Inspection Practices for Piping System Components

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Contents

Contents

Contents

Inspection Practices for Piping System Components

1 Scope

This recommended practice (RP) supplements API 570 by providing piping inspectors with information that can improve skill and increase basic knowledge of inspection practices. This RP describes inspection practices for piping, tubing, valves (other than control valves), and fittings used in petroleum refineries and chemical plants. Common piping components, valve types, pipe joining methods, inspection planning processes, inspection intervals and techniques, and types of records are described to aid the inspectors in fulfilling their role implementing API 570. This publication does not cover inspection of specialty items, including instrumentation, furnace tubulars, and control valves.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems*

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

API Recommended Practice 577, *Welding Inspection and Metallurgy*

API Recommended Practice 578, *Material Verification Program for New and Existing Alloy Piping Systems*

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

API Recommended Practice 580, *Risk-Based Inspection*

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

API Recommended Practice 584, *Integrity Operating Windows*

API Standard 598, *Valve Inspection and Testing*

API Recommended Practice 932-B, *Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems*

API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*

ASME B16.5, *Pipe Flanges and Flanged Fittings: NPS $^{1}/_{2}$ Through NPS 24 Metric/Inch Standard*

ASME B16.20, *Metallic Gaskets for Pipe Flanges: Ring-Joint, Spiral-Wound, and Jacketed*

ASME B16.25, *Buttwelding Ends*

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

ASME B16.47, *Large Diameter Steel Flanges: NPS 26 Through NPS 60 Metric/Inch Standard*

ASME B31.3, *Process Piping*

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

ASME *Boiler and Pressure Vessel Code (BPVC)*, *Section V: Nondestructive Examination; Article 11: Acoustic Emission Examination of Fiber Reinforced Plastic Vessels*

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

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

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1 ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

ASME RTP-1, *Reinforced Thermoset Plastic Corrosion-Resistant Equipment*

ASTM G57 [2], *Standard Test Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
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. Alloys may be ferrous or nonferrous based.

NOTE For purposes of this RP, carbon steels are not considered alloys.

3.1.2
alteration
A physical change in any component that has design implications affecting the pressure-containing capability or flexibility of a piping system beyond the scope of its original design. The following are not considered alterations: comparable or duplicate replacement and replacements in kind.

3.1.3
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. Examples include flush lines, seal oil lines, analyzer lines, balance lines, and buffer gas lines.

3.1.4
cladding
A metal plate bonded onto a substrate metal under high pressure and temperature whose properties are better suited to resist damage from the process than the substrate metal.

3.1.5
condition monitoring locations
CMLs
Designated areas on piping systems where periodic examinations are conducted in order to assess the condition of the piping. CMLs may contain one or more examination points and utilize multiple inspection techniques that are based on the predicted damage mechanism(s). CMLs can be a single small area on a piping system (e.g. a 2-in. diameter spot or plane through a section of pipe where examination points exist in all four quadrants of the plane).

NOTE CMLs now include, but are not limited to, what were previously called thickness monitoring locations (TMLs).

3.1.6
contact points
The locations at which a pipe or component rests on or against a support or other object, which may increase its susceptibility to external corrosion, fretting, wear, or deformation, especially as a result of moisture and/or solids collecting at the interface of the pipe and supporting member.

3.1.7
corrosion allowance
Material thickness in excess of the minimum required thickness to allow for metal loss (e.g. corrosion or erosion) during the service life of the piping component.

NOTE Corrosion allowance is not used in design strength calculations.

[2] ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

3.1.8
corrosion rate
The rate of metal loss [e.g. reduction in thickness due to erosion, erosion/corrosion, or the chemical reaction(s) with the environment, etc.] from internal and/or external damage mechanisms.

3.1.9
corrosion specialist
A person acceptable to the owner/user who is knowledgeable and experienced in the specific process chemistries degradation mechanisms, materials selection, corrosion mitigation methods, corrosion monitoring techniques, and their impact on piping systems.

3.1.10
corrosion under insulation
CUI
External corrosion of carbon steel and low-alloy steel piping resulting from water trapped under insulation. External chloride stress corrosion cracking (ECSCC) of austenitic and duplex stainless steel under insulation is also classified as CUI damage.

3.1.11
critical check valves
Check valves in piping systems that have been identified as vital to process safety. Critical check valves are those that need to operate reliably in order to avoid the potential for hazardous events or substantial consequences should reverse flow occur.

3.1.12
cyclic service
Refers to service conditions that may result in cyclic loading and produce fatigue damage (e.g. cyclic loading from pressure, thermal, and/or mechanical loads). Other cyclic loads associated with vibration may arise from such sources as impact, turbulent flow vortices, resonance in compressors, and wind, or any combination thereof. Also see API 579-1/ASME FFS-1 definition of cyclic service in Section I.13 and screening method in Annex B1.5, as well as the definition of “severe cyclic conditions” in ASME B31.3, Section 300.2, Definitions.

3.1.13
damage mechanism
Any type of deterioration encountered in the refining and chemical process industry that can result in metal loss/flaws/defects that can affect the integrity of piping systems (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical, or chemical impacts). See API 571 for a comprehensive list and description of damage mechanisms that may affect process piping systems in the refining, petrochemical, and chemical process industries.

3.1.14
dead-legs
Components of a piping system that normally have little or no significant flow. 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, pressure-relieving valve inlet and outlet header piping, pump trim bypass lines, high-point vents, sample points, drains, bleeders, and instrument connections. Dead-legs also include piping that is no longer in use but still connected to the process.

3.1.15
defect
An imperfection of a type or magnitude exceeding the acceptance criteria.

3.1.16
design pressure (of a piping component)
The pressure at the most severe condition of coincident internal or external pressure and temperature (minimum or maximum) expected during service. It is the same as the design pressure 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.

3.1.17

design temperature (of a piping component)

The temperature at which, under the coincident pressure, the greatest thickness or highest component rating is required. It is the same as the design temperature defined in ASME B31.3 and other code sections and is subject to the same rules relating to allowances for variations of pressure or temperature or both.

NOTE 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.

3.1.18

examination point

recording point, measurement point, test point

A specific location on a piping system to obtain a repeatable thickness measurement for the purpose of establishing an accurate corrosion rate. CMLs may contain multiple test points.

NOTE Test point is a term no longer in use, as “test” in this RP refers to mechanical or physical tests (e.g. tensile tests or pressure tests).

3.1.19

examination

The act of performing any type of nondestructive examination (NDE) for the purpose of data collection and/or quality control functions performed by examiners.

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

3.1.20

examiner

A person who assists the inspector by performing specific NDE on piping system components and evaluates to the applicable acceptance criteria (where qualified to do so), but does not evaluate the results of those examinations in accordance with API 570 requirements, unless specifically trained and authorized to do so by the owner/user.

3.1.21

external inspection

A visual inspection performed from the outside of a piping system to locate external issues that could impact the piping systems’ ability to maintain pressure integrity. External inspections are also intended to find conditions that compromise the integrity of coatings, insulation coverings, supporting structures, and attachments (e.g. stanchions, pipe supports, shoes, hangers, and small branch connections).

3.1.22

fiber reinforced plastic specialist

FRP specialist

A person acceptable to the owner/user who is knowledgeable and experienced in fiber reinforced plastics (FRPs) concerning the process chemistries, degradation mechanisms, materials selection, failure mechanisms, fabrication methods, and their impact on piping systems.

3.1.23

Fitness-For-Service evaluation

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

3.1.24
fitting
Piping component usually associated with a branch connection, a change in direction, or a change in piping diameter. Flanges are not considered fittings.

3.1.25
flammable materials
As used in this RP, includes all fluids that will support combustion. Refer to NFPA 704 for guidance on classifying fluids.

NOTE 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, auto-ignition temperature, or other properties are used in addition to better describe the hazard.

3.1.26
flash point
The lowest temperature at which a flammable product emits enough vapor to form an ignitable mixture in air (e.g. gasoline's flash point is about −45 °F, diesel's flash point varies from about 125 °F to 200 °F).

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

3.1.27
flaw
An imperfection in a piping system usually detected by NDE, which may or may not be a defect, depending upon the applied acceptance criteria.

3.1.28
general corrosion
Corrosion that is distributed more or less uniformly over the surface of the piping, as opposed to being localized in nature.

3.1.29
hold point
A point in the repair or alteration process beyond which work may not proceed until the required inspection/examination has been performed and verified.

3.1.30
imperfection
Flaws or other discontinuities noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis.

3.1.31
indication
A response or evidence resulting from the application of a nondestructive evaluation technique.

3.1.32
industry-qualified ultrasonic angle beam examiner
A person who possesses an ultrasonic (UT) angle beam qualification from API (e.g. API QUTE/QUSE, *Detection and Sizing Tests*) or an equivalent qualification approved by the owner/user.

NOTE Rules for equivalency are defined on the API Individual Certification Program (ICP) website.

3.1.33
injection points
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, desalter 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 in order to achieve specific process objectives.

Examples include chlorinating agents in reformers, water injection in overhead systems, polysulfide injection in catalytic cracking wet gas, antifoam injections, inhibitors, and neutralizers.

NOTE 2 Injection points do not include locations where two process streams join [see **mixing points** (3.1.49)].

3.1.34
in service
Designates a piping system that has been placed in operation as opposed to new construction prior to being placed in service or retired. A piping system not currently in operation due to a process outage is still considered to be in service.

NOTE 1 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 2 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." Installed spare piping is also considered in service, whereas spare piping that is not installed is not considered in service.

3.1.35
in-service inspection
All inspection activities associated with piping after it has been initially placed in service, but before it has been retired.

3.1.36
inspection
The external, internal, or on-stream evaluation (or any combination of the three) of piping condition conducted by the authorized inspector or his/her designee.

NOTE NDE may be conducted by examiners at the discretion of the responsible authorized piping inspector and become part of the inspection process, but the responsible authorized piping inspector shall review and approve the results.

3.1.37
inspection code
Shortened title for API 570.

3.1.38
inspection plan
A documented set of actions and strategies detailing the scope, extent, methods, and timing of specific inspection activities in order to determine the condition of a piping circuit based on defined/expected damage (see Section 7).

3.1.39
inspector
An authorized piping inspector per API 570.

3.1.40
integrity operating window
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 amount of time.

3.1.41
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 do not constitute intermittent service.

3.1.42
internal inspection
An inspection performed on the inside surface of a piping system using visual and/or NDE methods (e.g. boroscope). NDE on the outside of the pipe to determine remaining thickness does not constitute an internal inspection.

3.1.43
jurisdiction
A legally constituted governmental administration that can adopt rules relating to process piping systems.

3.1.44
level bridle
The piping assembly associated with a level gauge attached to a vessel.

3.1.45
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.

3.1.46
localized corrosion
Deterioration restricted to isolated regions on a piping system, i.e. corrosion that is confined to a limited area of the metal surface (e.g. nonuniform corrosion).

3.1.47
minimum alert thickness (flag thickness)
A thickness greater than the minimum 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.

3.1.48
minimum required thickness
The thickness without corrosion allowance for each component of a piping system based on the appropriate design code calculations and code allowable stress that consider pressure, mechanical, and structural loadings.

NOTE Alternately, minimum required thicknesses can be reassessed using Fitness-For-Service analysis in accordance with API 579-1/ASME FFS-1.

3.1.49
mixing point
Mixing points are locations in a process piping system where two or more streams meet. 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.

3.1.50
on-stream piping
Piping systems that have not been isolated and decontaminated, i.e. still connected to in-service process equipment.

NOTE Piping systems that are on-stream can be full of product during normal processing or empty or may still have residual process fluids in them and not be currently part of the process system (e.g. temporarily valved out of service).

3.1.51
owner/user
The organization that exercises control over the operation, engineering, inspection, repair, alteration, pressure testing, and rerating of the piping systems.

3.1.52
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 Materials designated “tube” or “tubing” in the specifications are treated as pipe when intended for pressure service external to fired heaters. Piping internal to fired heaters should be in compliance with API 530.

3.1.53
pipe spool
A section of piping with a flange or other connecting fitting, such as a union, on both ends, which allows the removal of the section from the system.

3.1.54
piperack piping
Process piping that is supported by consecutive stanchions or sleepers (including straddle racks and extensions).

3.1.55
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.

3.1.56
piping engineer
One or more persons or organizations acceptable to the owner/user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics that affect the integrity and reliability of piping components and systems.

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

3.1.57
piping system
An assembly of interconnected pipe that typically are subject to the same (or nearly the same) process fluid composition and/or design conditions.

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 beams, and foundations.

3.1.58
pressure design thickness
Minimum pipe wall thickness needed to hold the design pressure at the design temperature.

NOTE 1 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.

NOTE 2 Pressure design thickness is determined using the rating code formula, including needed reinforcement thickness.

3.1.59
primary process piping
Process piping in normal, active service that cannot be valved off or, if it were valved off, would significantly affect unit operability. Primary process piping typically does not include small-bore or auxiliary process piping (see also **secondary process piping**).

3.1.60
process piping
Hydrocarbon or chemical piping located at, or associated with, a refinery or manufacturing facility. Process piping includes piperack, tank farm, and process unit piping, but excludes utility piping (e.g. steam, water, air, nitrogen, etc.).

3.1.61
quality assurance
All planned, systematic, and preventative actions required to determine if materials, equipment, or services will meet specified requirements so that the piping will perform satisfactorily in service. Quality assurance plans will specify the necessary quality control activities and examinations.

NOTE The contents of a quality assurance inspection management system for piping systems are outlined in API 570, Section 4.3.1.

3.1.62
quality control
Those physical activities that are conducted to check conformance with specifications in accordance with the quality assurance plan (e.g. NDE techniques, hold point inspections, material verifications, checking certification documents, etc.).

3.1.63
rating
The work process of making calculations to establish pressures and temperatures appropriate for a piping system, including design pressure/temperature, maximum allowable working pressure (MAWP), structural minimums, required thicknesses, etc.

3.1.64
repair
A repair is the work necessary to restore a piping system to a condition suitable for safe operation at the design conditions.

NOTE If any of the restorative changes result in a change of design temperature or pressure, the requirements for rerating also shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair. Repairs can be temporary or permanent.

3.1.65
rerating
A change in the design temperature, design pressure, or the MAWP of a piping system.

NOTE A rerating may consist of an increase, decrease, or a combination. Derating below original design conditions is a means to provide increased corrosion allowance.

3.1.66
Risk-Based Inspection
RBI
A risk assessment and risk management process that is focused on inspection planning for piping systems for loss of containment in processing facilities, which considers both the probability of failure and consequence of failure due to materials of construction deterioration.

3.1.67
scanning
The movement of a device (visual, ultrasonic, etc.) over a wide area as opposed to a spot reading and used to find flaws/defects (e.g. the thinnest thickness measurement at a CML or cracking in a weldment).

3.1.68
secondary process piping
Process piping located downstream of a block valve that can be valved off without significantly affecting the process unit operability is commonly referred to as secondary process piping. Often, secondary process piping is small-bore piping (SBP).

3.1.69
small-bore piping
SBP
Pipe or pipe components that are less than or equal to NPS 2.

3.1.70
soil-to-air interface
SAI
An area in which external corrosion may occur or be accelerated on partially buried pipe or buried pipe 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 the operating temperature. The zone generally is considered to be from 12 in. (30 cm) below to 6 in. (15 cm) above the soil surface. Pipe running parallel with the soil surface that contacts the soil is included.

3.1.71
strip lining
Strips of metal plates or sheets that are welded to the inside of the pipe wall.

NOTE Normally, the strips are of a more corrosion-resistant or erosion-resistant alloy than the pipe wall and provide additional corrosion/erosion resistance.

3.1.72
structural minimum thickness
Minimum required thickness without corrosion allowance, based on the mechanical loads other than pressure to prevent sagging, buckling, and plastic collapse of the piping.

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

3.1.73
tell-tale holes
Small pilot holes drilled in the pipe or component wall using specified and controlled patterns and depths to act as an early detection and safeguard against ruptures resulting from internal corrosion, erosion, and erosion-corrosion.

3.1.74
temporary repairs
Repairs made to piping systems in order to restore sufficient integrity to continue safe operation until permanent repairs can be scheduled and accomplished within a time period acceptable to the inspector and/or piping engineer.

3.1.75
testing
Procedures used to determine pressure tightness, material hardness, strength, and notch toughness.

Examples include pressure testing, whether performed hydrostatically, pneumatically, or a combination of hydrostatic/pneumatic, or mechanical testing.

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

3.1.76
utility piping
Nonprocess piping associated with a process unit (e.g. steam, air, water, nitrogen, etc.).

3.1.77
weld overlay
A lining applied by welding of a metal to the surface.

NOTE The filler metal typically has better corrosion and/or erosion resistance to the environment than the underlying metal.

3.2 Acronyms and Abbreviations

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

ACFM	alternating current field measurement
AE	acoustic emission examination technique
AWWA	American Water Works Association
CR	computed radiography
CML	condition monitoring location
CSCC	chloride stress corrosion cracking
CUI	corrosion under insulation
DN	nominal diameter (used in SI system to describe pipe size)
ECSCC	external chloride stress corrosion cracking
EMAT	electromagnetic acoustic transducer
ERW	electric resistance welded
ET	eddy current examination technique
FCC	fluid catalytic cracking
FRP	fiber reinforced plastic
GRP	glass reinforced plastic
HF	hydrofluoric acid
HIC	hydrogen-induced cracking
ID	inside diameter
IDMS	Inspection Data Management System
ILI	in-line inspection
IP	initial pulse
LCD	liquid crystal display
LED	light-emitting diode
MOC	management of change
MAWP	maximum allowable working pressure

MFL	magnetic flux leakage
MT	magnetic particle examination technique
MW	microwave examination technique
NPS	nominal pipe size (followed, when appropriate, by the specific size designation number without an inch symbol)
OD	outside diameter
OSHA	Occupational Safety and Health Administration
P&ID	piping and instrument diagram
PAUT	phased array ultrasonic testing
PEC	pulsed eddy current
PFD	process flow diagram
PMI	positive material identification
PPE	personal protective equipment
PRD	pressure-relief device
PT	liquid penetrant examination technique
PWHT	postweld heat treatment
RBI	Risk-Based Inspection
RT	radiographic examination technique
SAI	soil-to-air interface (of buried piping)
SBP	small-bore piping
SCC	stress corrosion cracking
SDO	standards development association
TML	thickness monitoring location
TOFD	time-of-flight diffraction
UT	ultrasonic examination technique
UV	ultraviolet
WFMT	wet fluorescent magnetic particle examination technique
WPS	welding procedure specification

4 Piping Components

4.1 Piping

4.1.1 General

Piping can be made from any material that can be rolled and welded, cast, or drawn through dies to form a tubular section. The two most common carbon steel piping materials used in the petrochemical industry are ASTM A53/A53M and ASTM A106. The industry uses both seamless and electric resistance welded (ERW) piping for process services, depending upon current economics and the potential for accelerated corrosion of the weld seam in the service. Piping of a nominal size larger than 16 in. (406 mm) is usually made by rolling plates to size and welding the seams. Centrifugally cast piping can be cast then machined to any desired thickness. Steel and alloy piping are manufactured to standard dimensions in nominal pipe sizes (NPSs) up to 48 in. (1219 mm).

Pipe wall thicknesses are designated as pipe schedules in NPSs up to 36 in. (914 mm). The traditional thickness designations—standard weight, extra strong, and double extra strong—differ from schedules and are used for NPSs up to 48 in. (1219 mm). In all standard sizes, the outside diameter (OD) remains nearly constant regardless of the thickness. The size refers to the approximate inside diameter (ID) of standard weight pipe for NPSs equal to or less than 12 in. (305 mm). The size denotes the actual OD for NPSs equal to or greater than 14 in. (356 mm). The pipe diameter is expressed as NPS, which is based on these size practices. Table 1 and Table 2 list the dimensions of ferritic and stainless steel pipe from NPS $^{1}/_{8}$ [DN (nominal diameter) 6] up through NPS 24 (DN 600). See ASME B36.10M for the dimensions of welded and seamless wrought steel piping and ASME B36.19M for the dimensions of stainless steel piping.

Allowable tolerances in pipe diameter differ from one piping material to another. Table 3 lists the acceptable tolerances for diameter and thickness of most ASTM ferritic pipe standards. The actual thickness of seamless piping can vary from its nominal thickness by a manufacturing tolerance of as much as 12.5 %. The under tolerance for welded piping is 0.01 in. (0.25 mm). Cast piping has a thickness tolerance of $+^{1}/_{16}$ in. (1.6 mm) and –0 in. (0 mm), as specified in ASTM A53/A53M. Consult the ASTM or the equivalent ASME material specification to determine what tolerances are permitted for a specific material. Piping that has ends that are beveled or threaded with standard pipe threads can be obtained in various lengths. Piping can be obtained in different strength levels depending on the grades of material, including alloying material and the heat treatments specified.

Cast iron piping is generally used for nonhazardous service, such as water; it is generally not recommended for pressurized hydrocarbon service because of its brittle nature. The standards and sizes for cast iron piping differ from those for welded and seamless piping.

4.1.2 FRP Pipe

Nonmetallic materials also have some limited uses in piping systems in the hydrocarbon process industry. They have significant advantages over more familiar metallic materials, but they also have unique construction and deterioration mechanisms that can lead to premature failures if not addressed adequately.

The term nonmetallic has a broad definition but in this section refers to the fiber reinforced plastic groups encompassed by the generic acronym FRP and GRP (glass reinforced plastic). The extruded, generally homogenous nonmetallics, such as high- and low-density polyethylene, are excluded from coverage in this document but are also used in some utility and specialty services.

Typical service applications of FRP piping include service water, process water, cooling medium, potable water, sewage/gray water, nonhazardous waste, nonhazardous drains, nonhazardous vents, chemicals, firewater ring mains, firewater deluge systems, and produced and ballast water.

Table 1—Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Ferritic Steel Pipe

Pipe Size NPS	Pipe Size DN	Actual OD in.	Actual OD mm	Schedule	Weight Class	Approximate ID in.	Approximate ID mm	Nominal Thickness in.	Nominal Thickness mm
1/8	6	0.405	10.3	40	STD	0.269	6.84	0.068	1.73
				80	XS	0.215	5.48	0.095	2.41
1/4	8	0.540	13.7	40	STD	0.364	9.22	0.088	2.24
				80	XS	0.302	7.66	0.119	3.02
3/8	10	0.675	17.1	40	STD	0.493	12.48	0.091	2.31
				80	XS	0.423	10.7	0.126	3.20
1/2	15	0.840	21.3	40	STD	0.622	15.76	0.109	2.77
				80	XS	0.546	13.84	0.147	3.73
				160		0.464	11.74	0.188	4.78
				—	XXS	0.252	6.36	0.294	7.47
3/4	20	1.050	26.7	40	STD	0.824	20.96	0.113	2.87
				80	XS	0.742	18.88	0.154	3.91
				160		0.612	15.58	0.219	5.56
				—	XXS	0.434	11.06	0.308	7.82
1	25	1.315	33.4	40	STD	1.049	26.64	0.133	3.38
				80	XS	0.957	24.3	0.179	4.55
				160		0.815	20.7	0.250	6.35
				—	XXS	0.599	15.22	0.358	9.09
1 1/4	32	1.660	42.2	40	STD	1.380	35.08	0.140	3.56
				80	XS	1.278	32.5	0.191	4.85
				160		1.160	29.5	0.250	6.35
				—	XXS	0.896	22.8	0.382	9.70
1 1/2	40	1.900	48.3	40	STD	1.610	40.94	0.145	3.68
				80	XS	1.500	38.14	0.200	5.08
				160		1.338	34.02	0.281	7.14
				—	XXS	1.100	28	0.400	10.15
2	50	2.375	60.3	40	STD	2.067	52.48	0.154	3.91
				80	XS	1.939	49.22	0.218	5.54
				160		1.687	42.82	0.344	8.74
				—	XXS	1.503	38.16	0.436	11.07
2 1/2	65	2.875	73.0	40	STD	2.469	62.68	0.203	5.16
				80	XS	2.323	58.98	0.276	7.01
				160		2.125	53.94	0.375	9.53
				—	XXS	1.771	44.96	0.552	14.02
3	80	3.500	88.9	40	STD	3.068	77.92	0.216	5.49
				80	XS	2.900	73.66	0.300	7.62
				160		2.624	66.64	0.438	11.13
				—	XXS	2.300	58.42	0.600	15.24
3 1/2	90	4.000	101.6	40	STD	3.548	90.12	0.226	5.74
				80	XS	3.364	85.44	0.318	8.08

Table 1—Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Ferritic Steel Pipe (Continued)

Pipe Size		Actual OD in.	Actual OD mm	Schedule	Weight Class	Approximate ID in.	Approximate ID mm	Nominal Thickness in.	Nominal Thickness mm
NPS	DN								
4	100	4.500	114.3	40	STD	4.026	102.26	0.237	6.02
				80	XS	3.826	97.18	0.337	8.56
				120		3.624	92.04	0.438	11.13
				160		3.438	87.32	0.531	13.49
				—	XXS	3.152	80.06	0.674	17.12
5	125	5.563	141.3	40	STD	5.047	128.2	0.258	6.55
				80	XS	4.813	122.24	0.375	9.53
				120		4.563	115.9	0.500	12.70
				160		4.313	109.54	0.625	15.88
				—	XXS	4.063	103.2	0.750	19.05
6	150	6.625	168.3	40	STD	6.065	154.08	0.280	7.11
				80	XS	5.761	146.36	0.432	10.97
				120		5.501	139.76	0.562	14.27
				160		5.187	131.78	0.719	18.26
				—	XXS	4.897	124.4	0.864	21.95
8	200	8.625	219.1	20		8.125	206.4	0.250	6.35
				30		8.071	205.02	0.277	7.04
				40	STD	7.981	202.74	0.322	8.18
				60		7.813	198.48	0.406	10.31
				80	XS	7.625	193.7	0.500	12.70
				100		7.437	188.92	0.594	15.09
				120		7.187	182.58	0.719	18.26
				140		7.001	177.86	0.812	20.62
				—	XXS	6.875	174.64	0.875	22.23
				160		6.813	173.08	0.906	23.01
10	250	10.75	273.0	20		10.250	260.3	0.250	6.35
				30		10.136	257.4	0.307	7.80
				40	STD	10.020	254.46	0.365	9.27
				60	XS	9.750	247.6	0.500	12.70
				80		9.562	242.82	0.594	15.09
				100		9.312	236.48	0.719	18.26
				120		9.062	230.12	0.844	21.44
				140		8.750	222.2	1.000	25.40
				160		8.500	215.84	1.125	28.58

Table 1—Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Ferritic Steel Pipe (Continued)

Pipe Size NPS	Pipe Size DN	Actual OD in.	Actual OD mm	Schedule	Weight Class	Approximate ID in.	Approximate ID mm	Nominal Thickness in.	Nominal Thickness mm
12	300	12.750	323.8	20		12.250	311.1	0.250	6.35
				30		12.090	307.04	0.330	8.38
				—	STD	12.000	304.74	0.375	9.53
				40		11.938	303.18	0.406	10.31
				—	XS	11.750	298.4	0.500	12.70
				60		11.626	295.26	0.562	14.27
				80		11.374	288.84	0.688	17.48
				100		11.062	280.92	0.844	21.44
				120		10.750	273	1.000	25.40
				140		10.500	266.64	1.125	28.58
				160		10.126	257.16	1.312	33.32
14	350	14.000	355.6	10		13.500	342.9	0.250	6.35
				20		13.376	339.76	0.312	7.92
				30	STD	13.250	336.54	0.375	9.53
				40		13.124	333.34	0.438	11.13
				—	XS	13.000	330.2	0.500	12.70
				60		12.812	325.42	0.594	15.09
				80		12.500	317.5	0.750	19.05
				100		12.124	307.94	0.938	23.83
				120		11.812	300.02	1.094	27.79
				140		11.500	292.088	1.125	31.756
				160		11.188	284.18	1.406	35.71
16	400	16.000	406.4	10		15.500	393.7	0.250	6.35
				20		15.376	390.56	0.312	7.92
				30	STD	15.250	387.34	0.375	9.53
				40	XS	15.000	381	0.500	12.70
				60		14.688	373.08	0.656	16.66
				80		14.312	363.52	0.844	21.44
				100		13.938	354.02	1.0311	26.19
				120		13.562	344.48	1.219	30.96
				140		13.124	333.34	1.438	36.53
				160		12.812	325.42	1.594	40.49
18	450	18.000	457	10		17.500	444.3	0.250	6.35
				20		17.376	441.16	0.312	7.92
				—	STD	17.250	437.94	0.375	9.53
				30		17.124	434.74	0.438	11.13
				—	XS	17.000	431.6	0.500	12.70
				40		16.876	428.46	0.562	14.27
				60		16.500	418.9	0.750	19.05
				80		16.124	409.34	0.938	23.83
				100		15.688	398.28	1.156	29.36
				120		15.250	387.14	1.375	34.93
				140		14.876	377.66	1.562	39.67
				160		14.438	366.52	1.781	45.24

Table 1—Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Ferritic Steel Pipe (Continued)

Pipe Size		Actual OD in.	Actual OD mm	Schedule	Weight Class	Approximate ID in.	Approximate ID mm	Nominal Thickness in.	Nominal Thickness mm
NPS	DN								
20	500	20.000	508	10		19.500	495.3	0.250	6.35
				20	STD	19.250	488.94	0.375	9.53
				30	XS	19.000	482.6	0.500	12.70
				40		18.812	477.82	0.594	15.09
				60		18.376	466.76	0.812	20.62
				80		17.938	455.62	1.031	26.19
				100		17.438	442.92	1.281	32.54
				120		17.000	431.8	1.500	38.10
				140		16.500	419.1	1.750	44.45
				160		16.062	407.98	1.969	50.01
22	550	22.000	559	10		21.500	546.3	0.250	6.35
				20	STD	21.250	539.94	0.375	9.53
				30	XS	21.000	533.6	0.500	12.70
				60		20.250	514.54	0.875	22.23
				80		19.750	501.84	1.125	28.58
				100		19.250	489.14	1.375	34.93
				120		18.750	476.44	1.625	41.28
				140		18.250	463.74	1.875	47.63
				160		17.750	451.04	2.125	53.98
24	600	24.000	610	10		23.500	597.3	0.250	6.35
				20	STD	23.250	590.94	0.375	9.53
				—	XS	23.000	584.6	0.500	12.70
				30		22.876	581.46	0.562	14.27
				40		22.624	575.04	0.688	17.48
				60		22.062	560.78	0.969	24.61
				80		21.562	548.08	1.219	30.96
				100		20.938	532.22	1.531	38.89
				120		20.376	517.96	1.812	46.02
				140		19.876	505.26	2.062	52.37
				160		19.312	490.92	2.344	59.54

Table 2—Nominal Pipe Sizes, Schedules, and Dimensions of Stainless Steel Pipe

Pipe Size NPS	Pipe Size DN	Actual OD in.	Actual OD mm	Schedule	Wall Thickness in.	Wall Thickness mm
1/8	6	0.405	10.3	10S	0.049	1.24
				40S	0.068	1.73
				80S	0.096	2.41
1/4	8	0.540	13.7	10S	0.065	1.65
				40S	0.088	2.24
				80S	0.119	3.02
3/8	10	0.675	17.1	10S	0.065	1.65
				40S	0.091	2.31
				80S	0.126	3.20
1/2	15	0.840	21.3	5S	0.065	1.65
				10S	0.083	2.11
				40S	0.109	2.77
				80S	0.147	3.73
3/4	20	1.050	26.7	5S	0.065	1.65
				10S	0.083	2.11
				40S	0.113	2.87
				80S	0.154	3.91
1	25	1.315	33.4	5S	0.065	1.65
				10S	0.109	2.77
				40S	0.133	3.38
				80S	0.179	4.55
1 1/4	32	1.660	42.2	5S	0.065	1.65
				10S	0.109	2.77
				40S	0.140	3.56
				80S	0.191	4.85
1 1/2	40	1.900	48.3	5S	0.065	1.65
				10S	0.109	2.77
				40S	0.145	3.68
				80S	0.200	5.08
2	50	2.375	60.3	5S	0.065	1.65
				10S	0.109	2.77
				40S	0.154	3.91
				80S	0.218	5.54
2 1/2	65	2.875	73	5S	0.083	2.11
				10S	0.120	3.05
				40S	0.203	5.16
				80S	0.276	7.01
3	80	3.500	88.9	5S	0.083	2.11
				10S	0.120	3.05
				40S	0.216	5.49
				80S	0.300	7.62

Table 2—Nominal Pipe Sizes, Schedules, and Dimensions of Stainless Steel Pipe (Continued)

Pipe Size NPS	Pipe Size DN	Actual OD in.	Actual OD mm	Schedule	Wall Thickness in.	Wall Thickness mm
$3^1/_2$	90	4.000	101.6	5S	0.083	2.11
				10S	0.120	3.05
				40S	0.226	5.74
				80S	0.318	8.08
4	100	4.500	114.3	5S	0.083	2.11
				10S	0.120	3.05
				40S	0.237	6.02
				80S	0.337	8.56
5	125	5.563	141.3	5S	0.109	2.77
				10S	0.134	3.40
				40S	0.258	6.55
				80S	0.375	9.53
6	150	6.625	168.3	5S	0.109	2.77
				10S	0.134	3.40
				40S	0.280	7.11
				80S	0.432	10.97
8	200	8.625	219.1	5S	0.109	2.77
				10S	0.148	3.76
				40S	0.322	8.18
				80S	0.500	12.70
10	250	10.750	273.1	5S	0.134	3.40
				10S	0.165	4.19
				40S	0.365	9.27
				80S	0.500	12.70
12	300	12.750	323.9	5S	0.156	3.96
				10S	0.180	4.57
				40S	0.375	9.53
				80S	0.500	12.70
14	350	14.00	355.6	5S	0.156	3.96
				10S	0.188	4.78
16	400	16.00	406.4	5S	0.165	4.19
				10S	0.188	4.78
18	450	18.00	457	5S	0.165	4.19
				10S	0.188	4.78
20	500	20.00	508	5S	0.188	4.78
				10S	0.218	5.54
22	550	22.00	559	5S	0.188	4.78
				10S	0.218	5.54
24	600	24.00	610	5S	0.218	5.54
				10S	0.250	6.35

Table 3—Permissible Tolerances in Diameter and Thickness for Ferritic Pipe

ASTM Material Standard	Acceptable Diameter Tolerances [a]			Acceptable Thickness Tolerances [b]
A53	≤ NPS 1 1/2	+1/64 in. (0.4 mm)	–1/64 in. (0.4 mm)	–12.5 %
	> NPS 1 1/2	±1 %		
A106 A312/A312M A530/A530M A731/A731M A790/A790M	≥ NPS 1/8 ≤ NPS 1 1/2	+1/64 in. (0.4 mm)	–1/64 in. (0.4 mm)	
	> NPS 1 1/2 ≤ NPS 4	+1/32 in. (0.79 mm)	–1/32 in. (0.79 mm)	
	> NPS 4 ≤ NPS 8	+1/16 in. (1.59 mm)	–1/32 in. (0.79 mm)	
	> NPS 8 ≤ NPS 18	+3/32 in. (2.38 mm)	–1/32 in. (0.79 mm)	
	> NPS 18 ≤ NPS 26	+1/8 in. (3.18 mm)	–1/32 in. (0.79 mm)	
	> NPS 26 ≤ NPS 34	+5/32 in. (3.97 mm)	–1/32 in. (0.79 mm)	
	> NPS 34 ≤ NPS 48	+3/16 in. (4.76 mm)	–1/32 in. (0.79 mm)	
A134	Circumference ±0.5 % of specified diameter			Acceptable tolerance of plate standard
A135/A135M	+1 % of nominal			–12.5 %
A358/A358M	±0.5 %			–0.01 in. (0.3 mm)
A409/A409M	Wall < 0.188 in. (4.8 mm) thickness ±0.20 %			–0.018 in. (0.46 mm)
	Wall ≥ 0.188 in. (4.8 mm) thickness ±0.40 %			
A451/A451M	—			+1/8 in. (3 mm); –0
A524	> NPS 1/8 ≤ 1 1/2	+1/64 in. (0.4 mm)	–1/32 in. (0.8 mm)	–12.5 %
	> NPS 1 1/2 ≤ 4	+1/32 in. (0.8 mm)	–1/32 in. (0.8 mm)	
	> NPS 4 ≤ 8	+1/16 in. (1.6 mm)	–1/32 in. (0.8 mm)	
	> NPS 8 ≤ 18	+3/32 in. (2.4 mm)	–1/32 in. (0.8 mm)	
	> NPS 18	+1/8 in. (3.2 mm)	–1/32 in. (0.8 mm)	
A587	See ASTM A587, Table 4			
A660/A660M	—			10 % greater than the specified minimum wall thickness
				Zero less than the specified minimum wall thickness
A671/A671M	+0.5 % of specified diameter			0.01 in. (0.3 mm) less than the specified thickness
A672/A672M, A691/A691M	±0.5 % of specified diameter			

Table 3—Permissible Tolerances in Diameter and Thickness for Ferritic Pipe (Continued)

ASTM Material Standard	Acceptable Diameter Tolerances [a]		Acceptable Thickness Tolerances [b]
A813/A813M	≥ NPS $1^1/_4$	±0.010 in. (0.25 mm)	±12 % for wall thickness < 0.188 in. (4.8 mm) ±0.030 in. (0.8 mm) for wall thickness ≥ 0.188 in. (4.8 mm)
	≥ NPS $1^1/_2$ ≤ NPS 6	±0.020 in. (0.5 mm)	
	≥ NPS 8 ≤ NPS 18	±0.030 in. (0.75 mm)	
	≥ NPS 20 ≤ NPS 24	±0.040 in. (1 mm)	
	NPS 30	±0.050 in. (1.25 mm)	
A814/A814M	See ASTM A814/ A814M, Table 1		

[a] Tolerance on DN unless otherwise specified.
[b] Tolerance on nominal wall thickness unless otherwise specified.

