Inspection Practices for Piping System Components

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FOREWORD

This recommended practice is based on the accumulated knowledge and experience of engineers, inspectors, and other personnel in the petroleum and petrochemical industry. It is intended to supplement the API 570 Piping Inspection Code.

Some of the information contained in this Publication was previously presented as Chapter XI of the Guide for Inspection of Refinery Equipment, which is currently being reorganized as individual recommended practices. The information in this recommended practice does not constitute and should not be construed as a code of rules, regulations, or minimum safe practices. The practices described in this Publication are not intended to supplant other practices that have proven satisfactory, nor is this Publication intended to discourage innovation and originality in the inspection of refineries and chemical plants. Users of this recommended practice are reminded that no book or manual is a substitute for the judgment of a responsible, qualified inspector or piping engineer.

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Inspection Practices for Piping System Components

1 Scope

This recommended practice covers the inspection practices for piping, tubing, valves (other than control valves), and fittings used in petroleum refineries and chemical plants. Although this publication is not specifically intended to cover specialty items, many of the inspection methods described in this recommended practice are applicable to specialty items such as: control valves, level gages, instrument controls columns, etc.

2 References

The following standards and specifications are cited in this recommended practice:

API

IRE, Chapter II	*Conditions Causing Deterioration or Failures (out of print; to be replaced by RP 571, currently under development)*
Std 570	*Piping Inspection Code*
Std 590	*Steel Line Blanks*
Std 594	*Wafer and Wafer-Lug Check Valves*
Std 598	*Valve Inspection and Testing*
Std 599	*Metal Plug Valves—Flanged and Welding Ends*
Std 600	*Steel Gate Valves—Flanged and Butt-Welding Ends*
Std 602	*Compact Steel Gate Valves—Flanged, Threaded, Welding, and Extended-Body Ends*
Std 603	*Class 150, Cast, Corrosion-Resistant, Flanged-End Gate Valves*
Std 608	*Metal Ball Valves—Flanged, and Butt-Welding End*
Std 609	*Lug- and Wafer-Type Butterfly Valves*
RP 651	*Cathodic Protection of Aboveground Petroleum Storage Tanks*
Publ 2217A	*Guidelines for Work in Inert Confined Spaces in the Petroleum Industry*

ASME[1]

B1.20.1	*General Purpose Pipe Threads (Inch)*
B16.25	*Buttwelding Ends*
B16.34	*Valves -- Flanged, Threaded, and Welding End*
B16.47	*Large Diameter Steel Flanges, NPS 26 Through NPS 60*
B16.5	*Pipe Flanges and Flanged Fittings, Steel, Nickel Alloy and Other Special Alloys*
B31.3	*Process Piping*
B31G	*Manual for Determining the Remaining Strength of Corroded Pipelines*
B36.10M	*Welded and Seamless Wrought Steel Pipe*
B36.19M	*Stainless Steel Pipe*

ASTM[2]

A 53	*Specification for Pipe, Steel, Black and Hot-Dipped, Zinc Coated Welded and Seamless*
A 106	*Specification for Seamless Carbon Steel Pipe for High Temperature Service*
A 358	*Electric-Fusion-Welded Austenitic Chromium-Nickel Alloy Steel Pipe for High-Temperature Service*
A 530	*General Requirements for Specialized Carbon and Alloy Steel Pipe*
A 671	*Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures*
A 672	*Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures*
G 57	*Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*

NACE[3]

RP 0169	*Control of External Corrosion of Underground or Submerged Metallic Piping Systems*

Code of Federal Regulations

29 *CFR* 1910.119 *Process Safety Management of Highly Hazardous Chemicals*

3 Definitions

For the purposes of this publication, the following definitions apply:

3.1 ASME B31.3: Abbreviation for ASME/ANSI B31.3, *Process Piping*, published by the American Society of Mechanical Engineers. ASME B31.3 is written for design and construction of piping systems. However, most of the technical requirements on design, welding, examination, and materials also can be applied in the inspection, rerating, repair, and alteration of operating piping systems. When ASME B31.3 cannot be followed because of its new construction coverage, such as revised or new material specifications, inspection

[1]American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017.

[2]American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959.

[3]NACE International, 440 South Creek Drive, Houston, Texas 77084.

requirements, certain heat treatments, and pressure tests, the piping engineer/inspector shall be guided by API 570 in lieu of strict conformance with ASME B31.3. As an example of intent, the term "principles" of ASME B31.3 has been employed in API 570 rather than the phrase "in accordance with" ASME B31.3.

3.2 CUI: Corrosion under insulation, which includes stress corrosion cracking under insulation.

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

3.4 defect: In NDE usage, a defect is an imperfection of a type or magnitude exceeding the acceptable criteria.

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

3.6 imperfection: Flaws or other discontinuities noted during inspection that may be subject to acceptance criteria on engineering/inspection analysis.

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

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

3.9 inspector: An authorized piping inspector.

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

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

3.12 NDE: Nondestructive examination.

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

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

3.15 owner-user: An operator of piping systems who exercises control over the operation, engineering, inspection, repair, alteration, testing, and rerating of those piping systems.

3.16 PT: Liquid penetrant testing.

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

3.18 piping circuit: Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and record keeping. A piping circuit is a section of piping of which all points are exposed to an environment of similar corrosivity and which is of similar design conditions and construction material. 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.

3.19 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 which 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 a technical requirement.

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

3.21 PWHT: Post weld heat treatment.

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

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

3.24 small bore piping (SBP): Less than or equal to NPS 2.

3.25 soil-to-air (S/A) interface: An area in which external corrosion may occur on partially buried pipe. The zone of the corrosion will vary depending on factors such as moisture, oxygen content of the soil, and the operating temperature. The zone generally is considered to be from 12 inches (30 cm) below to 6 inches (15 cm) above the soil surface. Pipe running parallel with the soil surface that contacts the soil is included.

3.26 spools: A section of piping encompassed by flanges or other connecting fittings, such as unions.

3.27 temper embrittlement: A loss of ductility and notch toughness in susceptible low-alloy steels (e.g., $1^1/_4$ Cr and $2^1/_4$ Cr) due to prolonged exposure to high temperature service (between 700° to 1070° F (371° to 577° C)).

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

3.29 WFMT or WFMPT: Wet fluorescent magnetic particle testing.

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 and A106. The industry generally uses seamless piping for most services. Piping of a nominal size larger than 16 inches (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 up to 48 inches (1219 mm). Pipe wall thicknesses are designated as pipe schedules in nominal pipe sizes up to 36 inches (914 mm). The traditional thickness designations—standard weight, extra strong, and double extra strong—differ from schedules and are used for nominal pipe sizes up to 48 inches (1219 mm). In all standard sizes, the outside diameter remains nearly constant regardless of the thickness. For nominal pipe sizes of 12 inches (305 mm) and smaller, the size refers to the inside diameter of standard weight pipe; for nominal pipe sizes of 14 inches (356 mm) and larger, the size denotes the actual outside diameter. The pipe diameter is expressed as nominal pipe size (NPS) which is based on these size practices. Tables 1 and 1a list the dimensions of ferritic pipe from NPS $^1/_8$ up through NPS 24. (See, also, 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 ferritic pipes ASTM Standards. The actual thickness of seamless piping may vary from its nominal thickness by a manufacturing tolerance of as much as 12.5 percent. The under tolerance for welded piping is 0.01 inch (0.25 mm). Cast piping has a thickness tolerance of $+^1/_{16}$ inch (1.6 mm) and -0 inch (0 mm), as specified in ASTM A530. Consult the ASTM or the equivalent ASME material specification to determine what tolerances are permitted for a specific material. Piping which 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. The standards and sizes for cast iron piping differ from those for welded and seamless piping.

4.1.2 Small Bore Pipe

Small-bore piping (NPS 2 pipe size and less) can be used as primary process piping or as nipples, secondary, and auxiliary piping. Nipples are normally 6 inches (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 and used for flush lines, instrument piping, analyzer piping, lubrication, and seal oil piping for rotating equipment.

4.2 TUBING

With the exception of heater, boiler, and exchanger tubes, tubing is similar to piping, but is manufactured in many outside diameters and wall thicknesses. Tubing is generally seamless, but may be welded. Its stated size is the actual outside diameter. (ASTM B88 tubing, which is often used for steam tracing, is an exception in that its size designation is $^1/_8$ inch (3.2 mm) less than the actual outside diameter.) Tubing is usually made in small diameters and is mainly used for heat exchangers, instrument piping, lubricating oil services, steam tracing, and similar services.

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

Pipe Size (NPS)	Actual O.D., Inches	SCH.	WGT. Class	Approx. I.D. Inches	Nominal thickness, Inches
1/8	0.405	40	STD	0.269	0.068
		80	XS	0.215	0.095
1/4	0.540	40	STD	0.364	0.088
		80	XS	0.302	0.119
3/8	0.675	40	STD	0.493	0.091
		80	XS	0.423	0.126
1/2	0.840	40	STD	0.622	0.109
		80	XS	0.546	0.147
		160		0.464	0.188
		–	XXS	0.252	0.294
3/4	1.050	40	STD	0.824	0.113
		80	XS	0.742	0.154
		160		0.612	0.219
		–	XXS	0.434	0.308
1	1.315	40	STD	1.049	0.133
		80	XS	0.957	0.179
		160		0.815	0.250
		–	XXS	0.599	0.358
1 1/4	1.660	40	STD	1.380	0.140
		80	XS	1.278	0.191
		160		1.160	0.250
		–	XXS	0.896	0.382
1 1/2	1.900	40	STD	1.610	0.145
		80	XS	1.500	0.200
		160		1.338	0.281
		–	XXS	1.100	0.400
2	2.375	40	STD	2.067	0.154
		80	XS	1.939	0.218
		160		1.687	0.344
		–	XXS	1.503	0.436
2 1/2	2.875	40	STD	2.469	0.203
		80	XS	2.323	0.276
		160		2.125	0.375
		–	XXS	1.771	0.552
3	3.500	40	STD	3.068	0.216
		80	XS	2.900	0.300
		160		2.624	0.438
		-	XXS	2.300	0.600
3 1/2	4.000	40	STD	3.548	0.226
		80	XS	3.364	0.318
		–	XXS	2.728	0.636
4	4.500	40	STD	4.026	0.237
		80	XS	3.826	0.337
		120		3.624	0.438
		160		3.438	0.531
		–	XXS	3.152	0.674
5	5.563	40	STD	5.047	0.258
		80	XS	4.813	0.375
		120		4.563	0.500
		160		4.313	0.625
		–	XXS	4.063	0.750

Table 1 — Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Steel Pipe (cont'd)

Pipe Size (NPS)	Actual O.D., Inches	SCH.	WGT. Class	Approx. I.D. Inches	Nominal thickness, Inches
6	6.625	40	STD	6.065	0.280
		80	XS	5.761	0.432
		120		5.501	0.562
		160		5.187	0.719
		–	XXS	4.897	0.864
8	8.625	20		8.125	0.250
		30		8.071	0.277
		40	STD	7.981	0.322
		60		7.813	0.406
		80	XS	7.625	0.500
		100		7.437	0.594
		120		7.187	0.719
		140		7.001	0.812
		–	XXS	6.875	0.875
		160		6.813	0.906
10	10.75	20		10.250	0.250
		30		10.136	0.307
		40	STD	10.020	0.365
		60	XS	9.750	0.500
		80		9.562	0.594
		100		9.312	0.719
		120		9.062	0.844
		140		8.750	1.000
		160		8.500	1.125
12	12.750	20		12.250	0.250
		30		12.090	0.330
		–	STD	12.000	0.375
		40		11.938	0.406
		–	XS	11.750	0.500
		60		11.626	0.562
		80		11.374	0.688
		100		11.062	0.844
		120		10.750	1.000
		140		10.500	1.125
		160		10.126	1.312
14	14.000	10		13.500	0.250
		20		13.376	0.312
		30	STD	13.250	0.375
		40		13.124	0.438
		–	XS	13.000	0.500
		60		12.812	0.594
		80		12.500	0.750
		100		12.124	0.938
		120		11.812	1.094
		140		11.500	1.125
		160		11.188	1.406

Table 1 — Nominal Pipe Sizes, Schedules, Weight Classes, and Dimensions of Steel Pipe (cont'd)

Pipe Size (NPS)	Actual O.D., Inches	SCH	WGT. Class	Approx. I.D. Inches	Nominal thickness, Inches
16	16.000	10		15.500	0.250
		20		15.376	0.312
		30	STD	15.250	0.375
		40	XS	15.000	0.500
		60		14.688	0.656
		80		14.312	0.844
		100		13.938	1.031
		120		13.562	1.219
		140		13.124	1.438
		160		12.812	1.594
18	18.000	10		17.500	0.250
		20		17.376	0.312
		–	STD	17.250	0.375
		30		17.124	0.438
		–	XS	17.000	0.500
		40		16.876	0.562
		60		16.500	0.750
		80		16.124	0.938
		100		15.688	1.156
		120		15.250	1.375
		140		14.876	1.562
		160		14.438	1.781
20	20.000	10		19.500	0.250
		20	STD	19.250	0.375
		30	XS	19.000	0.500
		40		18.812	0.594
		60		18.376	0.812
		80		17.938	1.031
		100		17.438	1.281
		120		17.000	1.500
		140		16.500	1.750
		160		16.062	1.969
22	22.000	10		21.500	0.250
		20	STD	21.250	0.375
		30	XS	21.000	0.500
		60		20.250	0.875
		80		19.750	1.125
		100		19.250	1.375
		120		18.750	1.625
		140		18.250	1.875
		160		17.750	2.125
24	24.000	10		23.500	0.250
		20	STD	23.250	0.375
		–	XS	23.000	0.500
		30		22.876	0.562
		40		22.624	0.688
		60		22.062	0.969
		80		21.562	1.219
		100		20.938	1.531
		120		20.376	1.812
		140		19.876	2.062
		160		19.312	2.344

