods, such as those mentioned above. The type of surface preparation required depends on the individual circumstances and NDE technique, but surface preparations, such as wire brushing, blasting, chipping, grinding, or a combination of these preparations, may be required.

Advice from NDE specialists may be needed to select and apply the proper surface preparation for each individual NDE technique.

5.7.6 UT Angle Beam Examiners

The owner-operator shall specify owner-operator–approved or industry-qualified UT angle beam examiners when the owner-operator requires the following:

a) detection of interior surface [inside diameter (ID)] breaking flaws when inspecting from the external surface [outside diameter (OD)]; or

b) detection, characterization, and/or through-wall sizing of flaws.

Application examples for the use of industry-qualified UT angle beam examiners include detecting and sizing planer flaws from the external surface and collecting data for Fitness-For-Service evaluations.

The API Individual Certification Programs are one example of an industry qualified program, and API 587 provides guidance to the development of ultrasonic examiner qualification programs.

5.8 CUI Inspection

Inspection for CUI shall be considered for externally insulated piping, including sections in intermittent service or operate at temperatures between:

a) 10 °F (−12 °C) and 350 °F (177 °C) for carbon and low-alloy steels;

b) 140 °F (60 °C) and 350 °F (177 °C) for austenitic stainless steels;

c) 280 °F (138 °C) and 350 °F (177 °C) for duplex stainless steels.

CUI inspections may be conducted as part of the external inspection. If CUI damage is found during spot checks, the inspector should inspect other susceptible areas on the piping. API 583 on CUI has much more detailed information on CUI and should be used in conjunction with piping CUI inspection programs.

Although external insulation may appear to be in good condition, CUI damage may still be occurring. Nonintrusive techniques, such as real-time RT, can help determine if any scale is present behind the insulation without removal. Other techniques, such as profile RT, pulsed eddy current (PEC), and guided wave examination can help locate damage. Removal of scale on live equipment and removal of insulation where leaks are suspected can pose a significant safety risk. CUI damage is often quite insidious in that it can occur in areas where it seems unlikely.

Considerations for insulation removal include, but are not limited to, the following:

a) history of CUI for the specific piping system or comparable piping systems;

b) visual condition of the external covering and insulation, rust stains, biological growth, bulged, dented or punctured weather jacketing;

c) evidence of fluid leakage (e.g. drips or vapors);

d) whether the systems are in intermittent service;

e) condition/age of the external coating, if known;

f) evidence of areas of wet insulation;

g) potential for the type of insulation to absorb/hold more water (e.g. open cell versus closed cell hydrophobic versus nonhydrophobic materials);

h) low points of sagging lines;

i) bottom of vertical pipe;

j) proximity to equipment that could increase local humidity (e.g. cooling towers);

k) area where temperature regimes are moving into and out of the CUI susceptible temperature range;

l) piping components (e.g. nipples, nozzle, supports, and deadlegs) that are part of the piping system but penetrate the insulation or can transition into the CUI range.

Replacement of all insulation and weather jacketing removed for the purpose of CUI inspection is critical and shall be performed in the shortest possible timeframe following removal. Material of the same type, thickness, and layering shall be installed. Care shall be taken to ensure proper watershed of all-weather jacket materials.

5.9 Mixing Point Inspection

Mixing points are locations in piping systems where two or more different streams meet. The difference in streams may be composition, temperature, or any other parameter that may contribute to deterioration, accelerated or localized corrosion, and/or thermal fatigue during normal or abnormal operating conditions.

Mixing points, identified by the owner-operator to have an increased susceptibility to damage, shall be reviewed to determine the rate of degradation from specific damage mechanisms as compared to the parent/contributing piping streams. Mixing points, identified as such, may be treated as separate inspection circuits, and these areas may need to be inspected differently, using special techniques, different scope, and at more frequent intervals when compared to the inspection plan for the parent/contributing piping stream(s). It should be recognized that after review, some mixing points may not require any special emphasis inspection techniques or intervals.

Given the wide variation of mixing point designs and operation parameters, it is beyond the scope of this code to provide specific inspection recommendations for mixing point circuits. It is anticipated that defining those inspection recommendations will require careful review in consideration of mix point design (configuration and metallurgy), stream flow regime, composition, and temperature differences, along with expected damage mechanism susceptibilities and rates of degradation. Refer to API 574 for additional information on process mixing points.

Like injection point circuits, the preferred methods of inspecting mixing points include RT and ultrasonics (straight beam and/or angle beam) to determine the minimum measured thickness and/or the presence of other susceptible damage mechanisms (e.g. thermal fatigue cracking and pitting) at each CML.

Changes to mixing points, including, but not limited to, changes in flow regime, stream composition or characteristics, or components of construction and their orientation, should be identified and reviewed to determine what, if any, changes to the inspection plan may be required as a result.

See NACE SP0114 for additional information.

5.10 Injection Point Inspection

Injection points can be subject to accelerated and/or localized damage from normal and abnormal operating conditions. Injection points, identified by the owner-operator to have an increased susceptibility to damage, shall be reviewed to determine the rate of degradation from specific damage mechanisms as compared to the parent piping streams. Injection points, identified as such, may be treated as separate inspection circuits (e.g. injection point circuits), and these areas may need to be inspected differently, using special techniques, different scope, and at more frequent intervals when compared to the inspection plan for the parent piping streams. It should be recognized that after review, some injection points may not require any special emphasis inspection techniques or intervals.

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 in. (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 ft (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 1.

The selection of CMLs within injection point circuits subject to localized corrosion should be in accordance with the following guidelines:

a) establish CMLs on appropriate fittings within the injection point circuit;

b) establish CMLs on the pipe wall at the location of expected pipe wall impingement of injected fluid;

c) establish CMLs at intermediate locations along the longer straight piping within the injection point circuit may be required;

d) establish CMLs at both the upstream and downstream limits of the injection point circuit.

The preferred methods of inspecting injection points are RT and/or UT scanning or closely spaced UT grid inspection, as appropriate, to establish the minimum measured thickness at each CML. Close grid ultrasonic measurements or scanning may be used, if 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 in. (300 mm) upstream of the injection nozzle and continuing for at least 10 pipe diameters downstream of the injection point. Additionally, measure and record the thickness at all CMLs within the injection point circuit. The potential for localized corrosion can occur at the junction where the injection point enters the primary pipe. The use of profile RT at the junction and UT manual scanning of the primary pipe (surrounding and downstream of the junction) is recommended.

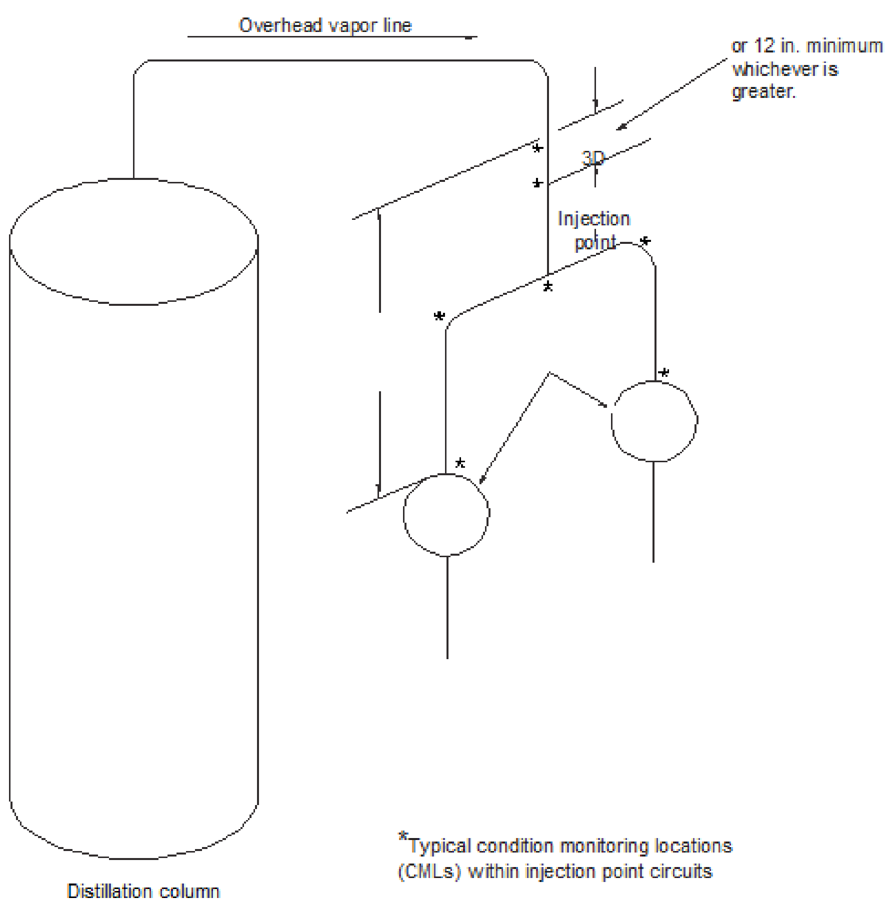

Figure 1—Typical Injection Point Piping Circuit

Hardware used to inject the fluid into the process stream is important for proper mixing of the streams. Most configurations use either an injection nozzle or quill that projects into the process stream. These injection nozzles (or quills) should be periodically inspected to ensure that they are still intact and are in the correct orientation (i.e. nozzle pointed upstream if that is the intended design). Use of RT for periodic inspections of the injection nozzle or quill is recommended for this purpose.

5.11 Pressure Testing of Piping Systems

5.11.1 General

Pressure tests are not normally conducted as part of a routine inspection (see 8.2.8 for pressure testing requirements for repairs, alterations, and rerating). Exceptions to this include requirements of the Coast Guard for over water piping and requirements of local jurisdictions, after welded alterations, buried piping, 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 for pressure testing are provided in API 574, API 579-1/ASME FFS-1, and ASME PCC-2, Article 501. Service tests and/or lower-pressure tests, which are used only for tightness of piping systems, may be conducted at pressures designated by the owner-operator.

Pressure tests are typically performed on an entire piping circuit. However, where practical, pressure tests of individual components/sections can be performed in lieu of entire circuit (e.g. a replacement section of piping). An engineer should be consulted when a pressure test of piping components/sections is to be performed, including use of isolation devices, to ensure that it is suitable for the intended purpose.

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

Before applying a hydrostatic test, the supporting structures and foundation design should be reviewed by an engineer to ensure that they are suitable for the hydrostatic load.

NOTE The owner-operator is cautioned to avoid exceeding 90 % of the specified minimum yield strength (SMYS) for the material at test temperature and especially for equipment used in elevated temperature service.

5.11.2 Test Fluid

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 (e.g. process incompatibility with water) 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 austenitic stainless steel should be hydrotested with a solution made up of potable water (see NOTE below), deionized/demineralized water, or steam condensate having a total chloride concentration (not free chlorine concentration) of less than 50 ppm.

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 where accelerated corrosion of the sensitized region may be an issue (see NACE SP0170).

If a pressure test is to be maintained for a given time and the test fluid in the system is subject to thermal expansion, precautions shall be taken to avoid pressure buildup beyond that specified.

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.

5.11.3 Pneumatic Pressure Tests

A pneumatic (or hydropneumatic) 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. See ASME PCC-2 for precautions on pneumatic pressure testing.

5.11.4 Test Temperature and Brittle Fracture Considerations

At ambient temperatures, carbon, low-alloy, and other steels, including high-alloy steels embrittled by service exposure, may be susceptible to brittle failure. Several failures have been attributed to brittle fracture of steels that were exposed to temperatures below their transition temperature and to pressures greater than 25 % of the required hydrostatic test pressure or 8 ksi of stress, whichever is less. Most brittle fractures, however, have occurred on the first application of a high stress level (the first hydro test or overload). The potential for a brittle failure shall be evaluated by an engineer prior to hydrostatic testing or especially prior to pneumatic testing because of the higher potential energy involved. Special attention should be given when testing low-alloy steels, especially $1^1/_4$Cr-1Mo, because they may be prone to temper embrittlement.