Design of these piping systems is largely dependent on the application. Many companies have developed their own specifications that outline the materials, quality, fabrication requirements, and design factors. ASME B31.3, Chapter VII covers design requirements for nonmetallic piping. American Water Works Association (AWWA) is an organization that also provides guidance on FRP pipe design and testing. These codes and standards, however, do not offer guidance as to the right choice of corrosion barriers, resins, fabricating methods, and joint systems for a particular application. The user should consider other sources such as resin and pipe manufacturers for guidance on their particular application.

Historically, many of the failures in FRP piping are related to poor construction practice. Lack of familiarity with the materials can lead to a failure to recognize the detail of care that must be applied in construction.

FRP materials require some understanding as to their manufacture. Each manufacturing technique will generate a different set of physical properties. Each resin system has a temperature limitation, and each joint system has its advantages and disadvantages. Qualification of bonders and jointers is as important for FRP fabrication as qualification of welders is for metal fabrication. Due to limitations in NDE methods, the emphasis must be placed on procedure and bonder qualifications and testing. Similarly, because the material stiffness is much less than metal and because FRP has different types of shear, small-bore connections will not withstand the same shear stress, weight loadings, or vibrations that are common with metallic piping; supporting attachments such as valves, etc. on small-bore connections should be analyzed in detail.

FRP piping is manufactured in many ways. Every service application should be reviewed for proper resin, catalyst, corrosion barrier (liner) composition, and structural integrity. Although FRP is considered to be corrosion resistant, using the wrong resin or corrosion barrier can be a cause for premature failure. FRP pipe can experience ultraviolet (UV) degradation over time if not adequately protected. Adding a UV inhibitor in the resin will help prevent premature fiber blooming caused by UV. The user should consider this option for all FRP piping applications and be aware that this would be a supplemental specification.

All FRP piping should be inspected by a person that is knowledgeable in the curing, fabrication, and quality of FRP materials. The level of inspection should be determined by the user. ASME RTP-1, Table 6-1 can be used as a guide to identify liner and structure imperfections that are common in FRP laminates. Standardized FRP piping systems commonly called “commodity piping” are manufactured for a variety of services and are sold as products with a predetermined design, resin, corrosion barrier, and structure. The piping manufacturers typically have a quality control specification that identifies the level of quality and allowable tolerance that is built into their product. Custom fabricated pipe is typically designed and manufactured for a specific application. The resin, catalyst system, corrosion barrier, and structure are specified and the pipe is manufactured to a specification and to a specified level of quality and tolerances.

The FRP inspector should verify by documentation and inspection that the piping system has been built with the proper materials, quality, hardness, and thickness as requested in the pipe specification. A final inspection should be performed at the job site to ensure that the pipe has not experienced any mechanical damage during shipment.

4.1.3 SBP, Secondary Piping, and Auxiliary Piping

SBP can be used as primary process piping or as nipples, secondary piping, and auxiliary piping. Nipples are normally 6 in. (152 mm) or less in length and are most often used in vents at piping high points and drains at piping low points and used to connect secondary/auxiliary piping. Secondary piping is normally isolated from the main process lines by closed valves and can be used for such functions as sample taps. Auxiliary piping is normally open to service but can be isolated from the primary process. Examples include flush lines, instrument piping, analyzer piping, lubrication, and seal oil piping for rotating equipment.

Inspectors and piping engineers should be aware of design, maintenance, and operating issues that cause SBP failures and may require mitigation. Those issues include but are not limited to:

— mismatched union connections from differing manufacturers;

— the potential for thermal growth or contraction that could cause SBP stresses that may lead to failure;

— cyclic loading from thermal or mechanical loads that could cause fatigue cracking (e.g. overhung SBP piping systems, potential for PRV chattering in certain relief scenarios, flow induced vibration, vaporization, and cavitation);

— inadequate management of change (MOC) consideration that may cause unanticipated thermal, mechanical, or corrosive scenarios on SBP;

— inadequate design (e.g. support and pipe schedule) for the various unanticipated transient loads imposed on SBP;

— inadequate protection from external impacts (e.g. vehicular traffic and maintenance activities);

— inadequate protection or support for SBP that could be subject to being used as personnel or tool/equipment support (e.g. step, tie-off, hand rail, pulley, lever);

— improperly selected components for the class of service;

— inadequate consideration for the use of socket weld versus threaded fittings, both of which can lead to premature failure if not specified and/or installed properly;

— inadequate thickness for threaded SBP after accounting for the loss of thickness from thread cutting or lack of bottom gap when welding socket welded fittings,

— not including alloy SBP in positive material identification (PMI) procedures;

— not including SBP in piping damage mechanism reviews;

— replacement of SBP components with different alloys without adequate consideration for potential new damage mechanisms (e.g. “upgrading” to stainless steel in a wet chloride environment).

4.1.4 Pipe Linings

Internal linings can be incorporated into piping design to reduce corrosion, erosion, product contamination, and pipe metal temperatures. The linings can generally be characterized as metallic and nonmetallic. Metallic liners are installed in various ways, such as cladding, weld overlay, and strip lining. Clad pipe has a metallic liner that is an integral part of the plate material rolled or explosion bonded before fabrication of the pipe. They may instead be separate strips of metal fastened to the pipe by welding referred to strip lining. Corrosion-resistant metal can also be applied to the pipe surfaces by various weld overlay processes. Metallic liners can be made of any metal resistant to the corrosive or erosive environment, depending upon its purpose. These include stainless steels, high alloys, cobalt-based alloys, etc.

Nonmetallic liners can be used to resist corrosion and erosion or to insulate and reduce the temperature on the pipe wall. Some common nonmetallic lining materials for piping are concrete, castable refractory, plastic, and thin-film coatings.

4.2 Tubing

With the exception of heater, boiler, and exchanger tubes, tubing is similar to piping, but is manufactured in many ODs and wall thicknesses. Tubing is generally seamless, but can be welded. Its stated size is the actual OD rather than NPS. [ASTM B88 tubing, which is often used for steam tracing, is an exception in that its size designation is $^{1}/_{8}$ in. (3.2 mm) less than the actual OD.] Tubing is usually made in small diameters and is mainly used for heat exchangers, instrument piping, lubricating oil services, steam tracing, and similar services.

A commonly used tubing material is the 18Cr-8Ni family of stainless steels, such as Types 304 and 316. However, it should be noted that even though these tubing materials may be resistant to many chemical fluids, they are susceptible to pitting and chloride stress corrosion cracking (CSCC) if:

a) there is a presence of chlorides that may come from insulation, PVC insulation cladding/jacketing, the atmosphere, rain (especially in marine environments), deluge water systems, washdown of surrounding decks and roads, etc. Internally, chlorides can be common in many process streams and may, in fact, be introduced by hydrotest water. Concentration mechanisms such as local evaporation of water can also increase susceptibility to cracking;

b) there is a presence of water. Sources are similar to chlorides above. Often the chlorides are dissolved in various water sources;

c) exposed to a temperature above about 140 °F (60 °C);

   NOTE It should be noted that chloride pitting and CSCC can occur at temperatures below 140 °F in some instances, such as low pH environments, or in components with high residual stress.

d) there is tubing material stress, which is common from residual stresses imparted during tube manufacturing processes or during installation processes like tube bending and compression fitting makeup.

Tubing failures due to CSCC and/or pitting can be too unpredictable to manage through inspection efforts; therefore, a materials or corrosion specialist/engineer should be consulted for alloy recommendations used in aggressive environments. Consideration should be given to using materials like Incoloy 825 (for many elevated temperature refining applications), Hastelloy C276 (for sour water or hot hydrofluoric acid [HF] services where oxidizing species are present), and Alloy 20Cb3 (for sulfuric acid applications) or other available high alloys because of their improved resistance to CSCC and/or pitting.

4.3 Valves

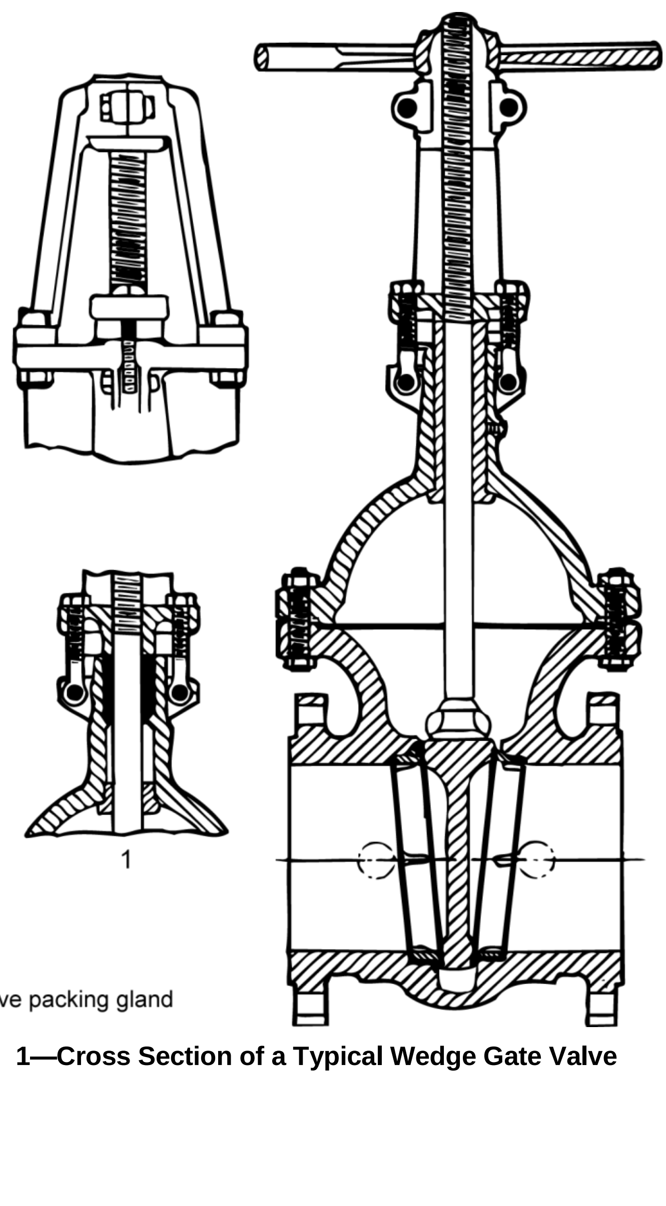
4.3.1 General

The basic types of valves are gate, globe, plug, ball, diaphragm, butterfly, check, and slide valves. Valves are made in standard pipe sizes, materials, body thickness, and pressure ratings that permit them to be used in any pressure-temperature service in accordance with ASME B16.34 or API 599, API 600, API 602, API 603, API 608, or API 609, as applicable. Valve bodies can be cast, forged, machined from bar stock, or fabricated by welding a combination of two or more materials. The seating surfaces in the body can be integral with the body, or they can be made as inserts. The insert material can be the same as or different from the body material. When special nonmetallic material that could fail in a fire is used to prevent seat leakage, metal-to-metal backup seating surfaces can be provided. Other parts of the valve trim can be made of any suitable material and can be cast, formed, forged, or machined from commercial rolled shapes. Valve ends can be flanged, threaded for threaded connections, recessed for socket welding, or beveled for butt-welding. Although many valves are manually operated, they can be equipped with electric motors and gear operators or other power operators to accommodate a large size or inaccessible location or to permit actuation by instruments. Body thicknesses and other design data are given in API 594, API 599, API 600, API 602, API 603, API 608, API 609, and ASME B16.34.

4.3.2 Gate Valves

A gate valve consists of a body that contains a gate that interrupts flow. This type of valve is normally used in a fully open or fully closed position and as such is often called a “block valve,” since it is not generally designed for regulating fluid flow. Gate valves larger than 2 in. (51 mm) usually have port openings that are approximately the same size as the valve end openings—this type of valve is called a full-ported valve. Figure 1 shows a cross section of a full-ported wedge gate valve.

Reduced port gate valves are also very common and have port openings that are smaller than the end openings. Reduced port valves should not be used as block valves associated with pressure-relief devices (PRDs) or in erosive applications, such as slurries, or lines that are to be “pigged.”



Key
1 alternative packing gland

Figure 1—Cross Section of a Typical Wedge Gate Valve

4.3.3 Globe Valves

A globe valve, which is commonly used to regulate fluid flow, consists of a valve body that contains a circular disc that moves parallel to the disc axis and contacts the seat. The stream flows upward generally, except for vacuum service or when required by system design (e.g. fail closed), through the seat area against the disc, and then changes direction to flow through the body to the outlet disc. The seating surface can be flat or tapered. For fine-throttling service, a very steep tapered seat can be used; this particular type of globe valve is referred to as a needle valve. A globe valve is commonly constructed with its inlet and outlet in line and with its port opening at right angles to the inlet and outlet. Figure 2 illustrates a cross section of a globe valve.

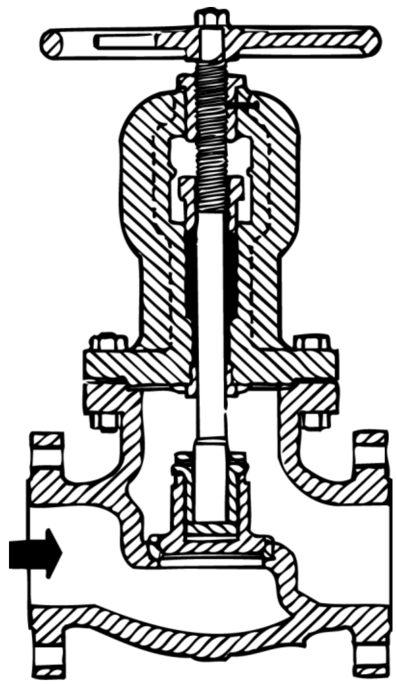


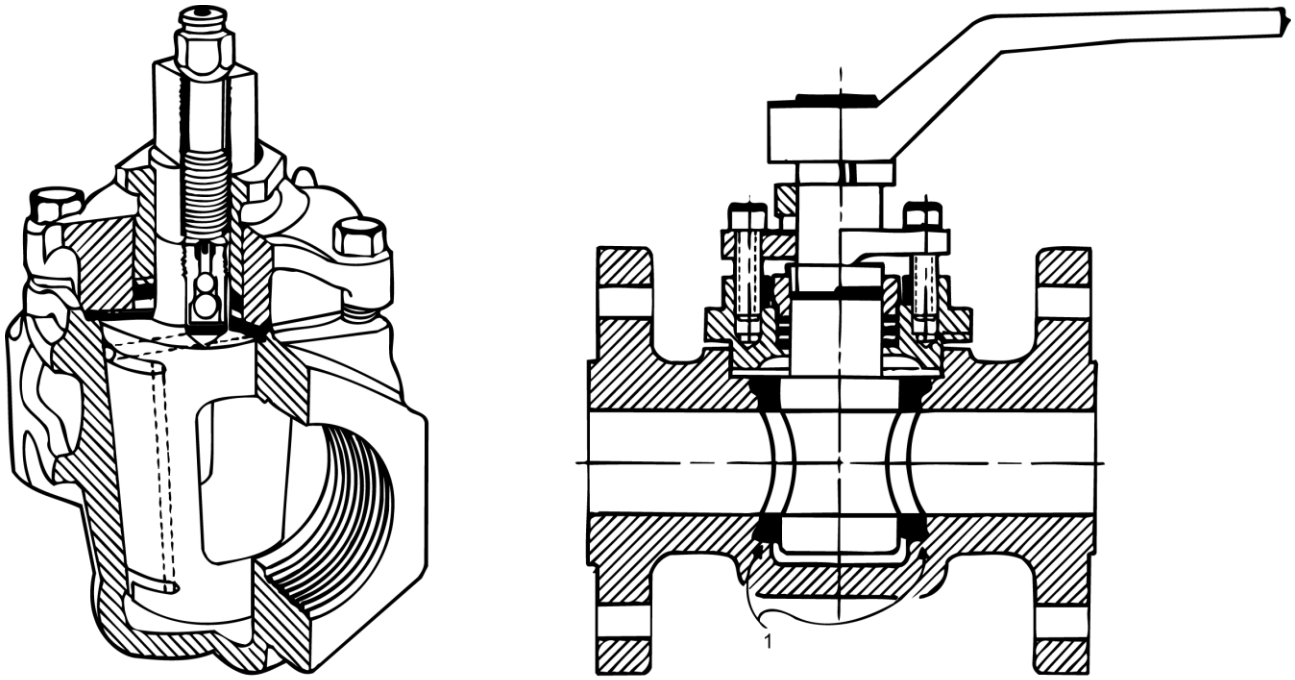
Figure 2—Cross Section of a Typical Globe Valve

4.3.4 Plug Valves

A plug valve consists of a tapered or cylindrical plug fitted snugly into a correspondingly shaped seat in the valve body. Plug valves usually function as block valves to close off flow. When the valve is open, an opening in the plug is in line with the flow openings in the valve body. The valve is closed by turning the plug one-quarter turn so that its opening is at right angles to the openings in the valve body. Plug valves can be operated by a gear-operated device or by turning a wrench on the stem. Plug valves are either lubricated or nonlubricated; Figure 3 illustrates both types. Lubricated plug valves use a grease-like lubricant that is pumped into the valve through grooves in the body and plug surfaces to provide sealing for the valve and promote ease of operation. Nonlubricated plug valves on the other hand use as sealing elements metal seats or nonmetallic sleeves, seats, or complete or partial linings or coatings.

4.3.5 Ball Valves

A ball valve is another one-quarter turn valve similar to a plug valve except that the plug in a ball valve is spherical instead of tapered or cylindrical. Ball valves usually function as block valves to close off flow. They are well suited for conditions that require quick on/off or bubble-tight service. A ball valve is typically equipped with an elastomeric seating material that provides good shutoff characteristics; however, all-metal, high-pressure ball valves are available. Figure 4 illustrates a ball valve.



a) Lubricated

b) Nonlubricated

Key

1 special seal

Figure 3—Cross Sections of Typical Lubricated and Nonlubricated Plug Valves

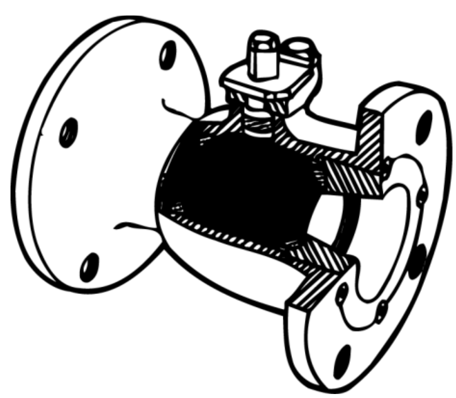


Figure 4—Cross Section of a Typical Ball Valve

4.3.6 Diaphragm Valves

A diaphragm valve is a packless valve that contains a diaphragm made of a flexible material that functions as both a closure and a seal. When the valve spindle is screwed down, it forces the flexible diaphragm against a seat, or dam, in the valve body and blocks the flow of fluid. These valves are not used extensively in the petrochemical industry, but they do have application in corrosive services below approximately 250 °F (121 °C), where a leak tight valve is needed. Figure 5 illustrates a diaphragm valve.

4.3.7 Butterfly Valves

A butterfly valve consists of a disc mounted on a stem in the flow path within the valve body. The body is usually flanged and of the lug or wafer type. A one-quarter turn of the stem changes the valve from fully closed to completely open. Butterfly valves are most often used in low-pressure service for coarse flow control. They are available in a variety of seating materials and configurations for tight shutoff in low- and high-pressure services. Large butterfly valves are generally mechanically operated. The mechanical feature is intended to prevent them from slamming shut in service. Figure 6 illustrates the type of butterfly valve usually specified for water service.

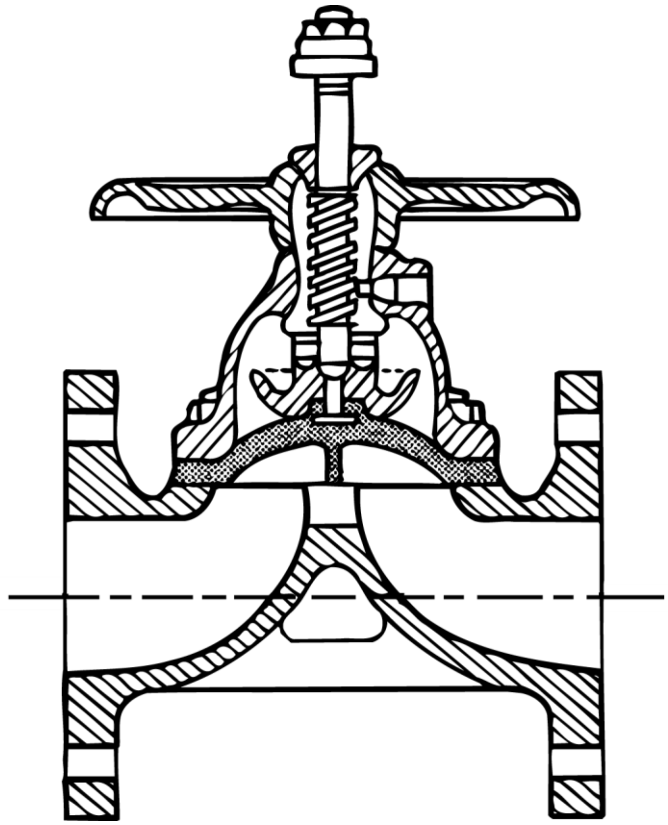
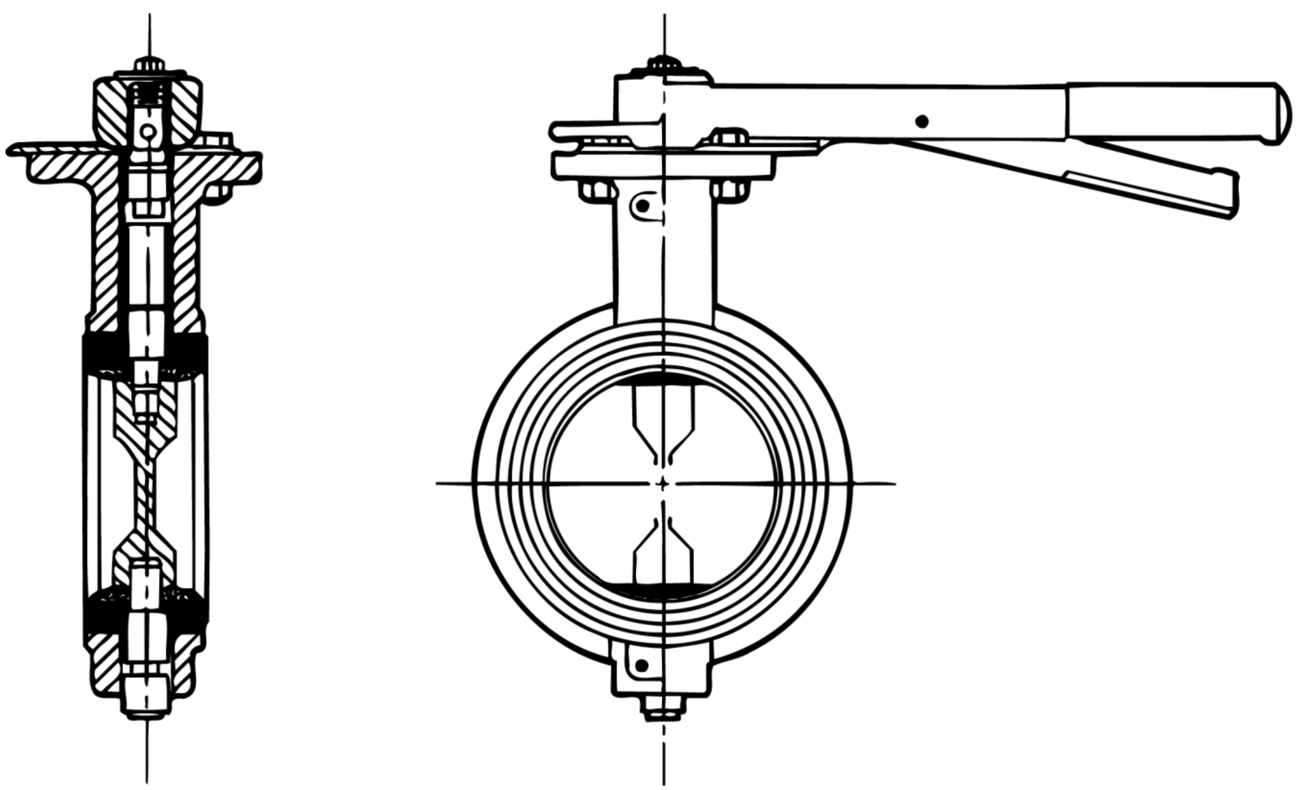


Figure 5—Cross Section of a Typical Diaphragm Valve



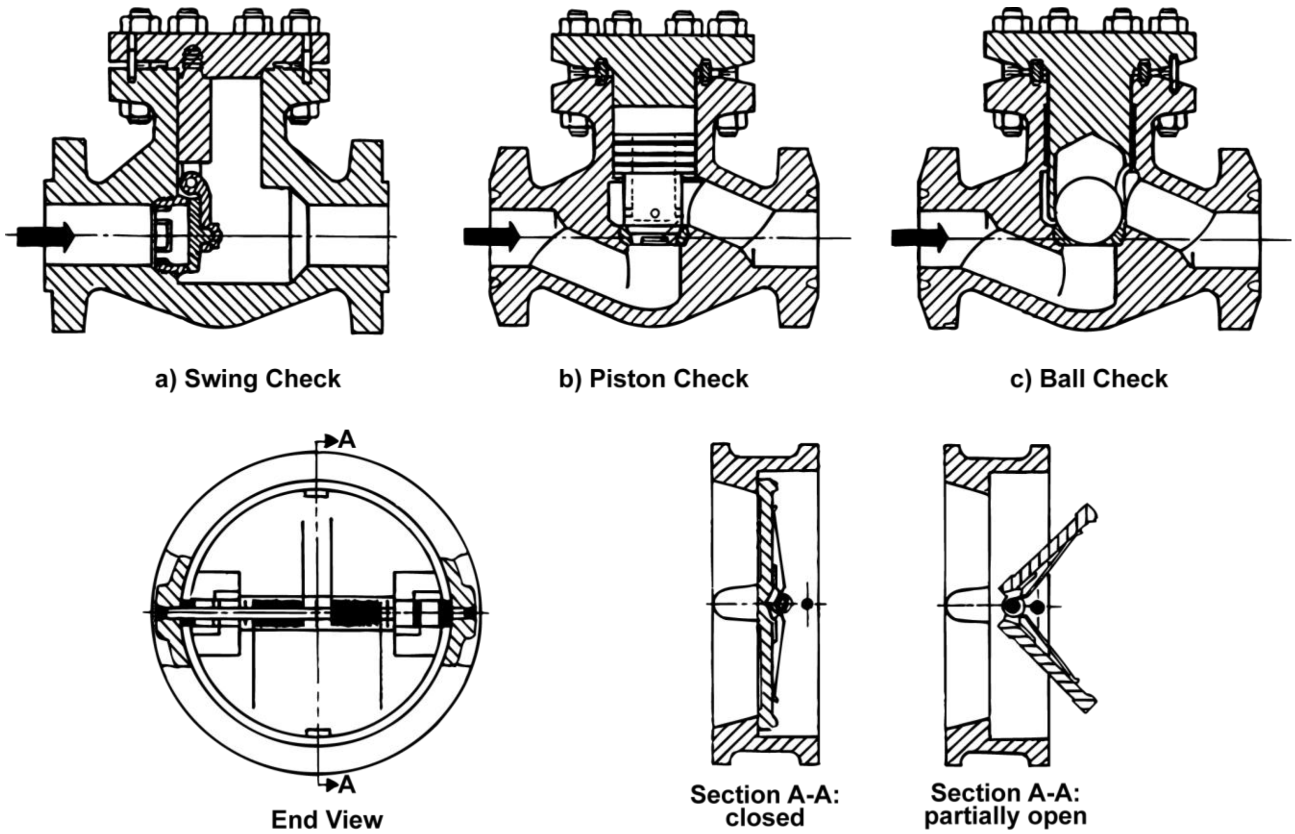
a) Side View

b) End View

Figure 6—Typical Butterfly Valve

4.3.8 Check Valves

A check valve is used to automatically prevent backflow. The most common types of check valves are swing, lift-piston, ball, and spring-loaded wafer check valves. Figure 7 illustrates cross sections of each type of valve; these views portray typical methods of preventing backflow.



d) Spring-loaded Wafer Check

Figure 7—Cross Sections of Typical Check Valves

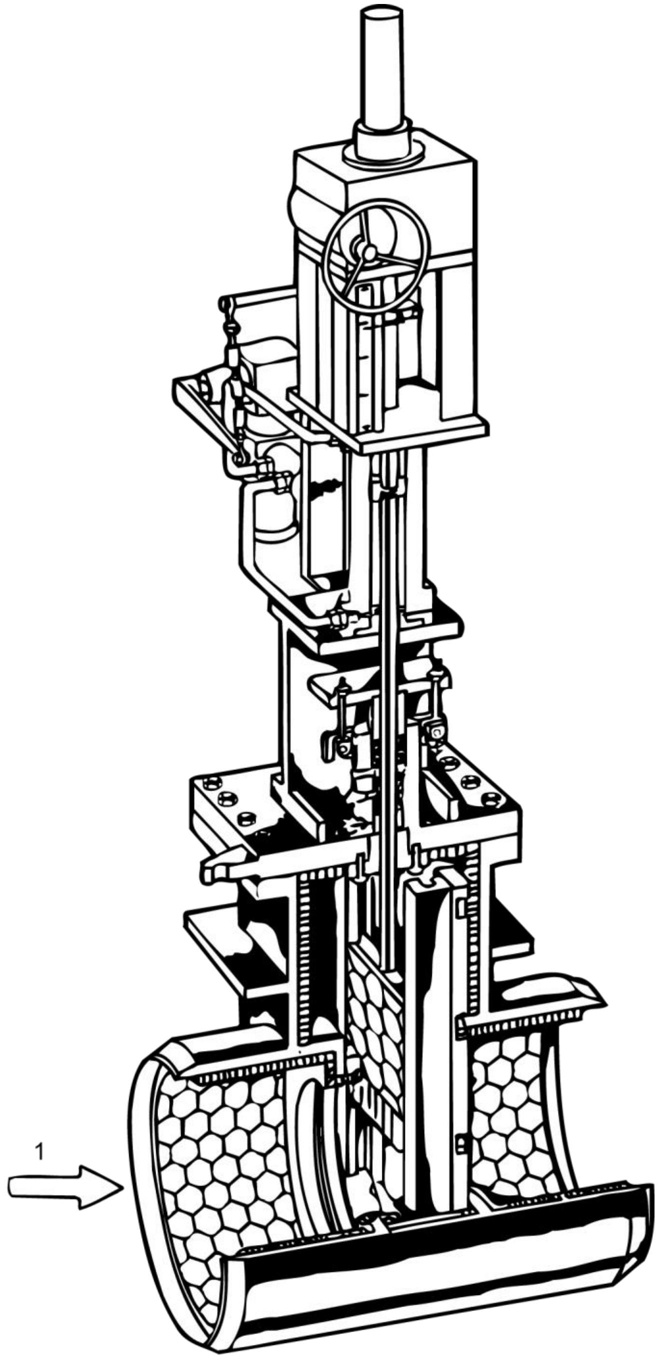
4.3.9 Slide Valves

The slide valve is a specialized gate valve generally used in erosive or high-temperature service. It consists of a flat plate that slides against a seat. The slide valve uses a fixed orifice and one or two solid slides that move in guides, creating a variable orifice that make the valve suitable for throttling or blocking. Slide valves do not make a gas tight shutoff. One popular application of this type of valve is controlling fluidized catalyst flow in fluid catalytic cracking (FCC) units. Internal surfaces of these valves that are exposed to high wear from the catalyst are normally covered with erosion-resistant refractory. Figure 8 illustrates a slide valve.

4.4 Fittings

4.4.1 Metallic Fittings

Fittings are used to connect pipe sections and change the direction of flow or allow the flow to be diverted or added to. Fittings can be cast, forged, drawn from seamless or welded pipe, or formed and welded. Fittings can be obtained with their ends flanged, recessed for socket welding, beveled for butt-welding, or threaded for threaded connections. Fittings are made in many shapes, such as wyes, tees, elbows, crosses, laterals, and reducers. Figure 9 illustrates types of flanged and butt-welded fittings. Figure 10 illustrates types of threaded and socket-welded fittings.