Table 1A—Nominal Pipe Sizes, Schedules, and Dimensions of Stainless Steel Pipe

		NOMINAL WALL THICKNESS			
Pipe Size (NPS)	Actual O.D., Inches	SCH 5S	SCH 10S	SCH 40S	SCH 80S
$^1/_8$	0.405	–	0.049	0.068	0.096
$^1/_4$	0.540	–	0.065	0.088	0.119
$^3/_8$	0.675	–	0.065	0.091	0.126
$^1/_2$	0.840	0.065	0.083	0.109	0.147
$^3/_4$	1.050	0.065	0.083	0.113	0.154
1	1.315	0.065	0.109	0.133	0.179
$1^1/_4$	1.660	0.065	0.109	0.203	0.191
$1^1/_2$	1.900	0.065	0.109	0.516	0.200
2	2.375	0.065	0.109	0.226	0.218
$2^1/_2$	2.875	0.083	0.120	0.203	0.276
3	3.500	0.083	0.120	0.216	0.300
$3^1/_2$	4.000	0.083	0.120	0.226	0.318
4	4.500	0.083	0.120	0.237	0.337
5	5.563	0.109	0.134	0.258	0.375
6	6.625	0.109	0.134	0.280	0.432
8	8.625	0.109	0.148	0.322	0.500
10	10.750	0.134	0.165	0.365	0.500
12	12.750	0.156	0.180	0.375	0.500
14	14.00	0.156	0.188	–	–
16	16.00	0.165	0.188	–	–
18	18.00	0.165	0.188	–	–
20	20.00	0.188	0.218	–	–
22	22.00	0.188	0.218	–	–
24	24.00	0.218	0.250	–	–

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 Standards 599, 600, 602, 603, 608, or 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 may 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 Standards 594, 599, 600, 602, 603, 608, 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. Gate valves larger than 2 inches (51 mm) usually have port openings that are approximately the same size as the valve end openings,

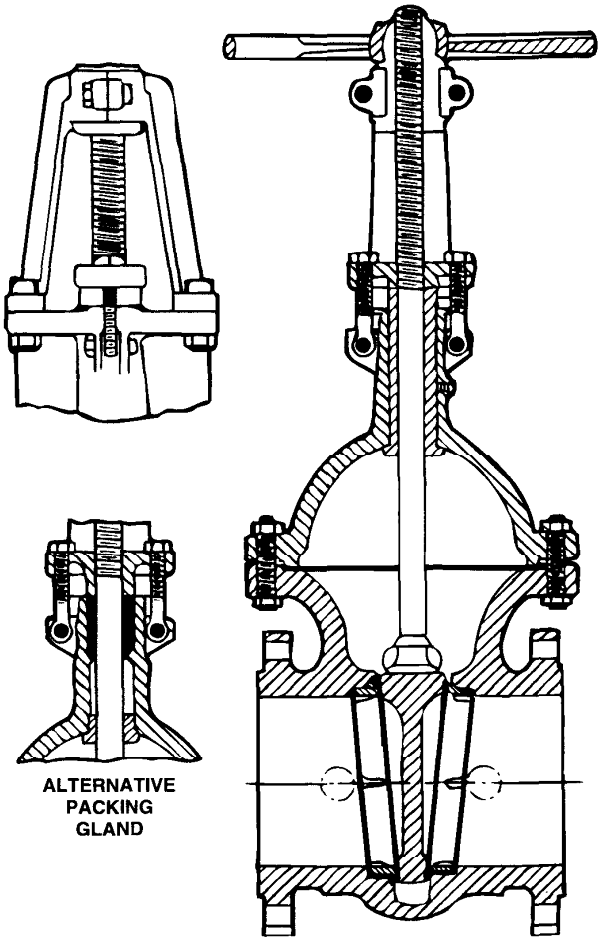


Figure 1—Cross Section of a Typical Wedge Gate Valve

which are called full-ported valves. Figure 1 shows a cross section of a full-ported wedge gate valve.

Reduced port gate valves 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 or in erosive applications, such as slurries, or lines that are to be "pigged."

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 may be flat or tapered. For fine-throttling service, a very steep tapered seat may 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.

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.

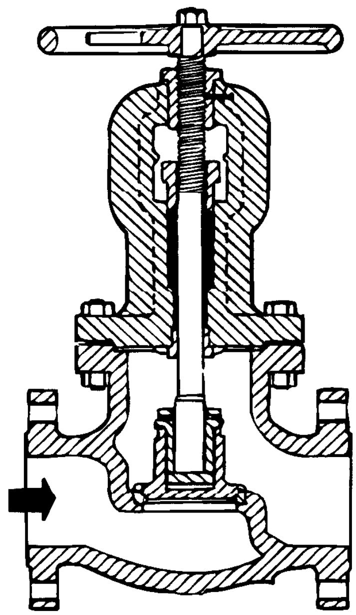


Figure 2—Cross Section of a Typical Globe Valve

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 may 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 metal seats, nonmetallic sleeves, complete or partial linings, or coatings as sealing elements.

4.3.5 Ball Valves

A ball valve is another one-quarter turn valve similar to a plug valve except 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.

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.

4.3.8 Check Valves

A check valve is used to automatically prevent back flow. 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 back flow.

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 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

Fittings are used to connect pipe sections and change the direction of flow, or allow the flow to be diverted or added to. Cast flanged fittings are made of various materials that meet primary ASME pressure class ratings. Fittings can be cast, forged, drawn from seamless or welded pipe, or formed and welded. Fittings may be obtained with their ends flanged,

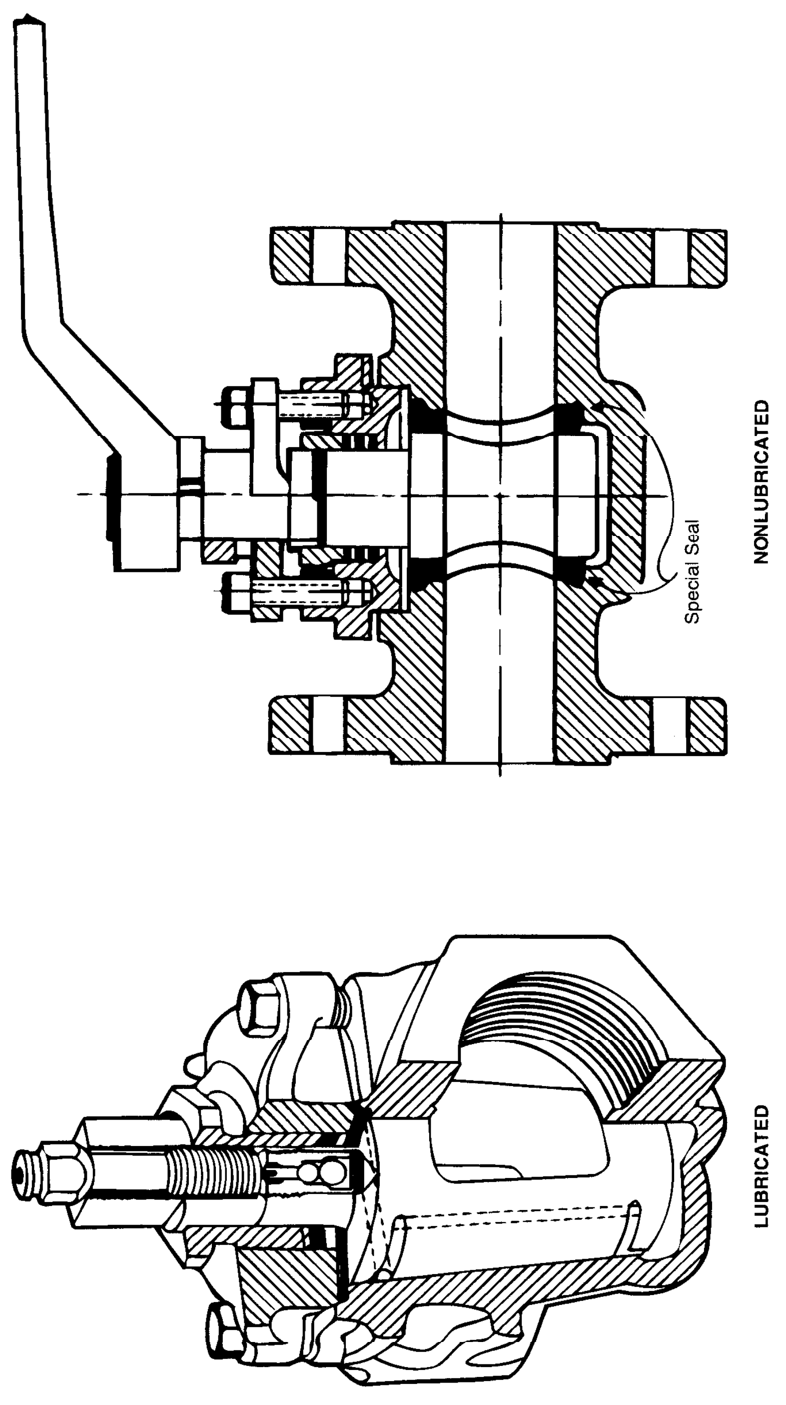


Figure 3—Cross Section of Typical Lubricated and Nonlubricated Plug Valves

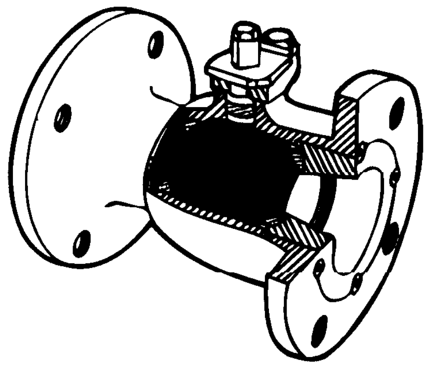


Figure 4—Cross Section of a Typical Ball Valve

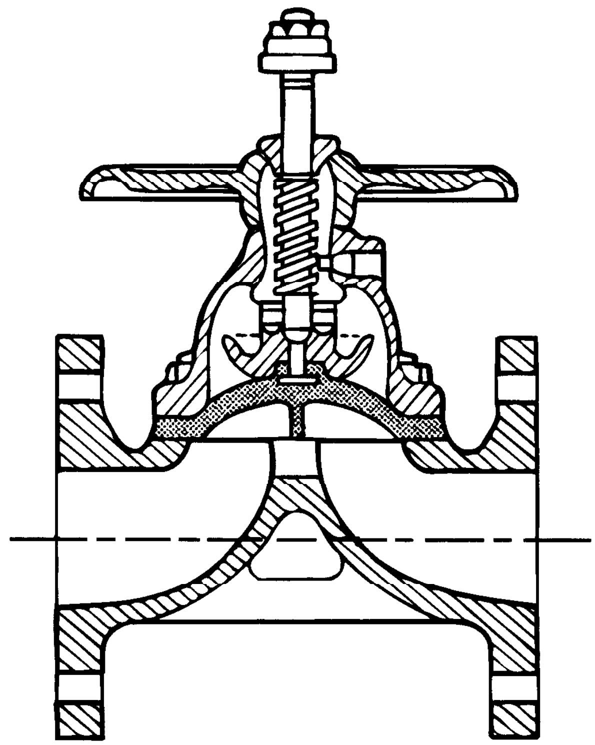


Figure 5—Cross Section of a Typical Diaphragm Valve

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.

4.5 PIPE-JOINING METHODS

4.5.1 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.

4.5.2 Threaded Joints

Threaded joints are generally limited to piping in noncritical service that has a nominal size of 2 inches (51 mm) or smaller. Threaded joints for nominal pipe sizes of 24 inches (610 mm) and smaller are standardized (see ASME B1.20.1).

Lengths of pipe may be joined by any of several types of threaded fittings (see Section 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 Section 4.5.4).

4.5.3 Welded Joints

4.5.3.1 General

Welded joints have generally replaced threaded and flanged joints except in small bore piping where some users still rely on threaded joints, and in cases where piping is connected to equipment requiring periodic maintenance. Joints are either butt-welded (in various sizes of pipe) or socket-welded (typically 2 NPS and smaller).

4.5.3.2 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 and aligned with adequate root opening in accordance with ASME B16.25, permitting the ends to be joined by fusion welding.

4.5.3.3 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. Space must 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.