To minimize the risk of brittle fracture during a pressure test, the metal temperature should be maintained at least 30 °F (17 °C) above the minimum design metal temperature (MDMT) for piping that is more than 2 in. (5 cm) thick, and 10 °F (6 °C) above the MDMT for piping that have a thickness of 2 in. (5 cm) or less. The test temperature need not exceed 120 °F (50 °C) unless there is information on the brittle characteristics of the piping construction material indicating that a higher test temperature is needed.

5.11.5 Precautions and Procedures

During a pressure test, where the test pressure will exceed the set pressure of the PRD on a piping system, the PRD(s) should be removed or blanked for the duration of the test. As an alternative, each valve disk shall 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 prohibited. 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, PRDs of the proper settings and other appurtenances removed or made inoperable during the pressure test shall be reinstalled or reactivated.

Before applying a pressure test, appropriate precautions and procedures should be considered to ensure the safety of personnel involved with the pressure test. A close visual inspection of piping components should not be performed until the equipment pressure is at or below the MAWP. This review is especially important for in-service piping.

5.11.6 Pressure Testing Alternatives

Appropriate NDE shall be specified and conducted when a pressure test is not performed after a major repair or alteration. Substituting NDE procedures for a pressure test after an alteration is allowed only after the engineer and inspector have approved the substitution.

For cases where UT is used in lieu of a pressure test, the owner-operator shall specify industry-qualified UT angle beam examiners. ASME B31 Code Case 179 may be used in lieu of RT for B31.1 piping welds, and alternative UT acceptance criteria provided in B31 Code Case 181 may be used in lieu of those described in paragraph 344.6.2 of ASME B31.3, as applicable, for closure welds that have not been pressure tested and for welding repairs identified by the engineer or the inspector.

5.12 Material Verification and Traceability

5.12.1 General

The owner-operator shall assess the need for and extent of application of a material verification program consistent with API 578 addressing inadvertent material substitution in existing alloy piping systems. A material verification program consistent with API 578 may include procedures for prioritization and risk ranking of piping circuits. That assessment may lead to retroactive positive material identification (PMI) examination, as described in API 578, to confirm that the installed materials are consistent with the intended service. Components identified during this verification that do not meet acceptance criteria of the PMI examination program (such as in API 578) would be targeted for replacement. The owner-operator and authorized piping inspector, in consultation with a corrosion specialist, shall establish a schedule for replacement of those components. The authorized inspector shall use periodic NDE, as necessary, on the identified components until the replacement.

During repairs or alterations to alloy material piping systems, where the alloy material is required to maintain pressure containment, the inspector shall verify that the installation of new materials is consistent with the selected or specified construction materials. This material verification program should be consistent with API 578. Using risk assessment procedures, the owner-operator can make this assessment by 100 % verification, PMI examination in certain critical situations, or by sampling a percentage of the materials. PMI examination can be accomplished by the inspector or the examiner with the use of suitable methods as described in API 578.

If a piping system component should fail because an incorrect material was inadvertently substituted for the proper piping material, the owner-operator shall determine 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 probability of further material errors.

5.12.2 Carbon Steel Sulfidation

Carbon steel pipe having less than 0.1 wt% silicon can corrode at significantly higher rates than carbon steel pipe having higher silicon contents (modern “silicon-killed” process) when operating above 500 °F (260 °C) and subject to sulfidation corrosion. For piping systems/circuits that have been identified in sulfidation corrosion service (see API 578) that may contain older low-silicon carbon steels, consideration should be given to conducting inspection of each piping component/segment/weld or spool to identify the worst-case corrosion rate limiting component.

After about 1985, most purchased pipe became double stamped, and hence the low-silicon issue diminished for piping purchased and installed after that time frame. Inspection techniques that can be useful for finding susceptible components under insulation include real-time RT, guided wave examination, and PEC. Inspection plans for sulfidation corrosion should be in accordance with API 939-C.

5.12.3 Carbon Steel in Hydrofluoric Acid Alkylation Unit Process

Residual elements (Cr, Ni, and Cu) in carbon steel have been found to increase corrosion rates of carbon steels significantly in some services exposed to hydrofluoric (HF) acid in refining alkylation process. API 751 contains additional information on the need for material verification and increased corrosion monitoring for steels in such service conditions.

5.13 Inspection of Valves

Typically, thickness measurements are not routinely taken on valves in piping circuits. Information on types of valves can be found in API 574. 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 personnel should visually examine the valve components for any unusual corrosion patterns or thinning and, when noted, report that information to the inspector. Bodies of valves that are exposed to significant 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 severe or unusual corrosion-erosion, thickness readings should be conducted on the body between the seats because 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 598.

Critical check valves (CCV) shall be inspected or tested to provide greater assurance that they will prevent flow reversals. CCVs should be defined and identified by the owner-operator based on a risk assessment of the valve’s function to prevent a potentially hazardous event should back-flow of a process fluid occur. This may include the possibility of overpressure, equipment damage, fluid contamination, inadvertent mixing, increased corrosion, or other undesirable effects. It is not expected that every check valve be designated as a CCV. Owner-operators may utilize process hazards assessment tools, such as HAZOP (hazard and operability study) and LOPA (layers of protection analysis), to identify when these scenarios pose an unacceptable risk.

An example of a CCV 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 piping and equipment not rated for the higher discharge pressures and in damage to the pump due to the reverse rotation of the impeller(s).

CCVs should be uniquely identified and tracked, for example, on ISOs, on process and instrumentation diagrams, and in the Inspection Data Management System (IDMS). Inspection frequencies for CCVs should be set by the owner-operator based on service performance, noted deficiencies upon inspection, and inspection history.

Leak checks of CCVs are normally not required but may be considered for special circumstances.

Additional information on valve inspection can be found in API 574 and API 621.

5.14 In-service Inspection of Welds

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 RT profile inspection or as part of on-stream. When preferential weld corrosion is noted, additional welds in the same circuit or system should be examined for corrosion. API 577 provides additional guidance on weld inspection.

Due to the different capabilities and characteristics of various NDE methods to find flaws, using an NDE method that is different from the one employed during original fabrication may reveal preexisting flaws that were not caused by in-service exposure (e.g. applying UT and MT for in-service inspection when only RT was applied during fabrication). For this reason, it is often a good practice to specify the types of NDE during original fabrication that the owner-operator plans to apply during in-service inspections.

On occasion, RT profile examinations of welds that have been in-service may reveal a flaw in the weld. If crack-like imperfections are detected while the piping system is in operation, further inspection with weld quality RT and/or UT should be used to assess the magnitude of the imperfection. Additionally, the inspector should try to determine whether the crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

Crack-like flaws and environmental cracking shall be assessed by an engineer in accordance with API 579-1/ASME FFS-1 and/or corrosion specialist. Preferential weld corrosion shall be assessed by the inspector and/or corrosion specialist. Issues to consider when assessing the quality of existing welds include the following:

a) original fabrication inspection method and 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) repair and heat treatment history;

k) dissimilar metal welds, such as ferritic-to-austenitic and alloy 400 to carbon steel welds;

l) weld hardness.

For in-service piping weldments, it may not be appropriate to use the original construction code RT acceptance criteria for weld quality in ASME B31.3. The ASME B31.3 acceptance criteria are intended to apply to new construction on a sampling of welds, not just the welds examined, 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 hydrostatically tested. This is especially true on small branch connections that are normally not examined during new construction.

The owner-operator shall specify industry-qualified UT angle beam examiners when the owner-operator requires either of the following items:

a) detection of interior surface (ID) breaking planar flaws when inspecting from the external surface (OD);

b) where detection, characterization, and/or through-wall sizing is required of planar flaws; application examples for the use of such industry-qualified UT angle beam examiners include obtaining flaw dimensions for Fitness-For-Service assessment and monitoring of known flaws.

5.15 Inspection of Flanged Joints

Flanged joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange fasteners and valve 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 (e.g. caustic cracking). If repumping is being considered, ultrasonic examination of the bolts before repumping may be necessary to assess their integrity depending upon the process conditions to which they are exposed. Refer to ASME PCC-2.

Accessible flange faces should be examined for distortion and to determine the condition of gasket-seating surfaces. Gasket-seating surfaces damaged and likely to result in a joint leak should be resurfaced prior to being placed back in-service. Special attention should be provided to flange faces in high-temperature/high-pressure hydroprocessing services prone to gasket leaks during start-up and on-stream. If flanges are excessively bent or distorted, their markings and thicknesses should be checked against engineering requirements.

Flange fasteners should be examined visually for corrosion and thread engagement. Fasteners shall be fully engaged for the full depth of the nut on new and reassembled bolted joints. Fasteners not fully engaged on existing bolted joint assemblies may be considered acceptably engaged if the lack of complete engagement is not more than one thread. Refer to ASME PCC-1 for more details.

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.

Guidance on inspection and repair of flanged joints can be found in ASME PCC-2, Article 305, and ASME PCC-1. Additionally, ASME PCC-1—Appendix A provides guidance for establishing criteria for the training and qualifications of bolted joint assembly personnel. Such training and qualifications may prevent flange joint leaks. Owner-operators may follow the guidance in this ASME PCC-1—Appendix A with their own training and qualification program or utilize an external organization providing such services. This appendix also provides guidance for the training, qualification, duties, and responsibilities for qualified bolting specialists and instructors engaged in the inspection and quality assurance of the assembly and disassembly of bolted joints.

5.16 Inspection of Piping in HF Acid Alkylation Process Units

Piping systems in HF acid alkylation units shall be inspected according to API 751 requirements and recommended practices and this code's requirements and recommendations.

6 Interval/Frequency and Extent of Inspection

6.1 General

6.1.1 Purpose

To ensure equipment integrity, all piping systems and PRDs shall be inspected at the intervals/ frequencies provided in this section. Scheduled inspections shall be conducted on or before their due date or be considered overdue for inspection. Alternatively, an inspection due date may be determined through a risk assessment in accordance with API 580. This RBI-determined due date may exceed the typical half-life interval, or the Table 1 interval limits used in an API 570 analysis. (Note that not all RBI analyses produce an inspection interval, some generate an inspection due date based on acceptable risk criteria. See 7.13 for more information and requirements on overdue inspections and deferrals.)

The appropriate inspection shall provide the information necessary to determine that all the essential sections or components of the equipment are safe to operate until the next scheduled inspection. The risks associated with operational shutdown and start-up and the possibility of increased corrosion due to exposure of equipment surfaces to air and moisture during shutdown should be evaluated when an internal inspection is being planned.

This code is based upon monitoring a representative sampling of inspection locations on selected piping with specific intent to reveal a reasonably accurate assessment of the condition of the piping. An RBI assessment according to API 580 may provide an inspection plan for groups of piping circuits assessed.

6.1.2 Life Cycle of Piping

Piping has different levels of activity and operation throughout its life cycle, per the various definitions. In Figure 2, the various stages are identified and are explored in greater detail in API 574 as to how pipe and its multiple components are manufactured, joined, and operated. The varying operational stages may require specific activities or tracking of activities.

This code does not include piping systems that are still under construction or in transport to the site prior to being placed in-service or piping systems that have been retired.

In the operational part of the life cycle piping systems that are not currently in operation due to a temporary outage of the process, turnaround, or other maintenance activity are still considered to be “in-service.” Idled piping that is subsequently brought into operational service shall be highlighted to the mechanical integrity program owner to reflect current status. Installed spare piping is also considered in-service, whereas spare piping that is not installed is not considered in-service.