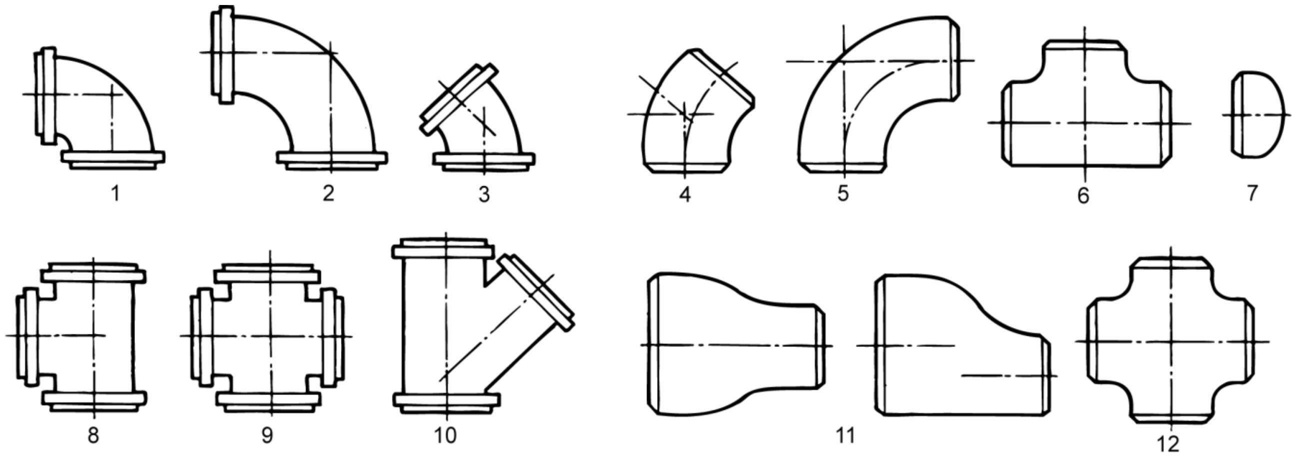


Key
1 flow

Figure 8—Cross Section of a Typical Slide Valve

4.4.2 FRP Fittings

FRP fittings are manufactured by different processes. Injection molding, filament winding and contact molding are the most common techniques. The same criteria used to accept the pipe should be applied to fittings. In particular, contact molded fittings should be inspected to ensure that they are manufactured to the same specification as the pipe. Contact molded fittings fabrication is critical because the layers of reinforcement must be overlapped to make sure that the strength of the layers is not compromised. One-piece contact molded fittings are the preferred method, but many items such as tees and branch connections are often manufactured using two pieces of pipe. The inspector must check to make sure that the reinforcement on those pieces and the gap between them is within the tolerance specified. The exposed cut edges must be protected accordingly.



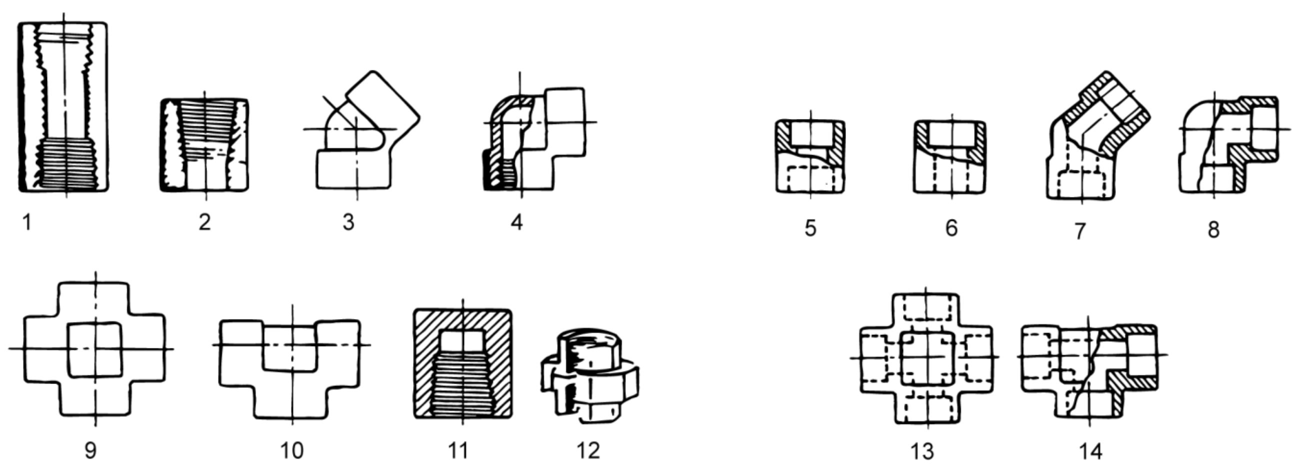
a) Flanged-end Fittings

b) Wrought Steel Butt-welded Fittings

Key

1 elbow
2 long-radius elbow
3 45° elbow
4 45° elbow
5 long-radius elbow
6 tee
7 cap
8 tee
9 cross
10 45° lateral (wye)
11 reducers
12 cross

Figure 9—Flanged-end Fittings and Wrought Steel Butt-welded Fittings



a) Threaded Fittings

b) Socket-welded Fittings

Key

1 coupling
2 half-coupling
3 45° elbow
4 90° elbow
5 coupling
6 half-coupling
7 45° elbow
8 90° elbow
9 cross
10 tee
11 cap
12 union
13 cross
14 tee

Figure 10—Forged Steel Threaded and Socket-welded Fittings

4.5 Flanges

4.5.1 Metallic Flanges

ASME B16.5 covers flanges of various materials through a NPS of 24 in. (610 mm). ASME B16.47 covers steel flanges that range from NPS 26 through NPS 60. The flanges of cast fittings or valves are usually integral with the fitting or the valve body.

4.5.2 FRP Flanges

FRP flanges are manufactured using the same methods as the fittings. Contact molded flanges should be inspected for dimensions, drawback, and face flatness. The layers of reinforcement should extend onto the pipe in order to create the proper bond and hub reinforcement. More information on FRP flanges can be found in MTI Project 160-04. FRP flanges should have the proper torques and gaskets.

4.6 Expansion Joints

Expansion joints are devices used to absorb dimensional changes in piping systems, such as those caused by thermal expansion, to prevent excessive stresses/strains being transmitted to other piping components, and connections to pressure vessels and rotating equipment. While there are several designs, those commonly found in a plant are metallic bellows and fabric joint designs. Metallic bellows can be single wall or multilayered, containing convolutions to provide flexibility. Often, these joints will have other design features, such as guides, to limit the motion of the joint or type of loading applied to the joint. Metallic bellows are often found in high-temperature services and are designed for the pressure and temperature of the piping system. Fabric joints are often used in flue gas services at low pressure and where temperatures do not exceed the rating of the fabric material.

4.7 Piping Supports

4.7.1 General

There are many different pipe support designs, types, and styles. They include hanger type, support shoes, saddles, bearing surfaces (e.g. structural members, concrete plinth blocks, etc.), spring type, dummy legs (trunnions), slide plates, sway braces/snubbers/struts, stands, sleeves, rollers, straps, clamps, and restrictive guides or anchors.

An understanding of the function and design of pipe supports is required to manage both their integrity and the integrity of piping systems. Pipe supports can be subject to various damage mechanisms (see 7.4.17) as well as significant stresses from static loading and thermal movements that can affect the pipe support itself, as well the supported piping and piping components.

4.7.2 Piping Support Design—General Considerations

Piping supports usually are designed to carry the weight of piping including valves, insulation, and the weight of the fluid contained in the pipe, including hydrostatic test conditions. Properly designed piping supports will ensure that:

a) pipes and piping components are not subjected to unacceptable stresses from sustained loads, external loads, or vibration;

b) the piping does not impose an unacceptable load on the connections to the equipment it services (e.g. pressure vessels, pumps, turbines, tanks);

c) thermal movement is controlled within allowable displacements so as not to interfere with adjacent piping or equipment and be maintained within allowable stress levels;

d) the potential for corrosion, cracking, and other in-service damage is minimized.

4.7.3 Piping Support Design—Specific Considerations

Pipe support design considerations can differ depending on the support type or style. While some pipe support manufacturers offer innovative and proprietary designs to eliminate or minimize some of the potential damage mechanisms, the following is a list of some special piping support design parameters to take into consideration.

a) Pipe Shoes—It is important that the shoe is long enough and/or guides or stops are provided on the structural steel to prevent the shoe from coming off the support, which could cause tearing or other damage to the pipe. Also, some pipe shoes may trap water between the pipe and shoe (e.g. clamp-on, bolt-on, saddles that have been stich welded, etc.) and make inspection difficult to determine the condition of the pipe.

b) Pipe Sleeves—Pipe sleeves are often used where pipe passes through a wall, under a roadway, or through an earthen berm. When used, design precautions should be taken to prevent corrosion on both the pipe, as well as the pipe sleeve. Centering devices should also be considered to keep the inner pipe centered and prevent coating damage and corrosion. Fully welded and/or sealed sleeves may be considered if loss of containment detection and control are necessary. It should be noted that sleeves can make future pipe inspections and examinations much more difficult.

c) Doubler Plates, Half Soles, and Wear Pads—Additional plates may be attached to a pipe system at points where the pipe rests on bearing surfaces. Plates should be fully welded to avoid crevice corrosion except in hydrogen charging environments, where a weep hole should be included that will not lead to moisture ingress. The use of adhesive bonded stainless steel or composite half soles may be considered, but it is very important to make sure that the adhesive is fully bonded and maintained so as to effectively eliminate water entrapment. Galvanic corrosion should also be considered when using dissimilar materials for this purpose.

d) Dummy Legs (Trunnions)—Historically, dummy leg (trunnion) supports were simple open-ended lengths of pipe welded to a piping system from which the piping system was supported. An open-ended design can allow moisture and debris to become trapped inside the support and cause corrosion of the support itself and of the pipe. Dummy leg design should include, as a minimum, drain holes no smaller than $^1/_4$ in. (6 mm) located at a low point, with the unattached end of the support being fitted with a fully welded cap or end plate to prevent debris or animals from entering. Trunnion design can be improved by using solid sections such as “C” channels or “I/H” beams, to reduce the risk of this problem. However, even solid member sections can trap water and debris depending upon their design and orientation. Incorporating a fully welded doubler pad to the pipe at the trunnion attachment location can provide additional corrosion protection and may help to more evenly distribute loads. The end of a dummy leg support that is not attached to the pipe may or may not be anchored or restrained.

e) Supports on Insulated Lines—Special attention is necessary for the design of supports on insulated lines so as to minimize the possibility of water ingress and wicking of water into the insulation.

f) Accessibility—The accessibility, and therefore inspectability/maintainability, of pipe supports should be considered during design.

g) Welding—Paths for water ingress into hollow supports can be minimized with the use of fully welded seams. Avoid welding undercut or excessive penetration. Welding defect associated with supports can contribute to loss of containment events and, in some cases, be of sufficiently small size so as to make leak detection and source identification difficult. In hydrogen charging environments, a weep hole should be provided to avoid buildup of pressure between the plate and pipe.

h) Anchors and Restraints—Attachment of an anchor or restraint to a pipe should preferably encircle the pipe in order to distribute the stresses evenly about the circumference of the piping component(s).

4.8 Flexible Hoses

Flexible hoses are often used to transfer hydrocarbons and other process fluids on a temporary basis to facilitate turnaround activities (clearing equipment, de-inventorying, purging, etc.) and for transfer of process fluids/products to rail cars and/or tanker trucks for shipment. Flexible hoses may also be installed within process piping systems to mitigate the effects of thermal expansion, vibration, or movement during normal operations. Some sites will maintain several flexible hoses to be used as needed in multiple services. Flexible hoses come in a variety of different construction materials and designs. Owner/users should have appropriate quality assurance systems in place to ensure that each different type of flexible hose is compatible with the process service in which it is used.

5 Pipe-joining Methods

5.1 General

The common joining methods used to assemble piping components are welding, threading, and flanging. Piping should be fabricated in accordance with ASME B31.3. Additionally, cast iron piping and thin wall tubing require special connections/joining methods due to inherent design characteristics.

5.2 Threaded Joints

Threaded joints are generally limited to auxiliary piping in noncritical service (minor consequence should a leak occur) that has a nominal size of 2 in. (51 mm) or smaller. Threaded joints for NPSs of 24 in. (610 mm) and smaller are standardized (see ASME B1.20.1).

Lengths of pipe can be joined by any of several types of threaded fittings (see 4.4). Couplings, which are sleeves tapped at both ends for receiving a pipe, are normally used to connect lengths of threaded pipe. When it is necessary to remove or disconnect the piping, threaded unions or mating flanges are required (see 5.4). Threaded joints that are located adjacent to rotating equipment or other specific sources of high vibration can be especially susceptible to failure due to fatigue. Special consideration should be given to these situations.

5.3 Welded Joints

5.3.1 General

Welded joints have for the most part replaced threaded and flanged joints, except in SBP where some users still rely on threaded joints and in cases where piping is connected to equipment that requires periodic maintenance. Joints are either butt-welded (in various sizes of pipe) or socket-welded (typically NPS 2 and smaller).

5.3.2 Butt-welded Joints

Butt-welded connections are the most commonly found in the petrochemical industry. The ends of the pipe, fitting, or valve are prepared (beveled) and aligned with adequate root opening in accordance with ASME B16.25 or any other end preparation that meets the welding procedure specification (WPS), permitting the ends to be joined by fusion welding.

5.3.3 Socket-welded Joints

Socket-welded joints are made by inserting the end of the pipe into a recess in a fitting or valve and then fillet welding the joint. A small space, per the construction code, should be provided between the end of the pipe and the bottom of the socket to allow for pipe expansion and weld shrinkage. Two lengths of pipe or tubing can be connected by this method using a socket-weld coupling. Figure 11 illustrates a cross section of a socket-welded joint.

5.3.4 Welded Branch Connections

A large number of piping failures occur at pipe-to-pipe welded branch connections. The reason for the failures is that branch connections are often subject to higher-than-normal stresses caused by excessive structural loadings from unsupported valves or piping, vibration, thermal expansion, or other configurations. The result is concentrated tri-axial stresses (e.g. bending and torsional) that can cause fatigue cracking or other types of failures. Where joints are susceptible to such failures, a forged piping tee typically offers better reliability because it removes the weld from the point of highest stress concentration. Weld-o-lets also can offer better reliability if they are properly welded to the main pipe using appropriate weld procedures and manufacturer’s recommendations for full penetration welds

5.4 Flanged Joints

Flanged joints are made by bolting two flanges together with some form of gasket between the seating surfaces. The gasket surfaces can be flat and range from serrated (concentric or spiral) to smooth (depending on the type of gasket, gasket material, and service conditions), or grooves can be cut for seating metal-ring gaskets. Flanged joints should be assembled by trained and qualified personnel (see Appendix A of ASME PCC-1). Consideration should be given to establishing a finished joint examination process. See 6.2 on flanged joint leakage.

Figure 12 illustrates common flange facings for various gaskets. The common types of flanges are welding neck, slip-on welding, threaded, blind, lap joint, and socket welded. Each type is illustrated in Figure 13.

5.5 Cast Iron Pipe Joints

Cast iron pipe joints can be of the flanged, packed, sleeve, hub-and-spigot-end or hub-and-plain-end, or bell-and-spigot-end or bell-and-plain-end type. Push-on joints with rubber or synthetic ring gaskets are available. Clamped joints are also used. The hub-and-plain-end joint is shown in Figure 14. Figure 15 illustrates cross sections of a bell-type mechanical joint, a sleeve connection, and a typical proprietary connection (see 5.7). These types of joints are rarely used in process piping service because of their low toughness and tendency toward brittle fracture.

5.6 Tubing Joints

Tubing can be joined by welding, soldering, or brazing or by using flared or compression fittings. Figure 16 illustrates flared and compression joints. Tubing joints should be assembled by trained and qualified personnel. Consideration should be given to establishing a finished joint examination process in accordance with tubing joint manufacturer’s recommendations.

5.7 Special Joints

Proprietary joints are available that incorporate unique gaskets, clamps, and bolting arrangements. These designs offer some advantages in some services over conventional joints in certain services including:

a) higher pressure and temperature ratings,

b) smaller dimensions,

c) easier installation—axial and angular alignment requirements are less stringent,

d) greater force and moment toleration.

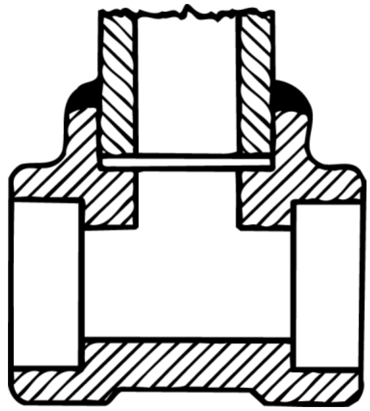


Figure 11—Cross Section of a Socket-welded Tee Connection

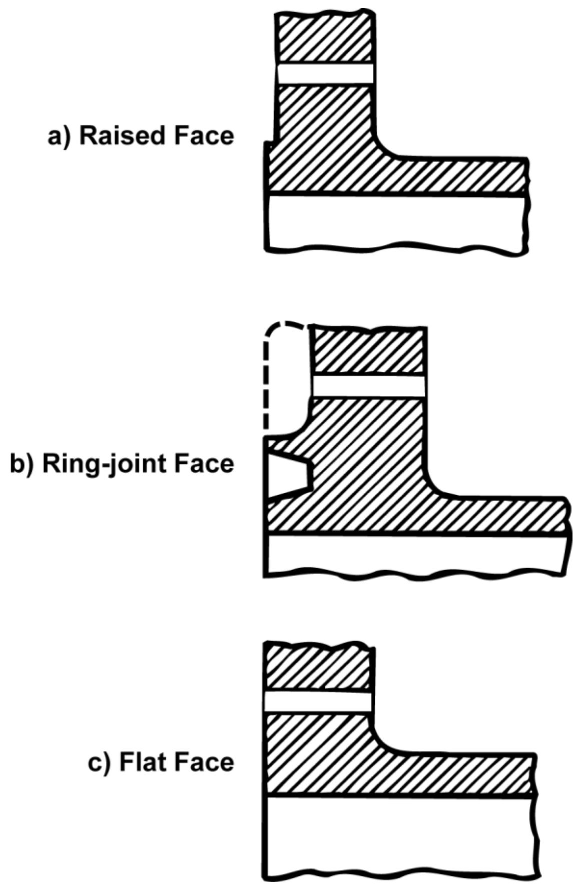
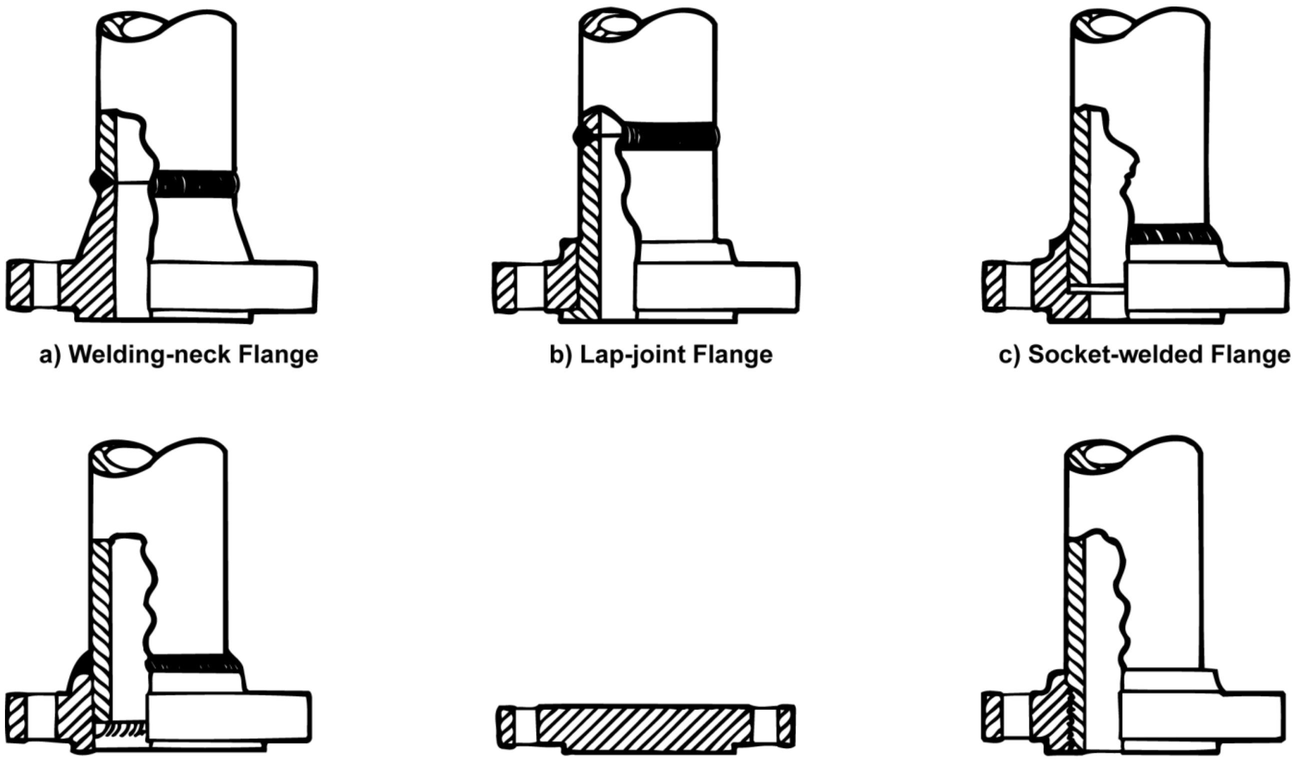


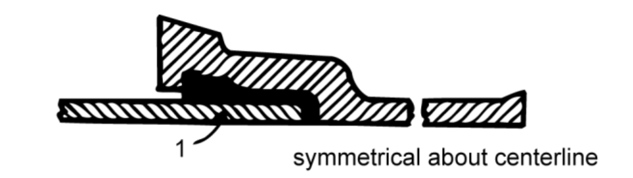
Figure 12—Flange Facings Commonly Used in Refinery and Chemical Plant Piping



a) Welding-neck Flange b) Lap-joint Flange c) Socket-welded Flange

d) Slip-on Welded Flange e) Blind Flange f) Threaded Flange

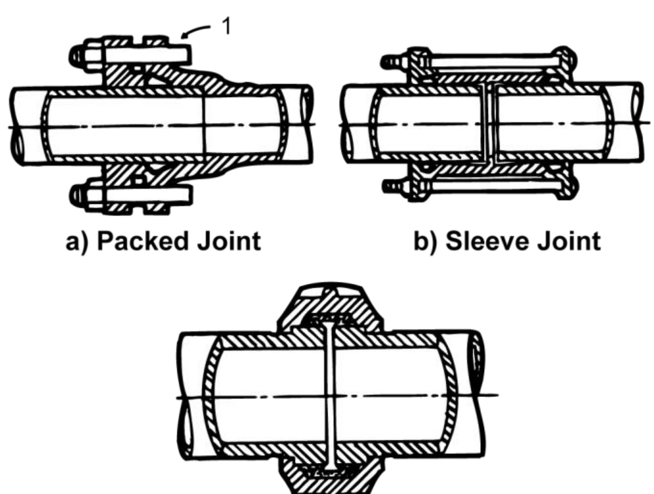
Figure 13—Types of Flanges



Key

1 elastomeric seal

Figure 14—Cross Section of a Typical Bell-and-spigot Joint



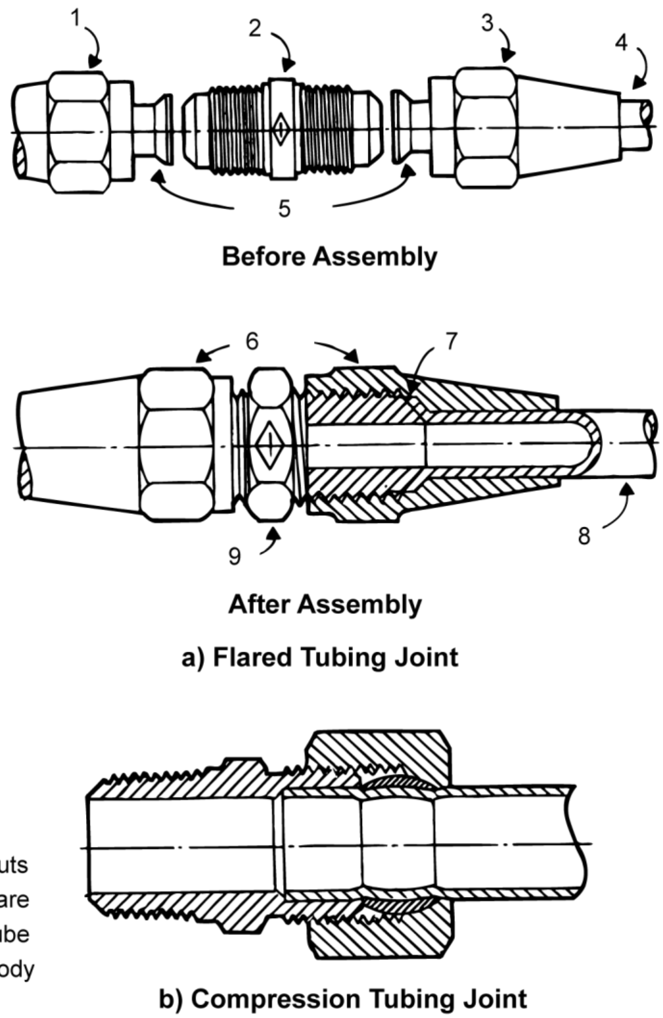
a) Packed Joint b) Sleeve Joint

c) Sleeve Joint

Key

1 tee-head bolt

Figure 15—Cross Sections of Typical Packed and Sleeve Joints



Key

1	nut	6	nuts
2	body	7	flare
3	nut	8	tube
4	tube	9	body
5	flares		

Figure 16—Cross Sections of Typical Tubing Joints

5.8 Nonmetallic Piping Joints

5.8.1 General

There are several methods of joining FRP pipe and fittings. Joints in nonmetallic piping are often of several different designs depending upon the manufacturer of the pipe. Some common joint designs in FRP pipe systems include a bell and spigot, butt and wrap, taper-taper, and flange-flange.

5.8.2 Bell and Spigot/Taper-taper

Bell-and-spigot and taper-taper joints are created by inserting the spigot end into the bell end. Proper surface preparation, insertion, and adequate adhesive are the key to make these types of joints. These joints should be inspected internally when possible for excess adhesive that can restrict the flow and specified gap. The inspector should perform an external inspection to look for proper surface preparation, insertion, joint assembly, and alignment.

5.8.3 Butt and Wrap

Butt-and-wrap joints involve butting plain end pipe together and applying layers of resin and fiber reinforcement layers around the joint. These types of joints should be done by qualified secondary bonders. The joints should be inspected internally for proper gap, cut edge protection and require paste to fill the gap.

Externally, the joint should be checked for proper alignment, gap tolerance, thickness, width, laminate sequence, and taper.

NOTE Fitting thickness is often greater than the matching pipe thickness. Proper taper of the fitting thickness is required in order to make the proper butt-and-wrap joint.

5.8.4 Flange-flange

Flange joints require proper gaskets and torques. A calibrated torque wrench should be used to ensure proper torqueing and to avoid damage by overstressing the FRP flanges. Proper flange alignment (including flatness and waviness according to the specification) is required in order to prevent damage at the specified torque values. Full-face gaskets are required for bolting full-face flanges. Flanges bolted to raised-face connections must be evaluated individually for required torque values and proper gasket requirements.

6 Reasons for Inspection

6.1 General

The primary purposes of inspection is to observe, report, and quantify damage (see API 571) and then to specify needed repairs or replacement. Planning for inspection entails identifying potential damage mechanisms for purposes of directing the inspection activity. The inspection activity requires obtaining information about the physical condition of the piping, which will lead to determining the causes of any deterioration and the rate of deterioration. By developing a database of inspection history, the user can predict and recommend future repairs and replacements, act to prevent or retard further deterioration, and most importantly, prevent loss of containment. These actions should result in increased operating safety, reduced maintenance costs, and more reliable and efficient operations. API 570 provides the basic requirements for such an inspection program.

6.2 Process and Personnel Safety

A leak or failure in a piping system can be a minor inconvenience for low-consequence fluids or it can become a potential source of a process safety incident for higher consequence fluids depending on the temperature, pressure, contents, and location of the piping. Piping in a petrochemical plant typically contains flammable fluids, acids, alkalis, toxic fluids, and other harmful fluids that would make leaks potentially hazardous to exposed personnel. Leaks in these kinds of piping systems can also have environmental consequences associated with their failure. Adequate inspection is a prerequisite for maintaining this type of piping in a safe, reliable condition.

Leakage can occur at flanged joints in piping systems for a variety of reasons including corrosion, cracking, bolt tightness issues, gasket issues, and thermal expansion issues, especially in high-temperature services, during start-ups or shutdowns, and sometimes during normal operation. For these reasons, it is important that process plant practices include quality assurance/control procedures to ensure that flanged joints are properly assembled, inspected, and tested after maintenance activities where the joints have been disassembled and that the proper gaskets have been selected and installed. ASME PCC-1 is a useful standard for flange joint assembly practices.

6.3 Reliable Operation

In addition to the need for inspection to provide for process and personnel safety, thorough inspection, data analysis, and maintenance of detailed inspection/repair/replacement records of piping systems are essential to the attainment of acceptable process reliability in order to meet the business plan. Piping maintenance and replacement schedules are developed to coincide with scheduled maintenance turnarounds to avoid unplanned outages and the consequences of lost production opportunities.

6.4 Regulatory Requirements

Regulatory requirements may cover those piping systems that could affect personnel or process safety and environmental concerns. Process safety regulations such as OSHA 29 *CFR* 1910.119 in the United States have mandated that equipment, including piping, that handles significant quantities of hazardous chemicals be inspected according to accepted codes and standards, which includes API 570. Local and state regulations may also cover process piping inspection and maintenance.

7 Inspection Plans

7.1 General

An inspection plan is often developed and implemented for piping systems within the scope API 570. Other piping systems may also be included in the inspection program and accordingly have an inspection plan.

An inspection plan should contain the inspection tasks, scope of inspection, and schedule required to monitor identified damage mechanisms and ensure the mechanical integrity of the piping components in the system. API 570 defines the minimum contents of an inspection plan.

Inspection plans for piping systems can be maintained in spreadsheets, hardcopy files, and proprietary inspection software databases.

7.2 Developing an Inspection Plan

7.2.1 General

An inspection plan is often developed through the collaborative work of the inspector, piping engineer, corrosion specialist, and operating personnel. The team should consider several pieces of information such as operating temperature ranges, operating pressure ranges, process fluid corrosive contaminant levels, piping material of construction, piping system configuration, process stream mixing, and inspection/maintenance history. In addition, other information sources can be consulted, including API and NACE publications, to obtain industry experience with similar systems. All of this information provides a basis for defining the types of damage and locations for its occurrence. Knowledge of the capabilities and limitations of NDE techniques allows the proper choice of examination technique(s) to identify particular damage mechanism in specific locations. Ongoing communication with operating personnel when process changes and/or upsets occur that could affect damage mechanisms and rates are critical to keeping an inspection plan updated.

For piping systems, inspection plans should address the following:

a) condition monitoring locations (CMLs) for specific damage mechanisms;

b) piping contact points at pipe support;

c) pipe supports and support appurtenances;

d) corrosion under insulation (CUI);

e) injection points;

f) process mixing points;

g) soil-to-air (concrete-to-air) interfaces (SAIs);

h) dead-leg sections of pipe;

i) PMI;

j) auxiliary piping;

k) critical utility piping as defined by owner/user;

l) vents/drains;

m) threaded pipe joints;

n) internal linings;

o) critical valves;

p) expansion joints.

Inspection plans may be based upon various criteria but should include a risk assessment or fixed intervals as defined in API 570.

7.2.2 Risk-Based Inspection (RBI) Plans

Inspection plans based upon an assessment of the likelihood of failure and the consequence of failure of a piping system or circuit is RBI. RBI may be used to determine inspection intervals or due dates and the type and extent of future inspection/examinations. API 580 details the systematic evaluation of both the likelihood of failure and consequence of failure for establishing RBI plans. API 581 details an RBI methodology that has all of the key elements defined in API 580.

Identifying and evaluating potential damage mechanisms, current piping condition, and the effectiveness of the past inspections are important steps in assessing the likelihood of a piping failure. The likelihood assessment should consider all forms of degradation that could reasonably be expected to affect piping circuits in any particular service. Examples of those degradation mechanisms include internal or external metal loss from an identified form of corrosion (localized or general), all forms of cracking, including hydrogen-assisted and stress corrosion cracking (SCC) (from the inside or outside surfaces of piping), and any other forms of metallurgical, corrosion, or mechanical degradation, such as fatigue, embrittlement, creep, etc. See API 571 for details of common degradation mechanisms.

Identifying and evaluating the process fluid(s), potential injuries, environmental damage, unit piping and equipment damage, and unit loss of production are important aspects in assessing the consequences associated with a failure of piping.

Any RBI assessment should be thoroughly documented in accordance with API 580, defining all the factors contributing to both the probability and consequence of a failure of the piping system.

After an RBI assessment is conducted, the results may be used to establish the 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 piping to examine);

c) the date for internal, 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 and mitigation steps to reduce the probability and consequence of a piping failure (e.g. repairs, process changes, inhibitors, etc.).

7.2.3 Interval-based Inspection Plans

Inspection plans that are based upon the specific inspection intervals for the various types of piping inspection and of specific types of damage are considered interval based. The types of inspection where maximum intervals are defined in API 570 include external visual, CUI, thickness measurement, injection point, SAI, SBP, auxiliary piping, and threaded connections.

The interval for inspections is based upon a number of factors, including the corrosion rate and remaining life calculations, piping service classification, applicable jurisdictional requirements, and the judgment of the inspector, the piping engineer, or a corrosion specialist. The governing factor in the inspection plan for many piping circuits is the piping service classification.

7.2.4 Classifying Piping Service

According to API 570, Section 6.3.4, all process piping shall be classified according to consequence of failure, except for piping that has been planned on the basis of RBI. Piping classes vary from Class 1—high consequence to Class 3—low consequence. Additionally, there is a Class 4 for services that are essentially nonflammable and nontoxic. Adding more CMLs in appropriate locations to higher consequence piping subject to higher corrosion rates or localized corrosion and monitoring those CMLs more frequently may reduce the likelihood of high-consequence events. This strategy gives more accurate prediction of retirement dates and reduces inspection uncertainty in the piping where reliability is more important. Factors to consider when classifying piping are:

a) toxicity,

b) volatility,

c) combustibility,

d) location of the piping with respect to personnel and other equipment, and

e) experience and history.

7.3 Monitoring Process Piping

7.3.1 General

The single most frequent damage mechanism leading to pipe replacement is corrosion. For this reason, an effective process piping inspection program should include monitoring piping thickness from which corrosion rates, remaining life, next inspection dates, and projected piping retirement dates can be determined.

A key to the effective monitoring of piping corrosion is identifying and establishing CMLs. CMLs are designated areas in the piping system where measurements are periodically taken. UT thickness measurements are obtained within examination points on the pipe. Thickness measurements may be averaged within the examination point. By taking repeated measurements and recording data from the same points over extended periods, damage rates can more accurately be calculated or assessed.

Some of the factors to consider when establishing the corrosion-monitoring plan for process piping are:

a) classifying the piping service in accordance with API 570 or risk ranking based on RBI analysis;

b) categorizing the piping systems into piping circuits of similar corrosion behavior (e.g. localized, general, environmental cracking);

c) identifying susceptible locations where accelerated damage is expected;

d) accessibility of the CMLs for monitoring when localized corrosion is not predicted;

e) RBI to identify high-risk piping circuits and/or specific piping locations.

7.3.2 Piping Systems

Developing piping systems and circuits based on expected/identified damage mechanisms enables the development of concise inspection plans and forms the basis for improved data analysis. Refer to API 570 for the common characteristics of piping systems.

The following are some examples of documenting piping systems. Piping systems can be documented on the process flow diagrams (PFDs) as described below and contain the following information for each.

a) Systems can be highlighted by a unique color coding and name.

b) Piping system nomenclature may utilize conventions that are readily understood within the facility, ideally providing a common language between operating and inspection personnel. Typically, the piping system identifier is appended to a unit prefix, with piping system and individual piping circuits incrementing from unit feed to product streams.

c) Each piping system may have other characteristics associated with them documented, including the boundaries, general process concerns, integrity operating window parameters, general damage mechanisms, and process corrosion control measures.