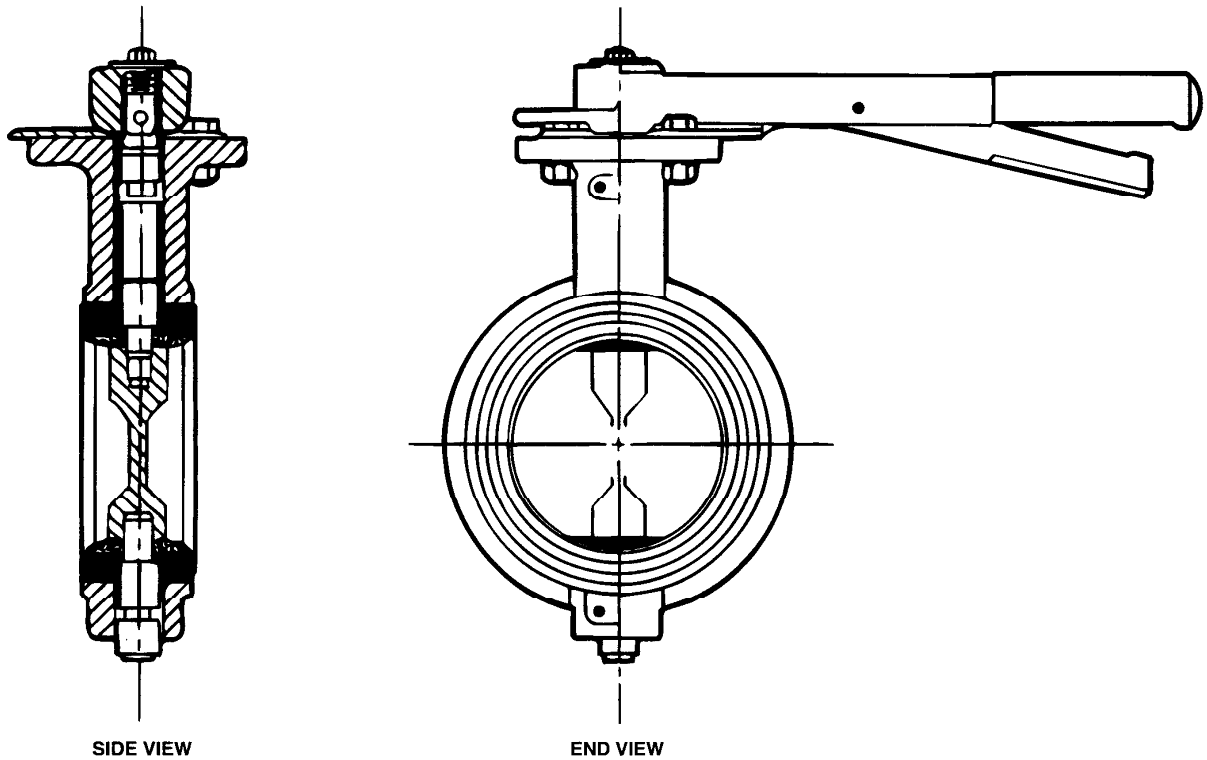


Figure 6—Typical Butterfly Valve

4.5.3.4 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 stresses that may cause fatigue cracking or other failures.

4.5.4 Flanged Joints

Flanged joints are made by bolting two flanges together with some form of gasket between the seating surfaces. The gasket surfaces may be flat and range from serrated (concentric or spiral) to smooth (depending on the type of gasket, gasket material, and service conditions), or grooves may be cut for seating metal-ring gaskets. 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. The flanges of cast fittings or valves are usually integral with the fitting or the valve body.

ASME B16.5 covers flanges of various materials through a nominal pipe size of 24 inches (610 mm). ASME B16.47 cover steel flanges that range from NPS 26 through NPS 60.

4.5.5 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. Threaded joints are seldom used for cast iron. 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 (Section 4.5.7). These types of joints are seldom used in process piping service.

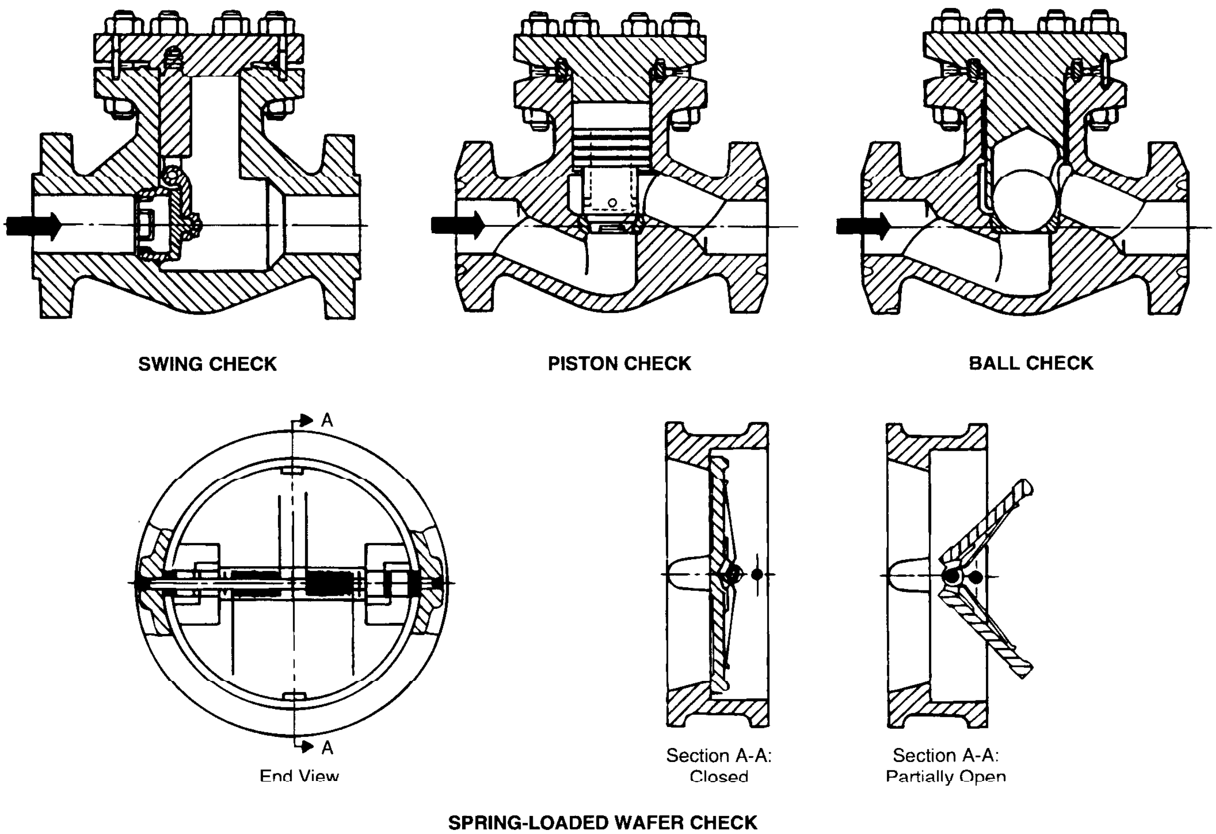


Figure 7—Cross Sections of Typical Check Valves

4.5.6 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.

4.5.7 Special Joints

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

a. Higher pressure, temperature ratings.

b. Smaller dimensions.

c. Ease of installation—axial and angular alignment requirements are less.

d. Tolerate greater forces and moments.