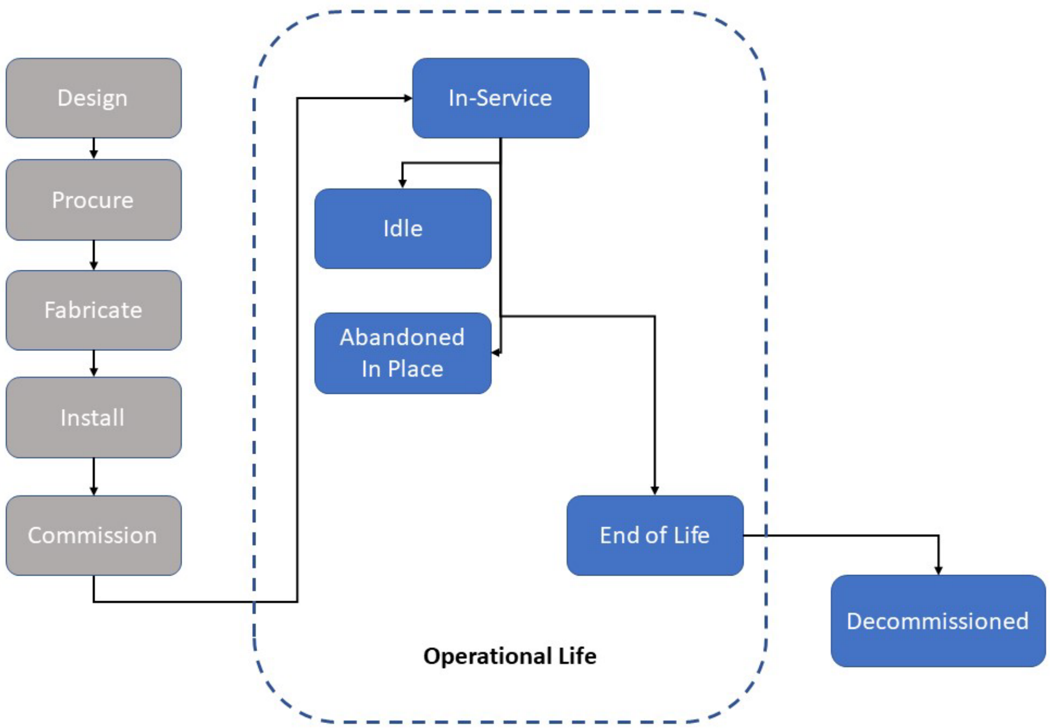

Figure 2—Life Cycle of Piping Systems

6.2 Inspection during Installation and Service Changes

6.2.1 Piping Installation

Piping should have been inspected in accordance with code of construction and all contractual requirements during fabrication and installation. The purpose of installation inspection is to verify that the piping is clean and safe for operation and to initiate plant inspection records for the piping systems. The minimum installation inspection should include the following items:

a) verifying that piping is installed correctly, the correct metallurgy is installed, supports are adequate and secured, exterior attachments (such as supports, shoes, and hangers) are secured, insulation is properly installed, flanged and other mechanical connections are properly assembled, and the piping is clean and dry;

b) verifying that the PRDs satisfy design requirements (correct device and correct set pressure) and are properly installed.

This installation inspection should document baseline thickness measurements to be used as initial thickness readings for corrosion rate calculations in lieu of nominal and minimum design thickness data in specifications and design data sheets/drawings. This will also facilitate the creation of an accurate corrosion rate calculation after the first in-service thickness measurements are recorded.

6.2.2 Piping Service Change

If the service conditions of the piping system are changed—i.e. will exceed the current operating envelope (e.g. process contents, maximum operating pressure, and the maximum and minimum operating temperature)—inspection intervals shall be established for the new service conditions, including the review of applicable PRD settings.

If both the ownership and the location of the piping are changed, the piping shall be inspected before it is reused. Also, the allowable service conditions and the inspection interval shall be established for the new service.

6.3 Piping Inspection Planning

6.3.1 General

The frequency and extent of inspection on piping circuits whether above or below ground 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 process piping circuits are described in API 571 in more detail.

A simplified classification of piping based on the consequence of failure is defined in 6.3.4. The classification is used to establish frequency and extent of inspection. The owner-operator 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. Refer to API 580 regarding the guidelines on assessing the consequence of failure. As described in 5.2, inspection strategy based on probability and consequence of failure is referred to as RBI.

After an effective assessment is conducted, the results can be used to establish a piping circuit inspection strategy and define the appropriate inspection plan per 5.1.

6.3.2 Setting Inspection Intervals with RBI

An RBI assessment, in accordance with API 580, may be used to determine the inspection intervals or next inspection due date and extent of inspection for piping, as well as the inspection and testing intervals for associated pressure relief devices.

6.3.3 Setting Inspection Intervals without the Use of RBI

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

If RBI is not being used, the interval between piping inspections should be established and maintained by using the following criteria:

a) the corrosion rate and remaining life calculations;

b) the piping service classification (see 6.3.4);

c) and the 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 5.5.7.

For Class 1, 2, and 3 piping, the period between thickness measurements for CMLs or circuits should not exceed one-half the remaining life, or the maximum intervals recommended in Table 1, whichever is less. Whenever the remaining life is less than 4 years, the thickness measurement inspection interval may be the full remaining life up to a maximum of 2 years.

Table 1—Recommended Maximum Inspection Intervals [c]

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
Class 4	Optional	Optional
Injection points [a]	3 years	By class
SAIs [b]	—	By class

NOTE Thickness measurements apply to systems for which CMLs have been established in accordance with 5.6.

[a] Inspection intervals or due dates for potentially corrosive injection/mix points can also be established by a valid RBI analysis in accordance with API 580. Injection and mix points can be extended beyond 3 years if deemed relatively noncorrosive after review from a corrosion specialist.

[b] See API 574 for more information on SAIs.

[c] The maximum inspection intervals can be modified by the owner-operator with the application of RBI that meets the requirements contained in API 580.

Maximum intervals for Class 4 piping are left to the determination of the owner-operator depending upon reliability and business needs.

For piping that is in noncontinuous service, the interval between thickness measurements may be based on the number of years of actual service (piping in operation) instead of calendar years, provided that when idled, the piping is as follows:

a) isolated from the process fluids;

b) not exposed to corrosive internal environments (e.g. inert gas purged or filled with noncorrosive hydrocarbons); piping that is in noncontinuous service and not adequately protected from corrosive environments may experience increased internal corrosion while idle; the corrosion rates should be carefully reviewed before setting the intervals.

The inspection interval shall be reviewed and may be adjusted after each inspection. The inspection interval should also be reviewed when operating outside of a predetermined IOW exceedance threshold. General corrosion, localized corrosion, pitting, environmental cracking, and other applicable forms of deterioration mentioned in 5.4, and API 571 shall be considered when establishing the various inspection intervals.

6.3.4 Piping Service Classes

6.3.4.1 General

All process piping systems shall be categorized into different piping classes except for piping that has been planned based on RBI. 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 to affirm their integrity for continued safe operation. Classifications should be based on potential safety and environmental effects should a leak occur. When pipe service conditions change, pipe classifications and inspection plans should be reviewed and updated as necessary to reflect the changed operating conditions (e.g. a hydrocarbon service temperature increase that might change from “slowly vaporizing during a release” to “rapidly vaporizing during a release”).

Owner-operator shall maintain a record of process piping fluids handled, including their classifications. NFPA 704 provides information that may be helpful in classifying piping systems according to the potential hazards of the process fluids they contain.

NOTE The operating temperature of a hydrocarbon stream relative to its flash point, boiling point, and autoignition temperature is a significant factor in defining potential consequence of a release. Operating temperature of hydrocarbon piping systems should be considered when assigning piping service class. For example, on-site ambient temperature gasoline is Class 2 because it is below the boiling point but above the flash point of gasoline. However, on-site gasoline at 550 °F should be Class 1 since autoignition can occur.

The four classes listed below in 6.3.4.2 through 6.3.4.5 are recommended.

6.3.4.2 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 can autorefrigerate and lead to brittle fracture;

b) pressurized services that can rapidly vaporize during release, creating vapors that can collect and form an explosive mixture, such as C2, C3, and C4 streams; fluids that can rapidly vaporize are those with atmospheric boiling temperatures below 50 °F (10 °C) or where the atmospheric boiling point is below the operating temperature (typically a concern with high-temperature services);

c) hydrogen sulfide (greater than 3 % weight) in a gaseous stream;

d) anhydrous hydrogen chloride;

e) HF acid (e.g. in HF alkylation units, as discussed in API 751, etc.);

f) piping over or adjacent to water and piping over public throughways (refer to national or local regulations [e.g. the Department of Transportation and Coast Guard] for inspection of over water piping);

g) flammable services operating above their autoignition temperature.

6.3.4.3 Class 2

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

a) on-site hydrocarbons that will slowly vaporize during release, such as those operating below the boiling point but above the flash point;

b) on-site hydrogen, fuel gas, and natural gas;

c) on-site strong acids and caustics.

6.3.4.4 Class 3

Services that are either flammable but do not significantly vaporize when they leak, i.e. below the flash point, or flammable but are in remote areas and operate below the boiling point are in Class 3. Services that are potentially harmful to human tissue but are in remote areas may be included in this class. Examples of Class 3 service include, but are not necessarily limited to, those containing the following:

a) on-site hydrocarbons that will not significantly vaporize during release such as those operating below the flash point;

b) off-site distillate and product lines to and from storage and loading;

c) tank farm piping;

d) off-site acids and caustics;

e) off-site hydrogen, fuel gas, and natural gas;

f) other lower risk hydrocarbon piping that does not fall in Class 1, 2, or 4.

6.3.4.5 Class 4

Services that are essentially nonflammable and nontoxic are in Class 4, as are most utility services. Inspection of Class 4 piping is optional and usually based on reliability needs and business impacts as opposed to safety or environmental impact. Examples of Class 4 service include, but are not necessarily limited to, those containing the following:

a) steam and steam condensate;

b) air;

c) nitrogen;

d) water, including boiler feed water or stripped sour water;

e) lube oil and seal oil;

f) ASME B31.3, Category D services;

g) plumbing and sewers.

6.4 Extent of Visual External and CUI Inspections

External visual inspections, including inspections for CUI, should be conducted in accordance with 6.3.3. Alternatively, external visual inspection intervals or due dates can be established by using a valid RBI assessment conducted in accordance with API 580. This external visual inspection for potential CUI is also to assess insulation condition and shall be conducted on all piping systems susceptible to CUI. The results of the visual inspection should be documented to facilitate follow-up inspections.

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 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 2 at suspect locations operating between 10 °F (−12 °C) and 350 °F (175 °C) for carbon steel and low-alloy steel piping. Piping that may be determined to not fall within this range but may cycle in and out of the range or may be susceptible to CUI during shutdowns and should be considered. RT 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 % of the circuit should be inspected.

Table 2—Recommended Extent of CUI Inspection Following Visual Inspection for Susceptible Piping [a]

Pipe Class	At Damaged Insulation Locations	At Nondamaged Locations (No Visual Damage Identified during Visual Examination)
	Approximate Amount of Examination with NDE or Insulation Removal at Areas with Damaged Insulation	Approximate Amount of CUI Inspection with NDE or Insulation Removal at Areas without Damaged Insulation [b]
1	75 %	50 %
2	50 %	33 %
3	25 %	10 %
4	Optional	Optional

[a] Susceptible piping is piping systems operating within the susceptible temperature ranges as indicated in API 574.

[b] The third column are additional areas to consider inspecting and not progressive from the second column.

The extent of the CUI program described in Table 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 the following:

a) local climatic conditions;

b) insulation design and maintenance;

c) coating quality;

d) service conditions.

Facilities with CUI inspection experience may increase or reduce the CUI inspection targets of Table 2. An exact accounting of the CUI inspection targets is not required. The owner-operator 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 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.

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.