7.3.3 Piping Circuits

Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and recordkeeping. When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for recordkeeping and performing field inspection. By identifying like environments and damage mechanisms as circuits, the spread of calculated corrosion rates of the CMLs in each circuit is reduced. Proper selection of components in the piping circuit and the number of CMLs are particularly important when using statistical methods to assess corrosion rates and remaining life. Figure 17 is an example of one way to break piping up into circuits.

Piping circuit layout and associated CMLs are often identified on inspection piping sketches to aid the inspector in performing inspection tasks. See 13.2 for information on piping sketches.

Materials of construction have specific potential for corrosion/erosion characteristics and may respond differently when placed into like operating parameters. Material of construction is a key element in determining the damage mechanisms and/or rate of damage based on operating environment. Circuit breaks should be placed when there is a change in piping materials of construction, which can cause a change in corrosive/erosive behavior. A metallurgist/corrosion engineer experienced in the process unit under review should be consulted for assignment of damage mechanisms and/or rate of damage for differing materials of construction.

A number of factors can affect the rate and nature of pipe wall corrosion. Individual circuits should be limited to piping components within the system where the damage rate and type of damage (common damage mechanisms) are consistent. Considerations for the limits of the piping circuit may include, but are not limited to, the following items:

a) piping metallurgy;

b) process fluid and its phase (e.g. gas, liquid, two phase, solid);

c) flow velocity;

d) temperature;

e) pressure;

f) changes in temperature, velocity, pressure, direction, phase, metallurgy, or pipe cross section;

g) injection of water or chemicals;

h) process fluid contaminants;

i) mixing of two or more streams;

j) piping external conditions, including coating/painting, insulation, and soil conditions, as applicable;

k) stagnant flow areas (e.g. dead-legs).

Piping circuits should be identified with common damage mechanisms to facilitate inspection planning and data analysis and will generally have the following characteristics.

a) Common materials of construction.

b) Common design conditions.

c) Common operating conditions

d) Common set (one or more) of damage mechanisms.

e) Common expected corrosion rate.

f) Common expected damage locations/morphology.

g) For risk-based programs, piping circuits may be further subdivided based on risk level. For example, a pump discharge or upstream of a control valve may have the same corrosion characteristics as pump suction or downstream of the control valve, but the risk may be greater on the high-pressure segments due to higher leak rate potential. In such cases, the higher pressure components may be assigned to a separate circuit

In addition, based on the nature of the corrosion, damage type/morphology, and piping metallurgy, circuits may contain the following.

a) Multiple line numbers.

b) Multiple line sizes.

c) Both primary and secondary piping components.

d) Short dead-legs (e.g. the greater of $< 2D$ or 8 in. in length) (e.g. drains/vents and blinded/capped tee runs), depending on the potential for dead-leg/under-deposit corrosion.

The following are some examples of documenting piping circuits. Piping circuits are typically shown on isometric drawings or the piping and instrument diagram (P&ID) and may contain the following information for each circuit.

Piping circuits may be highlighted by a unique color coding (or symbol) and name. Each piping circuit can be further documented (written description), which includes the boundaries for the circuit and the following information.

a) Specific damage mechanisms expected to be active.

b) Metallurgy.

c) Damage type—degree of generalized or localized corrosion expected.

d) Generalized locations where inspection points should be specified based on operating conditions and metallurgy.

e) Specific concern locations or areas—injection point impingement, dead-legs/drains for condensed acid, etc.

f) Specific process concerns.

g) Process corrosion control measures.

Piping circuits may also be identified on individual isometric drawings. Additional attributes may be identified on the circuit drawings to facilitate or identify other special emphasis programs, including:

a) numbered injection or mix point locations,

b) contact support locations for inspection,

c) SAI locations,

d) extent of insulation,

e) CUI/CUF locations for inspection.

7.3.4 Statistical Analysis of Circuit CMLs

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. The results of statistical analysis of the CML data using descriptive statistics and statistical plots should be evaluated for validity and interpreted by a person who is deemed competent by the owner/user.

Probability plots are convenient tools for modeling circuit thickness or corrosion rate data. There are many statistical programs that can be utilized to visualize large quantities of data and obtain the parameters of interest. Generally, simple two-parameter distributions such as normal, log normal, and Weibull are good candidates to describe thickness and corrosion rate trends. In many cases, the “goodness of fit” to a particular distribution can be visually assessed from a probability plot, although many statistical packages also provide goodness of fit statistics. Any significant deviation from the best fit line may be an indication of localized corrosion and/or data anomalies to be investigated.

Graphical visualization tools may be used in addition to descriptive statistics to demonstrate the validity of the statistical modeling assumptions and goodness of fit of the data, especially in the range of highest interest from an integrity point of view. Examples include the use of normal probability or extreme value distribution plots to indicate goodness of fit for largest or smallest values in a data set of interest. Visualization of all data on an appropriately selected scale may reveal lack of goodness of fit or correlations that are not readily apparent from descriptive statistics.

While the following discussion focuses on the use of probability plots, similar results may be obtained without plotting software. Descriptive statistics may be generated in spreadsheets that estimate distribution parameters, calculate projected values, and provide other useful circuit analysis information. If calculations are performed without the aid of data visualization, some assessment as to the goodness of fit and presence of outliers would provide additional data.

Typical circuit analysis applications include the following.

1) Creating separate plots for long-term and short-term corrosion rates, to determine if the rate distributions are significantly different.

   A shift in the distribution's location parameter (e.g. the mean, for normal distribution) may indicate higher or lower rates, while changes in the shape parameter (e.g. the standard deviation) suggest a change in the degree of localized corrosion. This type of analysis can be useful for assessing feedstock and other process changes that may have occurred over a period of time. Due to the impact of thickness measurement accuracies and the physical nature of corrosion phenomena, special care should be taken when comparing data sets over different time intervals. A direct comparison of 1-year interval to 5-year interval data may be misleading for the following two reasons.

   — The time scale of corrosion physics dictates decreasing correlation between measurements as the time lag between successive measurements increases. Therefore, short-term and long-term variability usually have different scatter.

   — Measurement uncertainty tends to affect the results as well. If the measurements are significantly impacted by measurement errors, the scatter would follow a square root relationship with time.

2) Screening circuit corrosion rate and thickness data for uniform vs. localized trends

   When plotting thicknesses or corrosion rates, the best-fitting distribution type as well as trends in the parameters can be used to screen for localized corrosion. Parameter trends may additionally reveal important changes over time, relating to higher corrosion rates and/or localized corrosion tendencies. For example, corrosion rate distributions for uniform services tend to follow a normal distribution. Significantly nonuniform/localized services (such ammonium bisulfide or naphthenic acid corrosion) will typically fit best to a log normal distribution with a wide shape parameter. On thickness plots, reductions in the scale parameter are related to the corrosion rate, while wider shape parameters suggest more localized behavior.

3) Estimating a representative corrosion rate for a piping circuit.

   Once a corrosion rate plot has been prepared (considering both long-term and short-term rates), a representative rate may be assigned for the entire piping circuit. The owner/user may establish guidelines based (for example) on service class or risk, utilizing a specific occurrence level rate, in remaining life calculations. For uniform services, a mean rate might be appropriate, while localized corrosion services may require a much higher occurrence level (say 0.90 or 0.95). If an additional factor of safety is needed, confidence intervals may be added to the plot and a specified occurrence level at the upper confidence interval could be used.

4) Evaluating the circuit design, to confirm the assumption of similar damage mechanisms and corrosion rates within a circuit.

   If all corrosion rates in a circuit do not demonstrate a satisfactory fit as defined by owner/user, consider grouping the data based on knowledge of the piping design, assigned damage mechanisms, and pertinent process conditions. This type of grouping is generally required when subpopulations may be present. For example, a plot of all circuit corrosion data may not exhibit a satisfactory goodness of fit. It may be subsequently observed that higher rates tend to be associated with elbow fittings (or even more specifically, the extrados). This would suggest that elbow (or extrados) readings be plotted separately. If the resulting plots demonstrate a significantly improved goodness of fit, the circuit design may be validated, but the assigned damage mechanisms may require review. This type of feedback often provides considerable insight to the inspection program.

A nongraphical method for identifying potential subpopulations is to calculate the covariance. For example, a covariance exceeding 10 % could suggest the presence of subpopulations, requiring the data to be grouped, as outlined above.

5) Identifying data outliers and other anomalies.

   Sometimes, the data that does not fit the model is of most interest. Elevated corrosion rates or low thicknesses that appear as outliers (e.g. points lying outside the plot confidence intervals) should not be discarded unless a specific cause can be assigned. Each such outlier should be carefully reviewed to confidently rule out the possibility of localized corrosion. In some cases, this may require obtaining confirmation readings.

6) Estimating the thickness at a low occurrence level, or the probability of the minimum required thickness for a particular size/component within a circuit.

   Thickness probability plots may be used to estimate the minimum thickness at a selected low occurrence level (say 0.001) for size/component combinations in a circuit. Alternatively, the probability of reaching the minimum required thickness may be estimated, essentially yielding a probability of retirement that may be used in risk-based programs. Suitable data validation to identify replacement sections or potential schedule changes would typically accompany this type of analysis.

   Because of thickness measurement uncertainty, the scatter in the corrosion rate distribution can be overestimated. Any thickness measurement uncertainty effects should be estimated, with adequate corrections made, to minimize the impact on probability estimates, otherwise some overconservatism may be expected in the results.

7) Assessing the standard error of the data.

   It is often useful to gain an understanding of how "good" a representative corrosion rate or minimum thickness estimate may be. It may also be of interest to estimate how much data should be taken for subsequent inspections. Such estimates can be made by exploring different confidence intervals on the probability plot. Current and future inspections can be modeled to estimate the effects of additional (or less) data. The owner/user may choose to adopt practices using variable confidence intervals depending on service class or risk to estimate minimum data requirements. Such techniques may also be used to quantify representative sampling requirements.

   Given the nature of piping thickness data and its many sources of error, all data used in any statistical analysis should be carefully validated. The validation might include steps to identify, to the extent possible, typical issues such as undocumented replacements, anomalous readings, calibration shifts, or data entry errors. The error can and should be prevented with adequate QA/QC, training/certification of personnel (data entry, undocumented replacements, use of improper tools, probes or techniques), and periodic system calibrations.

   There are numerous related statistical techniques that may be employed in the analysis of circuit thickness data. The owner/user may elect to use the methodologies outlined above or may utilize more advanced statistical techniques (either corrosion rate or thickness based) as a means to establish representative rates and estimate minimum remaining thickness.

   Any statistical approach should be documented. Care should be taken to ensure that the statistical treatment of data results reflects a reasonably conservative representation of the various pipe components within the circuit.

7.3.5 Identifying Locations Susceptible to Accelerated Corrosion

In the presence of certain corrodants, corrosion rates are normally increased at areas of increased velocity and/or turbulence. Elbows, reducers, mixing points, control valves, and orifices are examples of piping components where accelerated corrosion can occur because of increased velocity and/or turbulence. Such components are normally areas where an inspector would locate additional CMLs in a piping circuit. However, the inspector should also be aware that areas of no flow, such as dead-legs (see 7.4.4), can cause accelerated corrosion and may need additional CMLs. In situations where cracking is anticipated, a CML may be established temporarily to monitor the rate of cracking.

7.3.6 Accessibility of CMLs

When assigning CMLs, the inspector should consider accessibility for monitoring them. CMLs at grade level normally provide the easiest accessibility. Other areas with good accessibility are equipment platforms and ladders. In some piping systems, the nature of the active damage mechanisms will require monitoring at locations with limited accessibility. In these cases, inspection planning should decide among scaffolding, portable manlifts, or other methods to provide adequate access.

7.4 Inspection for Specific Damage Mechanisms

7.4.1 General

Oil refinery and chemical plant piping can be subject to internal and external damage mechanisms. This piping carries a range of fluids that can be highly corrosive, erosive, and prone to SCC or subject to material degradation in service. In addition, both aboveground and buried piping is subject to external corrosion. The inspector should be familiar with the potential damage mechanisms for each piping system. API 571 has been developed to give the inspector added insights on various causes of damage. Figure 18, Figure 19, Figure 20, and Figure 21 illustrate several examples of corrosion and erosion of piping.

If an inspection of an area of piping indicates damage is occurring, the piping upstream and downstream of this area, along with associated equipment, should also be inspected. Additionally, if deterioration is detected in pressure equipment, associated piping should also be inspected.

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

a) injection points,

b) process mixing points,

c) dead-legs,

d) CUI,

e) SAIs,

f) service specific and localized corrosion,

g) erosion and erosion-corrosion,

h) environmental cracking,

i) corrosion beneath linings and deposits,

j) fatigue cracking,

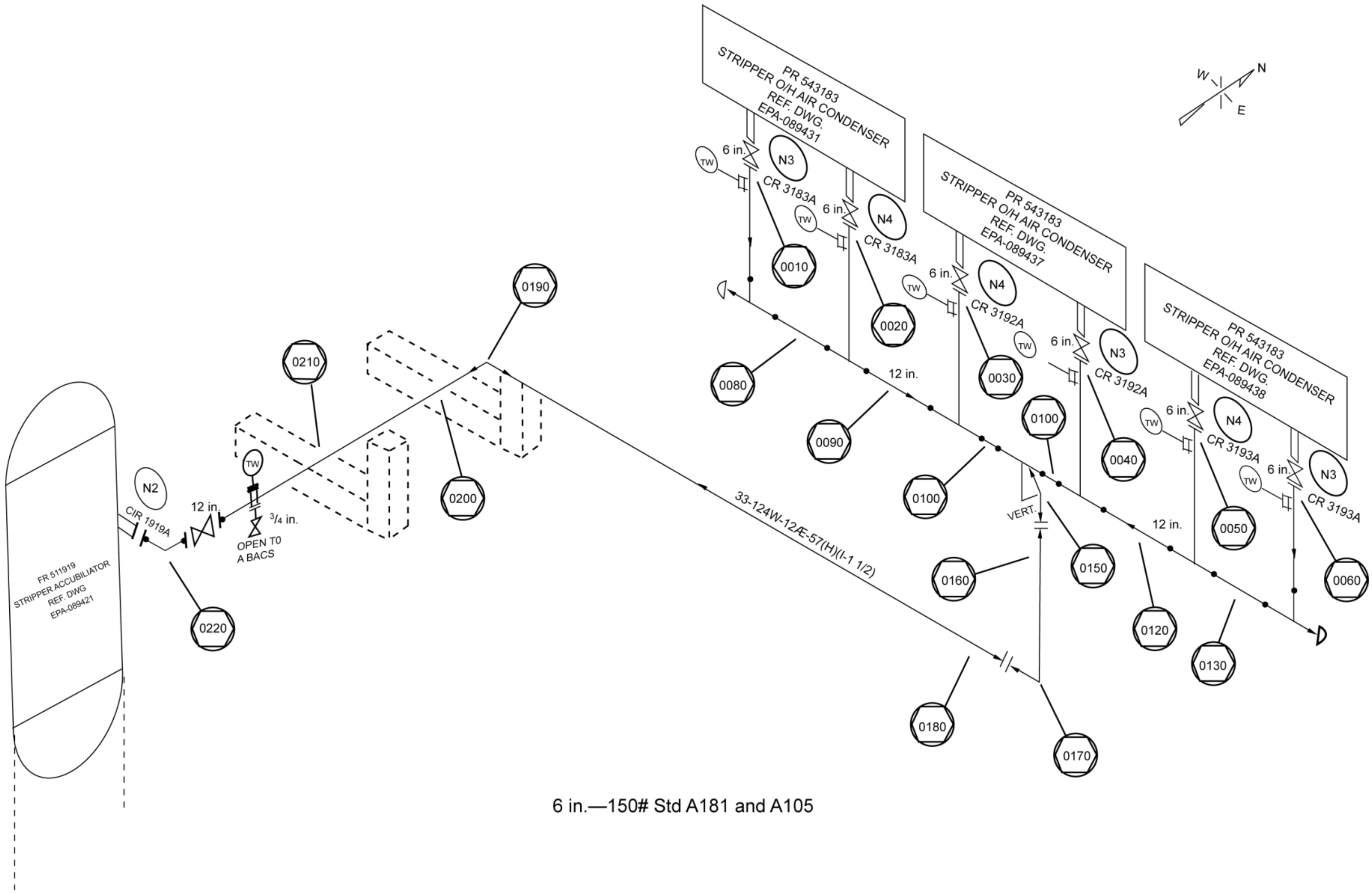
k) creep cracking,

l) brittle fracture,

m) freeze damage,

n) contact point corrosion,

o) dew-point corrosion.



NOTE Ballon symbols indicate positions of circuit TMLs.

Figure 17—Piping Circuit Example

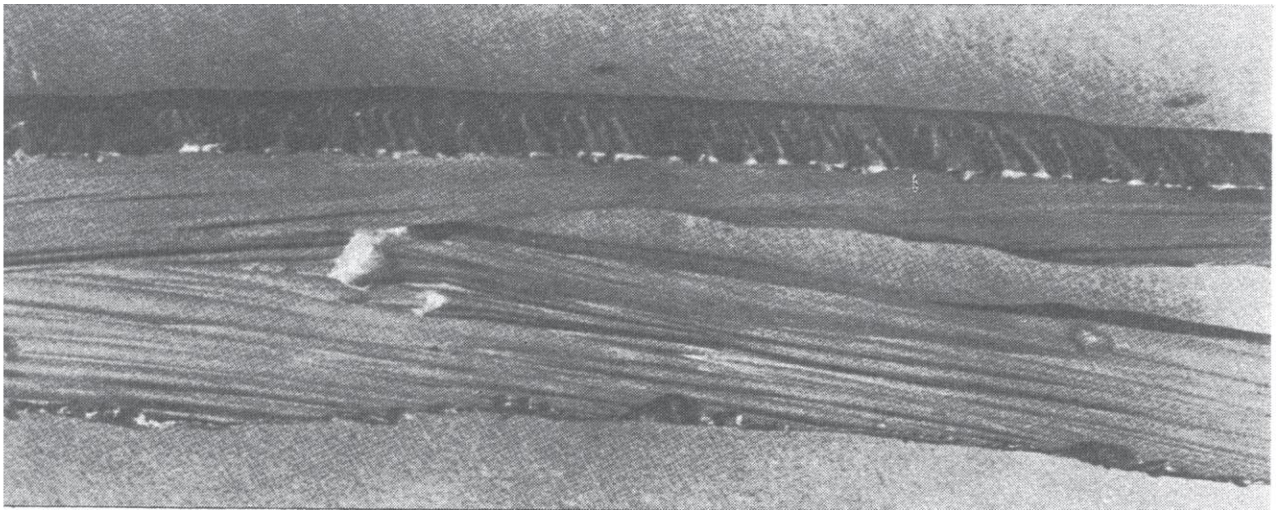


Figure 18—Erosion of Piping

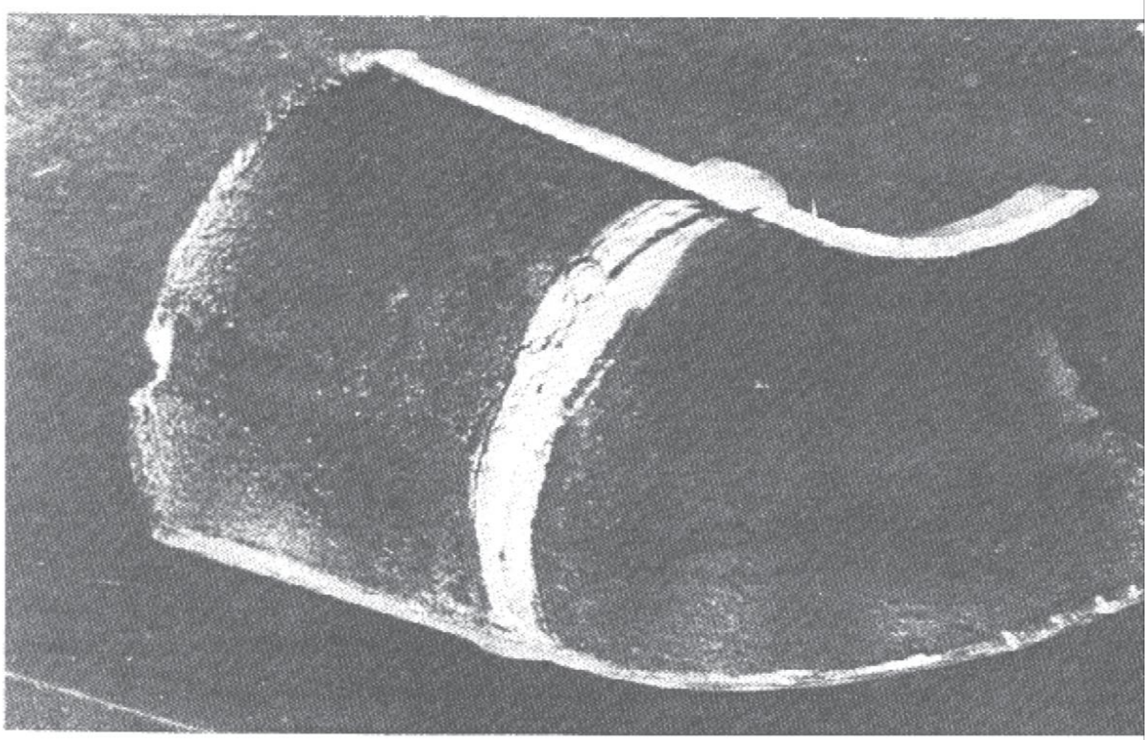


Figure 19—Corrosion of Piping

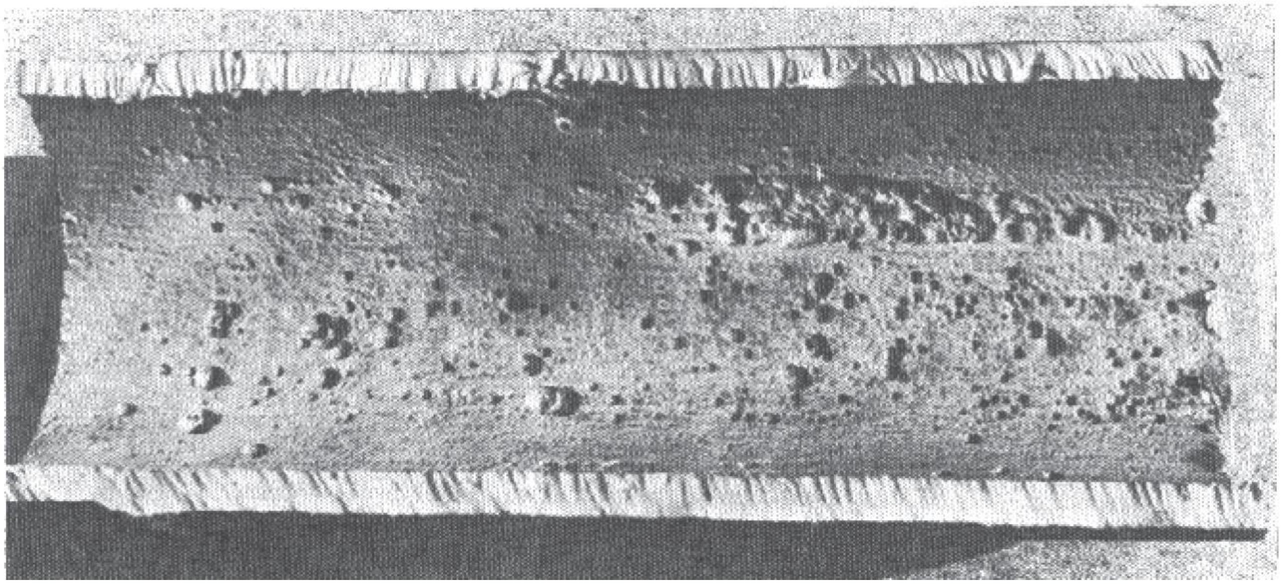


Figure 20—Internal Corrosion of Piping

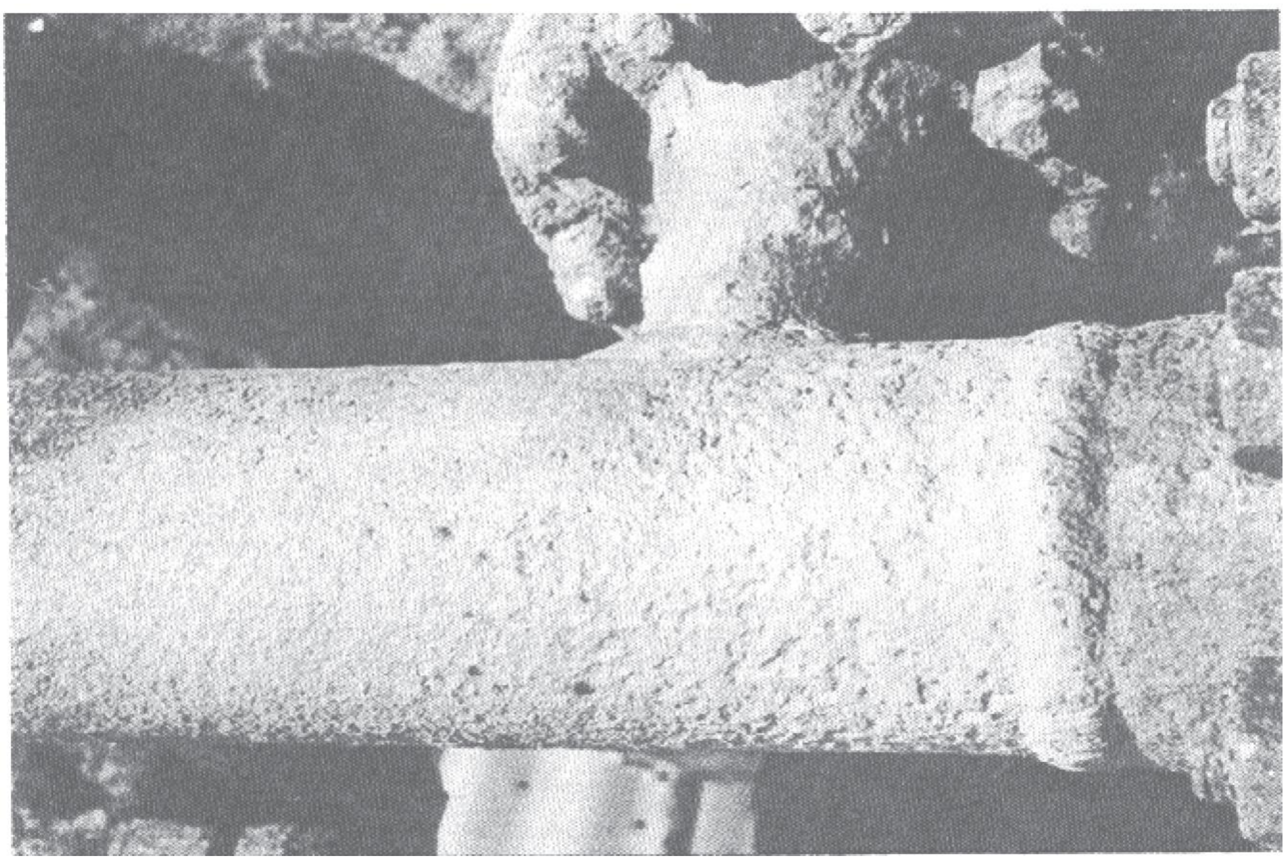


Figure 21—Severe Atmospheric Corrosion of Piping

7.4.2 Injection Points

API 570 has identified injection points for additional monitoring and/or enhanced inspection during operation. This was done in recognition of the fact that injections have caused significant equipment integrity problems, and part of the reason was that their design and operation might have received insufficient scrutiny. Some injection points have been installed without close attention simply because they were perceived as small add-ons with little potential for causing a problem.

Many different types of process additives are used to maintain reliability and optimal performance of plant operations. Typically, additives are injected into piping systems through small branch connections either directly or through a quill or spray nozzle. The locations at which these additives are introduced into process streams are commonly referred to as injection points.

An additive may be one of the following types:

a) a proprietary chemical such as a corrosion inhibitor, antifoulant, or oxygen scavenger;

b) a water stream injected to dissolve salt deposits;

c) dilute corrosive process components.

Some common injection systems found in refinery applications include:

a) ammonium polysulfide (APS) injection into sour gas streams (FCC, coker, sour water stripper);

b) steam/condensate injection into flue gas and catalyst piping;

c) washwater injection (continuous and intermittent) into hydroprocessing effluent to control corrosion, which may be caused by NH_4HS and NH_4Cl salts. Refer to API 932-B, Section 6.8.1 and Table 2 for additional details;

d) crude desalter washwater;

e) caustic injection into crude feed;

f) caustic injection into reformer regeneration section piping;

g) chloride, e.g. PERC (perchlorethylene), injection into reformer reactor feed piping;

h) methanol/condensate injection into reformer reactor system piping;

i) ammonia or neutralizing amine injection into crude tower overhead systems;

j) cold H_2 quench injection into hydroprocessing reactor system piping;

k) Filming amine inhibitor injection into fractionation and gas plant overhead piping.

Several corrosion mechanisms associated with injection points have become apparent over the years. Many of these problems have resulted in highly localized deterioration. Corrosion damage associated with injection points may produce corrosion rates one order of magnitude higher than reported for the main process streams, with localized losses being the most common form of problem.

Corrosion associated with injection points may be highly localized. Inspection practices geared to scanning areas of the piping are necessary to be able to detect the localized corrosion. Problems with injection points have generally been avoided when specification, design, training, operation, and condition monitoring were adequately carried out. After installation of injection systems the following should be reviewed:

a) injection system has been documented and installed hardware has been checked,

b) procedures and measurements in place to verify injection system performance,

c) inspection plan in place to check for equipment degradation related to the injection.

During the design and period audit of the injection systems, the following would typically be considered:

a) the injection was designed to achieve its process objectives;

b) the range of desired injection rates and the range of process conditions expected in the receiving stream were considered;

c) the ultimate destination of the injectant and its components were considered;

d) design of the injection as a system, including the injection point, supply system, instrumentation, and control was considered;

e) the system was designed to achieve the desired process reliability;

f) potential materials degradation problems were anticipated, and designs and materials of construction to achieve the desired pressure equipment reliability were chosen;

g) an approved MOC process was used in implementing or modifying the injection, as a way to ensure that changes were adequately thought out;

h) operating and maintenance personnel were trained on the proper operation and servicing of the injection equipment;

i) performance of the injection was verified and monitored to see that it was accomplishing its objective and not causing unanticipated process problems;

j) the integrity of the injection point and related equipment was monitored;

k) minimum inspection requirements for injection points in accordance with API 570 were implemented. Potential problem process mixing points were identified and similarly inspected;

l) the injection system, including the process operating window, anticipated conditions, equipment design, materials of construction, anticipated chemical and physical interactions, and monitoring/inspection requirements were documented;

m) injection quills and nozzles that project into the process stream were visually inspected for fouling and loosening of joints;

n) injection quills and nozzles that project into the process stream that are subject to fatigue were liquid penetrant inspected;

o) spray patterns of nozzles were tested;

p) antiblowout features of retractable injection hardware were inspected.

For more thorough and complete information, see NACE SP0114.

7.4.3 Process Mixing Points

7.4.3.1 General

Process mixing points occur where pipe components combine two process streams of differing composition, temperature, or other parameter that could cause damage. Mixing points can be subject to accelerated damage either from corrosion or mechanical mechanisms (e.g. thermal fatigue). Problems with mixing points have generally been avoided when specification, design, training, operation, and condition monitoring were adequately carried out.

Some examples of process mixing points include:

a) mixing of a chloride-containing stream from a catalytic reformer (e.g. naphtha) with a wet hydrocarbon stream from elsewhere;

b) mixing a low-temperature, high-sulfur-containing hydrocarbon stream with a high-temperature stream is an issue when bulk fluid temperature is increased where high-temperature sulfidation becomes active;

c) mixing hydrogen into a hydrocarbon stream where the stream temperatures are significantly different;

d) mixing of streams from hydroprocessing hot and cold separators;

e) mixing where high-temperature sulfidation can become an issue if the overall fluid temperature is increased.

The inspector, unit process engineer, and corrosion engineer will typically review PFDs to identify susceptible process mixing points and define the extent of the mix point circuit. More intensive inspection chosen for the damage mechanism is usually required at specific mixing points. This could include close grid thickness surveys, UT scanning techniques, and profile radiographic examination (RT) for corrosion. Other NDE techniques (e.g. angle beam UT, PT, etc.) may be appropriate when inspecting for thermal fatigue cracking. Under some conditions, users may apply injection point inspection requirements to susceptible process mixing points.

Some mixing points may incorporate proven technology resulting in complete mixing of each stream. These mixing points may not fall within the intended scope/definition of corrosive mixing points and, therefore, may not require any special emphasis inspections

7.4.3.2 Mixing Point Design Considerations

It is important to identify mixing points in the design phase of the piping system's life cycle. Proper design of mixing points should incorporate a number of considerations, like mixing effectiveness, flow regime, materials of construction, stream composition and stream volume, and normal operating conditions, as well as abnormal operating conditions along with the likelihood/frequency of those abnormal/excursive conditions.

Table 4 is an example that may be used for screening the material, fluid types and temperature difference between the two streams at a mixing point to determine whether thermal fatigue may be a concern. If the temperature difference between two process streams exceeds the number below, a thermal sleeve may be needed in order to prevent thermal fatigue.

Caution—This table is for the potential for thermal cracking at mix points. Corrosion at mix points can be created at much lower temperature differentials.

Table 4—Mix Point Thermal Fatigue Screening Criteria

Flow Medium		**Delta Temp** (°F)	
Main Pipe	**Secondary Pipe**	**Ferritic**	**Stainless**
Gas	Gas	450	300
Liquid	Liquid	450	300
Liquid	Gas	450	300
Gas	Liquid	275	125

7.4.3.3 Effectiveness of Mixing and Flow Regime

When two streams are combined, turbulence starts the mixing process, and the effectiveness will depend on the degree of penetration by the mixing stream and whether the two streams are miscible or immiscible. If the streams are miscible, then a single phase will be formed, but dispersion and dissolution are time dependent. Complete mixing may not develop until 100 pipe diameters or more downstream; inspection plans should consider the area where incomplete mixing is predicted. If the streams are immiscible, two phases may remain in the mixed stream or a third phase may form downstream of the mixing point (e.g. amine salt deposition).

The flow regime that develops depends on:

a) stream velocity,

b) relative amounts/densities of the phases,

c) size and orientation of both lines.

Flow regimes are different in horizontal and vertical lines because of gravity. Fully developed flow may not occur until many pipe diameters downstream.

7.4.3.4 Mixing, Contacting, or Wetting

Injection and mixing points involve mixing, contacting, or wetting.

a) Mixing—The rate of mixing is improved by an increase in velocity of the injected stream, which can be accomplished by injecting through a quill or spray nozzle.

b) Contacting—Contacting or intimate mixing of the separate phases is improved by maximizing the area between the phases (e.g. by a spray nozzle).

c) Wetting—In single-phase streams, wetting of walls by injected fluid is readily achieved. In two-phase streams, wetting is dependent on the flow regime with annular, bubble, and froth flow enhancing wetting of the walls, while stratified and wavy flow will impede wall wetting.

7.4.3.5 Quantity of Injected/Mixed Water

In some situations, the quantity of water needs to be calculated carefully to ensure sufficient un-vaporized water remains to fulfill the function and not exacerbate corrosion. Process engineers should check this periodically. Water quality can also affect corrosion rates.

See NACE SP0114 for additional information.