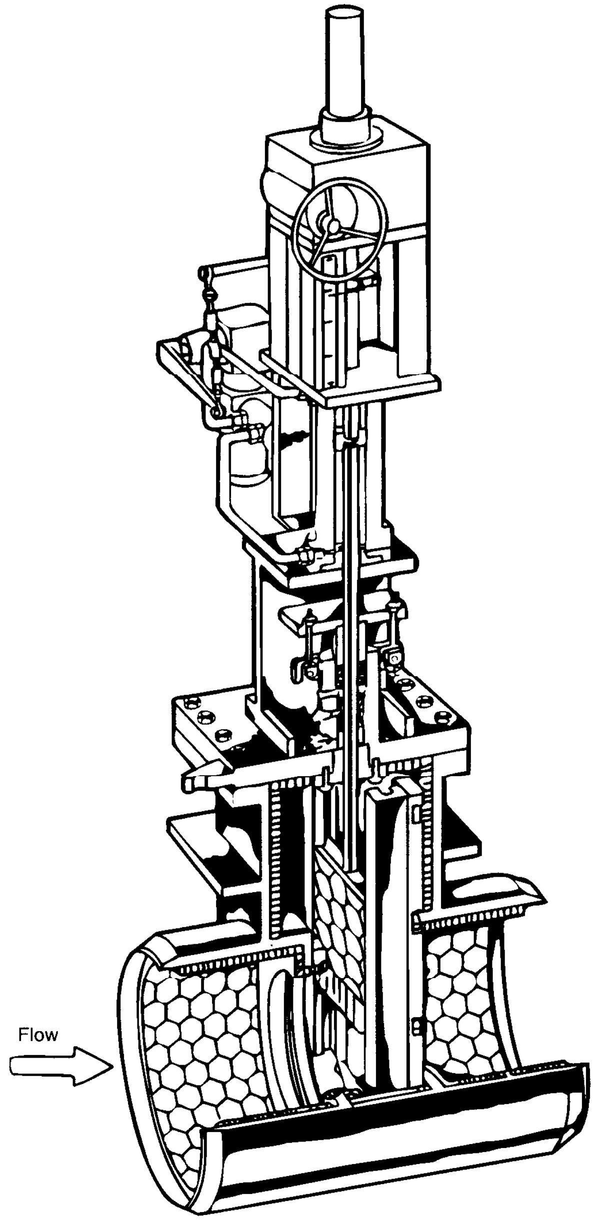


Figure 8—Cross Section of a Typical Slide Valve

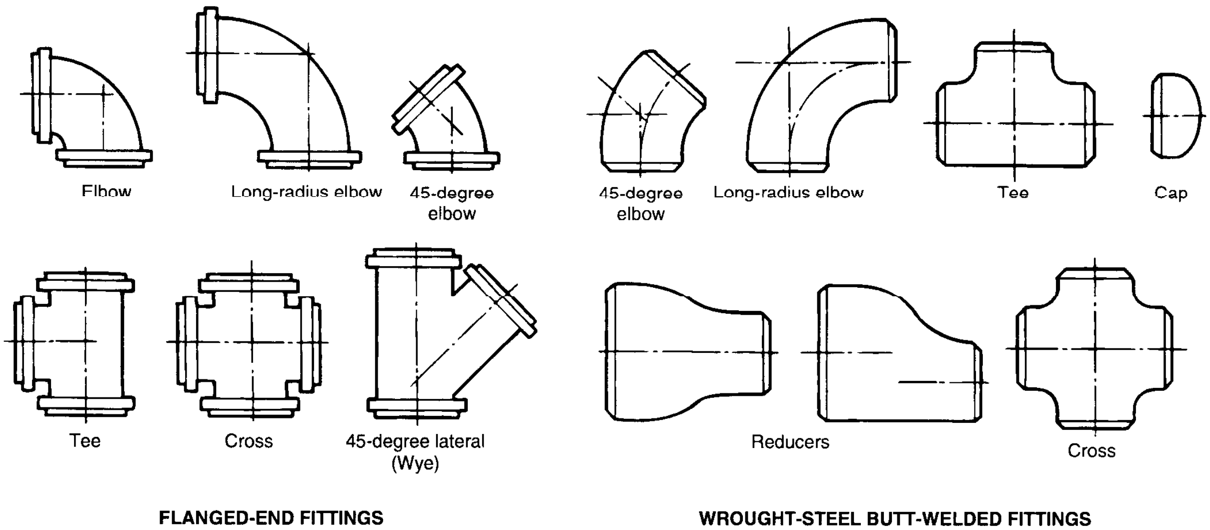


Figure 9—Flanged-End Fittings and Wrought Steel Butt-Welded Fittings

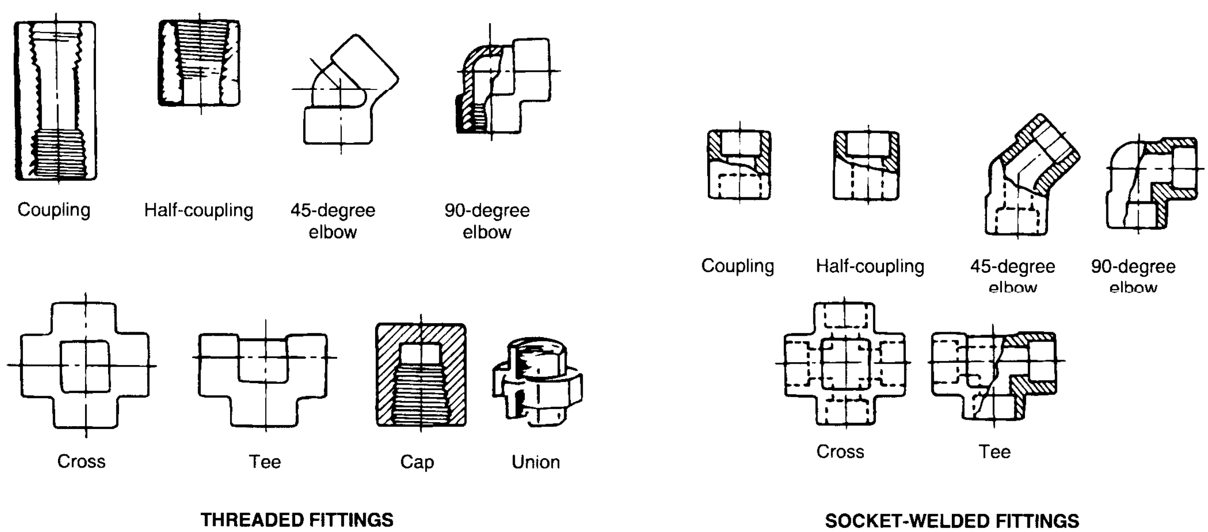


Figure 10—Forged Steel Threaded and Socket-Welded Fittings

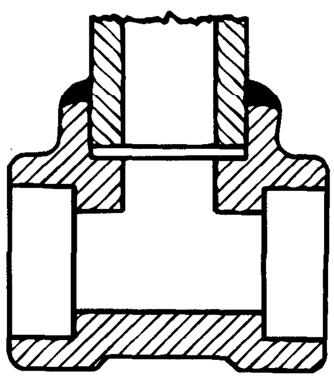


Figure 11—Cross Section of a Socket-Welded Tee Connection

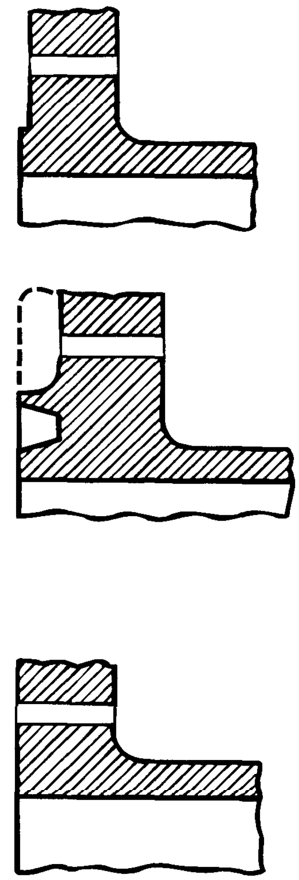


Figure 12—Flange Facings Commonly Used in Refinery Piping

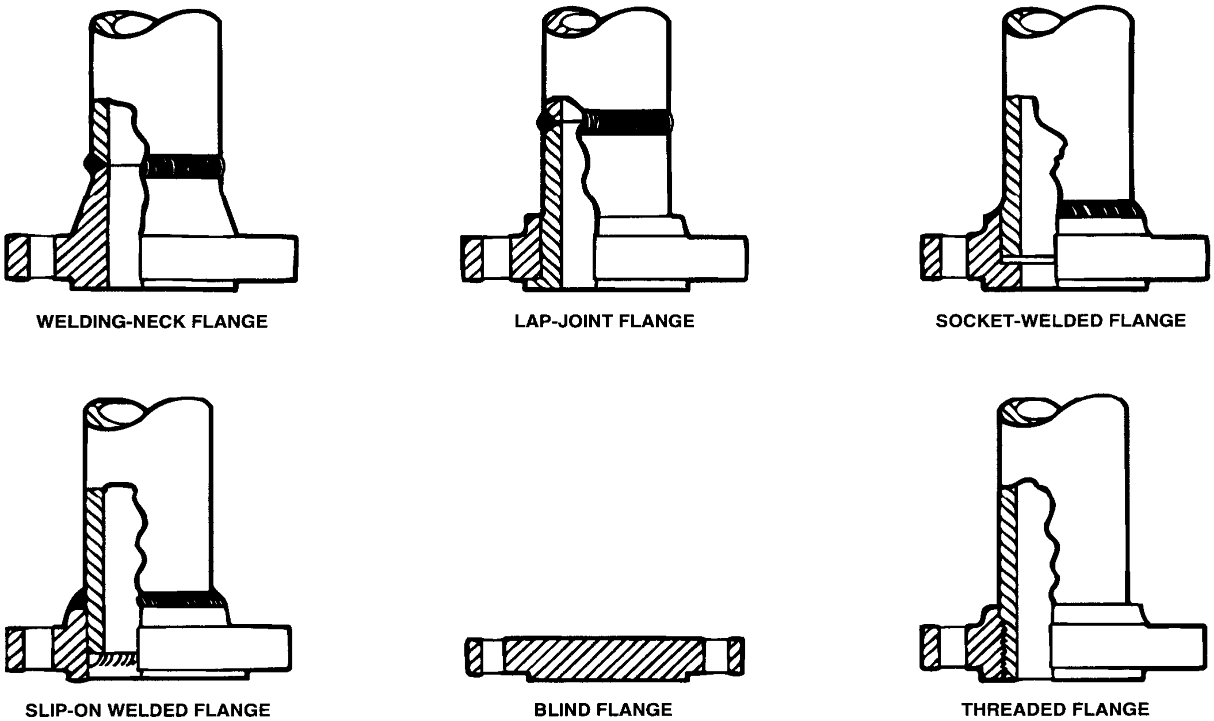


Figure 13—Types of Flanges

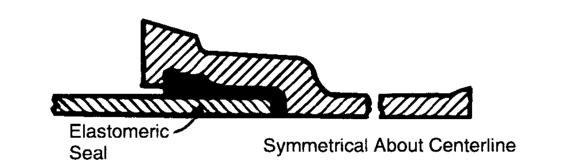


Figure 14—Cross Section of a Typical Bell-and-Plain-End Joint

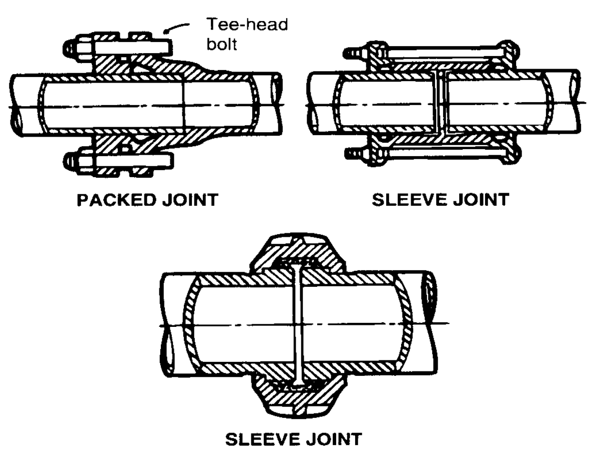


Figure 15—Cross Sections of Typical Packed and Sleeve Joints

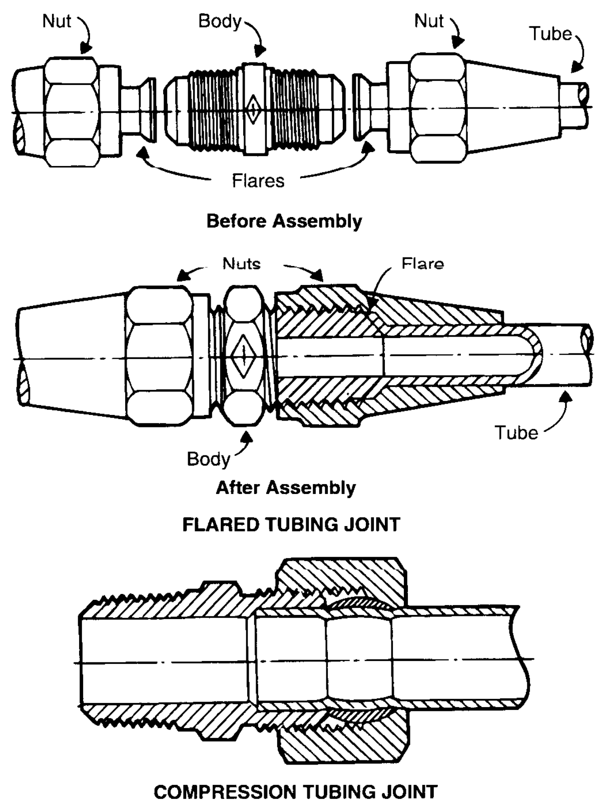


Figure 16—Cross Section of Typical Tubing Joints

5 Reasons For Inspection

5.1 GENERAL

The primary purpose of inspection is to perform activities using appropriate techniques to identify active deterioration mechanisms and to specify repair, replacement, or future inspections for affected piping. This requires developing information about the physical condition of the piping, the causes of its deterioration, and its rate of deterioration. By developing a database of inspection history, the user may predict and recommend future repairs and replacements. The user can then act to prevent or retard further deterioration and, most importantly, prevent loss of containment. This should result in increased operating safety, reduced maintenance costs, and more reliable and efficient operations. API 570, *Piping Inspection Code,* provides the basic requirements for such an inspection program. This recommended practice supplements API 570 by providing piping inspectors with information that can improve skill and increase basic knowledge and practices.

5.2 SAFETY

A leak or failure in a piping system may be only a minor inconvenience, or it may become a potential source of fire or explosion, depending on the temperature, pressure, contents, and location of the piping. Piping in a petrochemical plant may carry flammable fluids, acids, alkalis, and other harmful chemicals that would make leaks dangerous to personnel. Other piping may carry process streams that contain toxic by-products generated during processing. Leaks in these kinds of lines can create dangerous environmental conditions. Adequate inspection is a prerequisite for maintaining this type of piping in a safe, operable condition. In addition, federal regulations such as OSHA's 29 *CFR* 1910.119 mandates equipment, including piping, that carries significant quantities of hazardous chemicals be inspected according to accepted codes and standards, which includes API 570.

Leakage may occur at flanged joints in piping systems, especially in critical high temperature services, during startups or shutdowns, and sometimes after the equipment has reached operating temperature. Special attention should be given to assure plant personnel are aware of these hazards and be prepared to act in case leakage does occur.

5.3 RELIABILITY AND EFFICIENT OPERATION

Thorough inspection and analysis and the use of detailed historical records of piping systems are essential to the attainment of acceptable reliability, efficient operation, and optimum on-stream service. Piping replacement schedules can be developed to coincide with planned maintenance turnaround schedules through methodical forecasting of piping service life.

5.4 REGULATORY REQUIREMENTS

Regulatory requirements usually cover only those conditions that affect safety and environmental concerns. Inspection groups in the Petrochemical industry familiar with the industry's problems often inspect for other conditions that adversely affect plant operation.

API 570, was developed to provide an industry standard for the inspection of in-service process piping. It has been adopted by a number of regulatory and jurisdictional authorities. In addition, in some areas other requirements have been specified for the inspection of piping. Each plant should be familiar with the local requirements for process piping inspection.

6 Inspecting for Deterioration In Piping

6.1 GENERAL

Oil refinery and chemical plant piping carry fluids that range from highly corrosive or erosive, to noncorrosive or nonerosive. In addition, both aboveground and buried piping are subject to external corrosion. The inspector should be familiar with the potential causes of deterioration for each piping system. If an area of piping is observed to be deteriorating, 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. API IRE Chapter II, *Conditions Causing Deterioration or Failures*, has been developed to give the inspector added insights on various causes of deterioration. Figures 17, 18, 19, and 20 illustrate several examples of corrosion and erosion of piping.

6.2 CORROSION MONITORING OF PROCESS PIPING

The single most frequent reason for replacing piping is from thinning due to corrosion. For this reason an effective process piping inspection program will include monitoring piping thickness from which corrosion rates, next inspection dates, and projected piping retirement dates can be determined. A good monitoring program includes prioritizing the piping systems by identifying consequences and potentials of piping failures. API 570 provides a detailed guide for classifying piping according to consequences of failure.

The key to the effective monitoring of piping corrosion is identifying and establishing thickness-monitoring locations (TMLs). TMLs are designated areas in the piping system where thickness measurements are periodically taken. By taking repeated measurements and recording at the same points over extended periods, corrosion rates can more accurately be calculated.

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

a. Classifying the piping in accordance with API 570.
b. Categorizing the piping into circuits of similar corrosion behavior (e.g., localized, general, environmental cracking).
c. Identifying susceptible locations where accelerated corrosion is expected.
d. Accessibility of the TMLs for monitoring.

6.2.1 Piping Circuits

A number of factors may affect the rate and nature of pipe wall corrosion. They include, but are not limited to, the following items:

a. Piping metallurgy.
b. Piping contents.
c. Flow velocity.
d. Temperature.
e. Pressure.
f. Injection of water or chemicals.
g. Mixing of two or more streams.
h. Piping external conditions.
i. Stagnant flow areas, such as deadlegs.