6.5 Extent of Thickness Measurement Inspection and Data Analysis

6.5.1 CML Monitoring

To satisfy inspection interval requirements, each thickness measurement inspection should obtain thickness readings on a representative sampling of the total number of CMLs on each circuit (see 5.6). It is not the intent of this code that every established CML needs to be measured each time. A statistical sampling of active

CMLs is an acceptable approach, for a circuit-based analysis per the provisions outlined in 6.5.3. In addition, some CMLs may be documented as inactive and therefore do not need to be measured and would not be considered overdue. 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 shall include CMLs with the earliest renewal date as of the previous inspection. Where general thinning is predicted, this sampling should include all the various types of components within the circuit. Where localized damage mechanisms are identified, sampling should also include the location and orientation (top/bottom, inside/outside radius, etc.) where the damage is most likely to occur. The number and specific CMLs to be monitored at each inspection shall be determined by the inspector in consultation with a piping engineer and/or corrosion specialist where nonuniform corrosion or other damage mechanisms are expected. Therefore, scheduled inspection of circuits should obtain as many measurements as necessary to satisfactorily monitor the type and extent of damage anticipated in each piping system. If RBI is used to set the inspection interval or due date, CMLs not required for inspection per the RBI assessment do not need to be inspected in accordance with the recommended maximum inspection intervals in Table 1.

To determine the extent of thickness measurements necessary to develop a corrosion rate and remaining life, two basic approaches are acceptable as discussed below.

6.5.2 Point-to-Point Method

This analysis method is where the corrosion rate, remaining life, and reinspection interval are determined for each individual CML without adjustment for the results of other CML measurements in the circuit. Future inspections are managed based on the $^1/_2$ life established at each CML location. During a reinspection of a piping system, all the CMLs may be reinspected or only those that are coming due. This method can lead to frequent inspections of the same piping system if not carefully managed. It is generally not possible to apply a statistical analysis with the point-to-point method since 1) a relationship of one CML to another has not been established, making it difficult to compare corrosion rates in the circuit or between CMLs, and 2) the individual CML rates may be generated over significantly different time periods, when operating conditions may have changed.

6.5.3 Circuit Analysis Method

Where piping has been circuitized into common corrosion mechanisms and expected rates, a statistical analysis may be used to determine the appropriate number of representative sample points, a representative circuit corrosion rate, and the inspection interval. There are a number of considerations for using a statistical analysis approach that are necessary to remain appropriately conservative, some of which include the following.

a) Approach is generally applicable to damage mechanisms that produce uniform corrosion. However, when considering localized corrosion, the approach must be constructed for proper application.

b) Locations that exhibit significantly different corrosion rates and locations with shorter remaining life may need to be analyzed separately and/or moved to separate circuits.

c) A sampling statistic should be considered to check the statistical confidence factor given the variability of the data set (within a circuit).

d) The number of data points (CMLs) may need to be adjusted to achieve the desired statistical confidence before employing a statistical methodology.

e) A safety factor or confidence interval, which may be dependent on the expected damage mechanisms and may additionally account for circuit complexity, should be considered to account for uncertainties such as measurement error and overall failure risk.

f) CML reinspection shall not be extended beyond the date projected to reach the established minimum required thickness. Absolute limits should be considered for reinspection of CMLs based on the likelihood of failure (e.g. time or thickness limit).

g) Depending on the statistical analysis method used, the data population should be tested to make sure it meets the criteria for the distribution type utilized in the analysis.

As a minimum, the worst-case CMLs (those that are driving the need for the next inspection (e.g. those with the highest corrosion rate and/or the lowest remaining corrosion allowance) within the circuit shall be inspected at the next established inspection interval.

6.5.4 Data Analysis

Some level of data analysis is recommended under both approaches discussed above. Since the calculated corrosion rate used to predict the future remaining life was a product of the prior operating history, it is important to check for any acceleration of the corrosion rate over time and to be aware of planned operational changes. Good quality MOC and IOW programs are beneficial where critical process variables that may affect corrosion/damage rate or susceptibility are tracked. Additional data analysis should consider the following.

a) Is the measured rate within the expected/predicted range?

b) Is the short rate significantly different from the long rate?

c) Has the variability (or standard deviation) within the circuit data increased significantly over time?

d) Do components, orientations, sections within the circuit, or other identifiable features of the circuit exhibit significantly different rates?

e) Have data anomalies been resolved, either through a review process or verification readings, prior to data analysis?

f) Has the impact on results from measurement error in the technique used been incorporated?

In general, both approaches should be developed considering the potential active damage mechanisms within the piping system. Representative CMLs should be primarily based on the locations where the damage mechanisms are likely to be most active but should also include a sampling of all sizes, orientations, component types, and design features (e.g. control valve stations, equipment inlets/outlets, and alternate flow piping) within the line or circuit. This sampling also shall include CMLs with the earliest renewal date as of the previous inspection.

For general corrosion, it may not be necessary to identify the specific orientation of the examination point. Where localized damage mechanisms are expected, sampling should include the orientation (top/bottom, inside/outside radius, etc.) to help identify the specific active mechanism and provide data for future adjustments to CML locations.

Statistical tools may be used to determine or adjust the CML quantities when prior data are available. For new circuits or those with a change in-service, data from a similar service may be applied to estimate CML quantities and/or locations. Circuit inspections should include as many measurements as necessary to satisfactorily monitor the type and extent of damage anticipated in each piping system. CMLs that are not driving the next inspection interval do not necessarily need to be inspected in accordance with the recommended maximum inspection intervals in Table 1. If a circuit statistical analysis method is to be performed, a representative sampling of all CMLs should be taken to avoid skewing the data. Representative sampling is not an important consideration using the point-to-point method.

In addition, some CMLs may be documented as “inactive” or “archived.” These are CML points that have essentially been eliminated from the active registry but are being maintained for historical record purposes. There are several reasons to consider inactivating or archiving CMLs, including inappropriate placement of CML, sufficient coverage by other CMLs, lack of historical corrosion activity, etc. Although these CMLs may be maintained within the system (or electronic IDMS), they do not need to be measured on calculated intervals and would not be considered as overdue.

6.5.5 Review and Verification of Thickness Data Accuracy

Each owner-operator should have a procedure in place to provide for a review and/or verification of thickness data accuracy when data errors/anomalies are suspected. Such a procedure will reduce the chances for thickness data anomalies being used in the process of calculating short and LT corrosion rates, which in turn could affect the scheduled inspection interval and remaining life calculation. To help reduce inaccuracies in thickness data taking, examiners should have training and procedures that address the 10 factors included in 5.7.1 that can contribute to reduced accuracy of ultrasonic thickness measurements.

When thickness data measure errors/anomalies are suspected (e.g. thickness growths or losses of 10 % or more), then implementation of a data verification process may be warranted. Such a procedure/work process may include validation of the questionable measurements with:

a) additional thickness measurements being repeated at the CML(s) in question;

b) use of another trained NDE technician or inspector to take the validation readings;

c) use of a different, calibrated thickness measuring device to take the validation readings;

d) review and corrective action implemented for any of the other applicable factors listed in 5.7.1 that may have been a factor in the questionable readings.

When questionable thickness measurements have been validated, inspection records should be updated to note that the reading(s) has been validated and/or changed and which reading should be used in the succeeding data analysis.

6.6 Extent of Inspections on SBP, Deadlegs, Auxiliary Piping, and Threaded Connections

6.6.1 SBP

SBP that is primary process piping shall be inspected in accordance with all the requirements of this document. As with larger diameter piping, inspection practices for SBP shall have inspection plans based upon credible damage mechanisms in API 571 other than just wall thinning (e.g. stress corrosion cracking, hydrogen-induced cracking, embrittlement, etc.). Specific attention should be paid to damage that may have been inflicted by mechanical overloading on SBP since the strength and support systems for SBP are sometimes not adequate to avoid overload (e.g. vents, drains, and bridles).

Where RBI is not in use, SBP that is secondary process piping has different minimum requirements depending upon service classification. Class 1 and Class 2 secondary SBP shall be inspected to the same requirements as primary process piping. Inspection of Class 3 and Class 4 secondary SBP is optional at the owner-operator’s discretion depending upon reliability and risk.

Insulated SBP should receive the same inspection practices for CUI as the primary piping or vessels to which it is attached. Insulation stripping and RT are the preferred inspection methods for insulated SBP. Attention should be paid to insulation system resealing on SBP.

Reference API 574 for multiple design, fabrication, installation, and operating issues that can affect the likelihood of failure for SBP systems.

6.6.2 Deadleg Inspection

Deadlegs, including both large-bore piping and SBP (e.g. level bridles), can be areas of increased corrosion requiring special attention if they are deemed potentially corrosive by a corrosion specialist because of the accumulation of contaminated water, solid materials, different temperatures from the main line, or the accumulation or concentration of corrosive species (e.g. ammonium salts, organic acids, hydrogen sulfide, and acidic deposits). Risk assessment can be useful in determining which piping system deadlegs may be a higher threat to accelerated corrosion than active piping circuits. Deadlegs that are part of primary piping systems should be considered at greater risk because of the inability to valve them off in the event of a leak and the higher potential consequence of a large leak.

Consideration should be given to coordinating with operations to identify and remove potentially corrosive deadlegs that are deemed nonessential in order to reduce risk and inspection workload. Corrosion specialists should be consulted for placement of CMLs on deadlegs because of their potential for localized corrosion, especially about accelerated corrosion above and below liquid interfaces. Infrared thermography may be useful for locating liquid interfaces in deadlegs. Inspections of horizontal deadlegs that may not be liquid full should have examination points in all four quadrants of any CMLs.

Potentially corrosive deadlegs with CMLs should be tracked in a separate piping circuit from the mainline piping. These deadlegs or low points are typically identified and documented in the inspection records and on inspection ISOs. Deadlegs may be combined into the primary piping circuit if their anticipated damage mechanisms and corrosion rates are similar. Inspections should include profile RT on small diameter deadlegs (less than or equal to 8”), such as vents and drains, and scanning UT or RT on larger diameter deadlegs. Other examination techniques for deadlegs include EMAT and PEC. Profile RT should be employed for deadlegs that may be susceptible to fouling deposits that could cause under deposit corrosion or other integrity problems (e.g. fouling in relief lines).

Deadlegs that may collect water and be susceptible to freezing from external ambient conditions should be adequately insulated and heat traced for such cases.

NOTE Deadleg areas of a hot piping system that was defined as outside the CUI range can potentially be operating within the CUI temperature range or be exposed to CUI during downtime. When this is identified, then guidance related to CUI inspection from 6.4 should be applied.

Some examples include blanked (blinded) 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, PRD inlet and outlet header piping, pump trim bypass lines, high-point vents, sample points, drains, bleeders, and instrument connections. Deadlegs also include piping that is no longer in use but still connected to the process.

6.6.3 Auxiliary Piping Inspection

Inspection of auxiliary SBP associated with instruments and machinery is typically to be determined by risk assessment, including impacts on process safety and reliability. Criteria to consider in determining whether auxiliary SBP will need some form of inspection include the following:

a) piping classification;

b) potential for environmental or fatigue cracking, particularly on nonbraced SBP (e.g. reciprocating and centrifugal compressors, flow-induced vibration);

c) potential for corrosion based on experience with adjacent primary systems (especially since auxiliary SBP thickness will be thinner and likely results in full penetration corrosion sooner than in the primary pipe);

d) potential for CUI;

   NOTE See CUI inspection section for special requirements on auxiliary piping. Auxiliary piping systems can potentially be operating within the CUI range even though the primary piping system operates outside the CUI temperature range.

e) potential for fatigue and erosion and/or corrosion on thermowells.

6.6.4 Threaded-connection Inspection and Mitigation

Inspection of threaded connections should be according to the requirements listed above for small-bore and auxiliary piping. RT is an effective inspection method for these connections, which can help identify localized corrosion in the annular space between the threads and the amount of thread engagement and identify uniform wall loss from corrosion.