7.4.4 Dead-legs

The corrosion rate in dead-legs can vary significantly from adjacent active piping. The inspector should monitor wall thickness on selected dead-legs, including both the stagnant end and at the connection to an active line. In systems such as tower overhead systems and hydrotreater units where ammonium salts are present, the corrosion can occur in the area of the dead-leg where the metal is at the salting or dew-point temperature. In hot piping systems, the high-point area can corrode due to convective currents set up in the dead-leg. For these reasons, consideration should be given to removing dead-legs that serve no further process purpose. For such systems, extensive inspection coverage using such techniques as UT scanning and profile RT may be necessary in order to locate the area where dew-point or ammonium-salt corrosion is occurring. Additionally, water can collect in dead-legs, which can freeze in colder environments, resulting in pipe rupture.

7.4.5 CUI

7.4.5.1 General

External inspection of insulated piping systems should include a review of the insulation system integrity for conditions that could lead to CUI and signs of ongoing CUI. API 570 documents the requirements of a CUI inspection program. Sources of moisture can include rain, water leaks, condensation, deluge systems, and cooling towers. The two forms of CUI are localized corrosion of carbon steel and CSCC of austenitic stainless steels. See API 571 and API 583 for additional details on CUI mechanisms and inspection.

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

7.4.5.2 Insulated Piping Systems Susceptible to CUI

Certain areas of piping systems are potentially more susceptible to CUI, including:

a) those exposed to mist over-spray from cooling water towers;

b) those exposed to steam vents;

c) those exposed to deluge systems;

d) those subject to process spills or ingress of moisture or acid vapors;

e) carbon steel and low-alloy piping systems, including ones insulated for personnel protection, operating between 10 °F (–12 °C) and 350 °F (175 °C); CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and reevaporation of atmospheric moisture;

f) carbon steel and low-alloy piping systems that normally operate in service above 350 °F (175 °C), but are in intermittent service,

g) areas where temperature regimes are moving into and out of the CUI temperature range (this applies to both carbon steel and stainless steel susceptibility ranges);

h) dead-legs and attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line;

i) austenitic stainless steel piping systems operating between 140 °F (60 °C) and 350 °F (205 °C) (susceptible to CSCC);

j) vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress;

k) steam traced piping systems that can experience tracing leaks, especially at tubing fittings beneath the insulation;

l) piping systems with deteriorated insulation, coatings, and/or wrappings; bulges or staining of the insulation or jacketing system or missing bands (bulges can indicate corrosion product buildup);

m) piping systems susceptible to physical damage of the coating or insulation, thereby exposing the piping to the environment.

7.4.5.3 Typical Locations on Piping Circuits Susceptible to CUI

The above noted areas of piping systems can have specific locations within them that are more susceptible to CUI. These areas include the following.

a) All penetrations or breaches in the insulation jacketing systems, such as:

    1) dead-legs (vents, drains, etc.);

2) pipe hangers and other supports;

3) valves and fittings (irregular insulation surfaces);

4) bolt-on pipe shoes; and

5) steam and electric tracer tubing penetrations.

b) Termination of insulation at flanges and other piping components.

c) Damaged or missing insulation jacketing.

d) Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing.

e) Termination of insulation in a vertical pipe.

f) Caulking that has hardened, separated, or is missing.

g) Low points in piping systems, particularly ones that have a known breach in the insulation system, including low points in long unsupported piping runs and vertical to horizontal transitions.

h) Carbon or low-alloy steel flanges, bolting, and other components under insulation in high-alloy piping systems.

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

7.4.6 SAI

Inspection at grade should include checking for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is localized to the SAI or can be more pervasive to the buried system. Thickness readings at SAIs can expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. Figure 22 is an example of corrosion at a SAI although it had been wrapped with tape. If the buried piping has satisfactory cathodic protection as determined by monitoring in accordance with API 570, excavation is required only if there is evidence of coating or wrapping damage. Experience has shown that corrosion could occur under the tape even though it appears to be intact. Consideration should be given to excavate down 12 in. (300 mm) deep and remove the tape for inspection, or using appropriate NDE in lieu of the excavation and tape removal, to inspect for possible corrosion underneath the tape. If the buried piping is uncoated at grade, consideration should be given to excavating 6 in. (150 mm) to 12 in. (300 mm) deep to assess the potential for hidden damage. Alternately, specialized UT techniques such as guided wave can be used to screen areas for more detailed evaluation.

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

See API 571 for additional information on corrosion at SAIs.

Figure 22—SAI Corrosion

7.4.7 Service-specific and Localized Corrosion

An effective inspection program includes the following four elements that help identify the potential for service-specific and localized corrosion and select appropriate CMLs:

a) an inspector with knowledge of the service and where corrosion is likely to occur,

b) extensive use of NDE,

c) communication from operating personnel when process upsets occur that can affect corrosion rates,

d) identification of piping that may be overlooked from the routine piping circuit inspection programs that pose a degradation concern.

Examples include instrument bridles for equipment connecting to piping circuits, temporary piping used during maintenance outages, and swing-out spools.

There are many types of internal corrosion possible from the process service. These types of corrosion are usually localized and are specific to the service.

Examples of where this type of corrosion might be expected include:

a) downstream of injection and mixing points and upstream of product separators (e.g. hydroprocessor reactor effluent lines);

b) dew-point corrosion in condensing streams (e.g. overhead fractionation);

c) unanticipated acid or caustic carryover from processes into nonalloyed piping systems, or in the case of caustic, into non-postweld-heat-treated steel piping systems;

d) where condensation or boiling of acids (organic and inorganic) or water is likely to occur;

e) where naphthenic or other organic acids can be present in the process stream;

f) where high-temperature hydrogen attack can occur (see API 941);

g) ammonium salt condensation locations in hydroprocessing streams (see API 932-B);

h) mixed-phase flow and turbulent areas in acidic systems, also hydrogen grooving areas;

i) where high-sulfur streams at moderate-to-high temperatures exist;

j) mixed grades of carbon steel piping in hot corrosive oil service [500 °F (260 °C)] or higher temperature and sulfur content in the oil greater than 0.5 % by weight;

   NOTE Nonsilicon-killed steel pipe (e.g. ASTM A53/A53M and API 5L) can corrode at higher rates than silicon-killed steel pipe (e.g. ASTM A106) in high-temperature sulfidation environments.

k) under-deposit corrosion in slurries, crystallizing solutions, or coke-producing fluids;

l) chloride carryover in catalytic reformer units, particularly where it mixes with other wet streams;

m) welded areas subject to preferential attack;

n) "hot spot" corrosion on piping with external heat tracing;

   NOTE In services that become much more corrosive to the piping with increased temperature (e.g. sour water, caustic in carbon steel), corrosion or SCC can develop at hot spots that develop under low flow conditions.

o) steam systems subject to "wire cutting," graphitization, or where condensation occurs;

p) Locations subject to high-temperature sulfidation corrosion where residence times resulting from low flow conditions may result in increased corrosion. Susceptible locations include elbows, along the top of horizontal sections of line, and areas where localized heating may occur, i.e. double or triple heat trace areas and in stagnant and low flow piping systems with thermally induced currents (thermosiphon).

Where a temporary (or swing-out) piping spool has not been removed prior to process operation start-up, it should be verified that the temporary piping is either effectively isolated from the process (such as double-block valve or isolation blind) or that the temporary piping is of adequate material and mechanical design for the continued process operation, including potential no flow conditions. One particular concern is raised for temporary piping of inadequate material that may be subject to high-temperature sulfidation or other damage mechanisms if left exposed to the process. If the temporary piping is isolated and left for a significant period of time, lock-out/tag-out can be a means to prevent inappropriate and inadvertent service.

7.4.8 Erosion and Erosion-corrosion

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

This type of corrosion occurs at high-velocity and high-turbulence areas. Examples of places to inspect include:

a) downstream of control valves, especially where flashing or cavitation is occurring;

b) downstream of orifices;

c) downstream of pump discharges;

d) at any point of flow direction change, such as the outside radii of elbows;

e) downstream of piping configurations (welds, thermowells, flanges, etc.) that produce turbulence, particularly in velocity sensitive systems, such as ammonium hydrosulfide and sulfuric acid systems.

Areas suspected to have localized erosion-corrosion should be inspected using appropriate NDE methods that will yield thickness data over a wide area, such as UT scanning and profile RT.

See API 571 for additional information on erosion and erosion-corrosion.

7.4.9 Environmental Cracking

Piping system materials of construction are normally selected to resist the various forms of SCC. Some piping systems can be susceptible to environmental cracking due to upset process conditions, CUI, unanticipated condensation, or exposure to wet hydrogen sulfide or carbonates. Examples of this include the following.

a) CSCC of austenitic stainless steels resulting from moisture and chlorides under insulation, under deposits, under gaskets, or in crevices (see API 583). This is an especially aggressive form of cracking if environmental conditions cause drying and wetting (chlorides concentrate). SCC of austenitic stainless steels can also occur internally where chlorides are present with water.

b) Polythionic acid SCC of sensitized austenitic alloy steels resulting from exposure to sulfide/moisture condensation/oxygen.

c) Caustic SCC (sometimes known as caustic embrittlement).

d) Amine SCC in non-stress-relieved piping systems.

e) Carbonate SCC in alkaline systems.

f) Wet hydrogen sulfide stress cracking and hydrogen blistering in systems containing sour water.

g) Hydrogen blistering and hydrogen-induced cracking (HIC) damage. This has not been as serious of a problem for piping as it has been for pressure vessels. It is listed here because it is considered to be environmental cracking and can occur in piping although it has not been extensive. One exception where this type of damage has been a problem is longitudinally welded pipe fabricated from plate materials.

See API 571 for additional details on environmental cracking mechanisms.

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

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

7.4.10 Corrosion Beneath Linings and Deposits

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

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

Refractory linings used to insulate the pipe wall can spall or crack in service, causing hot spots that expose the metal to oxidation and creep cracking. Periodic temperature monitoring via visual, infrared, temperature indicating paints should be undertaken on these types of lines to confirm the integrity of the lining. Corrosion beneath refractory linings can result in separation and bulging of the refractory. Microwave examination technique (MW) can examine the refractory for volumetric flaws and for separation from the shell surface. If bulging or separation of the refractory lining is detected, portions of the refractory may be removed to permit inspection of the piping beneath the refractory. Otherwise, thickness measurements utilizing UT or profile RT may be obtained from the external metal surface.

Where operating deposits such as coke are present on the internal pipe surface, NDE techniques employed from the outside of the pipe such as profile RT, UT, and/or ET should be used to determine whether such deposits have active corrosion beneath them.

7.4.11 Fatigue Cracking

Fatigue cracking of piping systems can result from excessive cyclic stresses that are often well below the static yield strength of the material. The cyclic stresses can be imposed by pressure, mechanical, or thermal means and can result in low-cycle or high-cycle fatigue. The onset of low-cycle fatigue cracking is often directly related to the number of heat-up/cooldown cycles experienced. For example, trunnions or other attachments that extend beyond the pipe insulation can act as a cooling fin that sets up a situation favorable to thermal fatigue cracking on the hot pipe. Thermal fatigue can also occur at mix points when process streams at different operating temperatures combine. Excessive piping system vibration (e.g. machine or flow induced) can also cause high-cycle fatigue damage. See API 570, Section 5.5.5 for vibrating piping surveillance requirements and API 570, Section 7.8 for design requirements associated with vibrating piping.

Fatigue cracking can typically be first detected at points of high stress intensification such as branch connections. Locations where metals having different coefficients of thermal expansion are joined by welding can be susceptible to thermal fatigue. Preferred NDE methods of detecting fatigue cracking include PT, MT, and angle beam UT when inspecting from the OD for ID cracking. Suggested locations for UT on elbows would include the 3 and 9 o’clock positions. Acoustic emission examination technique (AE) also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test. See API 570, Section 6.6.4 for fatigue considerations relative to threaded connections.

It is important for the owner/user and the inspector to understand that fatigue cracking is likely to cause piping failure before detection with any NDE methods. Of the fatigue cycles required to produce failure, the vast majority are required to initiate cracking and relatively few cycles are required to propagate the crack to failure. As such, proper design and installation to prevent fatigue cracking are important.

See API 571 for additional information on thermal fatigue, mechanical fatigue, and vibration-induced fatigue.

7.4.12 Creep Cracking

Creep is dependent on time, temperature, and stress. Creep cracking can eventually occur at design conditions since some piping code allowable stresses are in the creep range. Cracking is accelerated by creep/fatigue interaction when operating conditions in the creep range are cyclic. Particular attention should be given to areas of high stress concentration. If excessive temperatures are encountered, mechanical property and microstructural changes in metals can also take place, which can permanently weaken equipment. An example of where creep cracking has been experienced in the industry is in $1^1/_4$ Cr steels above 900 °F (482 °C).

NDE methods of detecting creep cracking include PT, MT, UT, RT, and ET, and alternating current field measurement (ACFM), in-situ metallography, and dimensional verification (i.e. strapping pipe diameter) are other common practices for detection. NDE volumetric examination methods, including profile RT and UT, can be used for detection of creep cracking.

AE can be utilized to identify active creep cracking. The examination can be conducted while piping is in or out of operation. When the examination is conducted, the probability of detecting creep cracks can be a function of crack orientation. Any piping examined out of operation requires a pressure stimulus to activate any damage present.

See API 571 for additional information on creep and stress rupture.

7.4.13 Brittle Fracture

Carbon, low-alloy, and other ferritic steels can be susceptible to brittle failure at or below ambient temperatures. In some cases, the refrigerating effect of vaporizing liquids such as ammonia or C_2 or C_3 hydrocarbons can chill the piping and promote brittle fracture in material that may not otherwise fail. Brittle fracture usually is not a concern with relatively thin wall piping. Most brittle fractures have occurred on the first application of a particular stress level (i.e. the first hydrotest or overload) unless critical defects are introduced in service. The potential for a brittle failure should be considered when pressure testing or more carefully evaluated when pressure testing equipment pneumatically or when adding any other additional loads. Special attention should be given to low-alloy steels (especially $2^1/_4$ Cr-1 Mo material), because they can be prone to temper embrittlement, and to ferritic stainless steels.

A through-wall crack resulting from brittle fracture and causing a leak can be detected with helium leak detection. Alternatively, active cracking in embrittled material can be detected and possibly located with AE.

See API 571 for additional information on brittle fracture. API 579-1/ASME FFS-1, Section 3 provides procedures for the assessment of equipment for resistance to brittle fracture.

7.4.14 Freeze Damage

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

To prevent freeze damage, precautions need to be taken to drain, purge, or heat trace systems where moisture could collect and unexpectedly freeze during severe or sudden subfreezing temperature excursions. One of the most critical locations for these precautions is the top of the seat of relief valves and pilot-operated relief valves, when moisture could be present. Tail pipes on relief valves that discharge to the atmosphere should always have adequate drainage or heat tracing.

7.4.15 Contact Point Corrosion

Localized corrosion at pipe support contact points is the result of crevice corrosion due to deposits that contain corrosive species, water, and oxygen typical of an externally corrosive environment. More corrosion can be expected in moist climates, marine climates, and where contact between pipe and its supports is less of a “point” and more of an “area.” If undetected and/or not mitigated, contact point corrosion can lead to leaks.

7.4.16 Nonmetallic Damage Mechanisms

In many circumstances, the choice of FRP is based on its inherent resistance to degradation mechanisms such as corrosion. However, no material is totally resistant and so there is a potential for in-service degradation. OLF 055 has compiled an extensive review of the topic and produced a framework that may be used in risk assessments and in evaluating damage mechanisms.

Typical in-service damage mechanisms found in FRP nonmetallic piping systems are shown in Table 5.

Table 5—Damage Mechanisms Associated with Nonmetallic Piping

Damage	Cause
Flaws originating from poor construction/design	Inadequate thickness in design when piping is buried too deep. Poor joint assembly.
Erosion	High flow velocities and particle impact can cause erosion at changes in flow direction and restrictions.
Flange cracks	Overstressed bolted joints. High imposed loadings from corrosion deposits build up.
Chalking	UV damage when FRP material is exposed to solar radiation without the use of an outer UV light barrier.
Material aging	Breakdown of resin or fiber strength over extended periods of time. Breakdown can be accelerated by exposure to some chemicals, especially strong alkalines.
Deformation	Change in dimensions due to long-term exposure to stress—often described as creep.
Pit/pinhole	Small craters in the surface of the laminate from incomplete resin fill.
Softening	Reduction in hardness associated with moisture ingress when resin has excessive voids.
Creep	Permanent deflection of the material under long-term stress and temperature. Creep properties are dependent on the resin properties.
Star craze	Sharp impact to the external surface.
Blisters	Permeation of the service fluid into the laminate (common in HCl service).
Liner cracking/mud cracking	Chemical degradation, thermal shock, or temperature excursions.

MTI Project 129-99 is a good guide for identifying some of these failure mechanisms.

7.4.17 Piping Support Damage Mechanisms

7.4.17.1 External Corrosion at Supports

Corrosion of supports, and their associated pipe work, may occur in areas of protective coating breakdown where water and airborne debris become trapped (often referred to as "touch point corrosion"). Support design (i.e. support beams) can significantly contribute to this issue. Corrosion rates can be increased by local factors. Elevated temperatures from hot piping (e.g. steam piping) can increase corrosion, including fireproofed supports. Other factors such as heat tracing or steam trap drain outlets, or where moisture is increased such as from proximity to cooling towers, and vegetation (creating a wet environment on the underside of the pipe and on any supports in the proximity) all can contribute to locally high corrosion rates.

Crevice corrosion can occur under any partially or nonwelded shoe, doubler plate, wrapper, or half-sole plate. Considerations should also be given to intermittent environmental conditions such as testing of fire suppression deluge systems, etc.

Dummy leg supports may trap water and airborne debris, leading to corrosion of both the support and the pipe. When constructed using pipe, consideration should be given to capping all open-ended supports with fully welded caps or plates and providing a drain hole no smaller than $^{1}/_{4}$ in. (6 mm) at the lowest position. For horizontal dummy legs, drain holes should be provided at both ends and the dummy leg should slope slightly away from the pipe it is supporting.

7.4.17.2 Internal Corrosion at Supports

The chilling effect of a support on elevated temperature pipe may be sufficient to cause product or water condensation on the inside of the pipe. In some process services, this condensation may contribute to accelerated internal corrosion.

7.4.17.3 Fretting, Overstress, or Coating Damage at Supports due to Thermal Expansion

Thermal expansion and contraction due to temperature changes can damage protective coating systems and/or overstress both pipe and pipe supports.

7.4.17.4 Galvanic Corrosion at Supports

Galvanic corrosion is associated with the use of two or more materials of differing value in the galvanic series, in close proximity to each other. For example, carbon steel supports welded to stainless steel piping may be subject to corrosion at a higher rate than the stainless steel piping.

7.4.17.5 CUI at Supports

Supports that penetrate insulation systems may provide a potential for water ingress and subsequent CUI due to poor sealing at the penetration.

7.4.17.6 Environmental Cracking at Support

In predominantly alkaline process environments (e.g. amines and caustic), welding of supports to carbon steel piping either with or without postweld heat treatment (PWHT) can cause internal environmental cracking as a result of residual stresses.

7.4.17.7 External Cracking at Supports

Stainless steel piping may be susceptible to external chloride cracking where there is a source of chlorides above a threshold temperature. Pipe supports that trap water against the pipe can contribute to susceptibility of cracking

7.4.17.8 Foundation/Concrete Plinth Deterioration (Including Subsidence)

Deterioration of foundations and plinths are often a direct result of overloading the support and/or extended service life.

7.4.17.9 Vibration/Movement/Misalignment

Pipe vibration, movement, and misalignment can create a potential for fatigue, fretting, and/or overstressing of pipe and support members. Proper anchors, restraints, and movement allowances/guides should be considered during support design. This includes available travel of spring hangers.

7.5 Integrity Operating Windows

The use of well-defined, communicated, and properly controlled integrity operating windows for key process parameters (both physical and chemical) that could impact piping integrity if not properly controlled reinforces inspection plans. 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. Key process parameters for integrity operating windows containing upper and lower limits can be established, as needed, and deviations outside these limits brought to the attention of inspection/engineering personnel. Particular attention to monitoring integrity operating windows should also be provided during start-ups, shutdowns, and significant process upsets. Refer to API 584 for more information on integrity operating windows.

8 Frequency and Extent of Inspection

8.1 General

The frequency and extent of piping inspections will range from often and extensive in piping classes where deterioration is extreme or high consequence to seldom and cursory in piping classes in noncorrosive or low-consequence services. The frequency of piping inspections should be determined by the following conditions:

a) consequence of a failure (piping classification),

b) degree of risk (likelihood and consequence of a failure),

c) amount of corrosion allowance remaining,

d) available historical data,

e) regulatory requirements.

API 570 requires classifying piping systems according to the consequences of failure, unless RBI is used to determine piping inspection plans. Each refinery or process plant should review their own piping systems and develop either a classification system using the information provided in API 570 or an RBI analysis in accordance with API 580. Either system helps to establish minimum inspection frequencies for each piping classification or inspection due dates.

Some inspections can and should be made while the piping is operating. Inspections that cannot be made during operation should be made while the piping is not in service. Elevated operating temperature can limit the inspections techniques that can be effectively used during operation.

8.2 On-stream Inspection

8.2.1 Technical Reasons for Inspecting On-stream

Certain kinds of external inspections should be done while piping is operating. Vibration and swaying is evident with process flow through the pipe. Proper position and function of supports, hangers, and anchors is most apparent while piping is in operation at temperature. The inspector should look for distortion, settlement, or foundation movement, which could indicate improper design or fabrication. Pipe rollers and slide plates should be checked to ensure that they operate freely.

Leakage is often more obvious during operation. Inspectors should look for signs of leakage both coming from each pipe and onto each pipe. The leakage from a pipe can indicate a hole in the pipe, and leakage onto a pipe can indicate a leak from an unobserved source (e.g. beneath insulation).

Thermal imaging inspections may be performed for various reasons and should be done under operating conditions. Thermal images can show pluggage and/or maldistribution of flow that can affect corrosion mechanisms. Thermal imaging can also show wet insulation that can lead to CUI. Thermal imaging can show breakdown of internal insulating refractory, which can lead to high-temperature corrosion of the pipe wall. Thermal imaging may show malfunctions of heat tracing, which could allow unexpected damage mechanisms to operate. For instance, tracing that is too hot may cause caustic SCC of carbon steel carrying caustic solutions, and tracing that is too cold may allow dew-point corrosion.

Radiography can be as effective during operation as when the piping is offline. On-stream radiography could detect fouling that might be washed out of piping during unit entry preparation.

8.2.2 Practical Reasons for Inspecting On-stream

On-stream inspection can increase unit run lengths by giving assurance that piping is fit for continued service.

When piping must be replaced, on-stream inspection allows an inspector to define the extent of replacement necessary and have replacement piping fabricated before the shutdown.

Units are often crowded during a shutdown, and on-stream piping inspection can increase the safety and efficiency of shutdown operations by reducing the number of people who need to be in the unit during that time.

On-stream inspection can reduce surges in work load and thus stabilize personnel requirements.

8.3 Offline Inspection

A common limitation to on-stream inspection is temperature. The equipment used in some kinds of techniques cannot operate at temperatures much above ambient. In addition, the radiant heat from some piping can be too great for technicians to make measurements safely. In both of these instances, piping inspection may need to be done when the piping is not in operation.

Signs of wet insulation should be noted when piping is offline. Water dripping onto insulation may not show dampness during operation because heat from the pipe causes surface water to evaporate, but water deeper in the insulation can still cause CUI. If dampness is noted during a shutdown, the damp piping should be considered for CUI inspection.

When piping is opened for any reason, it should be inspected internally as far as accessibility permits. Some piping is large enough for internal inspection, which can only occur while the piping is offline.

Adequate follow-up inspections should be conducted to determine the causes of defects, such as leaks, misalignment, vibration, and swaying, that were detected while the unit was operating.

8.4 Inspection Scope

Piping inspection should be frequent enough to ensure that all piping has sufficient thickness to provide both pressure containment and mechanical support. For pipes undergoing uniform corrosion, calculating the corrosion rate and remaining life at each CML and setting the inspection interval at the half-life had traditionally given that assurance. The inspector, often in consultation with corrosion specialists and piping engineers, has decided the number and locations of CMLs (see API 570). RBI may be used to determine interval or due date and extent.

For degradation mechanisms other than uniform corrosion, the inspector should determine the type of inspection, the frequency, the extent, and the locations of CMLs. Corrosion and pressure equipment engineers have typically helped in this process.

9 Safety Precautions and Preparatory Work

9.1 Safety Precautions

Safety precautions should be taken before external inspections are performed and especially before any piping is opened for inspection. The appropriate personal protective equipment (PPE) should be utilized for each inspection. Procedures for the separation of piping, installation of blinds, and leak testing should be an integral part of safety practices. 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.

Hammer testing of pressured piping might cause failure and allow the contents of the piping to be released. Precautions should be taken before any hammer testing of in-service piping (see API 2217A).

Radiography must be performed in accordance with the applicable requirements of the site and jurisdiction due to potential radiation exposure.

Caution should be taken when attempting to remove scale and deposits from the external surfaces of in-service piping, especially when operating at high pressure or temperature with hazardous/flammable process fluids. Loss of containment incidents have occurred when deposits were removed while inspecting for CUI, support point corrosion, cooling water drift corrosion, etc. that were covering through-wall corrosion damage. The owner/user may consider the following to mitigate the risk of a through-wall event.

a) Use of profile RT or UT NDE to inspect under deposits and determine the amount of corrosion damage, before disturbing the deposits.

b) Develop an emergency response plan in the event that a through-wall leak develops. This plan should include provisions to isolate the affected area, temporary repair provisions, and any additional PPE requirements.

9.2 Communication

Before starting any piping system inspection and/or maintenance activities (NDE, pressure testing, repair, or alteration), personnel should obtain permission from operating personnel responsible for the piping to work in the vicinity.

When individuals are inside large piping systems, all persons working around the equipment should be informed that people are working inside the piping. Individuals working inside the piping should be informed when any work is going to be done on the exterior of the piping.

9.3 Preparatory Work

All possible preparatory work should be done before the scheduled start of inspection. Scaffolds should be erected, insulation removed, and surface preparation completed where required. Buried piping should be excavated at the points to be inspected. Equipment required for personal safety should be checked to determine its availability and condition. Any necessary warning signs should be obtained in advance, and barricades should be erected around all excavations. The appropriate signs and barricades as required by the site and jurisdiction should be in place before radiography is performed.

All tools, equipment, and PPE used during piping work (i.e. inspection, NDE, pressure testing, repairs, and alterations) should be checked for damage and/or operability prior to use. NDE equipment and the repair organization’s equipment are subject to the owner/user’s safety requirements for electrical equipment. Other equipment that might be needed for the piping system access, such as planking, scaffolding, and portable ladders, should be checked for adequacy and safety before being used.

During preparation of piping systems for inspection, PPE should be worn when required either by regulations, the owner/user, or the repair organization.

The tools needed for inspection should be checked for availability, proper working condition, calibration, and accuracy. The following tools and instruments are often used in inspection of piping:

a) ACFM crack detection equipment;

b) alloy analyzer (nuclear source for material identification);

c) borescope and/or fiberoptic;

d) camera;

e) crayon or marker;

f) direct-reading calipers with specially shaped legs;

g) eddy current equipment;

h) flashlight and additional portable lighting;

i) hammer;

j) ID and OD transfer calipers;

k) infrared pyrometer and camera;

l) knife;

m) leak detector (sonic, gas test, or soap solution);

n) liquid penetrant equipment;

o) magnet;

p) magnetic particle equipment;

q) magnifying glass;

r) material identification kit;

s) microwave inspection equipment;

t) mirror;

u) notebook or sketches;

v) paint;

w) pit-depth gauge;

x) portable hardness tester;

y) radiographic equipment;

z) remote television camera (for internal inspection);

aa) scraper;

ab) steel rule;

ac) thickness or hook gauge;

ad) ultrasonic equipment;

ae) wire brush.

In addition to the list above, grit blasting or comparable equipment may be required to remove paint and other protective coatings, dirt, or corrosion products so that the surface is properly prepared for the inspection technique (e.g. inspection for cracks with MT).

9.4 Investigation of Leaks

On-stream piping leaks in process units can occur for various reasons. Those who investigate the leak may be particularly at risk to the consequence associated with release of the process fluid. A site may want to create a general safety procedure to be followed during a piping leak investigation. A further precaution is to hold a safety review before any leak investigation. The review would consider the state of a piping system in terms of pressure, temperature, remaining inventory of process fluids, potential damage mechanisms, and similar factors. Where piping may be significantly thinned rather than contain isolated defects, potential pipe rupture is more likely and should be taken into consideration when investigating leaks or during firefighting efforts. Reference API 2001 for more information on leak response protocol.

The safety review team should define:

a) a “hot zone” around the leak site and establish PPE and additional firefighting equipment requirements to perform work inside this zone;

b) decontamination requirements upon exit from the hot zone and other requirements necessary to protect personnel and the environment.

The safety review team must be careful making assumptions about the leak’s cause. Incidents have occurred where investigative personnel assumed they knew the cause of a small leak on an operating line and were caught unprepared when the leak suddenly became quite large.

10 Inspection Procedures and Practices

10.1 External Visual Inspection

10.1.1 General

External visual inspections are performed to determine the external condition of piping, insulation system, painting/coating systems, and associated hardware and to check for signs of misalignment, vibration, and leakage. Annex A contains a sample checklist.

10.1.2 Leaks

Leaks can be safety or fire hazards. They can cause premature shutdown of equipment and often result in economic loss. Leaks in utility piping are seldom hazardous or cause shutdowns, but they do result in loss. Leaks in hot or volatile oil, gas, and chemical piping can result in a fire, an explosion, contamination of the surrounding atmosphere, a serious environmental problem, or a premature shutdown. Frequent visual surveillance should be made for leaks. Particular attention should be given to flanged joints, packing glands, bonnets of valves, and expansion joints on piping that carries flammable, toxic, corrosive, or other harmful materials. Many leaks can be stopped or minimized by tightening packing glands.

Tightening flange bolts in a pressurized line is only recommended when special steps are taken to avoid three potential problems:

a) bolt interactions—when a bolt is tightened the adjacent bolts are loosened,

b) a bolt can yield or fail due to overloading,

c) tightening one side of a flange can cause deflections in the areas opposite and adjacent to it.

Leaks of certain fluids can result in the cracking and/or corrosion of flange bolts; in such services, the bolts should be replaced. The prompt repair of leaks will often prevent serious corrosion or erosion of gasket surfaces or packing glands. Temporary or permanent repairs can possibly be made while lines are in service.

Wet hydrogen sulfide stress cracking and hydrogen blistering in systems in sour (H_2S laden) service may occur externally if trapped due a leak that is clamped.

10.1.3 Misalignment

Piping should be inspected for misalignment, which can be indicated by the following conditions:

a) piping dislodged from one or more supports so that its weight is not being properly distributed on the remaining hangers or saddles;

b) the deformation of a vessel or tank wall in the vicinity of a piping attachment, which may also be the result of thermal expansion in the piping system or major piping misalignment or inadequate piping support;

c) piping supports forced out of plumb by expansion or contraction of the piping;

d) excessive replacement or repair of bearings, impellers, and turbine wheels of centrifugal pumps, compressors, and turbine seals to which piping is connected;

e) the shifting of a base plate, breaking of a foundation, or shearing of foundation bolts of mechanical equipment to which piping is attached;

f) cracks in connecting flanges or the cases of pumps or turbines to which piping is attached;

g) expansion joints that are excessively deformed or not performing properly.

If significant piping misalignment is discovered, it should be promptly corrected.

10.1.4 Supports

10.1.4.1 General Pipe Support Inspection

Support locations should be identified in appropriate record systems and inspected to verify that the supports are functioning properly and are not causing damage to the pipe.

The prioritization of support inspections may be made on the basis of likelihood of damage or may be made on the basis of a risk assessment that also considers the consequence of a failure.

Statistical techniques may be used to determine the required inspection sample size to ensure the necessary degree of confidence. Site-specific data related to historical piping support problems should be referenced to better understand the vulnerability of particular support design, location, or application.

Statistical analysis may be used to evaluate the inspection data collected during sampling inspections and determine if additional inspection, up to and including 100 % inspection of particular piping supports and/or designs is warranted. Close visual inspection of piping supports or touch point locations may provide additional data to help determine where more detailed, quantitative techniques are required.

External inspection of supports should include the following examinations where applicable.

a) Visual examination for general physical damage, distortion, and deterioration of protective coatings or fireproofing.

b) Visual examination for evidence of corrosion, especially at or near touch points, the foundation attachments, and near dummy legs (trunnions).

Close visual examination of the touch point area between the piping and support can identify corrosion damage by the presence of rust buildup and/or paint blistering and discoloring. However, the severity of corrosion cannot always be assessed without further examinations. Further, highly localized corrosion may be missed as the visual appearance may not be significant. Mirrors can be used with great advantage when inspecting support locations with limited access.

Dummy leg drain holes should be examined to ensure they are open and unobstructed. Water should never be allowed to accumulate within a piping support trunnion. The dummy leg drain holes should not be sitting on any structural supports, which may allow water to wick into any horizontal closed dummy leg. Vertical dummy legs should have a drain hole at the bottom. Water should never be allowed to accumulate within a piping support trunnion.

Lifting pipe from supports or touch points using a crane or other lifting equipment can allow for a more accurate determination of condition and extent of damage. Lifting a pipe, which may already have suffered corrosion, can be hazardous and should be carried out with extreme caution. Safety precautions for lifting the pipe will vary depending on the fluid contained, line pressure, anticipated pipe condition, and location on site/off site. This should involve a job safety analysis prior to performing the task. In some instances, the pipe lifting may be considered too hazardous for particular fluids (e.g. propane), or for particular services if the line cannot be depressurized. If external corrosion is evident, any external cleaning using mechanical means, abrasive blasting, or high-pressure water blasting should be done with extreme caution so as to minimize the chance of prematurely causing a loss of containment event.

Support removal and temporary support placement, when possible, can also be an effective method to gain access and allow for a more thorough examination. When removing support, or using temporary support, the same precautions apply as for lifting pipe.

c) Visual examination for signs of movement, restricted operation of pipe rollers, slide plates, pulleys, or pivot points in counterbalanced support systems. Inspection should also include a search for small branch connections that are against pipe supports that might be constraining thermal movement of the larger line.

d) Visual examination for deterioration of concrete footings, foundations, or plinth blocks. If deterioration of concrete footings is found, the cause should be determined and corrective action should be taken.

e) Visual examination for failed fireproofing at support locations.

f) Visual examination for failed or loosening of foundation anchor bolts. Loose foundation bolts can be found by lightly rapping the bolt sideways with a hammer while holding a finger against the opposite side in contact with the bearing plate. Movement of the bolt will be easily detected. Trying the bolts by tightening the nuts with a wrench may also indicate loosening. Broken bolts can be detected using the same methods used to find loose bolts. Shifting of the bearing plate on its foundation can indicate that the foundation bolts are sheared.

g) Visual examination for insecure attachment of brackets and beams to the support, or insecure attachment or improper adjustment of pipe hangers.

h) Visual examination of spring can integrity and proper operation. For spring supports, the following items need to be inspected for any evidence of corrosion or mechanical overload:

   1) spring can,

   2) spring,

   3) locking device,

   4) hanger accessories (rods and support clamps),

   5) piping under support clamps,

6) supporting structural steel.