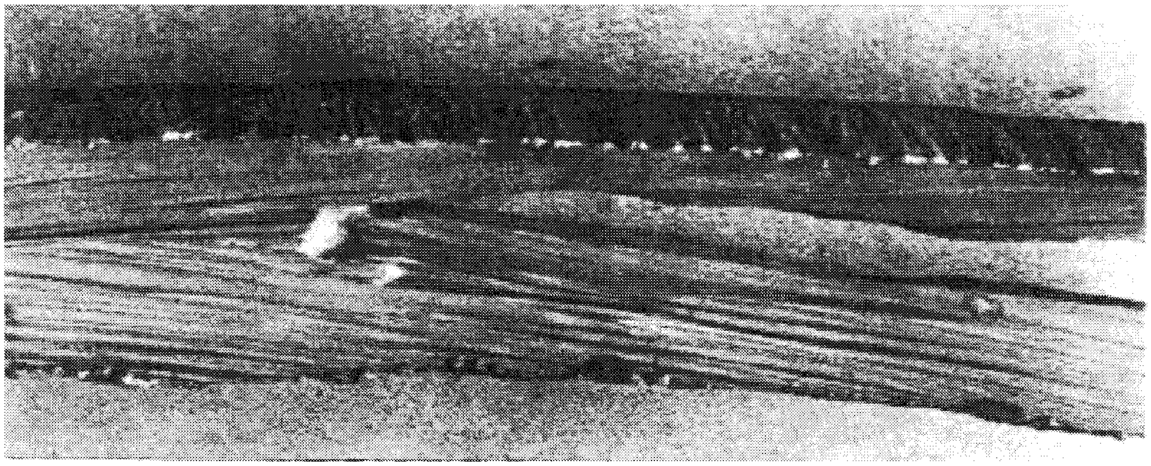


Figure 17—Erosion of Piping

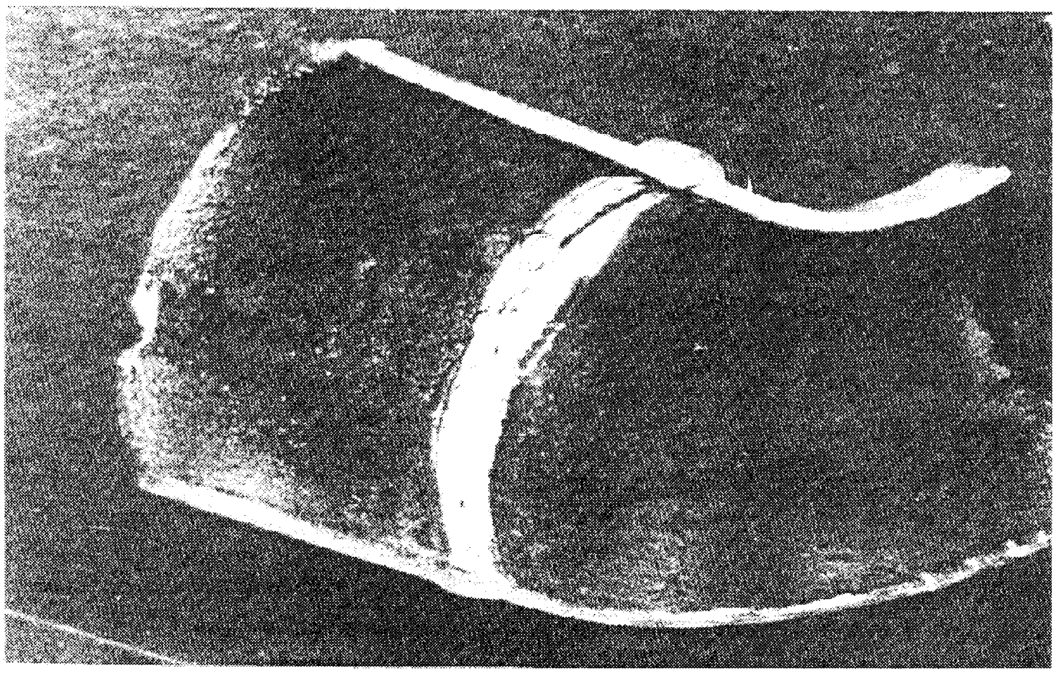


Figure 18—Corrosion of Piping

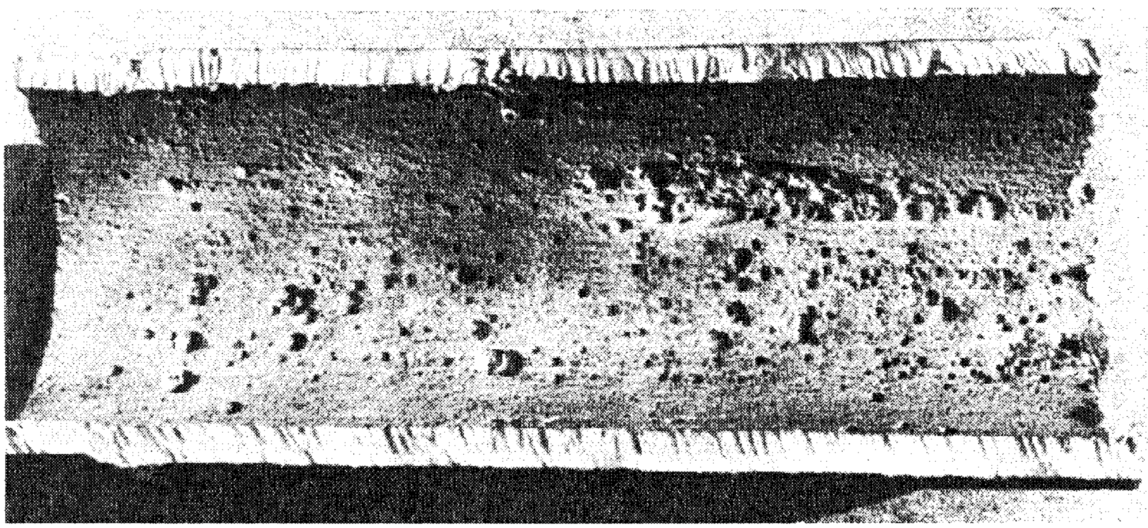


Figure 19—Internal Corrosion of Piping

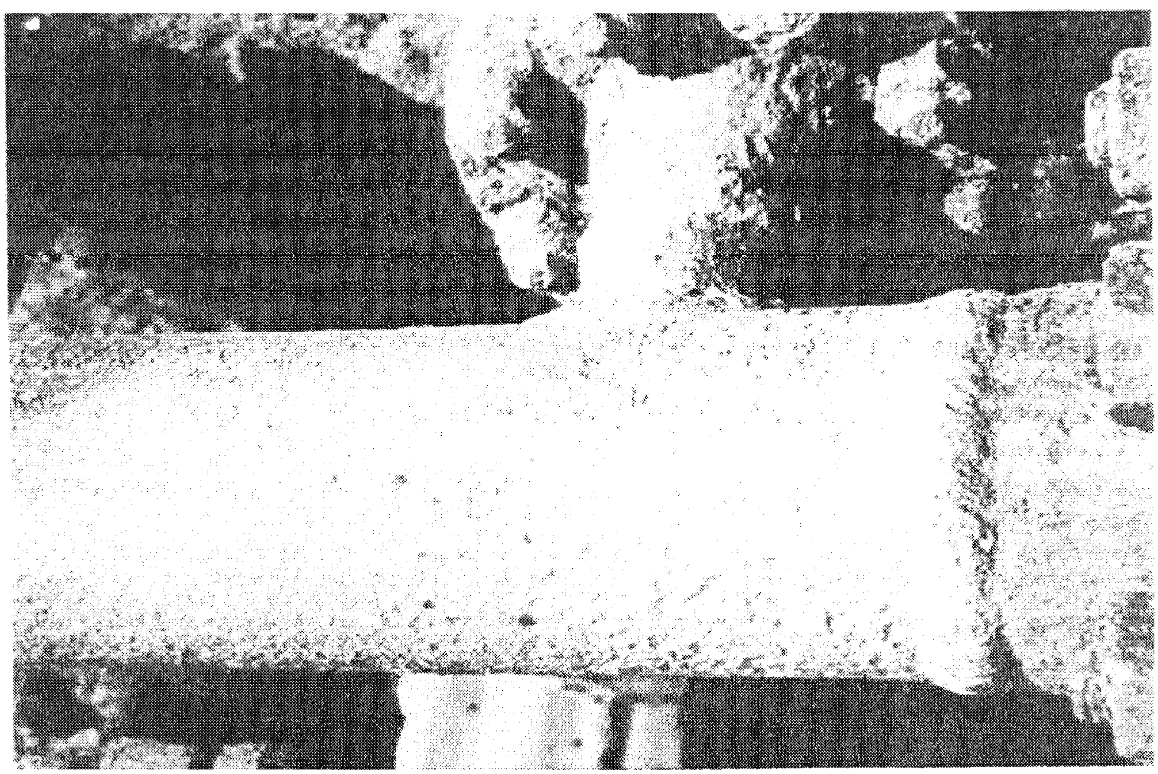


Figure 20—Severe Atmospheric Corrosion of Piping

Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and record keeping. A piping circuit is a section of piping of which all points are exposed to an environment of similar corrosivity and which is of similar design conditions and construction material. 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 as circuits, the spread of calculated corrosion rates of the TMLs in each circuit is reduced, and the accuracy of the calculated corrosion rate is improved. Proper selection of components in the piping circuit and the number of TMLs are particularly important when using statistical methods to assess corrosion rates and remaining life. Figure 21 is an example of one way to break piping up into circuits. For more information on piping sketches, see Section 12.2.

6.2.2 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 tees, control valves, and orifices are examples of piping components where accelerated corrosion may occur because of increased velocity and/or turbulence. Such components are normally areas where an inspector would locate additional TMLs in a piping circuit. However, the inspector should also be aware that areas of no flow, such as deadlegs (Section 6.3.2), may cause accelerated corrosion and may need additional TMLs.

6.2.3 Piping Classifications

According to API 570, Section 4.2, all process piping must be given a consequence of failure classification. The inspector reduces the uncertainty of the data obtained by assigning more TMLs to the lower classified piping and monitoring more frequently. This improves the ability to predict reliable retirement dates but also focuses limited inspection resources to areas that pose the greatest hazard. Factors to consider when classifying piping are (1) toxicity, (2) volatility, (3) combustibility, (4) location of the piping with respect to personnel and other equipment, and (5) experience and history.

6.2.4 Accessibility of the TMLs

When assigning TMLs, the inspector should consider accessibility for monitoring them. TMLs at grade level normally provide the easiest accessibility. Other areas with good accessibility are equipment platforms and ladders. There may be occasions where the inspector has no choice but to place TMLs in areas where accessibility is limited. In such cases the inspector needs to determine if scaffolding, portable manlifts, or other methods will provide adequate access.

6.3 INSPECTION FOR SPECIFIC TYPES OF CORROSION AND CRACKING[4]

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. Other areas of concern are noted in Section 10.1.

a. Injection points.
b. Deadlegs.
c. Corrosion under insulation (CUI).
d. Soil-to-air interfaces.
e. Service specific and localized corrosion.
f. Erosion and corrosion/erosion.
g. Environmental cracking.
h. Corrosion beneath linings and deposits.
i. Fatigue cracking.
j. Creep cracking.
k. Brittle fracture.
l. Freeze damage.
m. Corrosion at support points.
n. Dew point corrosion.

6.3.1 Injection Points

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

When designating an injection point circuit for the purposes of inspection, the recommended upstream limit of the injection point circuit is a minimum of 12 inches (305 mm) or three pipe diameters upstream of the injection point, whichever is greater. The recommended downstream limit of the injection point circuit is the second change in flow-direction past the injection point, or 25 feet (7.6 m) beyond the first change in flow direction, whichever is less. In some cases, it may be more appropriate to extend this circuit to the next piece of pressure equipment, as shown in Figure 22.

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

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

[4]For more thorough and complete information, see API IRE Chapter II.

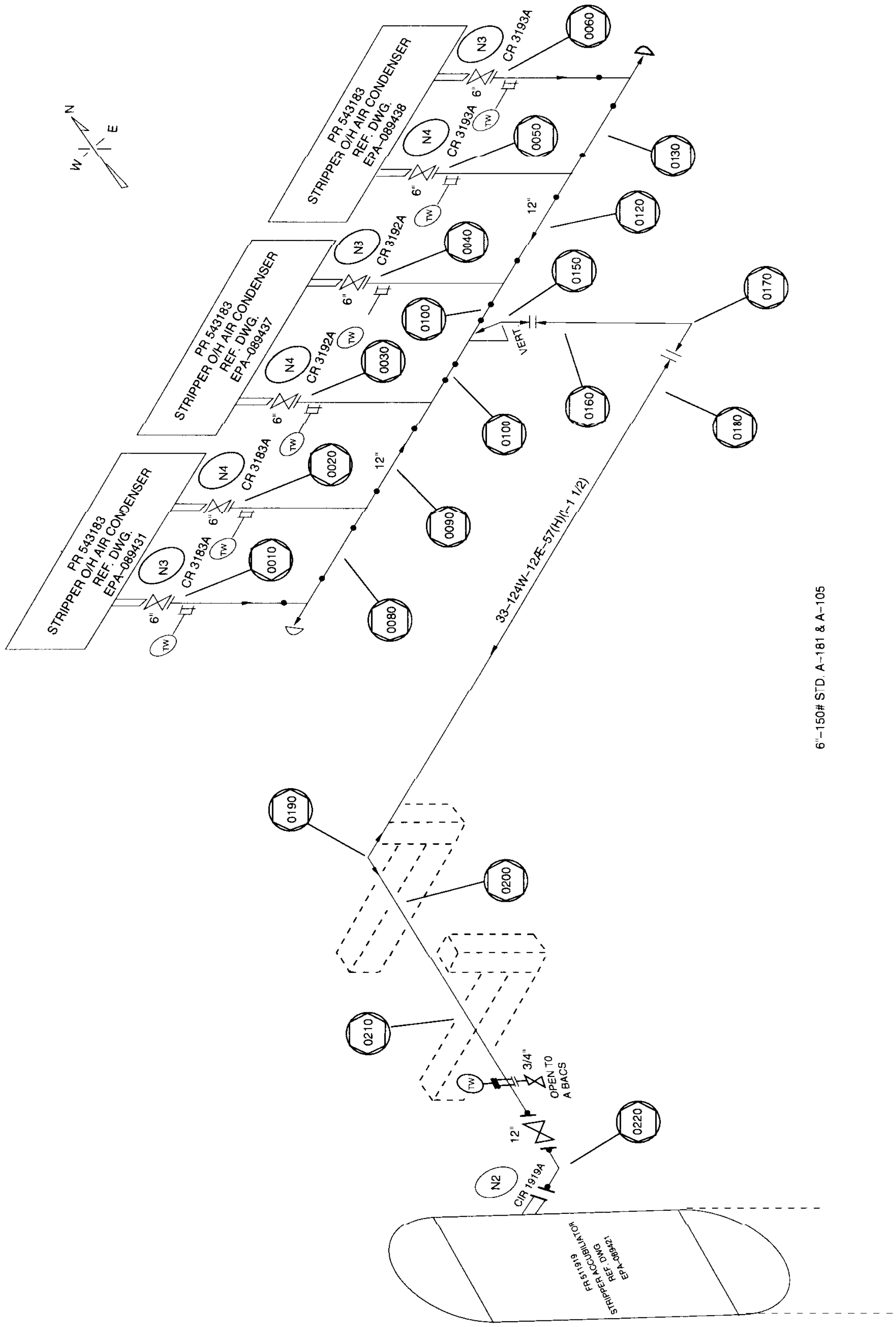


Figure 21—An Example of a Typical Piping Circuit

Note:Balloon Symbols Indicate Positions of Circuit TMLs.