SBP connections associated with rotating equipment, especially threaded connections, are often subject to fatigue damage. Due to the nature of fatigue damage and its rapid progression from crack initiation to final fracture, inspection is not a primary method for failure mitigation. Fatigue failures are best prevented through proper design of the joint or branch connection, such as eliminating exposed threads by covering the threads with a seal weld/“bridge” weld, reducing or eliminating any overhanging weight, or providing two-plane gussets to the small-bore branch connections. When seal-welding threaded connections, pay close attention to weld prep cleanliness to avoid welding defects and cover all threads completely.

SBP in known vibratory service should be periodically assessed and considered for possible renewal with a thicker wall or upgrading joint design. The need for such renewal will depend on the potential risk of failure, 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.

6.7 Inspection and Maintenance of PRDs

6.7.1 General

PRDs shall be inspected, tested, maintained, and repaired in accordance with this document and API 576. Repairs and maintenance shall be conducted by a repair organization qualified and experienced in PRD maintenance per definition in 3.1.92.

6.7.2 Quality Assurance Process for PRDs

Each PRD repair organization shall have a fully documented quality assurance system. As a minimum, the following shall be included in the quality assurance manual:

a) title page;

b) revision log;

c) contents page;

d) statement of authority and responsibility;

e) organizational chart;

f) scope of work;

g) drawings and specification controls;

h) requirements for material and part control;

i) repair and inspection program;

j) requirements for welding, NDE, and heat treatment;

k) requirements for valve testing, setting, leak testing, and sealing;

l) general example of the valve repair nameplate;

m) requirements for calibrating measurement and test gauges;

n) requirements for updating and controlling copies of the quality control manual;

o) sample forms;

p) training and qualifications required for repair personnel;

q) requirements for handling of non-conformances.

Each repair organization shall also have a documented training program that shall verify that repair personnel are qualified within the scope of the repairs they will be conducting.

6.7.3 PRD Testing and Inspection Intervals

6.7.3.1 General

PRDs shall be tested and inspected at intervals that are frequent enough to verify that the valves perform reliably in the service conditions. Other PRDs (e.g. rupture disks and vacuum-breaker valves) shall be inspected at intervals based on service conditions. The inspection interval for all PRDs is determined by the inspector, engineer, or other qualified individual per the owner-operators quality assurance system.

6.7.3.2 PRD Testing and Inspection Intervals

Unless documented experience and/or an RBI assessment indicates that a longer interval is acceptable, test and inspection intervals for PRDs in typical process services should not exceed:

a) 5 years for typical process services;

b) 10 years for clean (nonfouling) and noncorrosive services.

6.7.3.3 As-received Condition, Testing, and Actions

Wherever possible, as-received relief (pop) testing should be conducted prior to cleaning to yield accurate as-received pop testing results that will help establish/justify the appropriate inspection and servicing interval.

Cleaning of deposits prior to as-received relief (pop) testing can remove deposits that would have prevented the valve from opening at set pressure. Refer to API 576 for more information on as-received pop testing and cleaning with adjacent piping.

NOTE In some services, such as HF acid alkylation units, care needs to be taken to ensure safe handling and protection of personnel (refer to API 576 for further guidance).

When a PRD is found to be heavily fouled or stuck, or when a PRD fails an as-received relief (pop) test, the inspection and testing interval shall be reevaluated to determine if the interval should be shortened or other corrective action taken. The owner-operator should define the criteria that constitute an “as-received” relief (pop) test failure. The owner-operator may define criteria for failure based on as-received relief (pop) test pressure as a percentage of cold differential set pressure. Unless specified by the owner-operator, a pressure relief device is considered stuck when it has not relieved (popped) at 150 % of its set pressure. An investigation consistent with the principles documented in API 585 should be undertaken to determine the cause of the fouling or the reasons for the PRD not operating properly. Refer to API 576 for additional information on PRD relief (pop) test results and investigations.

7 Inspection Data Evaluation, Analysis, and Recording

7.1 Corrosion Rate Determination

7.1.1 General

The owner-operator may use either the point-to-point analysis method or a statistical analysis method, or a combination of both, to determine the LT or short-term (ST) corrosion rates.

7.1.2 Point-to-Point Method

The LT corrosion rate of an individual CML shall be calculated from the following formula:

$$\text{Corrosion rate (LT)} = \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time (years) between } t_{\text{initial}} \text{ and } t_{\text{actual}}}$$

The ST corrosion rate of an individual CML shall be calculated from the following formula:

$$\text{Corrosion rate (ST)} = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time (years) between } t_{\text{previous}} \text{ and } t_{\text{actual}}}$$

where

t_{initial} is the thickness, in inches (millimeters), at the same location as tactual measured at initial installation or at the commencement of a new corrosion rate environment;

t_{previous} is the thickness, in inches (millimeters), at the same location as tactual measured during one or more previous inspections.

LT and ST corrosion rates should be compared to see which results in the shortest remaining life as part of the data assessment. The authorized inspector, in consultation with a corrosion specialist, shall select the corrosion rate that best reflects the current process (see 6.3.3 for inspection interval determination). Measurement error exists in all systems and should be well defined or understood and where possible contained in narrow error bands. This is particularly important in ST corrosion rate use where the error bands may result in misleading decisions.

The inspector should consult with a corrosion specialist when the ST corrosion rate changes from the anticipated or previously identified rate to determine the cause (see API 574 for wider guidance). Appropriate responses to accelerated corrosion rates may include the following:

a) obtaining additional UT thickness readings;

b) using profile RT in lieu of, or to supplement UT readings;

c) performing UT scans in suspect areas;

d) performing other corrosion/process monitoring;

e) reviewing changes in operations/process;

f) revising the piping inspection plan;

g) addressing non-conformances.

Circuit corrosion rates should be estimated based on the anticipated damage mechanisms and operating conditions with a tolerance or range identified. Measured rates exceeding the established range signal the need to review the potential causes and adjust the inspection plan.

7.1.3 Statistical Analysis Method

The owner-operator may elect to use a statistical analysis method (e.g. probability plots or related tools) to establish a representative corrosion, remaining life estimate, and/or reinspection date. Any statistical approach shall be documented. The statistical treatment of data should be based on representation of the various pipe components within the circuit. Statistical analysis employing point measurements is not applicable to piping circuits with significant localized unpredictable corrosion mechanisms (see additional notes and statistical analysis in 6.5.3). There are many statistical tools that can be employed once piping circuits have been properly established. While such calculations offer a convenient means to numerically summarize circuit data, it is often the combination of descriptive statistics plus data visualization through statistical plots that provide the most useful results.

See API 574 for additional discussion on statistical analysis methods.

7.2 Remaining Life Calculations

The remaining life shall be calculated from the following formula:

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

where

t_{actual} is the actual thickness, in inches (millimeters), measured at the time of inspection for a given location or component as specified in 5.7.

t_{required} is the required thickness, in inches (millimeters), at the same location or component as the actual measurement computed by the design formulas (e.g. pressure and structural) before corrosion allowance and manufacturer's tolerance are added.

7.3 Newly Installed Piping Systems or Changes in Service

For a new piping system/circuit or for a piping system/circuit for which service conditions are being changed, one of the following methods shall be used to determine piping system/circuits probable corrosion rate. The remaining life and inspection interval can be determined from this rate.

a) A corrosion rate may be calculated from data collected by the owner-operator on piping operating in the same or similar service.

b) A corrosion rate may be determined through appropriately placed ultrasonic sensors on the piping.

c) A corrosion rate may be estimated by a corrosion specialist.

d) A corrosion rate may be estimated from published data on piping in same or similar service.

If the probable corrosion rate cannot be determined by either method listed under a) or d) above, the initial thickness measurement should be established at appropriate intervals until a credible corrosion rate is established. Corrosion monitoring devices, such as corrosion coupons or corrosion probes, may be useful in establishing the timing of direct measurements. Subsequent measurements need to be established on appropriate intervals until the corrosion rate is established. If it is later determined that an inaccurate corrosion rate was assumed, the corrosion rate in the remaining life calculations shall be amended to reflect the actual corrosion rate.

In a case where items listed a) through d) cannot be applied with confidence and to ensure that an unexpected, accelerated corrosion rate does not occur unidentified, the inspection plan shall include determining wall loss change rate on-stream by direct measurement techniques after 6 months of service. This may not determine an actual corrosion rate (because of potential measurement error) but ensuring that data are available to direct the inspection plan until a corrosion rate can be established. This is provided as a cautionary guideline due to the statistical variation in thickness readings taken in short interval, which may suggest a corrosion rate that is not truly indicative of the environment.

7.4 Existing and Replacement Piping

Corrosion rates shall be calculated using one of the methods identified in 7.1. For repaired or in-kind replacement piping, the corrosion rate shall be established based on the previous worst-case measured rate at the replacement location or the circuit average rate.

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.

7.5 MAWP Determination

The 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 minus twice the estimated corrosion loss before the date of the next inspection (see 6.3.3). 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 the associated code criteria are satisfied.

Annex C contains two examples of calculations of MAWP illustrating the use of the corrosion half-life concept.

7.6 Required Thickness Determination

The required thickness of a pipe shall be the greater of the pressure design thickness or the structural minimum thickness. For services with high risk, the piping engineer should consider increasing the required thickness to provide for unanticipated or unknown loadings, or undiscovered metal loss. See API 574, Section 10, for information on the determination of pressure design thicknesses, structural minimum thicknesses, minimum required thicknesses, and minimum alert thicknesses. Table 5 of API 574 provides examples of minimum alert thicknesses and default minimum structural thicknesses for carbon and low-alloy steel piping operating below 400 °F (205 °C).

7.7 Assessment of Inspection Findings

Pressure-containing components found to have damage that could affect their load-carrying capability (pressure loads and other applicable loads, such as weight and wind) shall be evaluated for continued service, or the piping should be removed from service until corrective action/repairs are performed. Fitness-For-Service evaluations, such as those documented in API 579-1/ASME FFS-1, should be used for this evaluation for the type of degradation being assessed.

The following techniques may be used as applicable.

a) To evaluate metal loss more than the corrosion allowance, a Fitness-For-Service assessment may be performed in accordance with one of the following parts of API 579-1/ASME FFS-1. This assessment requires the use of a future corrosion allowance, which shall be established based on 7.1.

b) Assessment of general metal loss—API 579-1/ASME FFS-1, Part 4.

c) Assessment of local metal loss—API 579-1/ASME FFS-1, Part 5.

d) Assessment of pitting corrosion—API 579-1/ASME FFS-1, Part 6.

e) To evaluate blisters and laminations, a Fitness-for-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Part 7. In some cases, this evaluation will require the use of a future corrosion allowance, which shall be established based on 7.1.

f) To evaluate weld misalignment and piping distortions, a Fitness-for-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Part 8.

g) To evaluate crack-like flaws, a Fitness-for-Service assessment should be performed in accordance with API 579-1/ ASME FFS-1, Part 9.

h) To evaluate the effects of fire damage, a Fitness-for-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Part 11.

7.8 Piping Stress Analysis

Piping shall be supported and guided so that:

a) its weight is carried safely;

b) it has sufficient flexibility for thermal expansion or contraction;

c) it does not vibrate excessively;

d) accounts for other loads (e.g. those included in the original code of construction).

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 5.5.5), 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 movement 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.

7.9 Reporting and Records for Piping System Inspection

7.9.1 Records

Piping system owner-operators shall maintain records of their piping systems and PRDs. Records shall be maintained throughout the service life of each piping system. As a part of these records, inspection and maintenance records shall be regularly updated to include new information pertinent to the operation, inspection, and maintenance history of the piping system. See also API 574 for more information of piping system records.