Spring hanger loads should be checked under both cold and hot conditions, and the readings obtained should be checked against the original cold and hot readings. Improper spring support settings can cause excessive pipe loads on rotating equipment that can result in misalignment. Other factors such as differential settlement and creep can make alternate settings necessary.

i) Ultrasonic thickness measurements or profile radiography used to determine corrosion damage should include the center of dummy leg (trunnion) support attachments, unless drain holes are present and historical inspection have determined that no pipe external corrosion exists within the dummy leg. A measurement of pipe thickness should include the center of the dummy leg attachment and be taken as near as possible to the edge where water may sit in the dummy leg.

10.1.4.2 Special Emphasis Support Inspection

There are several types of specialized NDE techniques that may allow inspection of touch points without lifting of the pipe or removal of the support. Some of these techniques may also be suitable for inspection of piping at dummy leg (trunnion) attachments.

a) Long-range Ultrasonic Technique: Ultrasonic Guided Wave Inspection—Low-frequency ultrasonic guided waves can be used for detection of internal and external corrosion from a single point of access on the pipe to a distance of about 30 m (98 ft) in both directions. The distance and effectiveness may be reduced by factors such as fittings, flanges, heavy external coatings and concrete, and heavy products inside the pipe. This technology cannot differentiate between internal and external corrosion or may not locate the most severe localized corrosion; however, it can be used as a screening tool. When supports are welded to the pipe, detection of defects is not effective. Highly localized corrosion is not reliably detected with long-range UT.

b) Electromagnetic Acoustic Transducer (EMAT) Ultrasound—The EMAT system can be used to inspect pipe support locations on live, on-stream process piping. This monitors ultrasonic Lamb wave mode and velocity changes and enables defects at support locations to be detected and sized.

   The EMAT system does not require contact or a couplant, and the ultrasonic transducers use magnetic waves and high-current tone bursts to generate Lamb waves. These waves propagate circumferentially around the pipe.

   Transducers housed in a scanner that moves along the pipe measure the mode and velocity changes of the Lamb waves and convert the output into readings of wall thickness. The accuracy can vary depending on the defect characteristic and material thickness. The owner/user should consider validating the performance accuracy.

   EMAT can (at the time of document release) be used to survey pipe diameters 100 mm to 600 mm NPS (4 in. to 24 in. NPS)

c) Creeping Head Wave Method—The Creeping Head Wave Method is able to detect corrosion of a pipe at a distance from the point of access. It requires contact with the pipe in two locations, one at either side of the pipe support (maximum effective span between transducer heads is 1 m).

   Ultrasonic compression waves are launched along the surface of the pipe and result in the production of shear waves in the body of the material. When the shear waves reach the opposite side of the pipe wall, they convert back to compression surface-skimming waves.

   Corrosion and other flaws result in a scattering of surface-skimming waves, and they can therefore be located and sized based on an analysis of the waves.

   The presence of too much debris can prevent the technique from being effective.

Creeping Head Wave Method results are usually reported by estimating the defect severity into three ranges that include the following.

1) Defect of less than 10 % through-wall thickness loss.

2) Defect of between 10 % and 40 % through-wall thickness loss.

3) Defect of greater than 40 % through-wall thickness loss.

Creeping Head Wave Method can also be utilized to survey for corrosion between pipe and saddle supports.

NOTE When choosing a special emphasis inspection technique for supports, some techniques such as Ultrasonic Guided Wave and Creeping Head Wave Method may not be effective at detecting localized corrosion areas with near through-wall depths and should not be relied upon to find this type of defect. Other inspection and sampling techniques should be used.

10.1.4.3 Pipe Support Risk Ranking

Risk assessment may be considered to identify vulnerable pipe supports and in deciding where sample inspection may and may not be used. Determination of the most vulnerable areas should consider the following.

a) Factors affecting likelihood of damage include the following.

   1) Is the support of a type that has a history of giving problems (e.g. open dummy legs, beam supports, and saddle clamps)? Supports with a flat surface, such as H beams and those listed above, provide a crevice for retention of water, which can promote corrosion.

   2) Does the support design promote continuous moist conditions (e.g. contact with insulation)?

   3) Is there an effective coating on the pipe in the area of the support?

   4) Is the support in an area of the plant that is particularly wet (e.g. near cooling towers)?

   5) Is the temperature in the area of contact such that corrosion could be accelerated?

   6) Could pipe movement result in distortion or high local stresses on the pipe in the area of the support?

   7) Age.

b) Factors affecting consequence of failure like the health and safety hazards to personnel if leaks occur, the impact on the environment, the unavailability of equipment, and any resultant financial impact.

c) On-site and Off-site Areas—There is usually no distinction between on-site and off-site areas in terms of corrosion vulnerability. However, the location can have corrosion contributing factors like flooding or lack of drainage, weeds, mud, etc.

10.1.5 Vibration

If vibration or swaying is observed, welds should be inspected for cracks, particularly at points of restraint, such as areas where piping is attached to equipment and near anchors. Problems frequently occur at small welded and screwed connections that have a heavy valve that accentuates vibration and at small lines that are tied down to a larger line and forced to move with it. Additional support should be considered for poorly braced small-sized piping and valves and for the main vibrating line to which they are attached. In cases of severe vibration, it may be advisable to have a competent consultant recommend a remedy, particularly if specialized equipment, such as a pulsation bottle or sway stabilizers, may be required.

10.1.6 External Corrosion

Defects in protective coatings and the waterproof coating of insulation will permit moisture to come into contact with the piping. When defects are found in the waterproof coating of insulation, either enough insulation should be removed or the affected area should be radiographed to determine the extent and severity of the corrosion. Sections of insulation may be removed from small connections, such as bleed lines and gauge connections, since difficulty in obtaining a good seal in the insulation makes these locations particularly vulnerable to external corrosion.

Lines that sweat are susceptible to deterioration at areas of support. Corrosion can be found under clamps on suspended lines. Piping mounted on rollers or welded support shoes is subject to moisture accumulation with resultant corrosion. Liquid spilled on piping, the impingement of a jet of steam, and water dripping on a line can cause deterioration. Loss of vapor-sealing mastic from the insulation of piping in cold service can result in local corrosion. Pipe walls inside open-ended trunion supports are subject to corrosion. All of these points should be investigated.

A loss in thickness can be determined by comparing the pipe diameter at the corroded area with the original pipe diameter. The depth of pits can be determined with a pit-depth gauge.

Bolting should also be checked, especially in marine environments and other corrosive environments.

10.1.7 Accumulations of Corrosive Liquids

Spilled liquid that has seeped into the ground can usually be located by looking for discoloration of the earth. The spill should be investigated to determine whether the liquid is corrosive to steel. This may involve a chemical analysis of soil samples or of the liquid, unless the source of the spill is known.

10.1.8 Hot Spots

Piping operating at temperatures higher than the design limit or in the creep range, even without higher pressure, can experience bulging. In piping that is protected from excessive temperatures by internal insulating refractory, failure of the insulation will result in overheating of the metal wall, causing a hot spot. The excessive temperature greatly reduces the strength of the metal and can cause bulging, scaling, localized buckling, metal deterioration, or complete failure.

Frequent inspection should be performed to detect hot spots on internally insulated piping. Any bulging or scaling should be noted for further investigation when the equipment is shut down. Some hot spots can be detected by a red glow, particularly if the inspection is made in the dark. The skin temperature of indicated hot spots should be measured using a portable thermocouple, temperature-indicating crayons, temperature-indicating paints, thermography, or a pyrometer. To ensure that an in-service rupture does not occur, the amount of bulging should not exceed the amount of creep permitted for the material. As an interim measure, cooling severe hot spots with steam, water, or air may be desirable or necessary until the system can be removed from service (this situation should be reviewed by a piping engineer). The condition of both the pipe metal and the internal insulation near hot spots should be investigated during the next shutdown period.

10.2 Thickness Measurements

10.2.1 UTs

10.2.1.1 General

There are many tools designed for measuring metal thickness. The selection of tools used will depend on several factors:

a) the accessibility to both sides of the area to be measured,

b) the limitations of NDE methods,

c) the time available,

d) the accuracy desired,

UT instruments are now the primary means of obtaining thickness measurements on equipment. Radiography and real-time radiography may also be used in a limited way to determine thickness of piping components. Methods such as depth drilling (i.e. sentinel or tell-tale holes), the use of corrosion buttons, and the use of test holes may be applied at some special locations. However, these methods have generally been replaced by NDE methods of thickness gauging, such as ultrasonic thickness measurements.

Ultrasonic instruments are widely used for thickness measurements and have become standard equipment in most petrochemical inspection organizations. The major advantages to utilizing digital thickness instruments are:

a) most instruments weigh no more than several pounds and are small enough that they are not cumbersome,

b) digital meters are economical to purchase and maintain compared to many other instruments,

c) training and experience requirements are less than would be required for flaw detection and weld quality evaluation.

However, the degree of training and experience required in order to ensure true and accurate measurements are obtained can be considerable and should not be underestimated. Owner/users should ensure that adequate training, examination, and certification of personnel takes place such as outlined in ASNT SNT-TC-1A or equivalent international standards. Personnel using these devices should have training on the proper use of this equipment, including ultrasonic theory, high-temperature thickness measurements, corrosion evaluation, midwall anomalies, potential for “doubling,” and equipment operations.

10.2.1.2 Thickness Instruments

10.2.1.2.1 General

There are three types of digital ultrasonic thickness instruments: numeric thickness readout, A-scan with numeric thickness readout, and flaw detectors.

10.2.1.2.2 Numeric Thickness Readout

Thickness readout instruments are small handheld pulse-echo thickness gauges with only a numeric readout. These instruments typically are equipped with dual-element pitch-catch transducers. The instruments have a probe zero and a velocity setting for calibration on various materials. The range on for these instruments usually ranges from 0.040 in. to 20.000 in., depending on the configuration. The instruments operate by measuring the time between the initial pulse (IP) and the first echo.

The use of numeric thickness readout only instruments should be carefully considered as they have been misused and misapplied within the industry and can lead to erroneous and inaccurate results.

10.2.1.2.3 A-scan with Numeric Thickness Readout

A-scan with thickness readout instruments are divided into two groups, thickness measurement and flaw detectors.

A-scan thickness measurement instruments incorporate a numeric display and an electronic display for viewing an A-scan presentation. The displays are usually liquid crystal displays (LCDs) or light-emitting diodes (LEDs). Some of these instruments have the ability to display both A- and B-scans.

The advantage to an A-scan display over a numeric display is that it allows the examiner to view the ultrasonic waveform to verify the proper signal is being measured by the instrument. This is extremely important in the case of doubling and for evaluating a laminar indication vs. corrosion damage.

Doubling occurs when measuring wall thickness below the instrument/transducers ability to separate the signals adequately for proper measurement gate function. This problem can occur on thin wall below approximately <0.1 in. thickness and for evaluating a laminar indication vs. corrosion damage. It is equally important when using echo-to-echo mode due to mode converted shear wave echoes occurring between the backwall echoes. The measuring gate can lock on the signal mode converted shear wave echo, causing incorrect wall thickness measurement, as shown in Figure 23.

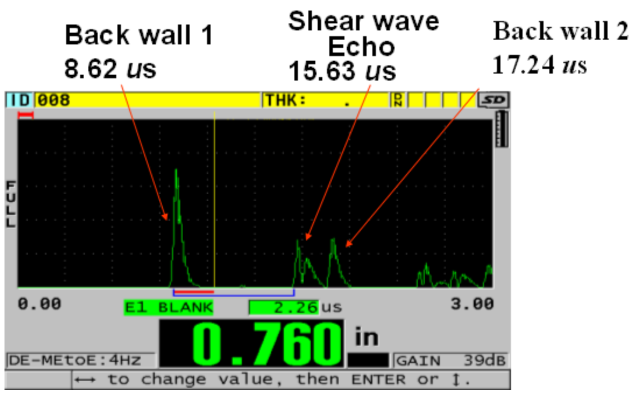


Figure 23—Case of Doubling due to Mode Converted Shear Wave Echo Occurring Between the Backwall Echoes

The A-scan display aids the examiner in distinguishing between a corroded surface and a midwall anomaly (e.g. laminar inclusion). The reflected signal from a laminar inclusion will come straight up from the baseline at a point prior to the reflected backwall signal indicating the depth. Often, while scanning a corroded area, the signal from corrosion will break the baseline at the backwall signal and the corrosion signal will move toward the IP signal until the minimum thickness is reached. This movement is due to the sound reflecting from the edges of the corrosion until the thinnest area is being reflected. This movement of the corroded signal is often referred to as "walking the signal."

A-scan instruments typically have the ability to operate in either of two timing modes, the IP timing mode or the multiple echo modes. The IP timing mode measures the transit time from the IP to the first echo. The multiple echo mode allows the examiner to set the instrument to measure between a set of multiple successive echoes instead of the IP to first in order to establish the thickness.

The multiple echo mode is used for measuring the remaining thickness on specimens with coated surfaces without including the coating thickness. This is accomplished by measuring the travel time between two successive backwall signals to obtain the thickness of the material and not including the travel time due to the thickness of the coating. When using this mode, the examiner should pay careful attention to the A-scan display to ensure that the proper signals are being measured.

Corrosion evaluation should be conducted using the IP timing mode. The reflected energy on rough and corroded or pitted surfaces is often times only strong enough to produce a single signal, and the instrument will indicate "0.000" when in the multiple echo mode because it requires two echoes to measure.

In cases where a component is painted at the measurement location and is corroded on the reflection side (which can cause lack of sufficient echo-to-echo signal and therefore measurement error), the paint should be removed for accurate thickness measurements.

UT thickness gauges and certain transducers can measure the thickness of paint and wall thickness simultaneously.

These instruments primarily use a 0.250-in. to 0.500-in. diameter, 2.0 MHz to 5.0 MHz, dual-element pitch-catch search unit, but some instruments have options to use single-element delay or even EMATs.

10.2.1.2.4 Ultrasonic Flaw Detectors with a Numeric Display

Ultrasonic flaw detectors with a numeric display are similar to the A-scan thickness gauges in that they have both an A-scan and a numeric display and can be used with single- or dual-element transducers. These instruments are more advanced than the others and typically have a lot more options and features, including the capability for angle beam examinations. However, modern UT thickness gauges utilize features that enhance the accuracy of thickness measurement, typically resulting in improved accuracy of measurement over flaw detectors.

Flaw detectors with numeric displays can be operated in either the IP or multiple echo timing modes.

Other applications requiring the use of ultrasonic flaw detectors are weld quality examinations, advanced flaw sizing, and high-temperature hydrogen attack detection. Weld quality examinations (angle beam) use specially designed transducer wedges to generate shear waves at 45°, 60°, or 70° for detecting, evaluating, and sizing of flaws. Flaws that can be detected are cracks, slag, lack of fusion, incomplete penetration, and porosity.

Advanced crack-sizing techniques for measuring the through-wall extent of the cracks include the use of tip diffraction, high-angled L-waves, 30-70-70 search units, and bimodal search units. All of the advanced techniques require additional hours of classroom and field experience and the examiner pass a performance-based demonstration examination. Other advanced ultrasonic testing technologies available for detecting and evaluating and sizing flaws include time-of-flight diffraction (TOFD) and phased arrays.

High-temperature hydrogen attack can be detected and evaluated utilizing other highly specialized ultrasonic techniques, including ultrasonic backscatter and velocity ratio techniques.

10.2.1.2.5 Some Factors Affecting Measurement Accuracy

Ultrasonic velocities are different in different materials. It is very important to use the proper velocity to obtain accurate thickness measurements. The ultrasonic instrument determines the thickness by measuring the roundtrip sound travel multiplied by the velocity and divided by two. The roundtrip sound travel is measured from the pulse generation to the time the sound waves from the backwall or another reflector is received. The wrong velocity can either increase or decrease the as-measured ultrasonic thickness.

Laminar inclusions can cause erroneous readings. Because laminar inclusions create a planar interface perpendicular to the direction of wave travel, they can reflect the sound back to the transducer. This reflected signal can be misinterpreted as being the backwall signal and will be calculated as a thinner reading.

If the ID surface is extremely rough or an irregular-shaped pit is encountered, often the only indication the examiner may encounter is a lower amplitude backwall signal or a complete loss of the backwall signal. This reduction or loss is due to the dispersion of the sound in the material and in turn there is not enough ultrasonic energy received by the instrument that will produce a signal above the noise level. In cases as these, the examiner should increase the gain setting on the instrument until the area where the diminished signal or loss of signal occurred can be fully evaluated to the extent the examiner can determine a minimum thickness.

Doubling occurs when measuring thin materials usually less than 0.100 in. (2.5 mm) and results in a reading much thicker than the actual wall thickness. The reflected backwall signal is masked by the noise from the IP, and the instrument reads the second or third reflection. Another occurrence of doubling can be caused in extremely thin materials by the sound reflecting in the material producing an extra skip distance before it is received, thereby doubling the travel time or sound distance and in turn doubling the measured thickness.

Each search unit should be tested to determine the minimum measurable thickness.

Sample steps are as follows:

a) measure the thickness of a set of feeler gauges beginning at 0.100 in. (2.5 mm);

b) measure the 0.090 in. (2.3 mm), 0.080 in. (2.0 mm), and so on, subtracting 0.010 in. (0.25 mm) every reading until the as-measured thickness is two times or more than the actual thickness;

c) take the thickness where the doubling occurred and multiply by 1.5 times and this should be the minimum measurable thickness for that search unit.

10.2.1.3 Corrosion Evaluations

The best search units for conducting corrosion evaluation are dual-element transducers. The piezoelectric elements in these search units are placed on slight angles for direct reflection of the transmitted sound toward the receiving transducer. This tilting of the transducers also provides some pseudo focusing of the sound beam. The dual-element search units provide better near-surface detection than conventional single-element search units.

The frequency for the majority of search units ranges from 2 MHz to 5 MHz and the diameter from 0.25 in. to 0.500 in. (6.3 mm to 12.7 mm). Special applications such as thick [>6.00 in. (152 mm)] materials, product forms such as castings, or coarse grain materials such as high-alloy or high-nickel steels can require lower frequencies (1 MHz) and/or larger diameter search units.

Search units used for corrosion detection or evaluation should have a good wear surface on the face of the search unit to allow the examiner to scan corroded areas for the minimum reading and minimize the wear on the search unit. When conducting corrosion detection or evaluation, the examiner should scan the area of interest with the search unit in lieu of conducting individual point measurements. Scanning provides a greater chance of detecting small diameter (less than one-half of the search unit diameter) indications than taking point measurements. The examiner should not scan faster than the A-scan displays refresh rate to avoid missing a small indication. This is typically 6 in./s (152 mm/s) or less. Additionally, the examiner should overlap each scan path by a minimum of 10 % of the transducer diameter.

10.2.1.4 High-temperature Thickness Measurements

The search unit is the most important component of the thickness testing equipment for high-temperature measurements. Some high-temperature search units are designed to withstand temperatures up to 1000 °F (538 °C) for very brief durations of time.

Special delay-line materials and water-cooled transducers are available that permit the use of pulse-echo instruments at temperatures up to 1100 °F (593 °C).The majority of high-temperature dual-element search units are manufactured with the delay material built into the case, while most single-element search units come with replaceable delays.

The duty cycle is another critical factor for the high-temperature search units. The search unit should be allowed to cool down between thickness measurements. This is especially critical in the case of the dual-element search units. Even though these search units are manufactured to withstand the high temperatures, continued use at elevated temperatures will cause these units to begin to breakdown. As a general rule of thumb, the search unit should be allowed to cool down between thickness measurements where the examiner can comfortably hold it in their bare hand.

The second most critical element for performing high-temperature thickness measurements is the ultrasonic couplant. There are several high-temperature couplants commercially available. The desirable characteristics of a couplant should be one with good acoustic properties, good chemical stability at elevated temperatures, the ability to withstand decomposition, the ability to remain on vertical surfaces for 10 seconds or longer, high boiling temperature, nonflammable, and nontoxic.

The test specimen temperature affects the UT thickness measurement. As the test specimen temperature increases above ambient temperature, the velocity of the material decreases, thereby increasing the as-measured ultrasonic thickness by a factor of 1 %/100 °F (1 %/55 °C).

Some modern UT thickness gauges have a feature that provides automatic temperature compensation. The surface temperature to be examined is measured with a pyrometer. The operator keys in the temperature of the surface being examined. The UT thickness gauge automatically compensates for the change in velocity due to elevated temperature (see Figure 24 for an example). The inspector should be cautioned when using such gauges. The UT thickness procedures should clearly describe how thickness data is collected when the metal temperature is greater than a defined temperature. The inspector should understand if and when the Inspection Data Management System (IDMS) that will be storing and analyzing the thickness data may also be used to compensate for temperature differences.

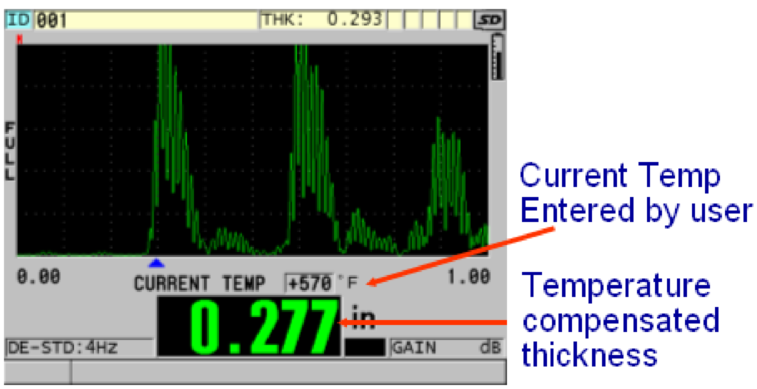


Figure 24—Example of Screen Display of UT Thickness Gauge with Automatic Temperature Compensation

The examiner must wear the proper PPE when conducting high-temperature thickness measurements for protection from the radiated heat.

10.2.2 RT

Gamma-radiographic techniques provide accurate pipe wall measurements and permit inspection of the internals of some equipment. The primary functions of this method are to detect metal loss and check weld quality. Radiography has the following advantages:

a) pipe insulation can remain intact;

b) the metal temperature of the line has little bearing on the quality of the radiograph, provided the film cassette can be protected from the heat of the piping;

c) radiographs of small pipe connections, such as nipples and couplings, can be examined for thread contact, corrosion, and weld quality;

d) film provides a permanent visual record of the condition of the piping at the time of the radiograph;

e) the position of internal parts of valves (dropped gates) can be observed;

f) radiographic equipment is easily maneuverable in the refinery or chemical plant;

g) isotope radiography is not an ignition source in the presence of hydrocarbons;

h) pitting and other nonuniform corrosion can be identified;

i) provides a view of a large area.

Gamma rays traveling through the pipe wall between the outside and inside radii of the pipe must penetrate metal that is approximately four times the wall thickness of the pipe. Most of the rays are absorbed by the metal, leaving an unexposed area on the film. This area that is lighter on the darkened film represents a slightly enlarged projected image of the pipe wall. The image can be measured, and a correcting calculation can establish the thickness of the pipe wall. Any deposits or scale inside the pipe usually appear on the developed film as distinctly separate from the pipe wall. Pitting can also be visible on the film.

Computed radiography (CR) can be utilized in place of film radiography, reducing exposure times and producing a digital image this is easily archived and electronically transmitted.

Because isotope radiography gives the inspector an “internal look” in the pipe, the somewhat higher cost of this inspection can be more than offset by the data obtained.

Ionizing radiation is the base principle in industrial radiography, and the most common radiation sources are iridium and cobalt. There are significant safety issues surrounding the use of ionizing radiation such that personnel performing RT are required to be trained and certified as identified in API 570 and ASME *BPVC* Section V, plus any jurisdictional requirements. Correct procedures must be established and implemented to ensure the safety of examiners and all other plant personnel.

RT thickness measurement accuracy relies somewhat on the abilities of the radiographic technician exposing the films and the person reviewing them. When using RT for this purpose, it is advisable to develop a written practice defining the method(s) of film placement, exposure, and reading or interpreting them. Radiographic test shots should be taken of piping, which can be examined with UT thickness measurements to determine the limits of accuracy of the RT once it has been developed. In addition, a test piece of known thickness can be placed on the same plane as the radiograph, which will help define radiographic magnification factors. Multiple caliper thickness readings of the shot will improve the precision.

When radiographic inspection is being performed, process-unit control systems, which use isotopes in liquid-level indicators and controls, occasionally give erroneous indications on control panels. Flame detectors used to indicate a furnace or boiler fire can also be affected. Unit operators must be warned of this possibility.

Profile RT is particularly useful for identifying internal and external corrosion of small connections, such as bleed lines and gauge connections, which are especially susceptible to external corrosion from CUI since it is difficult to obtain a good seal in the insulation.

Radiographs of piping are shown in Figure 25, Figure 26, and Figure 27.

10.2.3 Caliper Thickness Measurements

When piping is opened, the thickness of the pipe and fittings can be measured behind the flange using transfer or indicating calipers. The thickness of inaccessible piping that cannot be measured by radiographic or ultrasonic instruments during operation can be measured with these instruments during shutdown. If need be, the thickness of valve bodies and bonnets and pipe fittings can be measured using transfer or indicating calipers that have special legs designed to reach inaccessible areas.

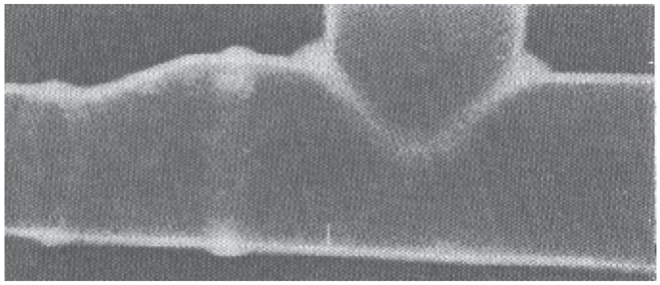


Figure 25—Radiograph of a Catalytic Reformer Line

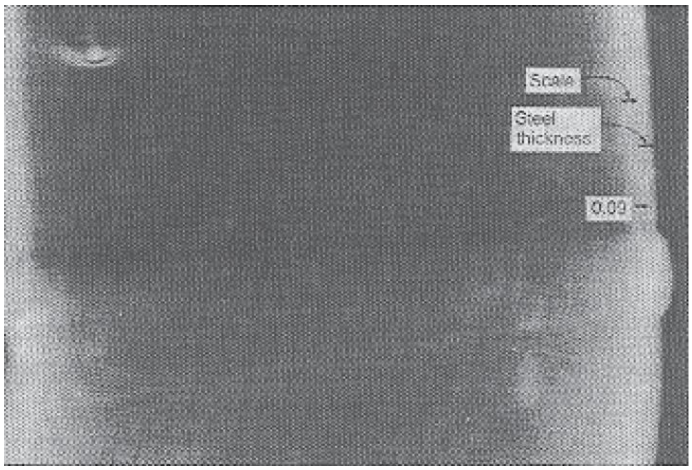


Figure 26—Radiograph of Corroded Pipe Whose Internal Surface is Coated with Iron Sulfide Scale

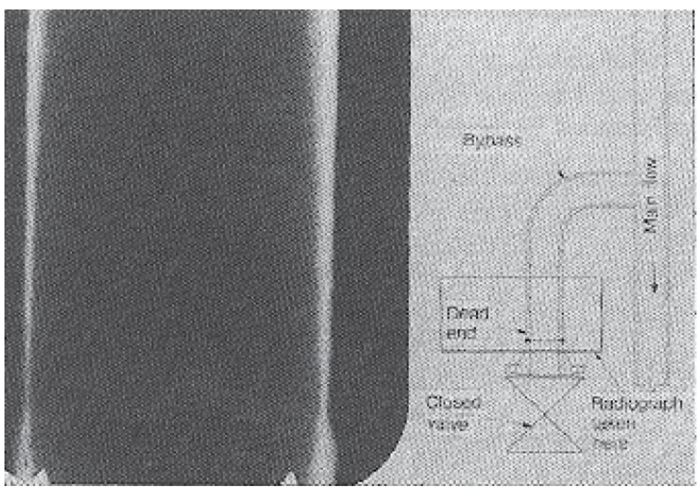


Figure 27—Sketch and Radiograph of Dead-end Corrosion

10.3 Internal Visual Inspection

10.3.1 Corrosion, Erosion, and Fouling

Piping can be opened at various places by removing a valve or fitting or by springing the pipe apart at flanges to permit visual inspection. The internal surfaces of the piping should be inspected visually over the greatest possible area. A flashlight or extension light is usually sufficient for this task, but a probe such as a borescope or a mirror and light will permit a more detailed view. Other inspection methods include optical/laser and mechanical calipers.

Where nonuniform corrosion or erosion conditions are noted in areas that are accessible for visual examination, it may be advisable to perform an RT or to measure thicknesses with ultrasonic instruments to extend coverage to parts of the piping that are inaccessible for visual examination. This applies particularly to piping that could not be or was not inspected during operation. Nonuniform corrosion or erosion can also be pinpointed for closer examination by directing sunlight along the surface of the piping with a mirror or by shining a light parallel to the surface.

The amount of fouling should be noted to determine whether cleaning is necessary. Fouling should be investigated to determine whether it consists of deposits from the product stream or is a buildup of corrosion products. Taking samples for chemical analysis may be necessary.

10.3.2 Cracks

The locations most susceptible to cracking are welds and the heat-affected zones including fillet welds at other than pressure welds, heat-affected areas adjoining welds, and points of restraint or excessive strain. Other areas prone to cracking are locations that contain crevices, such as socket-welded piping, flange surfaces, or threaded joints. Locations that are subject to SCC, hydrogen attack, and caustic or amine embrittlement also require attention, as do exposed threads of threaded joints.

The inspected surface should be clean if cracks are to be detected. Cleaning can be accomplished by wire brushing, sandblasting, or chemically removing coatings, deposits, and corrosion products. After thorough cleaning, the area should be visually inspected for any indications of cracks. (Spot checking by MT, PT, or UT should be considered even if visual inspection revealed no cracks.) Adequate lighting and a good magnifying glass will assist in locating such indications. Visual inspection may not differentiate between a surface scratch and a crack. Any apparent scratch should be further investigated by other methods. MT can be used on magnetic materials. PT and UT can be used on both nonmagnetic and magnetic materials. Only liquid penetrants with low or no chlorides should be used for austenitic materials. Other methods such as shear- or surface-wave UT, ET, ACFM, or sample removal for microscopic inspection may be used. The depth of a crack may be determined by NDE or by chipping or grinding until sound metal is reached. The inspector should determine if the area can be repaired properly before commencing to grind, however.

10.3.3 Gasket Faces of Flanges

The gasket seating faces of flanged joints that have been opened should be visually inspected for corrosion and defects such as scratches, cuts, and gouges that might cause leakage. The gasket faces should be checked for warping by placing a straight edge across the diameter of the face of the flange and rotating it around an axis through the flange centerline. Grooves and rings of ring joints should be checked for defects, including cracks at the bottom of the grooves or on the sealing surfaces. For HF alkylation services, see specific recommendations in API 751 on inspection for flange face corrosion. Phased array ultrasonic testing (PAUT) is a potential method for inspecting for flange face corrosion without having to disassemble flanges.

10.3.4 Valves

Normally, valves used in process piping systems have body thicknesses somewhat heavier than adjoining piping. For this reason, an adequate piping corrosion-monitoring program need not routinely include monitoring of valve body thicknesses. However, in piping circuits where corrosion rate monitoring of piping indicates severe corrosion or erosion, consideration should be given to routinely measuring thicknesses of selected valve bodies in the circuit.

In severe services, such as HF, slurry, and fluidized catalyst services, valves may need to be dismantled and inspected at specified intervals to ensure that internal parts are of sufficient integrity to provide reliable and safe operation.

Whenever valves are removed from service for overhaul or refurbished for reuse, they should be inspected and tested to the requirements of API 598. When a valve is disassembled for inspection, the bonnet gasket should be replaced. Any valve parts that do not meet the minimum requirements of the applicable valve standard should be either repaired or replaced. The used valves should then be restored for continued safe operation.

When body thicknesses are measured, the measurements should include locations that were inaccessible before dismantling, particularly at areas that show evidence of corrosion or erosion. Bodies of valves that operate in severe cyclic temperature service should be checked internally for cracks.

Gate valves should be measured for thickness between the seats, since turbulence can cause serious deterioration. This is a particularly weak location because of the wedging action of the disc, or wedge, when the valve is closed. The seating surfaces should be visually inspected for defects that might cause leakage. The wedge guides should be inspected for corrosion and erosion, both on the wedge and in the body.

The stem and the threads on the stem and in the bonnet should be examined for corrosion. The connection between the stem and the wedge should be inspected to ensure that the wedge will not detach from the stem during operation.

Swing-check valves can be inspected by removing the cover or cap. Check valves often flutter, making the shaft and hinges the principal points of deterioration. The disc should be checked for free rotation, and the nut holding either to the arm should be checked for security and the presence of a locking pin, lock washer, or tack weld. The arm should be free to swing, and the anchor pin or shaft should be inspected for wear. The seating surfaces on both the disc and the valve body can be checked for deterioration by feeling them with the fingers. It is extremely important that the cover is installed in the proper orientation for the wedge to operate properly. Refer to API 570 for requirements for inspection of critical check valves.

Quarter-turn valves can be inspected for ease of operation and the ability to open and close completely by operators. When they are serviced, all seating surfaces should also be examined.

When valves are reported by operators to have "operability" problems like leaking through the gate when fully closed, a review of the potential for that leakage to cause or accelerate deterioration downstream of the valve should be conducted to help establish the priority for valve replacement and the need of increased inspection of downstream piping.

10.3.5 Joints

10.3.5.1 General

Methods of inspection for specific types of joints are discussed in 10.3.5.2 through 10.3.5.5.

10.3.5.2 Flanged and Bolted Joints

Sites should have a program to ensure that flanges are made up properly. Proper makeup of every flange in a piping system is important for reliability. Proper makeup includes the use of the proper gasket and fastener material, type, and size, proper positioning of the gasket, and proper torqueing of the fasteners. The assurance program should include procedures for gasket and fastener selection and for fastener torqueing. ASME PCC-1 offers good guidance on proper makeup of bolted flange joints.

The program can incorporate varying degrees of sampling, visual inspection, field testing, and destructive testing of components. Gasket selection can usually be confirmed by visual examination of the gasket's color and markings on the OD surface. Spiral-wound gaskets should be marked and color coded in accordance with ASME B16.20. Fasteners can be visually examined for proper stampings or markings and PMI tested in accordance with API 578. Proper gasket positioning and torqueing depends on the training and craftsmanship of the pipefitters making up the flanges. Gasket positioning can be checked visually. Proper torqueing is difficult to check, but flange deformation can be a sign of improperly torqued fasteners.

Flanged joints should be visually inspected for cracks and metal loss caused by corrosion and erosion when they are opened. See 10.3.3 for methods of inspection for cracks. Inspection of gasket faces is covered in

10.3.4. Flange joints can be inspected while in service by applying single-element or phased array UTs to the external surfaces to measure flange face corrosion and to detect ring groove cracking.

Flange bolts should be inspected for stretching and corrosion. Where excessive bolt loading is indicated or where flanges are deformed, a nut can be rotated along the entire length of the stud. If the stud is stretched, the thread pitch will be changed and the nut will not turn freely. Inspection involves checking to determine whether bolts of the proper specification have been used, and it may involve chemical analysis or physical tests to determine the yield point and the ultimate strength of the material.

If flanges are bolted too tightly, they can bend until the outer edges of the flanges are in contact. When this occurs, the pressure on the gasket can be insufficient to ensure a tight joint. Visual inspection of the gasket will reveal this condition. Permanently deformed flanges should be replaced or refaced.

10.3.5.3 Welded Joints

In some services, welds can preferentially corrode. The inspection program should look at a sampling of welds if corrosion at welds is suspected.