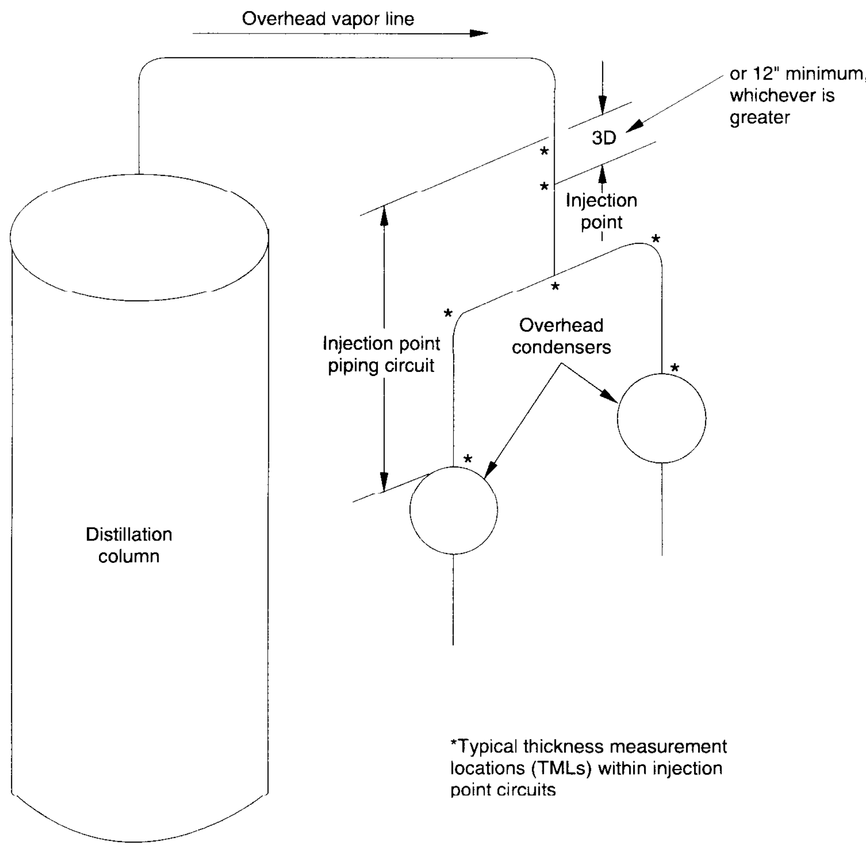


Figure 22—Typical Injection Point Piping Circuit

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

The preferred methods of inspecting injection points are radiography and/or ultrasonic, as appropriate to establish the minimum thickness at each TML. Close grid ultrasonic measurements or scanning may be used, as long as temperatures are appropriate. Other advanced NDE methods, such as Lamb wave ultrasonic and deep penetrating eddy currents, may be appropriate.

During periodic scheduled inspections, more extensive inspection should be applied to the injection point circuit in an area beginning 12 inches (305 mm) upstream of the injection nozzle and continuing for at least ten pipe diameters downstream of the injection point. Additionally, measure and record the thickness at all TMLs within the injection point circuit.

6.3.2 Deadlegs

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

6.3.3 Corrosion Under Insulation (CUI)

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 on-going CUI. Sources of moisture may include rain, water leaks, condensation, deluge systems, and cooling towers. The most common forms of CUI are localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels. This section provides guidelines for identifying potential CUI areas for inspection. The extent of a CUI inspection program may vary depending on the local climate. Marine locations in warmer areas may require a very active program, whereas cooler, drier, mid-continent locations may not need as extensive a program.

6.3.3.1 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 piping systems, including ones insulated for personnel protection, operating between 25°F (-4°C) and 250°F (121°C). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.
f. Carbon steel piping systems which normally operate in service above 250°F (121°C), but are in intermittent service.
g. Dead-legs and attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line.
h. Austenitic stainless steel piping systems operating between 150°F (65°C) and 400°F (204°C) (susceptible to chloride stress corrosion cracking).
i. Vibrating piping systems that have a tendency to inflict damage to insulation jacketing, providing a path for water ingress.
j. Steam traced piping systems that may experience tracing leaks, especially at tubing fittings beneath the insulation.
k. Piping systems with deteriorated insulation, coatings, and/or wrappings. Bulges or staining of the insulation or jacketing system or missing bands (bulges may indicate corrosion product build-up).
l. Piping systems susceptible to physical damage of the coating or insulation, thereby exposing the piping to the environment.

6.3.3.2 Typical Locations on Piping Circuits Susceptible to CUI

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

a. All penetrations or breaches in the insulation jacketing systems, such as:
  1. Deadlegs (vents, drains, etc.).
  2. Pipe hangers and other supports.
  3. Valves and fittings (irregular insulation surfaces).
  4. Bolt-on pipe shoes.
  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 which has hardened, separated, or is missing.
g. Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs.
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.

6.3.4 Soil-to-air (S/A) Interface

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 S/A interface or may be more pervasive to the buried system. Thickness readings at S/A interfaces may expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. Figure 23 is an example of corrosion at a soil-to-air interface although it had been wrapped with tape. If the buried piping has satisfactory cathodic protection as determined by monitoring in accordance with API 570 Section 7, excavation is required only if there is evidence of coating or wrapping damage. If the buried piping is uncoated at grade, consideration should be given to excavating 6–12 inches (152–305 mm) deep to assess the potential for hidden damage.

Figure 23—Soil/Air Interface Corrosion Resulting in Failure of Riser Pipe in Wet Soil

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 ten years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint.

6.3.5 Service Specific and Localized Corrosion

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. There are three elements to an effective inspection program which helps to identify the potential for these types of corrosion and to select appropriate TMLs:

1. The inspector, corrosion engineer and process engineer should have knowledge of the service and an idea of what types of corrosion are occurring and where they might be occurring.
2. Extensive use of NDE.
3. Communication from operating personnel when process changes and/or upsets occur that may affect corrosion rates.

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

a. Downstream of injection points and upstream of product separators, such as in hydroprocessor reactor effluent lines.
b. Dew point corrosion in condensing streams, such as overhead fractionation.
c. Unanticipated acid or caustic carryover from processes into nonalloyed piping systems or in the case of caustic, into nonpostweld heat treated steel piping systems.
d. Points at which condensation or boiling of acids (organic and inorganic) or water is likely to occur.
e. Points at which naphthenic or other organic acids may be present in the process stream.
f. Points at which high temperature hydrogen attack may occur.
g. Ammonium salt condensation locations in hydroprocess streams.

h. Mixed-phase flow and turbulent areas in acidic systems, also hydrogen grooving areas.

i. Points at which high-sulfur streams at moderate-to-high temperatures exist.

j. Mixed grades of carbon steel piping in hot corrosive oil service (450°F (232°C) or higher temperature and sulfur content in the oil greater than 0.5 percent by weight). Note that nonsilicon-killed steel pipe, e.g., A-53 and API 5L, may corrode at higher rates than does silicon-killed steel pipe, e.g., A-106, in high-temperature sulfidic 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. In services, which 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.

6.3.6 Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles, 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 may 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 (corrosion/erosion) results in significantly greater metal loss than can be expected from corrosion or erosion alone.

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

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

6.3.7 Environmental Cracking

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

a. Chloride stress corrosion cracking of austenitic stainless steels due to moisture and chlorides under insulation, under deposits, under gaskets, or in crevices.

b. Polythionic acid stress corrosion cracking of sensitized austenitic alloy steels due to exposure to sulfide/moisture condensation/oxygen.

c. Caustic stress corrosion cracking (sometimes known as caustic embrittlement).

d. Amine stress corrosion cracking in nonstress relieved piping systems.

e. Carbonate stress corrosion cracking 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 a problem for piping as it has been for pressure vessels. It is listed here because it is considered to be environmental cracking and may 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.

When the inspector suspects or is advised that specific circuits may be susceptible to environmental cracking, the inspector should schedule supplemental inspections. Such inspections can take the form of surface NDE (PT or WFMT), ultrasonic, or eddy current. Where available, suspect spools may be removed from the piping system and split open for internal surface examination.

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

6.3.8 Corrosion Beneath Linings and Deposits

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

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

Refractory linings used to insulate the pipe wall may spall or crack in service, causing hot spots that may 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. If bulging or separation of the refractory lining is detected, then portions of the refractory may be removed to permit inspection of the piping beneath the refractory. Otherwise, ultrasonic thickness measurements may be made from the external metal surface.

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

6.3.9 Fatigue Cracking

Fatigue cracking of piping systems may result from excessive cyclic stresses that are often well below the static yield strength of the material. The cyclic stresses may be imposed by pressure, mechanical, or thermal means and may result in low-cycle or high-cycle fatigue. The onset of low-cycle fatigue cracking is often directly related to the number of heat-up/cool-down cycles experienced. For example, trunions 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. Excessive piping system vibration (e.g., machine-or flow-induced) can also cause high-cycle fatigue damage. See API 570 Section 3.4.4 for vibrating piping surveillance requirements and Section 5.5 for design requirements associated with vibrating piping.

Fatigue cracking can typically be first detected at points of high stress intensification, such as branch connections. Locations where metals having different coefficients of thermal expansion are joined by welding may be susceptible to thermal fatigue. Preferred NDE methods of detecting fatigue cracking include liquid penetrant testing, magnetic particle testing, and angle beam ultrasonic testing. See API 570 Section 4.6.3 for fatigue considerations relative to threaded connections. Acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

It is important 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, design and installation to prevent fatigue cracking are important.

6.3.10 Creep Cracking

Creep is dependent on time, temperature, and stress. Creep cracking may eventually occur at design conditions, since some piping code allowable stresses are in the creep range. Cracking is accelerated by creep/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 also may take place, which may 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 liquid penetrant, magnetic particle, ultrasonic, radiography, and in-situ metallography. Acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

6.3.11 Brittle Fracture

Carbon, low-alloy, and other ferritic steels may be susceptible to brittle failure at or below ambient temperatures. In some cases, the refrigerating effect of vaporizing liquids such as ammonia or C2 or C3 hydrocarbons may 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 (that is, the first hydrotest or overload) unless critical defects are introduced in service. Special attention should be given to low-alloy steels (especially $2^1/_4$ Cr-1 Mo material), because they may be prone to temper embrittlement, and to ferritic stainless steels.

Information on the prevention of brittle fracture in pressure vessels, API Publication 920, may be useful in assessing brittle fracture potential in piping systems.

6.3.12 Freeze Damage

At subfreezing temperatures, water and aqueous solutions handled in piping systems may 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 may be temporarily prevented by the frozen fluid. Low points, drip legs, and deadlegs 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 Frequency and Time of Inspection

7.1 GENERAL

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

a. The consequence of a failure (piping classification).

b. The degree of risk (likelihood and consequence of a failure).

c. The amount of corrosion allowance remaining.

d. The historical data available.

e. Regulatory requirements.

API 570 requires classifying piping systems according to the consequences of failure. Each refinery or process plant should review their own piping systems and develop a classification system using the information provided in API 570. This system helps to establish minimum inspection frequencies for each piping classification.

Some inspections can and should be made while the equipment is operating. Inspections that cannot be made during operation must be made while the equipment is not in service.

7.2 INSPECTION WHILE EQUIPMENT IS OPERATING

An effective, integrated program of piping inspection will include obtaining as many of the required wall-thickness measurements as possible (maintaining the required accuracy) while a plant is on stream. Both ambient- and high-temperature ultrasonic thickness measurements may be taken. On most piping, wall-thickness radiographs can be taken independently through undisturbed insulation. Radiographs can also be used to identify corroded areas where ultrasonic thickness monitoring should be established and locate areas where deposits have accumulated during operation.

Historical records of piping should be studied to determine which sections will be approaching retirement thickness at the next planned shutdown. Historical records can also be used to determine inspection locations and to establish a replacement schedule.