7.9.2 Types of Piping Records

Piping system and PRD records shall contain four types of information pertinent to mechanical integrity as follows.

a) Fabrication, construction, and design information to the extent available—for example, manufacturer's data reports, material test reports, weld maps, welding procedure specification (WPS)/procedure qualification record (PQR), design specification data, piping design calculations, NDE records, heat treat records, PRD sizing calculations, and construction drawings.

b) Inspection history—for example, inspection reports and data for each type of inspection conducted (e.g. internal, external, and thickness measurements) and inspection recommendations for repair. Inspection reports shall document the date of each inspection and/or examination, the date of the next scheduled inspection, the name (or initials) of the person who performed the inspection and/or examination, the serial number or other identifier of the equipment inspected, a description of the inspection and/or examination performed, and the results of the inspection and/or examination. When data are collected using equipment that requires calibration prior, during, or after use, calibration records should be provided with the inspection results. Piping RBI records should be in accordance with API 580.

c) Repair, alteration, and engineering evaluation information—for example:

   1) repair and alteration forms if prepared;

   2) reports indicating that piping systems still in-service with either identified deficiencies, temporary repairs, or recommendations for repair are suitable for continued service until repairs can be completed; and

   3) rerating documentation, including rerating calculations and new design conditions.

d) Fitness-For-Service assessment documentation requirements are described in API 579-1/ASME FFS-1; specific documentation requirements for the type of flaw being assessed are provided in the appropriate part of API 579-1/ASME FFS-1.

7.9.3 Operating and Maintenance Records

Site operating and maintenance records, such as operating conditions, including process upsets that may affect mechanical integrity, changes in-service, and mechanical damage from maintenance, should also be available to the inspector.

7.9.4 Computer Records

A computer-based system for storing, calculating, and analyzing data—an IDMS—should be utilized when considering the volume of data that will be generated as part of a piping inspection program. The IDMS is useful for the following:

a) storing and analyzing the actual thickness readings;

b) calculating ST and LT corrosion rates, retirement dates, and minimum required thickness;

c) highlighting areas of high corrosion rates, piping close to the minimum required thickness, and other information;

d) inspection planning, including next inspection due dates, intervals, and deferrals;

e) recommendations for repairs and their due dates;

f) tracking temporary repairs.

7.9.5 Piping Circuit Records

The following information should be recorded for each piping circuit on which CMLs are located:

a) material of construction/piping specification;

b) piping diameter;

c) operating and design pressures and temperatures;

d) ANSI flange rating;

e) process fluids;

f) piping classification (if RBI is not being used);

g) insulation, heat tracing, postweld heat treatment (PWHT);

h) whether the circuit is a deadleg, injection point, intermittent service, or other special circuit;

i) the corrosion rate and remaining service life of, at least, the limiting examination point on the circuit;

j) maximum interval for external inspection;

k) maximum interval for thickness measurement inspection;

l) any unusual or localized corrosion mode that would require specialized inspection techniques;

m) circuit features that might subject it to rapid corrosion increases in the event of a process upset or loss of injection fluid flow.

7.9.6 ISOs

The primary purpose of inspection ISOs is to identify the location of CMLs and to identify the location of any recommended maintenance. Inspection ISOs are recommended and should contain the following:

a) all significant components of the piping circuits (e.g. all valves, elbows, tees, and branches);

b) material of construction and specification breaks;

c) all deadlegs, mix points, injection points, and other process connections to the primary piping system;

d) diameter of piping;

e) insulated or not;

f) all secondary piping for Class 1 (or high-consequence RBI) piping circuits;

g) secondary piping up to the block valve that is normally used for Class 2 (or appropriate RBI consequence) unit pipe;

h) all CMLs with appropriate information to locate the CMLs;

i) adequate orientation and scale to provide legible detail;

j) piping-circuit numbers and changes;

k) continuation drawing numbers;

l) location and type of pipe supports.

Inspection ISOs are recommended for all unit piping and all Class 1 (or high-consequence RBI) piperack piping on which CMLs have been identified for thickness measurement. Alternate methods for piperack piping that adequately describe the system without ISOs may be used.

Inspection ISOs are recommended for Class 2 (or appropriate RBI consequence) rack piping with CMLs, except that grid type drawings may be used if all other details are shown. The use of local details or local isometrics is acceptable to show the location of CMLs on grid drawings.

Inspection ISOs do not need to be drawn to scale or show dimensions unless necessary to locate CMLs.

7.9.7 Inspection Reports and Records

Documented results (reports and/or records) of the inspection shall be approved by the responsible owner-operator inspector, engineer, or qualified designee. These should be posted into the appropriate IDMS within 90 days of either the completion of the inspection or the operational start-up of the associated equipment.

7.10 Inspection Recommendations for Repair or Replacement

7.10.1 General

A management system for identifying, tracking, and periodically reviewing repair or replacement recommendations (includes recommendations for non-conformances) that impact piping integrity is required and shall be kept current. The recommendation tracking system shall include the following:

a) recommended corrective action or repair;

b) due or target date for completion of recommended action;

c) piping system identifier (e.g. piping system or circuit number) that the recommendation affects;

d) lists of temporary repairs that may require follow-up monitoring and eventual replacement;

e) Fitness-For-Service or derating documentation, if necessary;

f) any required monitoring or mitigation steps;

g) date recommendation is made;

h) planned repair date.

7.10.2 Review of Inspection Repair Recommendations

Inspection repair recommendations can be changed or deleted after review by the inspector or inspection supervisor and optionally by piping engineer. If inspection repair recommendations are changed or deleted, inspection records shall record the reasoning, date of change/deletion, and name of person who did the review.

7.11 Inspection Records for External Inspections

Results of external piping system inspections shall be documented. A combination of checklist and narrative recordkeeping is recommended when documenting inspection results. Checklists should serve the purpose of reminding recordkeepers of all the issues important to be included in piping inspection records, but narratives serve the purpose better than checklists for thoroughly documenting inspections results. The location of CUI inspections, either by insulation removal or NDE, should be identified. The location may be identified by establishing a CML on the appropriate inspection ISO or with marked-up construction ISOs and narrative reports.

7.12 Piping Failure and Near-miss Reports

Failures in piping that occur because of corrosion, cracking, or mechanical damage shall be recorded and reported to the owner-operator. Failures in piping systems shall be investigated to identify and correct the cause of failure. Near-misses in piping that occur from similar causes as failures should also be reported to the owner-operator and appropriately investigated to identify and correct the cause. See API 585 for more information on how to investigate piping incidents (i.e. failures, near-misses, and unanticipated discoveries). Temporary repairs to piping systems shall be documented in the inspection records.

7.13 Deferral of Inspections, Tests, and Examinations

7.13.1 General

Inspections, tests, or examinations for piping and associated PRDs that cannot be completed by their due date may be deferred for a specified period, subject to the requirements in the following subsections.

Piping or PRDs that are operated beyond the due date without a valid deferral in accordance with these requirements are not permitted by this code. Deferrals should be the occasional exception, not a frequent occurrence. All deferrals shall be documented. Piping or PRDs that were granted a deferral can be operated to the new due date without being considered overdue for the deferred inspections, tests, or examinations.

7.13.2 Simplified Deferral

A simplified short-term deferral may be approved by the owner-operator if all the following conditions are met.

a) The current due date for the inspection, test, or examination has not been previously deferred.

b) The proposed new due date would not increase the current inspection/servicing interval or due date by more than 10 % or 6 months, whichever is less.

c) A review of the current operating conditions, as well as the piping or PRD history, has been completed with results that support a short-term/one-time deferral.

d) The deferral request has the consent of the inspector representing or employed by the owner-operator and an appropriate operations management representative(s).

e) Updates to the piping or PRD records with deferral documentation are complete before it is operated beyond the original due date.

7.13.3 Deferral

Deferral requests not meeting the conditions of a simplified deferral shall follow a documented deferral procedure/process that includes all the following minimum requirements.

a) Perform a documented risk assessment or update an existing RBI assessment to determine if the proposed deferral date would increase risk above acceptable risk threshold levels as defined by the owner-operator. The risk assessment may include any of the following elements as deemed necessary by the owner-operator:

- — fitness for service analysis results;
- — consequence of failure;
- — applicable damage mechanism susceptibilities and rates of degradation;
- — calculated remaining life;

— historical conditions/findings from inspections, tests, and examinations and their technical significance;

— extent and/or probability of detection (i.e. effectiveness) of previous inspections, tests, or examinations, as well as the amount of time that has elapsed since they were last performed;

— considerations for any previous changes to inspection or test intervals (e.g. reductions in interval due to deteriorating conditions);

— disposition(s) of any previous requests for deferral on the same piping or PRD;

— historical conditions/findings for piping or PRDs in similar service, if available.

b) Determine if the deferral requires the implementation of or modification to existing IOWs or operating process control limits.

c) Review the current inspection plan to determine if modifications are needed to support the deferral.

d) Obtain the consent and approval of appropriate piping personnel, including the inspector representing or employed by the owner-operator and appropriate operations management representative(s).

e) Updates to the piping or PRD records with deferral documentation are complete before it is operated beyond the original due date.

7.14 Deferral of Inspection Repair Recommendation Due Dates

The deferral of inspection recommendations should be the occasional exception not a frequent occurrence.

Inspection and repair recommendations that cannot be completed by their due date can be deferred for a specific period. The deferral, including the justification of the due date and approval of the deferral by appropriate site personnel, shall be documented in the inspection records. At a minimum, this shall include the inspector and inspection supervisor; however, the owner-operator should include the appropriate site management representative when the authority to accept higher-than-normal operating risk is required. Inspection recommendations that have not been completed by the required due date without a documented and approved deferral are considered overdue for completion. Piping and piping components shall remain at or above the minimum required thickness during the deferral period. The minimum required thickness can be determined using methods defined in 7.6.

8 Repairs, Alterations, and Rerating of Piping Systems

8.1 Repairs and Alterations

8.1.1 General

The principles of ASME B31.3 or the code to which the piping system was built shall be followed to the extent practical for in-service repairs. 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.”

The principles and practices of API 577 shall also be followed for all welded repairs and modifications.

If any of the restorative changes of a repair result in a change of design temperature or pressure, the requirements for rerating also shall be satisfied.

8.1.2 Authorization

All repair and alteration work shall be done by a repair organization as defined in 4.3.2 and shall 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.

8.1.3 Approval

All proposed methods of design, execution, materials, welding procedures, examination, and testing shall be approved by the inspector or by the piping engineer, as appropriate. Owner-operator 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 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.

8.1.4 Welding Repairs (Including On-stream)

8.1.4.1 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. See various articles in ASME PCC-2 for more information on repairs to piping systems. 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. The design of temporary enclosures and repairs shall be approved by the piping engineer.

If the repair area is localized (for example, pitting or pinholes) and the SMYS of the pipe is not more than 40,000 psi (275,800 kPa), and a Fitness-For-Service analysis shows that it is acceptable, a temporary repair may be made by fillet welding a properly designed split coupling or plate patch over the pitted or locally thinned area. The material for the repair shall match the base metal unless approved by the piping engineer. A fillet-welded patch shall not be installed on top of an existing fillet-welded patch. When installing a fillet-welded patch adjacent to an existing fillet-welded patch, the minimum distance between the toe of the fillet weld shall not be less than:

$$d = 4\sqrt{Rt}$$

where

d is the minimum distance between the toes of fillet welds of adjacent fillet weld attachments, in inches (millimeters);

R is the inside radius in inches (millimeters);

t is the minimum required thickness of the fillet-welded patch in inches (millimeters).

For minor leaks and thinning below t_{min}, properly designed enclosures may be welded over the leak or thin piping while the piping system is in-service, provided the inspector is satisfied that adequate thickness remains in the actual location of the proposed weld and heat-affected zone, and the piping component can withstand welding without the likelihood of further material damage, such as from caustic service. Any leak in a Class 1 service, or where a risk ranking is determined to be high, shall be first reviewed by a piping engineer to determine if the work can be safely performed while the system remains on stream.