Welded joints may be subject to leaks caused either by cracks or by corrosion or erosion. Cracks in alloy-steel welds are often associated with excessive hardness resulting from improper control of preheat or PWHT. The hardness of air-hardenable alloy-steel welds should therefore be checked after heat treatment. Carbon steel welds in environmental cracking service should be checked for hardness.

Corrosion can occur in the form of pitting that has penetrated the weld or the adjacent heat-affected metal. Both pitting and welding defects can be detected by radiography. If severe defects are suspected and radiography is not feasible, the affected area can be chipped or gouged out until sound metal is reached, and the groove can be rewelded.

Welded joints in carbon steel and carbon-molybdenum steel exposed to elevated temperatures of 800 °F (426 °C) or greater can be subject to graphitization. When graphitization is suspected, a sample should be taken from a welded joint and examined metallurgically for evidence of excessive graphitization.

10.3.5.4 Threaded Joints

Threaded joints can leak because of improper assembly, loose threads, corrosion, poor fabrication, cross threading, through crack in the root of a thread, or threads that are dirty at the time of assembly. Lack of thread lubricant or the use of the wrong lubricant can also cause leaks. If the leak cannot be stopped by tightening the joint, the joint should be unscrewed and visually examined to determine the cause of the leak.

Caution—A leaking threaded joint should not be tightened while the system is in service under pressure unless there is reasonable certainty that the leak is not caused by a crack in the threads. An undetected crack in a thread root could open up significantly and cause a release of product with serious consequences.

10.3.5.5 Clamped Joints

A clamped joint that depends on machined surfaces for tightness can leak because of dirt, corrosion of the mating faces, mechanical damage, or failure of the clamp to provide sufficient force on the mating faces for proper contact. A clamped joint that depends on a gasket for tightness can leak because of damaged or dirty gasket seating surfaces or failure of the clamp to provide sufficient pressure on the gasket. If tightening the clamp does not stop the leak, the joint should be dismantled and visually inspected to determine the cause of the leak. ASME PCC-2, Article 3.6 provides useful guidance on the design, limitations, fabrication, installation, inspection, and testing of mechanical clamps.

Caution—Certain kinds of clamped joints should not be used without adequate axial restraint on the piping and sufficient pipe wall thickness at the ends of the clamp to resist collapsing by the clamping forces. Other types of clamps are designed to provide adequate strength to the joint.

10.3.6 Misalignment

Often, misalignment is not apparent until the piping has cooled and has moved to its cold position. The inspector should note, as in 10.1.3, indications of misalignment while the piping is cold. Note especially the hot and cold position of spring hangers to determine if the hangers are adjusting properly to the changes in piping positions from hot to cold. This is especially critical for large-diameter lines such as catalyst transfer lines in FCC units.

If misalignment of piping was noted during operation, the cause should be determined and corrected. Misalignment is usually caused by the following conditions:

a) inadequate provision for expansion;

b) broken or defective anchors or guides;

c) excessive friction on sliding saddles, indicating a lack of lubrication or a need for rollers;

d) broken rollers or rollers that cannot turn because of corrosion or lack of lubrication;

e) broken or improperly adjusted hangers;

f) hangers that are too short and thus limit movement or cause lifting of the piping;

g) excessive operating temperature;

h) failure to remove the spring blocks after system construction.

10.3.7 Vibration

Where excessive vibration or swaying was noted during operation, an inspection should be made for points of abrasion and external wear and for cracks in welds at locations that could not be inspected during operation. The visual inspection methods described in 10.1.5 should be followed. This inspection should be supplemented by surface NDE methods as applicable. The conditions causing excessive vibration or swaying should be corrected.

10.3.8 Hot Spots

The internal insulation of piping should be visually inspected for bypassing or complete failure in locations of hot spots on internally insulated piping noted during operation (see 10.1.8). The cause of the hot spot should be corrected. The pipe wall near the hot spot should be visually inspected for oxidation and resultant scaling. All the scale should be removed, and the remaining sound metal should be examined for incipient cracks. The sound metal should be measured to ensure that sufficient thickness remains for the service. The OD of piping in high-temperature service—metal temperatures of about 800 °F (427 °C) and above—should be measured to check for creep or deformation with time under stress. To ensure that an in-service fracture will not occur, the amount of creep permitted should be based on established data for the contemplated service life.

10.3.9 Expansion Joints

Inspection of expansion joints involves examinations both at maintenance outages and during operation prior to shutdown and shortly after start-up. While in operation, the "hot" settings and position of connected pipe supports/guides and the expansion joint should be recorded. Comparing measurements obtained prior to unit shutdown and after start-up allows for changes to be identified and subsequently studied. In addition, the joint and attached piping should be visually examined for alignment, distortion, cracks, and leaks. A check should be made prior to start-up to make sure all stops and other restricting devices are removed and all components are positioned in the cold setting. Temporary supports may be left in place as long as they will not interfere with the piping expansion in the hot setting.

Infrared thermography examination of the joint in high-temperature services can identify hot spots and bulk temperature to determine both the joint is operating within its design temperature and any internal fiber blanket and liner associated with the joint is functioning as designed.

During maintenance outages, additional inspection activities may be performed. The “cold” position and settings should be recorded and compared to previous “cold” and “hot” measurements. Changes should be reviewed against design. The expansion joint should be visually examined externally and, if possible, internally. Any external coverings should be removed to facilitate the inspection. The fabric in fabric joints should be examined for rips, holes, and flexibility. Metal attachment rings and bolting should be examined for distortion and corrosion. Metallic bellows may be examined with dye penetrant examination, ET, and UT for cracking. Cracks can occur in convolutions, at piping attachment fillet welds, and on any internal liner attachment welds. Thinning and pitting can occur in some services and should be examined during internal inspections.

10.4 Nonmetallic Piping

10.4.1 General

Nonmetallic piping systems are often used for fluids that are nontoxic, nonflammable, and environmentally benign. However, in some circumstances, even these piping systems are critical considering economic or operational consequences. Inspection intervals are probably best assessed using a risk-based approach. Factors that influence the initial inspection date are the amount and quality of the supervision and inspection performed during construction. The inspector should have adequate knowledge of FRP materials, resins, reinforcements, laminate imperfections, and manufacturing techniques.

Generally, experience shows an initial inspection within the first 2 years of operation and subsequent intervals being extended or reduced based on initial findings. A site experiencing a significant number of failures in the early years of operation may need to increase inspection activities and shorten intervals.

10.4.2 Initial Construction

Visual examination and pressure testing are the primary inspection and testing methods used during original construction. ASTM D2563 provides guidance for the visual examination of FRP components but is focused on manufacturing and assembly. Some of the more stringent specifications require RT and/or bond inspection tools of bonded nonmetallic joints. These are more advanced examinations to supplant the “coin tapping” method for locating delaminated or disbonded areas close to the surface of nonmetallic piping.

Pressure testing at up to 1.5 times design pressure will reveal leaks from major flaws such as severe impact damage. Pressure tests, however, are not a guarantee of structural integrity. Joints with up to 85 % disbond have reportedly passed pressure tests. The use of acoustic emission monitoring during pressure testing can identify material failure occurring prior to leakage, thereby increasing the sensitivity of the pressure test. This can be used real time to prevent the pressure test from causing irreversible damage to the pipe that might otherwise occur without monitoring and lead to future in-service failure.

10.4.3 On-stream Examination and Testing Techniques

Many traditional NDE techniques and testing are used to assess nonmetallic piping. These techniques include:

a) UT,

b) RT,

c) AE,

d) hardness testing,

e) thermographic imaging,

f) MW.

See Table 6 for comparison of those common nonmetallic piping NDE techniques.

Table 6—Comparison of Common Nonmetallic Piping NDE Techniques

Technique	Advantages	Limitations
Ultrasonic	Can identify erosion damage and to some degree lack of adhesive in joints.	UT of wall thickness requires special techniques and procedures to accommodate the unique characteristics of the nonmetallic materials construction. Probe selection, typically at the low-frequency range of 0.25 MHz to 2.25 MHz, is critical for ultrasonic attenuation characteristics vary with construction and manufacturing process. This technique cannot detect “kissing” bonds in thermal welds. Design and availability of suitable calibration samples is essential to successful examination.
Radiography	Can identify internal flaws of a volumetric nature and wall thickness variations. Can be used to verify joint gaps, offsets, etc.	Specific exposure techniques may need to be defined in procedures to obtain the best resolution as the lower atomic weight elements used in nonmetallic construction generally require lower exposure energy and times. Disbonding and lack of adhesion flaws may not be easily identifiable with this technique. Examination of nonmetallic piping has most of the typical limitations such as personnel safety, fluid absorption, and flaw orientation.
Acoustic emission	A wide range of flaws can be detected. AE has been used on vessels and tanks constructed from FRP for many years and these procedures are encompassed in ASME *BPVC* Section V, Article 11. Typical flaws identified include inadequate structural integrity due to weaknesses in design, production, or material degradation, growth of delaminations, crack growth, fiber fracture and pull out, inadequate curing, and physical leakage. Ability to characterize the cracking of fibers and delaminating of the matrix in real time. There is extensive successful reporting of the use of AE in relation to nonmetallic materials.	Some of the basic caveats related to AE still apply (e.g. the flaw must be active in emitting energy). Clear definition of the flaw is only possible with other complementary NDE techniques.
Hardness	Material property used to identify proper curing and long-term degradation of the resin. The most common hardness reference is ASTM D2583. Barcol hardness test method used to determine the hardness of both reinforced and nonreinforced rigid plastics.	Limited by available area (e.g. small-diameter bore pipe). Wax inhibition can yield lower hardness values.
Thermography	Has been used to detect gross wall thickness changes due to erosion and significant lack of adhesive in bonded joints.	Sensitive to surface or near-surface flaws. Does not reveal through-wall damage in thick wall piping. The limits of detection are relatively high with about a 0.25-in. difference in wall thickness and disbonded areas measuring 3 in. × 3 in. Detection is a function of thermal differentials. If the process stream is significantly different in temperature than the surrounding ambient temperature, then good profiles could be obtained. Alternate approaches are to introduce heat into the area of examination and monitor the rate of decay in relation to “good” samples.
Microwave	Gigahertz or terahertz microwave used to detect laminar nonfusion, “kissing” bonds, and impact damage. Has detected ingress of fluids into the substrate in woven materials. Technique has the ability to detect disbonds at a nonmetallic/metallic interface.	Unable to inspect through any metallic cladding or coating.

10.5 Flexible Hoses

Flexible hoses utilized in hydrocarbon or other hazardous service should be individually identified and include appropriate service (chemical) limitations and acceptable operating conditions. Generally, there are two purposes for flexible hoses: one being installed in lieu of hard piping and the other being used for short-term purposes. The purpose of the flexible hose should be taken into consideration when determining if the flexible hose should be inspected and how it should be inspected.

Flexible hoses used in permanent installations should be periodically inspected with the hard piping it is attached to or more frequently if determined necessary by the owner/user. Flexible hoses used in temporary applications should be cleaned and stored appropriately (per manufacturer’s instructions where available) when not in use to minimize both mechanical damage and exposure to environmental conditions and chemicals that could compromise one or more components of the hose assembly.

Each flexible hose (new and used) should be inspected prior to being placed in service. This inspection should include a verification of its intended service (process chemicals and temperature/pressure rating), overall condition (looking for mechanical damage to connections, fittings, flanges, etc.), and that the periodic inspection has been performed.

A complete inspection of the hose should be performed periodically. This inspection should include the following.

a) Ensure the hose has been individually identified (ID tag) and that the records contain appropriate design conditions and service limitations or compatibility.

b) Verify diameter, length, and end fittings for individual assemblies and compare with existing ID tags and documentation.

c) Verify the hose and fitting pressure ratings are within the design parameters for hydrostatic proof pressure test (generally 1.5 times MAWP), and check the condition of the fittings (thread condition and gasket or sealing surface condition to provide a proper seal). Fittings should also be examined for mechanical damage from overtightening of the threads or overtorquing of bolted assembly, causing flange face rotation. The hose to fitting attachment point should also be inspected for loose or damaged clamps or compression fittings.

d) Perform visual inspection of the hose cover for any cuts, gouges, breach, fraying, or other defects where reinforcement is exposed. The hose assembly should also be inspected for excessive abrasion damage to the outer covering/jacket and for damage from heat (brittleness and/or cracking).

e) Inspect for damage from excessive bending (kinking), which may produce partial crushing/flattening of the hose, crimping, or excessive strain at end connections. Check minimum installed bend radiuses to the manufacturer recommendations.

f) To the extent possible, examine the internal condition of the hose, looking for signs of erosion, cracking, or chemical attack/degradation of a nonmetallic liner (swelling, tears, abrasion/roughness, etc.).

g) Additional inspections may include the following.

    1) Visual inspection of the hose tube with boroscope or videoprobe for a general condition on the interior liner (looking for blisters, cracks, or other defects).

    2) Perform test to ensure electrical continuity between end fittings and perform electrical conductivity test on fluoropolymer and thermoplastic tube hose.

    3) If the transfer fluid inside the hose is nonconductive, then perform electrical conductivity test to ensure grounding/bonding of hose.

4) Check for appropriate alloy composition (PMI) per manufacturers and equipment records. Note that this may only be an initial inspection unless hose fittings or other components may be changed or modified.

5) On-stream inspection using infrared thermography examination may help to identify damage to one or more of the hose components/layers.

6) Fittings may be examined with dye penetrant, ET, and/or UT methods to identify cracking or other damage.

7) Perform hydrostatic pressure test in accordance with manufacturers' recommended design specifications (limited by the lowest pressure rating of included component).

8) Original equipment manufacturers recommended inspection and testing activities.

As effective inspections of process hoses are difficult, some owner/users stamp and track process hoses, periodically pressure test them, and require replacement after a set amount of service time based on risk and type of hose. Additionally visual inspection checklists are in use for issues that should be periodically checked to verify the integrity of the hose.

11 Pressure Tests

11.1 Purpose of Testing

A pressure test conducted on in-service piping may function as a leak test, or if the pressure is high enough, it can reveal gross errors in design or fabrication. Pressure tests of existing piping should be performed in accordance with the requirements of API 570. Piping systems that may be subjected to pressure testing include the following:

a) underground lines and other inaccessible piping;

b) water and other nonhazardous utility lines;

c) long oil-transfer lines in areas where a leak or spill would not be hazardous to personnel or harmful to the environment;

d) complicated manifold systems;

e) small piping and tubing systems;

f) all systems, after a chemical cleaning operation;

g) when required by the jurisdiction.

The reasons and procedures for pressure-testing piping are generally the same as those for equipment. When vessels of process units are pressure tested, the main lines connected to the vessels are often tested at the same time. Service testing of Category D piping systems is limited to the 150 psi (1034.2 kPa) design gauge pressure upper limit defined for Category D fluid service in ASME B31.3.

11.2 Performing Pressure Tests

API 570, Section 5.7 provides guidelines for preparing piping for pressure testing, and ASME PCC-2, Article 5.1 offers useful guidance on performing pressure and tightness testing of piping systems.

During liquid pressure testing, all air should be expelled from the piping through vents provided at all high points. If the system is not full of liquid, the trapped air will compress. With large quantities of a compressible medium in the system, a failure will be more violent than in a liquid-full system because of expansion of the compressible medium.

Care should be taken to ensure the test does not overpressure the system, including components (e.g. expansion joints) that may have a lower design pressure than the remainder of the piping system. Calibrated pressure gauges properly located and of the proper range should be used and carefully watched during pressuring. When all air is expelled from the system, the pressure will rise rapidly. A sudden rise in pressure can cause shock, resulting in failure of the tested equipment.

The pressure for a liquid pressure test is usually supplied by an available pump. If a pump of sufficient head is not available, the necessary test pressure can be supplied by bottled inert gas, such as nitrogen, bled in at the top of the system after the system is filled with the test liquid. This method has the disadvantage of introducing a compressible medium into the system, but the quantity can be kept small. In either case, if overpressuring can occur, a relief device should be installed to protect the system.

Various fluids can be used for pressure testing. The following are the most commonly used:

a) water with or without an inhibitor, freezing-point depressant, or wetting agent;

b) liquid products normally carried in the system, if they are not toxic or likely to cause a fire in case of a leak or failure;

c) steam;

d) air, carbon dioxide, nitrogen, helium, or another inert gas.

NOTE ASME B31.3 has restrictions on the use of the test mediums listed in Item c) and Item d).

If a leak or failure occurs, fluid may be released in the area of the piping being tested. For this reason, the fluid should not be harmful to adjoining equipment or to the plant sewer system, and appropriate safety precautions are taken to avoid personnel exposure.

Water may not be suitable as a test fluid in some piping systems, such as acid lines, cryogenic systems, and air-drier systems. Uninhibited salt water can cause corrosion of some nonferrous alloys and SCC of austenitic stainless steels. Salt water can also cause corrosion of ferritic steels and severe pitting of austenitic steels, such as valve trim or plating. Most natural waters contain bacteria that can lead to microbiologically induced corrosion if the water is left in the piping for too long after a pressure test. Austenitic stainless steels have failed after 2 to 5 weeks of this kind of exposure.

Water can freeze in cold weather unless a freezing-point depressant is used. The depressant should not be harmful to the sewer system or other place of disposal. Steam is sometimes used to warm the water and prevent freezing. The transition temperature of the steel should be considered to prevent brittle failure when the testing is during cold weather or with cold fluids.

A steam test may be advantageous where steam is used for heating or purging equipment before operation. The steam pressure should not exceed the operating pressure. An advantage of steam is that it heats the piping, thereby popping flux from welds in piping that could have passed a water test; however, steam testing does have several disadvantages. Condensation occurs, and the draining of condensate may be necessary before operations are started. When high-pressure steam is used, leaks are difficult to detect and can burn personnel who are in the area of the equipment. Steam also has the previously mentioned disadvantage of compressible media. ASME B31.3 allows for a leakage test with the flowing medium at operating conditions for Category D fluid services, i.e. the fluid should be nonflammable, nontoxic, and 366 °F (186 °C) or lower.

NOTE If steam is used as the test medium for piping other than Category D piping, the rules for pneumatic testing stated in ASME B31.3 should be followed.

Pneumatic tests in conjunction with a soap solution, foaming agent, or sonic leak detector are sometimes permissible for small lines and systems. The preferred medium for pneumatic testing is an inert gas. Compressed air should not be used where flammable fluids can be present. Leaks that would not be detected during a liquid pressure test can often be detected by a pneumatic test. Because nitrogen and helium are more penetrating than air, they are used when service conditions are particularly critical. Filling any piping system with an inert gas creates an asphyxiation hazard at every stage in the process. Precautions must be taken to ensure that no personnel are inadvertently exposed to a low-oxygen atmosphere.

Pneumatic testing should be conducted strictly in accordance with ASME B31.3. All the precautions specified in ASME B31.3 should be strictly observed, including the elimination of conditions under which brittle fracture might occur.

11.3 Hammer Testing

Hammer testing of piping, valves, and fittings for thickness is a largely outdated test method in which the component is struck with a hammer in order to listen to the sound or attenuation. The type of sound can be used by an experienced inspector in hammer testing to differentiate thin metal from thicker metal. While some experienced inspectors may gain some knowledge about a pipe's thinness using this technique, the difficulties of calibrating and standardizing a hammer test put this technique outside the scope of modern recommended practices. Individual sites may choose to allow hammer testing of certain lines but should do so only after evaluating the hazards involved and assessing whether the hammer strikes will damage the piping or cause a leak.

Hammer testing is still considered a valid test for:

a) support anchor or flange bolt tightness by tapping on the nut and monitoring for movement;

b) identifying other loose or broken parts;

c) checking the piping to ensure that it has drained properly of liquid or if it contains excess process or corrosion scale. Tapping the pipe and hearing a dull thud rather than a ring (attenuation) is an indication of a problem.

11.4 Tell-tale Hole Drilling

Tell-tale drilling (also referred to as sentinel holes or delforez holes) is the application of small pilot holes [e.g. $^{1}/_{8}$-in. (3.2-mm) diameter] drilled into the pipe component wall using specified and controlled patterns and depths. The purpose of the tell-tale holes is to prevent major incidents associated with undetected thinning damage due to internal corrosion, erosion, and erosion-corrosion, by alerting unit personnel with a leak through the tell-tale hole. Tell-tale holes are less effective where isolated pitting is occurring. Tell-tale holes are used in conjunction with typical detailed piping inspection programs although they may provide an added measure of protection against major ruptures.

Until the general acceptance of UT wall thickness measurements, the use of tell-tale holes was a more common practice to determine when some amount of pipe wall loss had occurred. This practice has been abandoned by most users in favor of UT thickness examinations. However, some locations continue the use of tell-tale holes to minimize risk in addition to employing recognized and generally accepted piping inspection practices (e.g. digital UT, profile RT, etc.).

The pilot holes are drilled from the OD to the outermost part of the corrosion allowance periphery such that when the internal corrosion allowance is consumed a small leak occurs at the tell-tale hole. Special drill assemblies and depth gauges are used to ensure that the hole is drilled to the proper depth. The hole pattern and density can vary depending upon the type of service, likelihood of failure, and consequence of failure. They are most commonly installed during pipe fabrication.

Older facilities may have piping installed with tell-tale holes. It is suggested to document those piping systems containing tell-tale holes as their presence should be known by operators and can alter the inspection plan.

11.5 Inspection of Piping Welds

API 570 provides a detailed discussion of inspection of in-service piping welds. In addition, API 577 provides details on inspection of pipe welding. The inspector should be familiar with the material contained in these documents.

11.6 Other Inspection Methods

Qualitative NDE methods have been developed to assist the inspector in identifying areas of piping that are experiencing deterioration. Additionally, new methods are in the process of development. Halogen leak detectors are available to detect leaks in special application piping such as vacuum systems. Several methods of detecting thinning piping, CUI, and other types of deterioration are available utilizing UT, magnetic flux leakage (MFL), real-time RT, neutron radiography, neutron backscatter, thermography, pulsed eddy current (PEC), ACFM, MW, CR, etc. Each method has its advantages and disadvantages for each application. The inspector should be aware of these methods and their applicability to particular inspection needs. Visual inspection at CMLs will typically not provide a representative evaluation of CUI conditions at other locations along the pipe. A detailed discussion of the various NDE methods for detecting CUI is contained in API 583.

11.7 Inspection of Underground Piping

11.7.1 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. Figure 28 illustrates external corrosion occurring to underground piping despite the use of tape wrap. Important references for underground piping inspection include NACE SP0169 and NACE SP0274, and API 570, Section 9.

11.7.2 Types and Methods of Inspection and Testing

11.7.2.1 Above-grade Visual Surveillance

Indications of leaks in buried piping can include moist ground or actual seepage of product carried in the underground piping, a change in the surface contour of the ground, discoloration of the soil, softening of paving asphalt, pool formation, bubbling water puddles, or noticeable odor. Surveying the route of buried piping is one method to identify problem areas. All lines should be inspected at and just below the point where they enter earth, asphalt, or concrete, since serious corrosion frequently occurs at such locations.

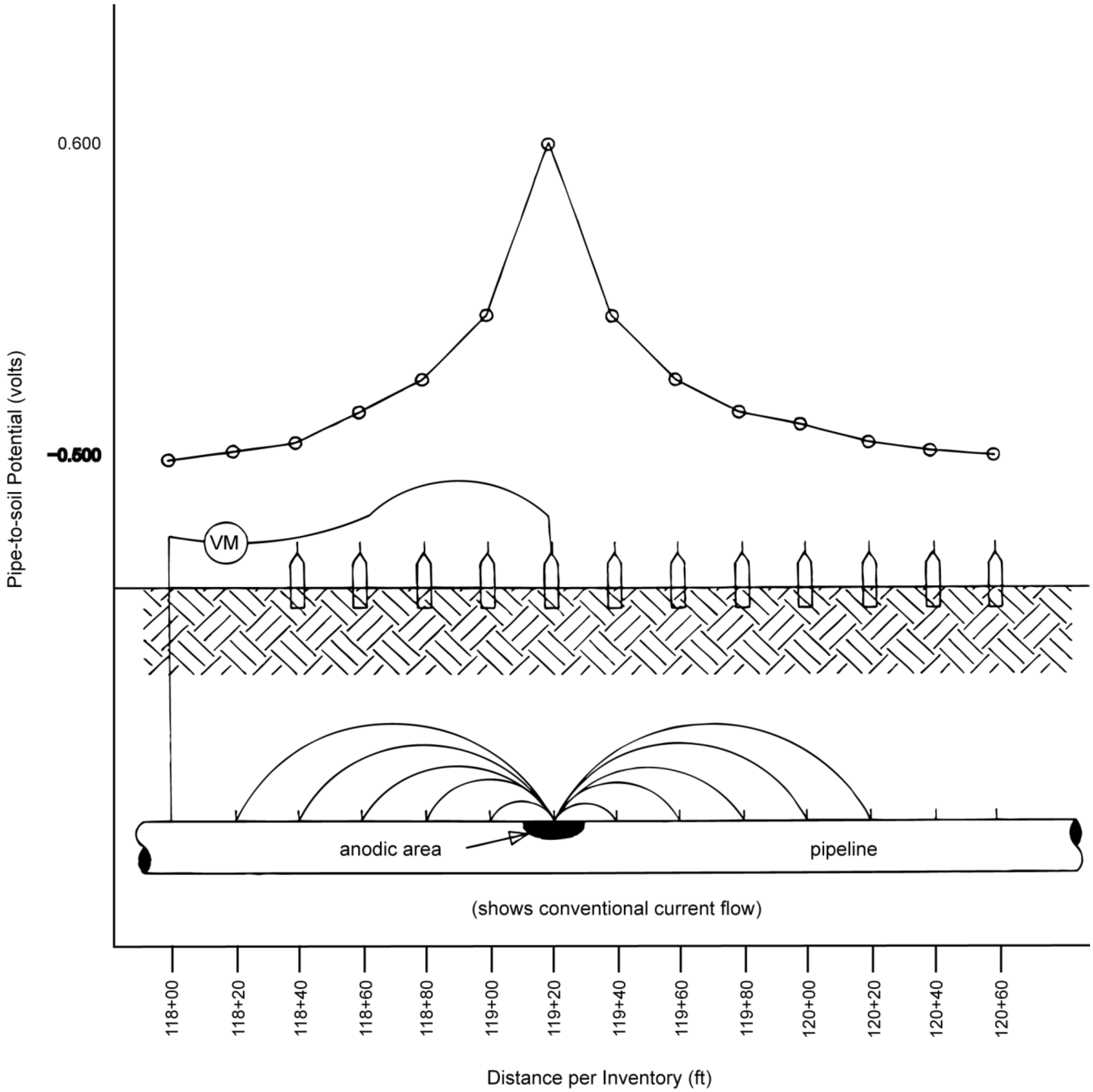
11.7.2.2 Close-interval Potential Survey

Close-interval potential surveys are used to locate corrosion cells, galvanic anodes, stray currents, coating problems, underground contacts, areas of low pipe-to-soil potentials, and other problems relating to cathodic protection.

A close-interval pipe-to-soil potential survey measures the potential of the pipe to the soil directly over the pipe, at predetermined intervals between measurements, usually at 2.5 ft, 5 ft, 10 ft, or 20 ft (0.8 m, 1.5 m, 3 m, or 6 m). The pipe contact can be made at an aboveground pipe attachment. An example of a standard type pipe-to-soil potential survey on a bare line is shown in Figure 29 and Figure 30.

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

Figure 28—Underground Piping Corrosion Beneath Poorly Applied Tape Wrap



NOTE This structure is not under cathodic protection.

Figure 29—Pipe-to-soil Internal Potential Survey Use to Identify Active Corrosion Spots in Underground Piping

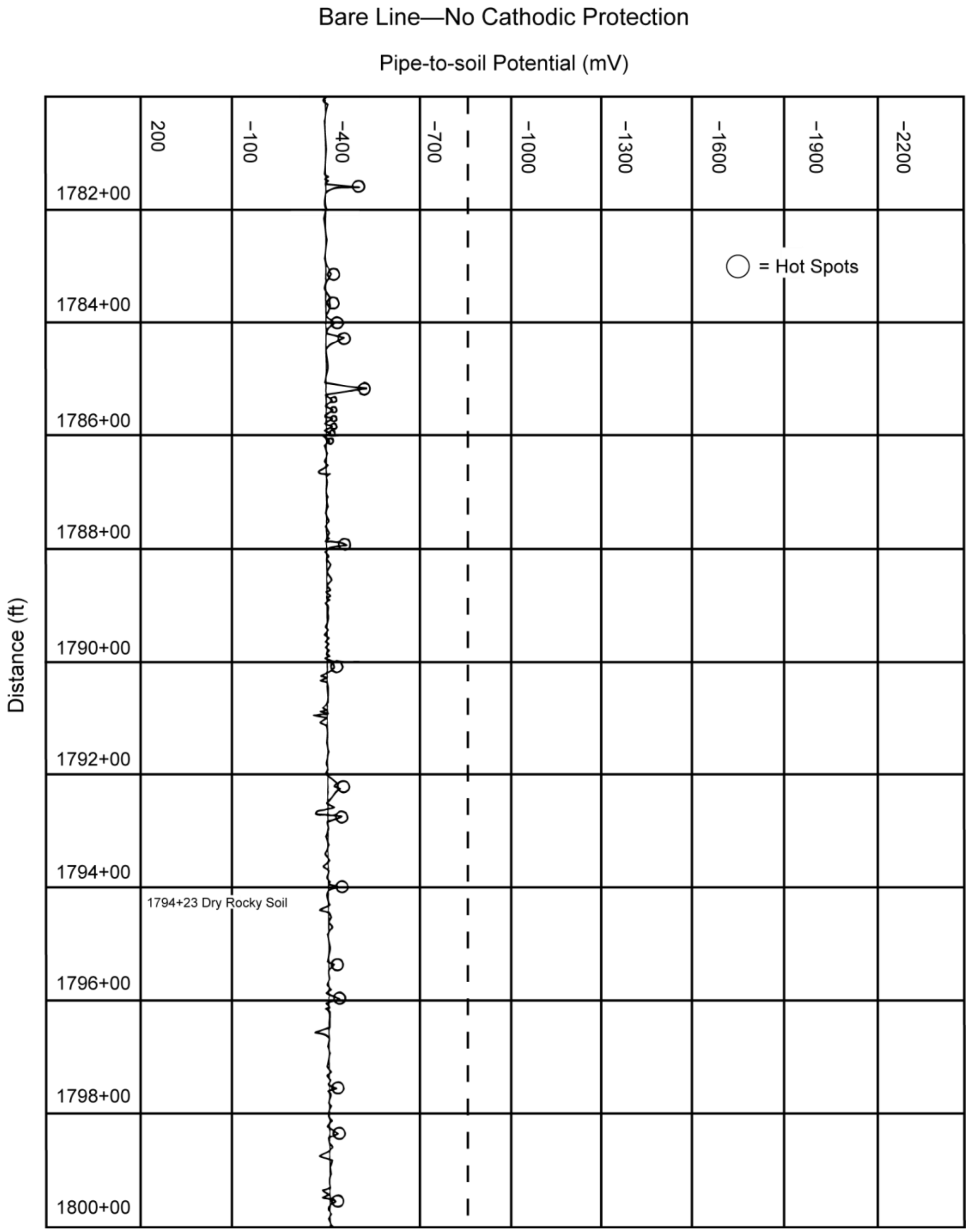


Figure 30—Example of Pipe-to-Soil Potential Survey Chart

11.7.2.3 Holiday Pipe Coating Survey

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

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

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 when an external corrosion leak occurs at a coating defect, a pipe coating holiday survey may be used to evaluate the coating.

11.7.2.4 Soil Resistivity Testing

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

There are three well-known methods of determining resistivity. These are the Wenner Four-pin Method, the soil bar (AC bridge), and the soil box. The procedures for the use of each of these three methods are simple in concept. Each one measures a voltage drop, caused by a known current flow, across a measured volume of soil. This “resistance” factor is used in a formula to determine the resistivity of the soil. Both the soil bar and the soil box use a multiplication factor to determine the soil resistivity. This factor should be imprinted on the bar or box.

Measurements of soil resistivity using the Wenner Four-pin Method should be in accordance with ASTM G57. The Four-pin Method uses the formula:

$$\text{resistivity (ohm-cm)} = 191.5 \times d \times R$$

The number “191.5” is a constant that takes into account the mathematical equation for the mass of the soil, and a conversion factor to convert feet to centimeters. “d” is the distance in feet between any of the equally spaced pins (with all of the pins in a straight line). “R” is a resistance factor of the voltage drop across the two inner pins, divided by the induced current flow in the earth between the two outer pins. The depth that the pins are inserted into the earth should be small compared to the pin spacing (see Figure 31). The following conditions should be considered in four-pin soil resistivity measurements:

a) all underground structures should be excluded from the measurement,

b) all of the pins should be in a straight line and equally spaced,

c) the depth of the pins inserted into the ground should be less than 4 % of the spacing,

d) the soil resistivity meter should be designed to exclude any effect of extraneous AC or DC currents.

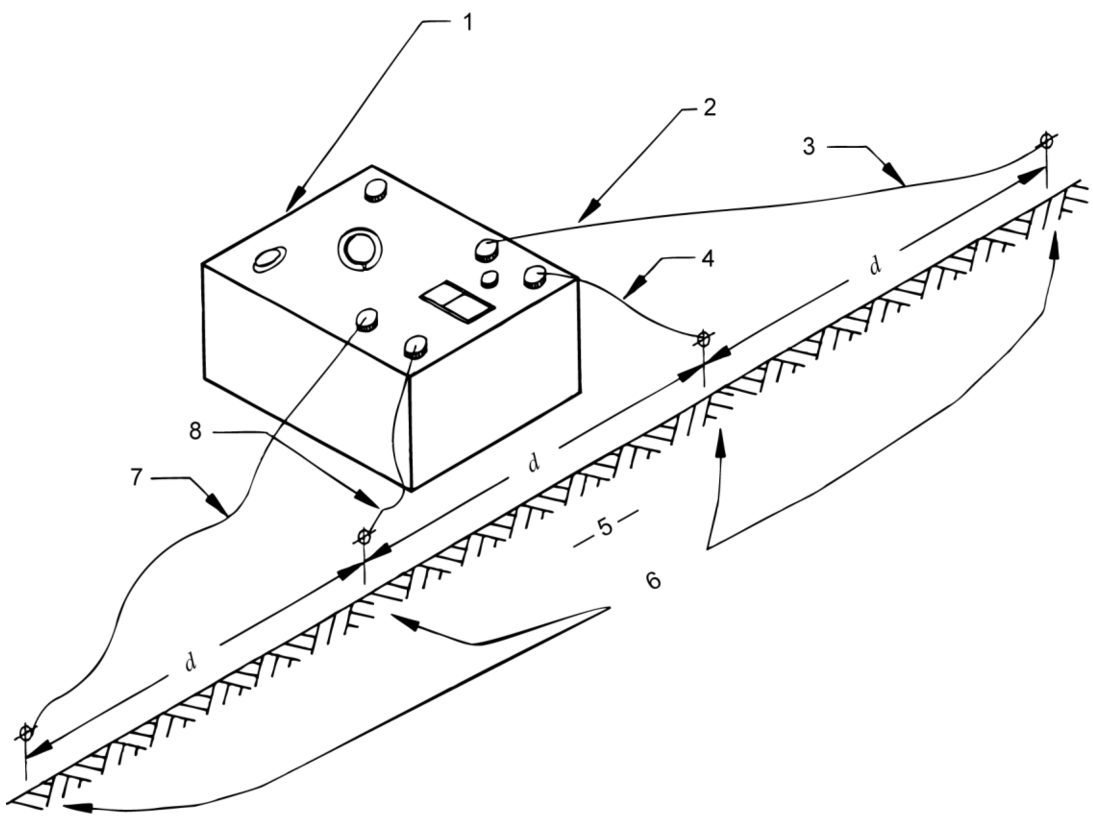
In cases of parallel pipes or in areas of intersecting pipelines, the Four-pin Method may not be applicable. Other methods include using a soil bar or a soil box.