On-stream inspection can reduce downtime by the following means:

a. Extending process runs by assuring piping conditions are suitable for continued operation.

b. Permitting fabrication of replacement piping before a shutdown.

c. Eliminating unnecessary work and reducing shutdown personnel requirements; for example, personnel who are otherwise used to remove insulation and break flanges for inspection during the turnaround can be made available for other work.

d. Aiding maintenance planning to reduce surges in work load, thus stabilizing personnel requirements.

Obviously, many other conditions in piping systems should be determined while the equipment is operating. Leaks in piping systems are most easily detected while the equipment is operating and should be pursued continuously. Whenever a leak occurs, operators should notify an inspector who can determine its seriousness and recommend the proper corrective action.

Pipe supports may be inspected for distortion and damage, settlement or movement of the foundation, and the condition of foundation bolts. Pipe anchors may be inspected to determine their condition and adequacy. Piping should be inspected for swaying or vibration. Pipe rollers and slide plates should be inspected to ensure that they operate freely.

Piping, supports, and spring hangers should be inspected for external corrosion, the condition of protective coatings and insulation, and correct location or position. In addition, an inspection should be made for liquid spills that can cause corrosion of piping.

7.3 INSPECTION WHILE EQUIPMENT IS SHUT DOWN

Inspections that cannot be made while the equipment is operating must be made when the system is shut down. In addition, when piping is opened for any reason, it should be inspected internally as far as accessibility permits. 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 Safety Precautions and Preparatory Work

8.1 SAFETY PRECAUTIONS

Procedures for the segregation of piping, installation of blinds, and leak testing should be an integral part of safety practices. Safety precautions must be taken before any piping is opened and before some types of external inspection are performed. In general, the section of piping to be opened should be isolated from all sources of harmful liquids, gases, or vapors, and purged to remove all oil and toxic or flammable gases and vapors. Precautions should be taken before hammer testing, which might cause failure or allow the contents of the piping to be released. See API Publication 2217A.

8.2 PREPARATORY WORK

All possible preparatory work should be done before the scheduled start of inspection. Scaffolds should be erected where required, and buried piping should be excavated at the points to be inspected. The tools needed for inspection should be checked for availability, proper working condition, and accuracy. 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.

9 Inspection Tools

See Table 2 for a list of tools commonly used to inspect piping.

Generally, contract inspection teams are available to perform the NDE work.

Table 2—Tools for Inspection of Piping

Ultrasonic equipment	Borescope
Radiographic Equipment	Magnet
Portable lights, including flashlight	Wire Brush
Thin-bladed knife	Small mirror
Scraper	Magnetic-particle equipment
Inspector's hammer	Liquid-penetrant equipment
ID and OD transfer calipers	Paint or crayon
Direct-reading calipers with specially shaped legs	Notebook or sketches
Steel rule	Portable hardness tester
Thickness or hook gauge	Material identification kit
Pit-depth gauge	Leak detector (sonic, gas test, or soap solution)
Magnifying glass	Infrared pyrometer and camera
Eddy-current equipment	Nuclear source-alloy analyzer (for material identification)
Remote television camera (for internal inspection)	

In addition to the tools listed in Table 2, sandblasting equipment may be required to remove paint or other protective coatings, dirt, or products of corrosion so that an inspection for cracks can be performed

10 Inspection Procedures

10.1 INSPECTION WHILE EQUIPMENT IS OPERATING

10.1.1 Visual Inspection

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. When corrosion product buildup is noted at pipe support contact areas, the inspector may choose to lift the piping off the support to facilitate inspection. If this is done, care should be exercised if the piping is in service because external corrosion products are easily dislodged, which could result in possible leaks.

10.1.1.1 Leaks

Leaks can be safety or fire hazards, they can cause the premature shutdown of equipment, and they 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 may 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, and 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 extra care is taken to avoid three potential problems:

1. Bolt interactions—when a bolt is tightened the adjacent bolts are loosened.
2. A bolt can yield or fail due to over loading.
3. 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.

10.1.1.2 Misalignment

Piping should be inspected for misalignment, which may 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.
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 pump or turbine casings 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.

10.1.1.3 Supports

Pipe supports consist of shoes, hangers (chains, rods, or variable or constant support springs), and braces. Supports should be visually inspected for the following problems:

a. Deterioration of protective coatings or fireproofing.
b. Evidence of corrosion, especially at or near the foundation attachments.
c. Distortion.
d. General physical damage.
e. Movement or deterioration of concrete footings.
f. Failure or loosening of foundation bolts.
g. Insecure attachment of brackets and beams to the support.
h. Restricted operation of pipe rollers or slide plates.
i. Insecure attachment or improper adjustment of pipe hangers, if used. 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 may cause excessive pipe loads on rotating equipment that may result in misalignment. Other factors, such as differential settlement and creep, can make alternate settings necessary.
j. Broken or defective pipe anchors.
k. Restricted operation of pulleys or pivot points in counterbalanced piping systems.

If fireproofing is found defective, enough should be removed to determine the cause and extent of corrosion. If corrosion is noted, thickness measurements should be taken to determine whether the remaining metal can sufficiently support the load.

If deterioration of concrete footings is found, the cause should be determined and corrective action should be taken.

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 will 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 may indicate that the foundation bolts are sheared.

Inspection should also include a search for small branch connections that are against pipe supports as a result of thermal movement of the larger line. In addition, hydraulic shock will often cause a small branch line to be damaged if it is located too near a support.

10.1.1.4 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 which 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.

10.1.1.5 External Corrosion

Defects in protective coatings and in 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 may 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.

10.1.1.6 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. Affected soil should be handled in accordance with applicable laws and regulations.

10.1.1.7 Hot Spots

Operating piping at temperatures higher than the design limit or in the creep range, even without higher pressure, may cause 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 may 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 must 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 qualified piping engineers). The condition of both the pipe metal and the internal insulation near hot spots should be investigated during the next shutdown period.

10.1.2 Thickness Measurements

10.1.2.1 Ultrasonic Inspection

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. Portability—Most instruments weigh no more than several pounds and are small enough that they are not cumbersome.

b. Low cost—Compared to many other instruments, digital meters are economical to purchase and maintain.

c. Minimum training requirements—Instrument is relatively simple to operate and consequently requires short training time to use effectively.

However, as with all NDE tools, ultrasonics do have limitations. Transducers that are not equipped with delay-line material can be damaged by temperatures above manufacturer's specification. The maximum permissible temperature depends on transducer design, contact time, and delay line (if any). Some transducers can be used for short time measurements at temperatures up to 1000° F (538° C) without any delay lines. 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).

UT is capable of evaluating only a small area approximately the diameter of the transducer. Consequently, UT may miss small, localized corrosion unless the inspector performs significant scanning in the area of interest.

The measurements obtained with pulse-echo instruments are average thicknesses of the area in contact with the transducer. Any pits in the measured area can affect the average thickness reading. Dual transducers, available for use with these instruments, will permit detection of pits as small as $^1/_8$ inch (3 mm) in diameter when the transducer is positioned directly over the pit on the opposite side of the wall. Caution should be used with meters without the "A" scan display (presentation of the actual signal). On highly corroded and pitted surfaces, digital display meters may not obtain consistent or accurate readings. The search unit can be moved slightly (one diameter or less) and a reading obtained. This is attributed to the sound beam being reflected away from the transducer. An instrument with an "A" scan display will also indicate thicknesses at pits, especially if high frequencies are used with tuned sensitivity. Readings at areas with surface temperatures above 200°F (93°C) are normally higher than actual thicknesses and may vary from approximately 1 percent higher at 300°F (149°C) to 5 percent higher at 700°F (371°C). Thickness correction tables or data base correction factors for temperatures greater than 200°F (93°C) should be established for the transducer by comparing thickness readings from unheated and heated pipe samples. With most ultrasonic instruments, the inspector needs to assure a reasonably scale-free surface by scraping or buffing off the scale.

Pulse-echo instruments are used with specially designed transducer wedges to generate shear waves for detecting and tracing cracks and other flaws. Special training is required for personnel to perform flaw detection.

Several advanced ultrasonic testing technologies are available for not only detecting flaws but also for measuring the distance of cracking from external surfaces. Time-of-flight diffraction and bimodal UT are two such methods available for this work.

10.1.2.2 Radiographic Inspection

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 more easily 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, which 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 may also be visible on the film.

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

Iridium and cobalt have become the most frequently used isotopes for radiographic inspection. The use of iridium 192 and cobalt 60 is controlled by the U.S. Nuclear Regulatory Commission (USNRC), the Canadian Atomic Energy Commission, and some states and localities. Personnel who handle radioactive sources must be trained and qualified, proper procedures must be followed, and the safety of personnel must be considered.

Radiographic thickness measurement accuracy relies somewhat on the abilities of the radiographic technician exposing the films and the person reviewing them. When using radiography 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 ultrasonic thickness measurements to determine the limits of accuracy of the radiographic method 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 expansion 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 may also be affected. Unit operators must be warned of this possibility.

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

Radiographs of piping are shown in Figures 24, 25, and 26.

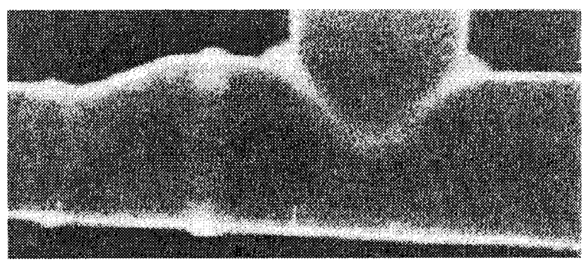


Figure 24—Radiograph of a Catalytic Reformer Line

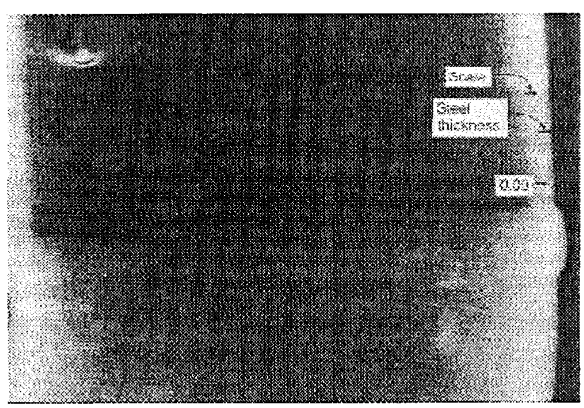


Figure 25—Radiograph of Corroded Pipe Whose Internal Surface is Coated With Iron Sulfide Scale

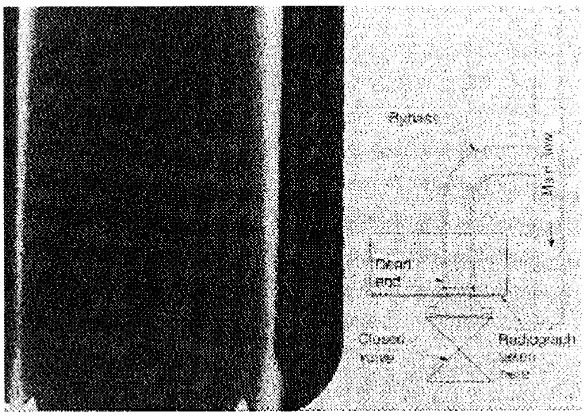


Figure 26—Sketch and Radiograph of Dead-End Corrosion

10.1.3 Other On-stream Inspections

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 ultrasonic, magnetic induction, real time radiography, neutron radiography, neutron backscatter, thermography, etc. Each method has its advantages and disadvantages for each application. The inspector should be aware of these methods and their applicability. Visual inspection at TMLs will typically not provide a representative evaluation of CUI conditions at other locations along the pipe.

10.2 INSPECTION WHILE EQUIPMENT IS SHUT DOWN

10.2.1 Visual Inspection

10.2.1.1 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 boroscope 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 a radiographic examination 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.

10.2.1.2 Cracks

The locations most susceptible to cracking are welds, including fillet welds at other than pressure welds, heat-affected areas adjoining welds, and points of restraint or excessive strain. Locations that are subject to stress-corrosion cracking, hydrogen attack, and caustic or amine embrittlement also require attention, as do exposed threads of threaded joints.

The inspected surface must 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 wet fluorescent magnetic-particle, magnetic-particle, liquid-penetrant, or ultrasonic testing 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. Magnetic-particle inspection can be used on magnetic materials. Liquid-penetrant, fluorescent, and ultrasonic inspection can be used on both nonmagnetic and magnetic materials. Only liquid penetrants with low or no chlorides should be used for austenitic materials. When magnetic-particle, liquid-penetrant, or fluorescent detection methods can not be used to detect interior surface stress corrosion or caustic embrittlement cracking, other methods such as radiography, shear- or surface-wave ultrasonics, eddy-current, or sample removal for microscopic inspection may be used. The depth of a crack can often be determined 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.

10.2.1.3 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.

10.2.1.4 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 acid, slurry, or fluidized catalyst services, valves may need to be dismantled and inspected at specified intervals to assure internal parts are of sufficient integrity to provide reliable and safe operation.

Whenever valves are removed from service and will be returned to service or refurbished for reuse, they should be inspected and tested to the requirements of API Standard 598, *Valve Inspection and Testing*. When a valve is disassembled for inspection, normally the bonnet gasket should be replaced as a minimum. 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 as necessary to the same condition as new valves.

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 serious deterioration may have occurred because of turbulence. 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 that might cause failure. 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 or the wedge may not operate properly.