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 only if approved and documented by the piping engineer.

8.1.4.2 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 % 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 in. (25 mm) minimum radius]. See ASME PCC-2 for more information on various welded repairs to piping systems.

8.1.5 Nonwelded Repairs (On-stream)

Temporary repairs of locally thinned sections or circumferential linear defects may be made on-stream by installing a properly designed and applied enclosure (e.g. bolted clamp, nonmetallic composite wrap, metallic and epoxy wraps, or another nonwelded applied temporary repair). The design shall include control of axial thrust loads if the piping component being enclosed is (or may become) insufficient to control pressure thrust. The effect of enclosing (crushing) forces on the component also shall be considered. See ASME PCC-2 for more information on nonmetallic composite wrap repair methods.

During turnarounds or other appropriate opportunities, temporary leak sealing and leak dissipating devices, (e.g. wire wrapping, mechanical clamps, etc.), including temporary repairs on 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. Temporary leak sealing and leak dissipating devices may remain in place for a longer period only if approved and documented by the piping engineer. From a mechanical integrity perspective, injection fittings on valves to seal fugitive (LDAR) emissions from valve stem seal are not considered to be temporary repairs. Their removal or valve replacement is at the discretion of the owner operator.

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, and any resulting crushing forces; the risk of sealant affecting downstream flow meters, PRDs, 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.

See ASME PCC-2 for more information on nonwelded repairs for piping systems.

8.2 Welding and Hot Tapping

8.2.1 General

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 shall be done in accordance with API 2201. The inspector shall use as a minimum the "Suggested Hot Tap Checklist" contained in API 2201 for hot tapping performed on piping components. See API 577 for further guidance on hot tapping and welding in-service.

8.2.2 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. See API 577 for guidance on welding procedures and qualifications.

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.

8.2.3 Preheating and PWHT

8.2.3.1 General

Refer to API 577 for guidance on preheating and PWHT.

8.2.3.2 Preheating

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

NOTE Preheating alone may not be considered as an alternative to environmental cracking prevention.

Piping systems constructed of steels initially requiring PWHT normally are postweld heat treated if alterations or repairs involving pressure-retaining welding are performed.

8.2.3.3 PWHT

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 8.2.4 for an alternative preheat procedure for some PWHT requirements. Exceptions for temporary repairs shall be approved by the piping engineer and be in accordance with ASME PCC-2.

Local PWHT may be substituted for 360° 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.

8.2.4 Preheat or Controlled Deposition Welding Methods as Alternatives to PWHT

8.2.4.1 General

In some instances, full PWHT may have potential adverse effects on equipment and piping. Nevertheless, the piping may have been originally postweld heat treated or may require PWHT according to the original construction code. In these cases, preheat and controlled deposition welding may be used in lieu of PWHT, as described in 8.2.4.2 and 8.2.4.3. However, prior to using alternative methods, a piping engineer shall ensure that the alternative is suitable based on a metallurgical review. The review shall consider factors such as the reason for the original PWHT, susceptibility to stress corrosion cracking, stresses in the location of the weld, susceptibility to high temperature hydrogen attack, susceptibility to creep, etc.

The welding method shall be selected based on the rules according to the applicable code/standard. In addition, the adequacy of the as-welded joint at operating and pressure test conditions should be considered.

When reference is made in this section to materials by the ASME designations, P-numbers and Group numbers, the requirements of this section apply to the applicable materials of the original code of construction, either ASME or other, which conform by chemical composition and mechanical properties to the ASME P-number and Group number designations.

Pressure boundary process piping alterations or repair welds that initially required PWHT shall be postweld heat treated, with the exceptions listed in 8.2.4.2 and 8.2.4.3. If valid for the current rated design, the original joint efficiency factor may be used when alternative PWHTs are practiced.

8.2.4.2 Preheating Method (Notch Toughness Testing Not Required)

The preheating method, when performed in lieu of PWHT, is limited to the following materials and weld processes.

a) The materials shall be limited to P-No. 1, Group 1, 2, and 3, and to P-No. 3, Group 1 and 2 (excluding Mn-Mo steels in Group 2).

b) The welding shall be limited to the shielded metal arc welding, gas metal arc welding, gas tungsten arc welding, and flux-cored arc welding processes.

The welders and welding procedures shall be qualified in accordance with the applicable rules of the original code of construction, except that the PWHT of the test coupon used to qualify the procedure shall be omitted.

The weld area shall be preheated and maintained at a minimum temperature of 300°F (150 °C) during welding. The 300 °F (150 °C) temperature should be checked to ensure that 4 in. (100 mm) of the material or four times the material thickness (whichever is greater) on each side of the groove is maintained at the minimum temperature during welding. The maximum interpass temperature shall not exceed 600 °F (315 °C). When the weld does not penetrate through the full thickness of the material, the minimum preheat and maximum interpass temperatures need only be maintained at 4 in. (100 mm) or four times the depth of the repair weld, whichever is greater on each side of the joint.

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.

NOTE Notch toughness testing is not required when using this preheat method in lieu of PWHT.

8.2.4.3 Controlled-deposition Welding Method (Notch Toughness Testing Required)

The controlled-deposition welding method may be used in lieu of PWHT in accordance with the following.

a) Notch toughness testing, such as that established by ASME B31.1—Chapter III, Section 323, is necessary when impact tests are required by the original code of construction or the construction code applicable to the work planned.

b) The materials shall be limited to P-No. 1, P-No. 3, and P-No. 4 steels.

c) The welding shall be limited to the shielded metal arc welding, gas metal arc welding, flux-cored arc welding, and gas tungsten arc welding processes.

d) A weld procedure specification shall be developed and qualified for each application. The welding procedure shall define the preheat temperature and interpass temperature and include the postheating temperature requirement in item f) 8). The qualification thickness for the test plates and repair grooves shall be in accordance with Table 3. The test material for the welding procedure qualification shall be of the same material specification (including specification type, grade, class, and condition of heat treatment) as the original material specification for the repair. If the original material specification is obsolete, the test material used should conform as much as possible to the material used for construction, but in no case shall the material be lower in strength or have a carbon content of more than 0.35 %.

e) When impact tests are required by the construction code applicable to the work planned, the PQR shall include sufficient tests to determine if the toughness of the weld metal and the heat-affected zone of the base metal in the as-welded condition is adequate at the MDMT (such as the criteria used in ASME B31.3). If special hardness limits are necessary (for example, as set forth in NACE SP0472 and NACE MR0103) for corrosion resistance, the PQR shall include hardness tests as well.

f) The WPS shall include the following additional requirements.

   1) The supplementary essential variables of ASME *BPVC*, Section IX, paragraph QW-250, shall apply.

   2) The maximum weld heat input for each layer shall not exceed that used in the procedure qualification test.

   3) The minimum preheat temperature for welding shall not be less than that used in the procedure qualification test.

   4) The maximum interpass temperature for welding shall not be greater than that used in the procedure qualification test.

   5) The preheat temperature shall be checked to ensure that 4 in. (100 mm) of the material or four times the material thickness (whichever is greater) on each side of the weld joint will be maintained at the minimum temperature during welding. When the weld does not penetrate through the full thickness of the material, the minimum preheat temperature need only be maintained at 4 in. (100 mm) or four times the depth of the repair weld, whichever is greater on each side of the joint.

   6) For the allowed welding processes in item c), use only electrodes and filler metals that are classified by the filler metal specification with an optional supplemental diffusible-hydrogen designator of H8 or lower. When shielding gases are used with a process, the gas shall exhibit a dew point that is not higher than –60 °F (–50 °C). Surfaces on which welding will be done shall be maintained in a dry condition during welding and free of rust, mill scale, and hydrogen-producing contaminants, such as oil, grease, and other organic materials.

7) The welding technique shall be a controlled-deposition, temper-bead, or half-bead technique. The specific technique shall be used in the procedure qualification test.

8) For welds made by shielded metal arc welding, once filling is completed, do not allow the weldment to cool below the minimum preheat temperature. In addition, raise the weldment temperature to 500 °F ± 50 °F (260 °C ± 30 °C) for a minimum period of 2 hours. This assists outgassing diffusion of any weld metal hydrogen picked up during welding. This hydrogen bake-out may be omitted when H4 filler metal (such as E7018-H4) is specified.

9) After the finished repair weld has cooled to ambient temperature, the final temper bead reinforcement layer shall be removed substantially flush with the surface of the base material.

Refer to WRC 412 for additional supporting technical information regarding controlled deposition welding.

Table 3—Welding Methods as Alternatives to PWHT Qualification Thickness for Test Plates and Repair Grooves

Depth t of Test Groove Welded [a]	Repair Groove Depth Qualified	Thickness T of Test Coupon Welded	Thickness Base Metal Qualified
t	$< t$	< 2 in. (50 mm)	$< T$
t	$< t$	≥ 2 in. (50 mm)	2 in. (50 mm) to unlimited

[a] The depth of the groove used for procedure qualification must be deep enough to allow removal of the required test specimen.

8.2.5 Design

Butt joints shall be full-penetration groove welds.

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 8.1.4.1 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.

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.

8.2.6 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 5.12.

Brittle fracture occurrences have been experienced in some manufactured steel materials that are otherwise exempted from toughness testing. Users have experienced brittle fracture of steel components during new construction, repairs, and alterations to existing systems. Some of the materials involved included those produced to A105, A106, and A234 WPB specifications. Current ASTM specifications exempt many of these standard materials from toughness testing down to −20 °F. Increased risk may occur and be experienced in services that involve hydrotesting, operational temperatures down to −20 °F, autorefrigeration, and depressurizing of systems involving LHC. Users are advised to evaluate the literature (see Bibliography) to be aware of this issue in case repairs, replacements, or modifications might be at risk due to these low-toughness fittings.

8.2.7 NDE

Acceptance of a welded repair or alteration shall include NDE in accordance with the applicable code and the owner/operator's specification, unless otherwise specified in API 570. The principles and practices of API 577 shall also be followed. When surface and volumetric examinations are required, they shall be in accordance with ASME *BPVC*, Section V (or equivalent).

8.2.8 Pressure Testing

After welding is completed, a pressure test in accordance with 5.11 shall be performed if practical and deemed necessary by the inspector. Pressure tests are normally required after alterations and major repairs. See ASME PCC-2, Article 5.1, for more information on conducting pressure tests. When a pressure test is not necessary or practical, NDE shall be utilized in lieu of a pressure test. Substituting appropriate NDE procedures for a pressure test after an alteration, rerating, or repair may be done only after consultation with the inspector and the piping engineer. For existing insulated lines that are being pressure tested after repairs, rerating, or alterations, it is not necessary to strip insulation on all existing welds. Pressure tests with longer hold times and observations of pressure gauges can be substituted for insulation stripping when the risks associated with leak under the insulation are acceptable.

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 the following requirements shall be satisfied.

a) The new or replacement piping section is pressure tested and examined in accordance with the applicable code governing the design of the piping system, or if not practical, welds are examined with appropriate NDE, as specified by the authorized piping inspector.

b) The closure weld is a weld between any pipe or standard piping component of equal diameter and thickness, axially aligned (not miter cut), and of equivalent materials. Where slip-on flanges or socket weld fittings are permitted by the specification for the piping system, they may be used within the limitations of that specification. Acceptable alternatives are as follows:

   1) slip-on flanges for design cases up to Class 150 and 500 °F (260 °C);

   2) socket-welded fittings for sizes NPS 2 or less and design cases up to 500 °F (260 °C); a spacer designed for socket welding or some other means shall be used to establish a minimum $^{1}/_{16}$ in. (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 examined by 100 % RT or by angle beam ultrasonic flaw detection, provided the appropriate acceptance criteria have been established.