A schematic illustrating use of a soil bar is shown in Figure 32. The soil bar is typically inserted to the depth in the soil where the resistivity is to be taken. An AC bridge-type meter is used to balance and read the indicated resistivity. Suggestions for use of the soil bar include:

a) use of a standard prod bar to provide the initial hole;

b) avoiding addition of water during, or after opening the hole;

c) applying pressure on the soil bar after insertion into the open hole.



Key

1 Four-pin soil resistivity meter
2 insulated meter leads
3 C-2 lead
4 P-2 lead
5 soil
6 steel pins
7 C-1 lead
8 P-1 lead

NOTES

p = "(rho)";
= soil resistivity in OHM-CM (OHM-CM = OHM-centimeters);
d = pin spacing, in feet (ft);
R = meter reading after balancing;
$P = 191.5 \times d \times R$.

Figure 31—Wenner Four-pin Soil Resistivity Test

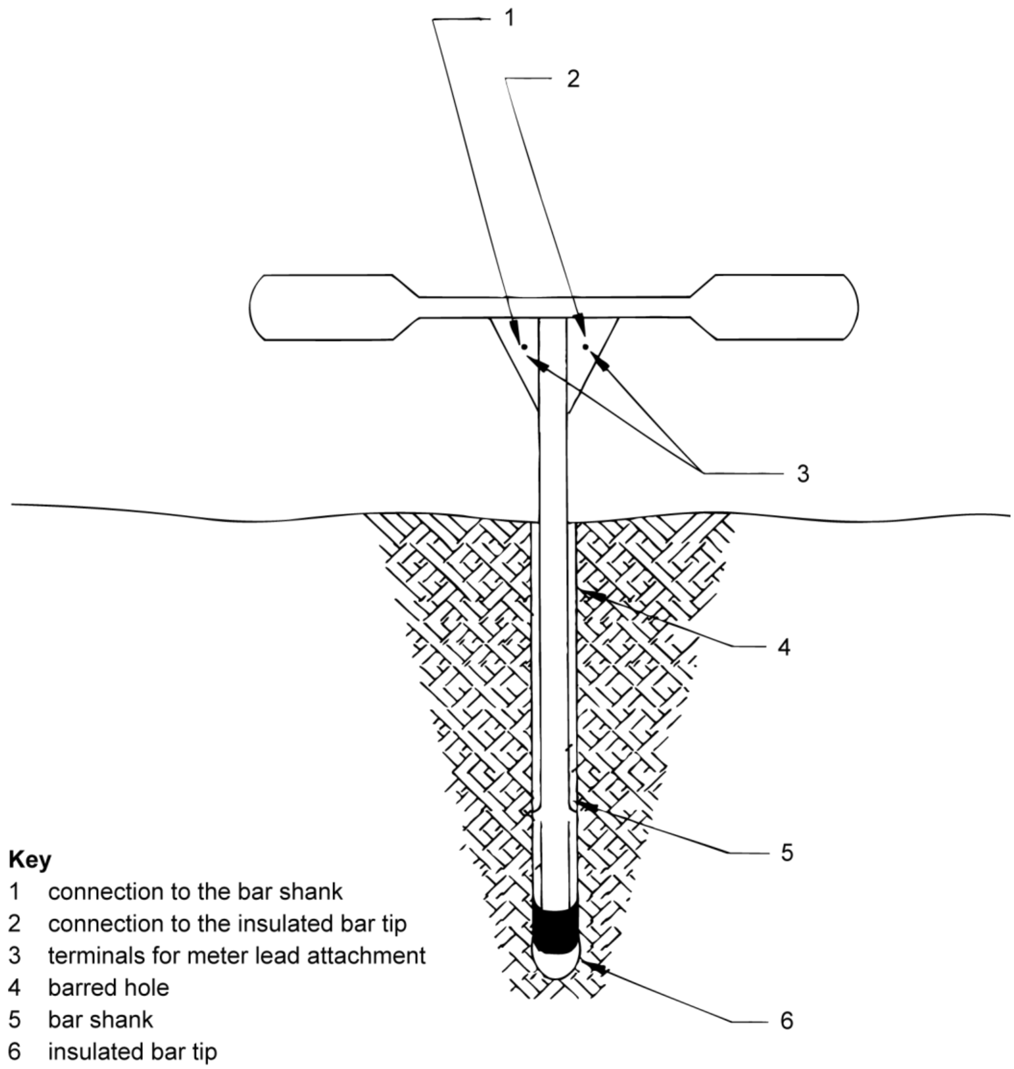


Figure 32—Soil Bar Used for Soil Resistivity Measurements

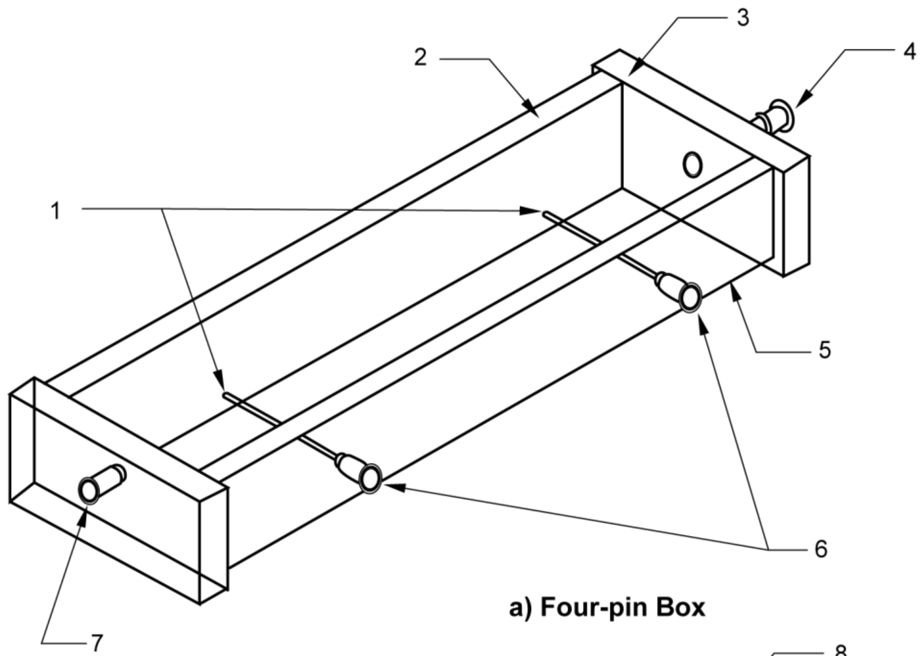
For measuring resistivity of soil samples from auger holes or excavations, a soil box serves as a convenient means for obtaining accurate results. The soil box is used to determine the resistivity of soil from a certain location by removing the soil from its location and placing it into a soil box. If the resistivity of the soil sample is not going to be measured immediately after its removal, the soil should be stored in a container that can preserve its moisture and prevent it from contamination. Figure 33 depicts two types of soil boxes used for resistivity measurement. Important points for consideration when using a soil box include:

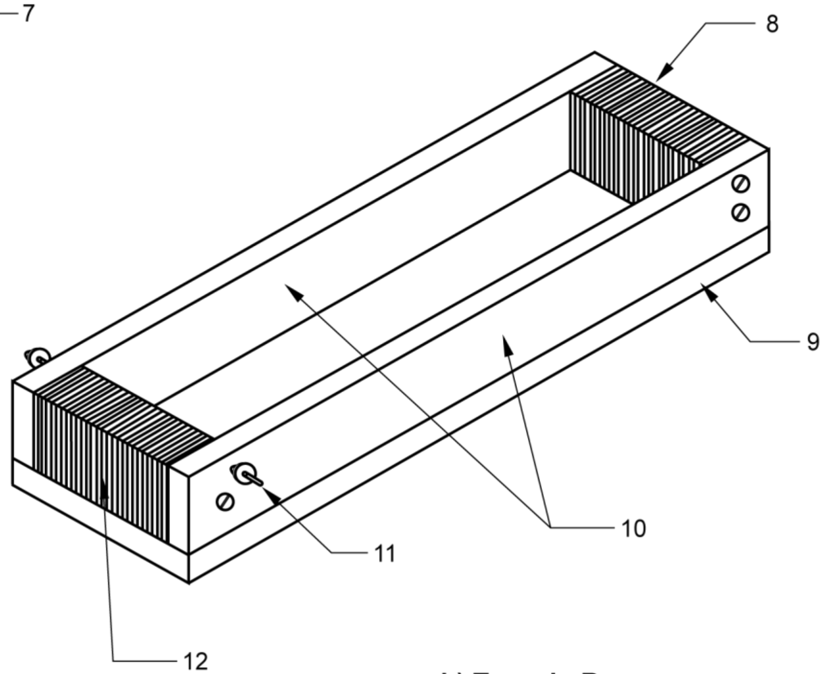
a) avoiding contamination during soil sample removal, handling, and storing;

b) avoiding adding or subtracting water;

c) having to compact the soil sample to the same density in the soil box as it was prior to removal from the ground.

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





Key

1 metal potential pins	7 current lead attachment
2 plastic	8 dark plastic box
3 metal	9 clear plastic box
4 current lead attachment	10 metal sides
5 plastic	11 terminal for meter lead attachment
6 potential lead attachments	12 dark plastic ends

Figure 33—Two Types of Soil Boxes Used for Soil Resistivity Measurements

11.7.2.5 Cathodic Protection Monitoring

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

See NACE SP0169 and API 651, Section 11 for guidance on inspecting and maintaining cathodic protection systems for buried piping.

11.7.3 Inspection Methods

11.7.3.1 General

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

11.7.3.2 Intelligent Pigging

In-line inspection (ILI) tools are commonly referred to as “smart” or “intelligent pigging.” This method involves the movement of a device (pig) through the piping either while it is in service or after it has been removed from service. Many devices are available employing different methods of inspection utilizing MFL, UT, optical, laser, ET, and other electromagnetic techniques. There are self-propelled ILI or free swimming tools now available that only require one point of access and can perform the wall loss examinations with or without product/fluid in the line. These tools use either ultrasonic or electromagnetic inspection methods to detect and size both ID and OD defects. These tools do not require typical launching and receiving line modifications; however, the use of an umbilical often restricts their inspection range. Beware of potential limitations of ILI on small-diameter piping.

11.7.3.3 Video Cameras

Television cameras are available that can be inserted into the piping. These cameras can provide visual inspection information on the internal condition of the line.

11.7.3.4 Guided Wave Inspection

Guided wave ultrasonic techniques can be used to inspect underground piping for internal and external corrosion. Guided waves are sent axially along the piping under examination. Localized wall loss due to corrosion may be located by analyzing signals of the reflected waves. The techniques require some access to the outside surface for mounting the guided wave transducers. The distance that the waves can travel and provide echoes of sufficient amplitude for analysis depends on many factors, including, for example, type and condition of coating on pipe surface, surface roughness due to internal and/or external corrosion, bonding between pipe and concrete at air-to-concrete interface, condition of soil in tight contact with the piping, and fittings on the piping.

11.7.3.5 Excavation

In many cases, the only available inspection method that can be performed is unearthing the piping in order to visually inspect the external condition of the piping and to evaluate its thickness and internal condition using the methods discussed in 10.2. Care should be exercised in removing soil from above and around the piping to prevent damaging the line or line coating, especially if the piping is in service. The last few inches of soil should be removed manually to avoid this possibility. If the excavation is sufficiently deep, the sides of the trench should be properly shored to prevent their collapse, in accordance with OSHA regulations, where applicable. If the coating or wrapping is deteriorated or damaged, it should be removed in that area to inspect the condition of the underlying metal.

See 7.4.6 for inspection of the SAI of buried piping.

11.7.4 Leak Testing

Underground lines that cannot be visually inspected should be periodically tested for leaks. Several methods are available to achieve this objective.

a) Pressure decay methods involve pressurizing the line to a desired amount, blocking it in, and then removing the source of pressure. Monitoring the line pressure over a period of time will provide an indication of system tightness. Tests may be conducted at a single pressure or multiple pressures. Testing at multiple pressures provides a means of compensating for temperature variations and may enable shorter test times compared to a single pressure test. For pressure decay methods, temperature variation and line pack (e.g. air pockets in a liquid-filled line) can affect the interpretation of results. If desired, the performance of pressure decay methods can be confirmed by leak simulation.

b) Volume in/volume out methods make use of volumetric measuring meters at each end of the line. Typically, these devices are permanently installed in situations requiring custody transfer and/or on-demand leak detection. A standard system would not be able to detect a leak under static (no flow) conditions. If desired, the performance of volume in/volume out methods can be determined by a leak simulation.

c) Single point volumetric methods are similar to pressure decay measurements requiring the line to be blocked in for a static test. A graduated cylinder is attached to the line to measure volume changes over time. Air pockets in a liquid-filled line and temperature variation can affect the results. Again, the performance of single point volumetric methods can be determined by a leak simulation.

d) Marker chemical (tracer) can be added to the line as a leak detection method. Soil gas samples near the line are collected and tested for the presence of the marker chemical. The absence of any marker chemical in the soil gas samples indicates the line is not leaking. Supplementary tests are usually required to determine the speed of sample probes in the soil and the speed at which the marker chemical travels through the backfill. Chemical tracers may be added to a liquid- or gas-filled line. This technology has the capability to both detect and locate leaks. The supplementary tests are equivalent to confirming technology performance with leak simulations.

e) Acoustic emission technology detects and locates leaks by the sound created by the leak. Sensors should be spaced to allow the sound generated by a leak to be detected at the sensor locations. Sensors are attached directly to the pipe so it may require the removal of any protective coating. It should be confirmed that the probable leak conditions will generate sufficient sound to be detected by the sensors. Since geometry and backfill will affect the noise generation, generalized leak simulations may not confirm technology performance.

11.8 Inspection of New Fabrication, Repairs, and Alterations

11.8.1 General

All subjects covered in this section should meet the principles of ASME B31.3 or equivalent pipe fabrication standard published by standards development associations (SDOs).

The procedures used to inspect piping systems while equipment is shut down are adaptable to the inspection of new construction. These procedures can include any number of the following activities: obtaining initial pipe wall thicknesses at designated CMLs; inspection for cracks; inspection of flange gasket seating faces, valves, and joints; inspection for misalignment of piping; inspection of welds; and pressure testing. Piping material selection should be based on service conditions and experience with piping in the same or similar service. The risk associated with substitution of wrong materials should determine the extent of PMI of new fabrication, repairs, or alterations. Existing connecting systems may require checks to determine whether rerating is necessary to meet the specified conditions. The extent of inspection during fabrication and installation depends largely on the severity of the service and the quality of the workmanship, and it should be part of the design.

11.8.2 Material Verification

Both materials and fabrication should be checked for conformance with the codes and specifications that are appropriate for the plant. Some piping items, such as those used in steam generation, can be subject to additional regulatory requirements. Although the piping, valves, and fittings should be specified in detail when orders are placed for new construction, there should be a positive means of identifying the materials installed in the intended piping systems, including weld filler metals. Checks should be made using material test kits or other positive identification means, such as portable X-ray fluorescence or portable optical emission spectrometry analyzers. In addition, manufacturers' material and test data can be obtained for review, particularly when special quality requirements are specified.

Examination of welds by RT or other special techniques is important in new construction. A representative number of welds can be checked for quality or the hardness of the weld and heat-affected zone. PT or MT can reveal cracks and surface defects. Similar techniques can be used to check for defects in castings and in machined surfaces such as gasket facings. Surface inspections often provide clues to whether destructive test methods should be used. See API 578 for additional guidance on material verification.

11.8.3 Deviations

Exceptions to specifications or standards for materials, tolerances, or workmanship are usually evaluated based on their effects on such factors as safety, strength, corrosion resistance, and serviceability. Special reviews may be required to determine whether piping items deviate to an extent that necessitates rejection and/or repairs. Risk analysis may be useful in these reviews. Any exceptions that have been accepted should be properly recorded and identified for future reference.

11.8.4 Repairs and Alterations

Inspection of repairs and alterations to piping systems may involve several steps in the performance of the work to ensure that it complies with the applicable sections of API 570. The inspector should be involved in planning, execution, and documentation of repairs and alterations. The inspector may need to consult with a piping engineer and corrosion specialist to properly plan and execute the piping work.

Some typical inspection activities involved with planning repairs and alterations include the following.

a) Providing necessary field data such as piping diameter, measured wall thickness, and material of construction. The required data can vary depending upon the work to be performed whether it is a temporary repair, a permanent repair, or alteration.

b) Developing and/or reviewing the scope of work. Supporting engineering design calculations should be available for review and assurance that they are applicable to the piping system and work being performed. If any restorative changes result in a change of design temperature or pressure, the requirements for rerating also should be satisfied. Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair. Additional requirements such as PWHT are defined for the work.

c) Developing an inspection plan for the work. The inspector should establish appropriate NDE hold points during the execution of the work and any testing requirements upon completion of the work.

d) Reviewing and accepting any weld procedures to be used for the work. API 577 should be reviewed for details on weld techniques and weld procedures.

e) Reviewing welder qualifications to verify that they are qualified for the welding procedures to be used for the work. API 577 should be reviewed for details on welder performance qualifications.

f) Reviewing material test reports, as required, to ensure that all materials of construction are per the piping specification and/or scope of work.

g) Reviewing applicable NDE procedures and NDE examiner qualifications/certifications. Verify that the NDE procedures are appropriate for the work to be performed and examiners are qualified/certified to perform the examination technique.

During the execution of repairs, the inspector should ensure that the work is executed per the scope and meets code requirements. Typical inspector activities include:

a) ensuring NDE is performed at the hold points as stated in the inspection plan;

b) reviewing examination results to ensure that they meet code and specification requirements;

c) ensuring any heat treatment is performed per the work scope;

d) ensuring testing requirements, such as hardness and pressure testing, are performed and acceptable.

Documentation of repairs and alterations can include the written scope of work, supporting engineering design calculations, NDE and test results, heat-treatment charts, material test reports, WPSs, and welding performance qualification records.

12 Determination of Minimum Required Thickness

12.1 Piping

12.1.1 General

ASME B31.3 contains formulas and data for determining the minimum required wall thickness for new uncorroded piping. The specification relates thickness, diameter, joint efficiency, and allowable stress to maximum safe working pressure. In specifying piping for original installation, ASME B31.3 requires that the following be taken into account when pipe thickness is determined:

a) corrosion allowance;

b) threads and other mechanical allowances (consideration should be given to crevice corrosion and loss of thickness due to cutting the threads);

c) stresses caused by mechanical loading, hydraulic surge pressure, thermal expansion, and other conditions;

d) reinforcement of openings;

e) other allowances.

Additional thickness is nearly always required when Item a) through Item e) are considered. Normally, the engineer will select the pipe schedule that accommodates the required thickness plus the manufacturing tolerance permitted by the pipe material specification.

Additional thickness is often needed near branch connections. This additional thickness is usually provided by one of the following:

a) a welding tee,

b) a saddle,

c) an integrally reinforced branch outlet (e.g. a weldolet), or

d) the header and/or run pipe thickness is greater than required by design conditions.

Caution should be exercised in calculating the retirement thickness for piping with branch connections reinforced per Item d). These calculations should be performed by a piping engineer.

For in-service piping subject to localized damage (e.g. pitting, cracking, blistering, gouging), as well as weld misalignment and distortion, the inspector may choose to evaluate the piping strength and suitability for continued service utilizing the approach discussed in API 579-1/ASME FFS-1. Such an analysis should be performed by, or under the direction of, a piping engineer.

12.1.2 Pressure Design Thickness

ASME B31.3 contains a formula for determining the required thickness of new, uncorroded, straight pipe subject to internal pressure. API 570 permits the use of the simple Barlow formula to determine the required wall thickness for in-service piping. ASME B31.3 provides the guidance of when other equations are applicable. The Barlow formula is as follows:

$$t = \frac{PD}{2SE}$$

where

t is the pressure design thickness for internal pressure, in inches (millimeters);

P is the internal design gauge pressure of the pipe, in pounds per square inch (kilopascals);

D is the OD of the pipe, in inches (millimeters);

S is the allowable unit stress at the design temperature, in pounds per square inch (kilopascals);

E is the longitudinal quality factor.

The Barlow formula gives results that are practically equivalent to those obtained by the more elaborate ASME B31.3 formula except in cases involving high pressures where thick-walled tubing is required. Metallic pipe for which $t \geq D/6$ or $P/SE > 0.385$ requires special consideration.

ASME B31.3 also contains the allowable unit stresses to be used in the formulas contained in that publication. These allowable stresses include a factor of safety and are functions of the pipe material and the temperature.

12.1.3 Structural Minimum Thickness

In low-pressure and low-temperature applications, the required pipe thicknesses determined by the Barlow formula can be so small that the pipe would have insufficient structural strength. For this reason, an absolute minimum thickness to prevent sag, buckling, and collapse at supports should be determined by the user for each size of pipe. The pipe wall should not be permitted to deteriorate below this minimum thickness regardless of the results obtained by the ASME B31.3 or Barlow formulas.

a) The owner/user should specify how structural minimum thicknesses are determined. An example table of calculated structural minimum thickness for straight spans of carbon steel pipe is provided in Table 7. Additional consideration and allowances may be required for the following conditions: screwed piping and fittings.

b) Piping diameters greater than 24 in. (610 mm).

c) Temperatures exceeding 400 °F (205 °C) for carbon and low-alloy steel.

d) Higher alloys (other than carbon steel and Cr-Mo).

e) Spans in excess of 20 ft (6 m).

f) High external loads (e.g. refractory lined, pipe that is also used to support other pipe, rigging loads, and personnel support loading).

g) Excessive vibration.

Engineering calculations, typically using a computerized piping stress analysis program, may be required in these instances to determine structural minimum thickness.

Austenitic stainless steel piping often have lower minimum structural thickness requirements based upon their typically higher strength, higher toughness and thinner initial thicknesses of piping components. Separate tables are often created for stainless steel piping.

12.1.4 Minimum Required Thickness

Generally, piping is replaced and/or repaired when it reaches the minimum required thickness unless a Fitness-For-Service analysis has been performed which defined additional remaining life. The minimum required thickness is the greater value of the pressure design thickness or the structural minimum thickness. The following steps should be followed when determining the minimum required thickness at a CML.

Step 1: Calculate pressure design thickness per rating code.

Step 2: Determine structural minimum thickness per owner/user table or engineering calculations.

Step 3: Select minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2.

For services with high potential consequences if a failure were to occur, the piping engineer should consider increasing the minimum allowed thickness above the one determined above in Step 3. This would provide extra thickness for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse.

Example 1: Determine the minimum required thickness for a NPS 2, ASTM A106, Grade B pipe designed for 100 psig @ 100 °F. P = 100 psig, D = 2.375 in., S = 20,000 psi, E = 1.0 (since seamless), Y = 0.4.

Step 1: Calculate pressure design thickness per rating code. (In this example, the ASME B31.3 design formula was used.)

$$t = \frac{100 \times 2.375}{2\left[(20{,}000 \times 1) + (100 \times 0.4)\right]} = 0.006$$

If this NPS 2 pipe was 100 % supported (e.g. laying on flat ground), then 0.006 in. would hold the 100 psig of pressure. This thickness includes a 3-to-1 safety factor; however, it would not hold up in the pipe rack.

Step 2: Determine structural minimum thickness per owner/user table or engineering calculations. From Table 6, the default structural minimum thickness is 0.070 in.

Step 3: Select minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2. Larger value of 0.006 in. and 0.070 in. is 0.070 in.

Example 2: Determine the minimum required thickness for a 14 NPS, ASTM A106, Grade B pipe designed for 600 psig @ 100 °F, D = 14 in., S = 20,000 psi, E = 1.0 (seamless), Y = 0.4.

Step 1: Calculate pressure design thickness per rating code. (In this example, the ASME B31.3 design formula was used.)

$$t = \frac{600 \times 14.0}{2x\left[(20{,}000 \times 1) + (600 \times 0.4)\right]} = 0.208$$

Step 2: Determine structural minimum thickness per owner/user table or engineering calculations. From Table 6, the structural minimum thickness is 0.110 in.

Step 3: Select minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2. Larger value of 0.208 in. and 0.110 in. is 0.208 in.

12.1.5 Minimum Alert Thickness

Users may establish a minimum alert thickness with values greater than either the minimum structural thickness or the pressure design thickness whichever governs the minimum required thickness. Alert thicknesses are often inputted into the facility's inspection data management program. The alert thickness signals the inspector that it is timely for a remaining life assessment. This could include a detailed engineering evaluation of the structural minimum thickness, Fitness-For-Service assessment, or developing future repair plans. In addition, when a CML reaches the alert thickness, it raises a flag to consider the extent and severity at other possible locations for the corrosion mechanism. Alert minimum thicknesses are usually not intended to mean that pipe components must be retired when one CML reaches the default limit. Table 7 shows an example of alert thicknesses for carbon and low-alloy steel pipe that could be used in conjunction with the default minimum structural thicknesses.

Table 7—Minimum Thicknesses for Carbon and Low-alloy Steel Pipe

NPS	**Default Minimum Structural Thickness for Temperatures < 400 °F (205 °C)** in. (mm)	**Minimum Alert Thickness for Temperatures < 400 °F (205 °C)** in. (mm)
1/2 to 1	0.07 (1.8)	0.08 (2.0)
1 1/2	0.07 (1.8)	0.09 (2.3)
2	0.07 (1.8)	0.10 (2.5)
3	0.08 (2.0)	0.11 (2.8)
4	0.09 (2.3)	0.12 (3.1)
6 to 18	0.11 (2.8)	0.13 (3.3)
20 to 24	0.12 (3.1)	0.14(3.6)

12.2 Valves and Flanged Fittings

Valves and flanged fittings are subject to stress both from internal pressure and from mechanical loadings and temperature changes. Valves are also subject to closing stresses and stress concentrations because of their shape. These stresses are difficult to calculate with certainty. For this reason, the thickness of valves and flanged fittings is substantially greater than that of a simple cylinder. ASME B16.34 establishes the minimum valve wall thickness at 1.5 times (1.35 times for Class 4500) the thickness of a simple cylinder designed for a stress of 7000 psi (48.26 MPa) and subjected to an internal pressure equal to the pressure rating class for valve Classes 150 to 2500. The actual valve wall thickness requirements given in Table 3 of ASME B16.34 are approximately 0.1 in. (2.54 mm) thicker than the calculated values. Valves furnished in accordance with API 600 have thickness requirements for corrosion and erosion in addition to those given in ASME B16.34.

The formula for calculating the minimum required thickness of pipe can be adapted for valves and flanged fittings by using the factor of 1.5 and the allowable stress for the material specified in ASME B31.3.

$$t = 1.5\left[\frac{PD}{2(SE)}\right]$$

where

t is the pressure design thickness for internal pressure, in inches (millimeters);

P is the internal design gauge pressure of the pipe, in pounds per square inch (kilopascals);

D is the OD of the pipe, in inches (millimeters);

S is the allowable unit stress at the design temperature, in pounds per square inch (kilopascals);

E is the longitudinal quality factor.

This calculated thickness will be impractical from a structural standpoint (as is the case with many piping systems); therefore, minimum thicknesses should be established based on structural needs.

The calculations described above do not apply to welded fittings. The calculations for pipe can be applied to welded fittings using appropriate corrections for shape, if necessary.

13 Records

13.1 General

The necessity of keeping complete records in a detailed and orderly manner is an important responsibility of the inspector as well as a requirement of many regulations (e.g. OSHA 29 *CFR* 1910.119). Accurate records allow an evaluation of service life on any piping, valve, or fitting. From such records, a comprehensive picture of the general condition of any piping system can be determined. When properly organized, such records form a permanent record from which corrosion rates and probable replacement or repair intervals can be determined. A computer program can be used to assist in a more complete evaluation of recorded information and to determine the next inspection date.

Inspection records should contain:

a) original date of installation;

b) specifications of the materials used;

c) original thickness measurements;

d) locations and dates of all subsequent thickness measurements;

e) calculated retirement thickness;

f) repairs and replacements;

g) temporary repairs;

h) pertinent operational changes, i.e. change in service;

i) Fitness-For-Service assessments;

j) RBI assessments.

These and other pertinent data should be arranged on suitable forms so that successive inspection records will furnish a chronological picture. Each inspection group should develop appropriate inspection forms.

13.2 Sketches

Isometric or oblique drawings provide a means of documenting the size and orientation of piping lines, the location and types of fittings, valves, orifices, etc. and the locations of CMLs. Although original construction drawings can be used, normally separate sketches are made by, or for, the inspection department. Figure 34 is a typical isometric sketch for recording field data.

Sketches have the following functions.

a) Identify particular piping systems and circuits in terms of location, size, material specification, general process flow, and service conditions.

b) Show points to be opened for visual inspection and parts that require replacement or repair.

c) Serve as field datasheets on which can be recorded the locations of thickness measurements, corrosion findings, and sections requiring replacement. These data can be transferred to continuous records at a later date.

d) Assist at future inspections in determining locations that require examination.

e) Identification of temporary repairs

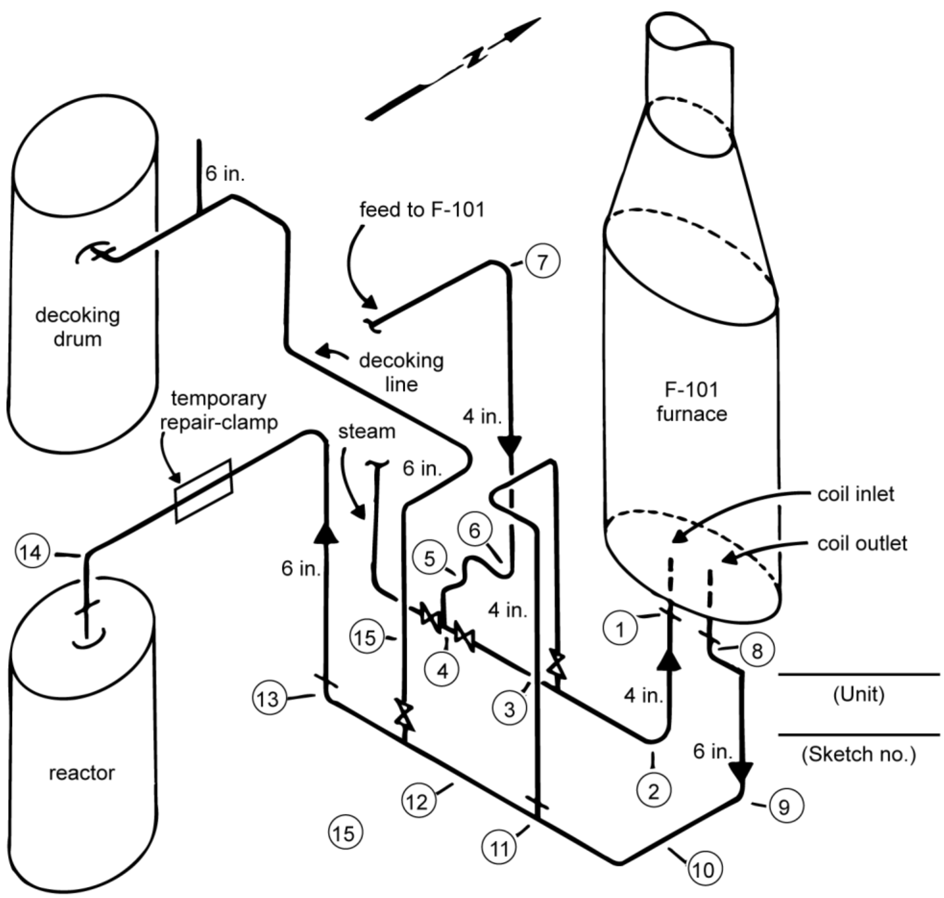
Sketches may also contain the following:

a) pipe schedule,

b) location of piping supports,

c) location of SAI,

d) P&ID number.



NOTE Circled numbers indicate points at which thickness should be monitored by the inspector when the thickness datasheet is filled out.

Figure 34—Typical Isometric Sketch

13.3 Numbering Systems

Typically, a coding system is used to uniquely identify the process unit, the piping system, the circuit, and the CMLs.

13.4 Thickness Data

A record of thickness data obtained during periodic or scheduled inspections provides a means of arriving at corrosion or erosion rates and expected material life. Some companies use computerized record systems for this purpose. The data can be shown on sketches or presented as tabulated information attached to the sketches. Figure 35 shows one method of tabulating thickness readings and other information.

13.5 Review of Records

Records of previous inspections and of inspections conducted during the current operating period should be reviewed soon after the inspections are conducted to schedule the next inspection date. This review should provide lists of areas that are approaching retirement thickness, areas that have previously shown high corrosion rates, and areas in which current inspection has indicated a need for further investigation. From these lists, a work schedule should be prepared for additional on-stream inspection, if possible, and for inspections to be conducted during the next shutdown period. Such a schedule will assist in determining the number of inspectors to be assigned to the work.

In addition, from the review of the records of previous inspections, a list should be made of all expected repairs and replacements. This list should be submitted to the maintenance department far enough in advance of the shutdown to permit any required material to be obtained or, if necessary, fabricated. This list will also assist the maintenance personnel in determining the number of personnel required during the shutdown period.

13.6 Record Updates

Records should be updated following inspection activities within a reasonable amount of time affording the inspector enough time to properly gather, analyze, and record data. Many sites have internal requirements indicating a maximum duration between obtaining data and updating records. These requirements generally allow records be updated within a few weeks of completing the inspection activities. Establishing a time frame for record updates helps ensure that data and information are accurately recorded and do not become lost and details forgotten.

13.7 Audit of Records

Inspection records should be regularly audited against code requirements, site’s quality assurance inspection manual, and site procedures. The audit should assess whether the records meet requirements and whether the records are of appropriate quality/accuracy. Regular audits provide a means to identify gaps and deficiencies in existing inspection programs and define corrective actions, such as focused training.

Identification Number								☐ Piping ☐ Vessel
								Description ______

Inspection Interval		Design Conditions		Operating Conditions		Material	
Internal	External	Temperature	Pressure	Temperature	Pressure		Remaining Life (Years/Months) ______ Set by Last Reading at Point No. ______ Next Recommended Inspection Date ______

Point	Reading Location	Size	Limit	Initial Reading					Subsequent Reading					Subsequent Reading				
				Thickness	Method	Month	Year	Inspection Temperature	Thickness	Method	Month	Year	Inspection Temperature	Thickness	Method	Month	Year	Inspection Temperature
				Inspector ______					Inspector ______					Inspector ______				

NOTE The "Method" column should be used to indicate the method used to measure the thickness (e.g. N = nominal; U = ultrasonic; X = radiography; and C = calipers).

Figure 35—Typical Tabulation of Thickness Data

Annex A
(informative)

External Inspection Checklist for Process Piping

Piping Circuit #:

Date Inspected:

Item Inspected by Status:

a) Leaks.

   1) Process.

   2) Steam tracing.

   3) Existing clamps.

b) Misalignment.

   1) Piping misalignment/restricted movement.

   2) Expansion joint misalignment.

c) Vibration.

   1) Excessive overhung weight.

   2) Inadequate support.

   3) Thin, small bore, or alloy piping.

   4) Threaded connections.

   5) Loose supports causing metal wear.

d) Supports.

   1) Shoes off support.

   2) Hanger distortion or breakage.

   3) Bottomed-out springs.

   4) Brace distortion/breakage.

   5) Loose brackets.

   6) Slide plates/rollers.

   7) Counterbalance condition.

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