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

When angle beam ultrasonic methods are used, the owner-operator shall specify industry-qualified UT angle beam examiners for closure welds that have not been pressure tested and for weld repairs identified by the piping engineer or authorized piping inspector.

8.3 Rerating

Rerating piping systems by changing the temperature rating or the MAWP may be done only after all 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 or other industry standards approved by a standards development organization (e.g. API 579-1/ASME FFS-1).

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 one of the following is true.

    1) Documented records indicate that a previous leak test was performed at greater than or equal to the test pressure for the new condition.

    2) The rerate is an increase in the rating temperature that does not affect allowable tensile stress.

    3) The piping integrity is confirmed by appropriate nondestructive inspection techniques in lieu of testing after consultation with the inspector and piping engineer.

e) The piping system is checked to affirm that the required PRDs 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) A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code.

Reratings shall be documented, and appropriate engineering records updated.

9 Inspection of Buried Piping

9.1 General

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 and the inspection can be hindered by the inaccessibility of the affected areas of the piping.

Important, nonmandatory references for underground piping inspection are API 574, API 651, and the following NACE documents: SP0102, SP0169, SP0274, and SP0502.

Buried piping shall be inspected to determine its external surface condition or periodically leak tested per the guidance given in 9.2.6. An inspection plan designed to address the unique challenges of these piping sections is required, and guidance can be found in API 574.

The inspection plans shall be based on an assessment of the effectiveness of protection systems and data obtained from one or more of the following methods:

a) an assessment of the performance of protection methods such as external coatings and cathodic protection;

b) above-ground visual surveillance results (see API 574);

c) observations during maintenance activity on connecting piping of similar materials;

d) representative portions of the actual piping;

e) buried piping in similar service including burial conditions;

f) permanently installed thickness monitoring devices;

g) inspections conducted with in-line inspection devices;

h) results of inspections above the pipe (e.g. direct current voltage gradient), local exposed areas (thickness surveys), or extended range (long-range UT) that provides data on condition and integrity (see API 574).

9.2 Frequency and Extent of Inspection

9.2.1 Above-grade Visual Surveillance

The owner-operator should, at approximately 6-month intervals, survey the surface conditions on and adjacent to each buried piping path (see API 574 for additional guidance on how to perform these actions).

9.2.2 Pipe-to-Soil Potential Survey

A close-interval potential survey on a line with cathodic protection may be used to verify that the buried piping has an acceptable protective potential throughout its length. For poorly coated pipes where cathodic protection potentials are inconsistent, the survey may be conducted at 3-to-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 for inspection or inspected with appropriate NDE at sites where possibilities of 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 better locate active corrosion cells. See API 574 for additional guidance on how to perform these actions.

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. See API 574 for additional guidance on when and how to perform these actions.

9.2.4 Soil Corrosivity

For piping buried in lengths greater than 100 ft (30 m) and not cathodically protected, evaluations of soil corrosivity should be performed at appropriate intervals based on likelihood of change. Soil resistivity measurements may be used for relative classification of the soil corrosivity (see 9.5). Additional factors that may warrant consideration are changes in soil chemistry and analyses of the polarization resistance of the soil and piping interface. See API 574 for guidance on how to perform these actions.

9.2.5 External and Internal Inspection Intervals

If internal corrosion of buried piping is expected because 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 in-line inspection, which can measure wall thickness, or by excavating according to the frequency given in Table 4. Significant external corrosion detected by in-line inspection 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 ft to 8 ft (2.0 m to 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 the minimum required 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 soil surface;

b) the ends of the casing are sealed if the casing is not self-draining;

c) the pressure-carrying pipe is properly coated and wrapped;

d) there is no metallic or electrolytic contact between the casing and the pressure carrying pipe.

9.2.6 Leak Testing Intervals

An alternative or supplement to inspection is leak testing with liquid at a pressure at least 10 % greater than maximum operating pressure at intervals one-half the length of those shown in Table 4 for piping not cathodically protected and at the same intervals as shown in Table 4 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 %, 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 hexafluoride). If the tracer is added to the service fluid, the owner-operator shall confirm suitability for process and product.

Table 4—Frequency of Inspection or Alternate Leak Testing for Buried Piping without Effective Cathodic Protection

Soil Resistivity (ohm-cm)	**Inspection Interval** (years)	**Alternate Pressure Test Interval with Effective Cathodic Protection** (years)	**Alternate Pressure Test Interval without Effective Cathodic Protection** (years)
< 2000	5	5	2.5
2000–10,000	10	10	5
> 10,000	15	15	7.5

9.3 Repairs to Buried Piping Systems

9.3.1 Repairs to Coatings

Any coating removed for inspection shall be renewed and inspected appropriately (preferably by a NACE certified coating inspector). 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 under-film 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

In general, bolted clamps should be avoided for temporary repairs to all buried piping. 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. Temporary repairs on buried piping should be permanently repaired at the next maintenance opportunity unless approved for extension by a piping engineer.

9.3.3 Welded Repairs

Welded repairs shall be made in accordance with 8.2.

9.4 Records

Record systems for buried piping should be maintained in accordance with 7.9. In addition, a record of the location and date of installation of temporary clamps shall be maintained. Also, buried piping should be located on a drawing (i.e. plot plan or piping iso) indicating size and external corrosion mitigation.

Annex A
(normative)

Inspector Certification

A.1 Examination

A written examination to certify inspectors within the scope of API 570 shall be based on the current API 570 Inspector Certification Exam Body of Knowledge as published by API.

To become an authorized API piping inspector, candidates must pass the examination.

A.2 Certification

To qualify for the certification examination, the applicant's 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, or 2 years of military service in a technical role (dishonorable discharge disqualifies credit), plus 1 year of experience in supervision of inspection activities or performance of inspection activities as described in API 570;

b) a 2-year degree or certificate in engineering or technology, or 3 or more years of military service in a technical role (dishonorable discharge disqualifies credit), plus 2 years of experience in the design, fabrication, repair, inspection, or operation of piping systems, of which 1 year shall be in supervision of inspection activities or performance of inspection activities as described in API 570;

c) a high school diploma or equivalent, plus 3 years of experience in the design, fabrication, repair, inspection, or operation of piping systems, of which 1 year shall be in supervision of inspection activities or performance of inspection activities as described in API 570;

d) a minimum of 5 years of experience in the design, fabrication, repair, inspection, or operation of piping systems, of which 1 year shall be in supervision of inspection activities or performance of inspection activities as described in API 570.

A.3 Recertification

A.3.1 Recertification is required 3 years from the date of issuance of the API 570 authorized piping inspector certification. Inspectors who are recertifying shall meet all recertification requirements as defined below. Recertification by written examination will be required for authorized piping inspectors who have not been actively engaged as authorized piping inspectors within the most recent 3-year certification period or fail to meet the recertification requirements prior to the end of their expiration grace period. Exams will be in accordance with all provisions contained in API 570.

A.3.2 "Actively engaged as an authorized piping inspector" shall be defined as a minimum of 20 % of time spent performing inspection activities or supervision of inspection activities, or engineering support of inspection activities, as described in the API 570, over the most recent 3-year certification period.

NOTE Inspection activities common to other API inspection documents (NDE, recordkeeping, review, of welding documents, etc.) may be considered here.

A.3.3 API's Individual Certification Programs includes continuing professional development (CPD) hours in its 3-year recertification requirements for API 570. The Individual Certification Programs will have a phased implementation of the CPD hour requirement. The full CPD requirements of 24 CPDs will be implemented for those expiring on or after January 1, 2025.

A.3.4 Once every other recertification period (every 6 years), actively engaged inspectors shall demonstrate knowledge of revisions to API 570 and other relevant API documents that encompass the body of knowledge. These documents are identified in the relevant Web Quiz Publication Effectivity sheet that were instituted during the previous 6 years or are still a relevant edition. This requirement shall be effective 6 years from the inspector's initial certification date.

Annex B
(informative)

Requests for Interpretations

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 request for interpretation to the API Request for Interpretation website at https://rfi.api.org.

B.3 Request for Interpretation Responses

Responses to previous request for interpretation can be found on the API website at https://mycommittees.api.org/myc-standards-techinterp.

Annex C
(informative)

Two Examples of the Calculation of MAWP Illustrating the Use of the Corrosion Half-life Concept

Table C.1—Examples of the Calculation of 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)	0.01 in./year (0.254 mm/year)
Next planned inspection	5 years
Estimated corrosion loss by date of next inspection	$= 5 \times 0.01 = 0.05$ in. ($5 \times 0.254 = 1.27$ mm)
Estimated thickness minus twice the estimated corrosion loss, t	$= (0.32 - (0.05 \times 2)) = 0.22$ in. [$= (8.13 - (1.27 \times 2)) = 5.59$ mm]
MAWP in U.S. Customary (USC) units	$= 2SEt/D = 550$ psig
In SI units	$= 3747$ kPa
Conclusion: OK	
Example 2	
Next planned inspection	7 years
Estimated corrosion loss by date of next inspection	$= 7 \times 0.01 = 0.07$ in. ($7 \times 0.254 = 1.78$ mm)
Estimated thickness minus twice the estimated corrosion loss, t	$= (0.32 - (0.07 \times 2)) = 0.18$ in. [$= (8.13 - (1.78 \times 2)) = 4.57$ mm]
MAWP In USC units	$= 2SEt/D = 450$ psig
In SI units	$= 3104$ kPa
Conclusion: 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.	
NOTE 1 psig = pounds per square inch gauge; psi = pounds per square inch. NOTE 2 The formula for MAWP is from ASME B31.3, Equation 3b, where t = corroded thickness.	

Bibliography

[1] API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*

[2] API Standard 530, *Calculation of Heater-tube Thicknesses in Petroleum Refineries*

[3] API Recommended Practice 572, *Inspection Practices for Pressure Vessels*

[4] API Recommended Practice 581, *Risk-based Inspection Methodology*

[5] API Recommended Practice 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks*

[6] API Recommended Practice 585, *Pressure Equipment Integrity Incident Investigation*

[7] API Bulletin 587, *Guidance for the Development of Ultrasonic Examiner Qualification Programs*

[8] API Recommended Practice 588, *Recommended Practice for Source Inspection and Quality Surveillance of Fixed Equipment*

[9] API Bulletin 590, *SCIMI Term, Definition, and Acronym Standardization Work Process*

[10] API Recommended Practice 621, *Reconditioning of Metallic Gate, Globe, and Check Valves*

[11] API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*

[12] API Recommended Practice 970, *Corrosion Control Document Systems*

[13] ABSA Information Bulletin IB16-018 [5], *Concerns about Carbon Steels with Low Toughness Properties*

[14] ASME B31.1, *Power Piping*

[15] AWS QC1 [6], *Standard for AWS Certification of Welding Inspectors*

[16] NACE SP0102, *In-Line Inspection of Pipelines*

[17] NACE SP0114, *Refinery Injection and Process Mix Points*

[18] NACE SP0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

[19] NACE SP0170, *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*

[20] NACE SP0502, *Pipeline External Corrosion Direct Assessment Methodology*

[21] WRC 412 [7], *Challenges and Solutions in Repair Welding for Power and Process Plants*

---

[5] Alberta Boilers Safety Association, 9410 20th Avenue NW, Edmonton, Alberta T6N 0A4, Canada, www.absa.ca.

[6] American Welding Society, 8669 NW 36 Street, #130, Miami, Florida 33166, www.aws.org.

[7] Welding Research Council, PO Box 1942, New York, New York 10156, www.forengineers.org.

200 Massachusetts Avenue, NW
Suite 1100
Washington, DC 20001-5571
USA

202-682-8000

Phone Orders:	1-800-854-7179	(Toll-free in the U.S. and Canada)
	303-397-7956	(Local and International)
Fax Orders:	303-397-2740	

Information about API publications, programs and services is available on the web at www.api.org.

Product No. C57005