Quarter-turn valves should be inspected for ease of operation and the ability to open and close completely. All seating surfaces should also be inspected.

10.2.1.5 Joints

Methods of inspection for specific types of joints are discussed in Sections 10.2.1.5.1 through 10.2.1.5.4.

10.2.1.5.1 Flanged Joints

When flanged joints are opened, they should be visually inspected for cracks and metal loss caused by corrosion and erosion. (See 10.3.1.2 for methods of inspection for cracks. Inspection of gasket faces is covered in Section 10.3.1.3.)

Flange bolts should be inspected for stretching and corrosion. Where excessive bolt loading is indicated or where flanges are deformed, a nut may 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. Verification of the proper gasket material, type, and size is important. If flanges are bolted too tightly, they may bend until the outer edges of the flanges are in contact. When this occurs, the pressure on the gasket may be insufficient to ensure a tight joint. Visual inspection of the gasket will reveal this condition. Permanently deformed flanges should be replaced or refaced.

10.2.1.5.2 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 postweld heat treatment. 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 may 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.

10.2.1.5.3 Threaded Joints

Threaded joints may 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. An undetected crack in a thread root might fail and cause a release of product with serious consequences.

10.2.1.5.4 Clamped Joints

A clamped joint that depends on machined surfaces for tightness may 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 may 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.

CAUTION: Certain kinds of clamped joints must 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.

10.2.1.6 Misalignment

Often, misalignment is not apparent until the piping has cooled and has moved to its cold position. The inspector should note (as in Section 10.1.1.2) 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.

10.2.1.7 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 Section 10.1.1.4 should be followed. This inspection should be supplemented by NDE methods as applicable. The conditions causing excessive vibration or swaying should be corrected.

10.2.1.8 Hot Spots

Where hot spots on internally insulated piping were noted during operation (see Section 10.1.1.9), the internal insulation should be visually inspected for bypassing or complete failure. 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 outside diameter 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.

10.2.2 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.

The exterior of piping that could not be examined during operation should be inspected for corrosion at the locations and using the methods described in Section 10.1.1.5.

Special attention should be given to small connections such as nipples. Radiography has successfully been used to determine nipple thickness. Hammer testing nipples is common practice. Care should be taken not to hammer hard enough to cause cracking at the root of the threads or the toe of the weld.

10.2.3 Pressure Tests

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 subject 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.

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. For service testing of category D piping systems, ASME B31.3 limits the gage pressure to 150 psi (1034.2 kPa).

API 570, Section 3.7, on pressure testing provides guidelines for preparing piping for pressure testing.

During liquid pressure testing, all air must 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 not to overpressure the 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 may 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 may be kept small. In either case, if overpressuring can occur, a relief device should be installed to protect the system.

Various fluids may 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 items c and d. If a leak or failure occurs, any 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.

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 stress corrosion cracking 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. 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 done 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 any condensate may be necessary before operations are started. When high-pressure steam is used, leaks are difficult to detect and may 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; that is, the fluid must 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 must 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 may 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.

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.

10.2.4 Hammer Testing

Hammer testing is a test method in which piping is struck with a hammer in order to make it ring. The type of ring can be used by an experienced inspector to differentiate thin metal. Hammer testing of piping, valves, and fittings is an older inspection method (almost a lost art) that is not used as frequently today as it once was. Normally, it is used to detect the presence of unexpected thin sections. (The exceptions to this method are cast iron and stress-relieved lines in caustic and corrosive service; these should never be hammered.) Hammer tests should be followed up with other inspection methods, such as ultrasonic thickness measurements or profile radiography. Care should be taken not to hammer hard enough to damage otherwise sound piping. For this reason, only inspectors who are experienced in hammer testing should use this method. It should not be performed on copper tubing, aluminum, or brass piping, or other piping made from soft materials. Glass, cement, or other internally coated lines should not be hammer tested. Hammer testing should also not be used on equipment that is under pressure. Hammer testing on some alloys can cause stress corrosion cracking; therefore, this inspection method should be employed with care and sound judgment and only at permitted locations. A typical hammer for hammer testing would be a 16 oz. ball peen.

10.2.5 Inspection of Piping Welds

API 570, Section 3.10, provides a detailed discussion of inspection of in-service piping welds. The inspector should be familiar with the material contained in that section.

10.3 INSPECTION OF UNDERGROUND PIPING

Inspection of buried process piping (not regulated by the Department of Transportation) is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions. Figure 27 illustrates external corrosion occurring to underground piping despite the use of tape wrap. Important references for underground piping inspection include the following NACE documents: RP0169, RP0274, and RP0275, and Section 7 of API 570.

10.3.1 Types and Methods of Inspection and Testing

10.3.1.1 Above-Grade Visual Surveillance

Indications of leaks in buried piping may 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.

10.3.1.2 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 feet, 5 feet, 10 feet, or 20 feet (0.8, 1.5, 3, or 6 meters). 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 Figures 28 and 29.

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.

10.3.1.3 Holiday Pipe Coating Survey

The holiday pipe coating survey can be used to locate 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.

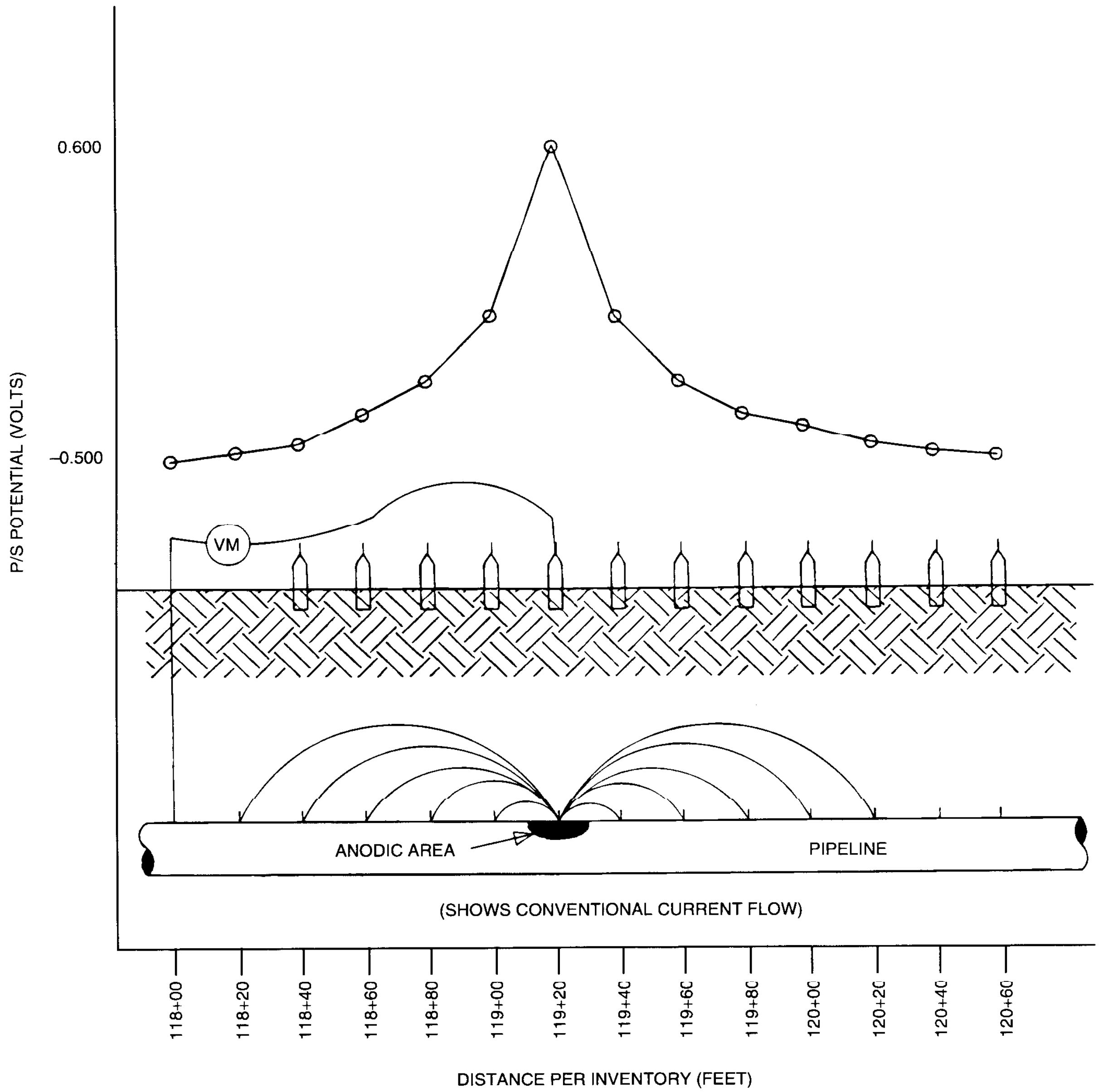
The frequency of pipe coating holiday surveys is usually based on indications that other forms of corrosion control are ineffective. For example, on a coated pipe where there is gradual loss of cathodic protection potentials, or when an external corrosion leak occurs at a coating defect, a pipe coating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

10.3.1.4 Soil Resistivity Testing

Soil resistivity measurements may 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 (4-pin) method, the soil bar (a-c 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

Figure 27—Corrosion Under Poorly Applied Tape



Note: This structure is *not* under Cathodic Protection

CLOSE INTERVAL P/S "HOT SPOT" SURVEY

Figure 28—Pipe to Soil Internal Potential Survey Used to Identify Active Corrosion Spots in Underground Piping

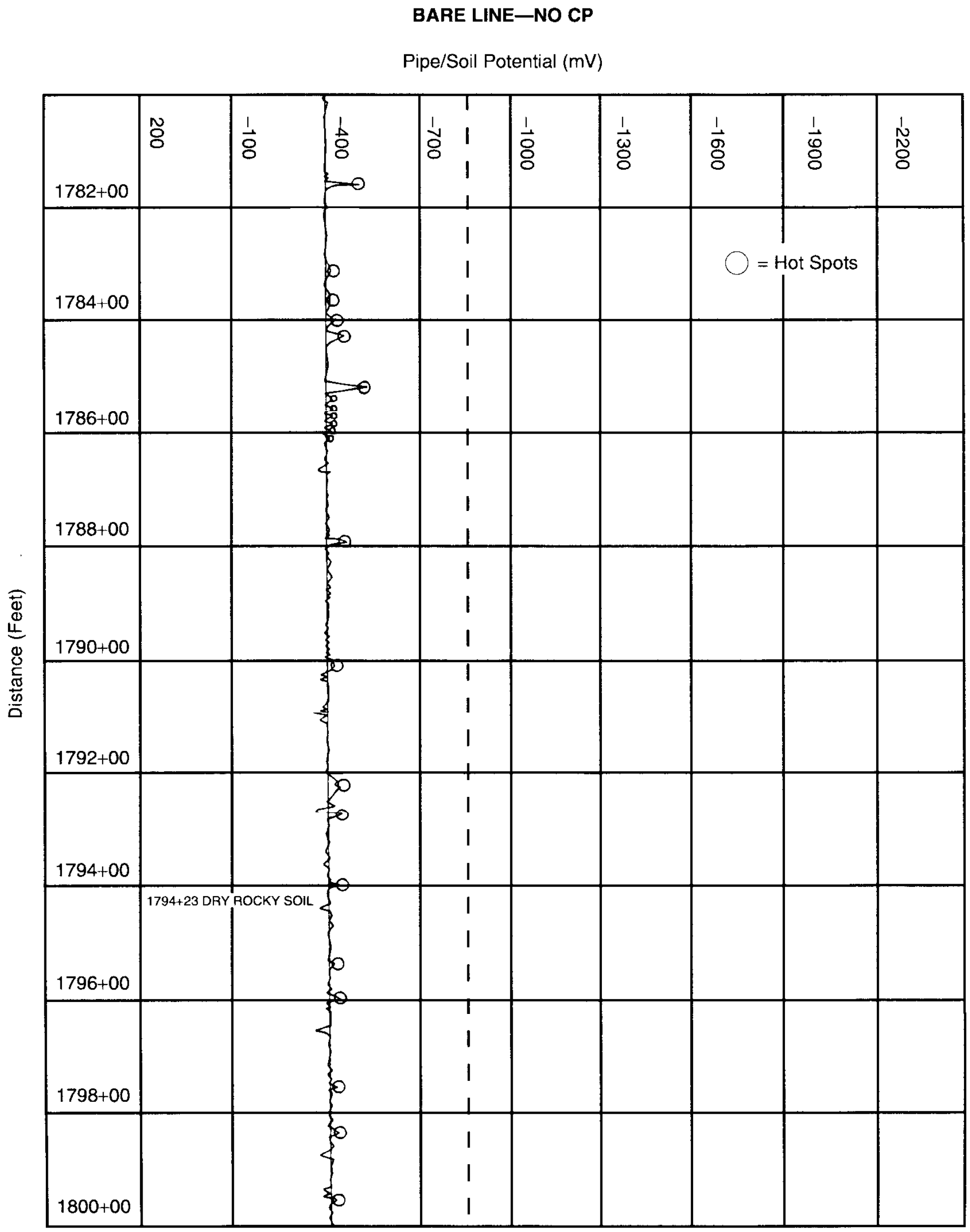
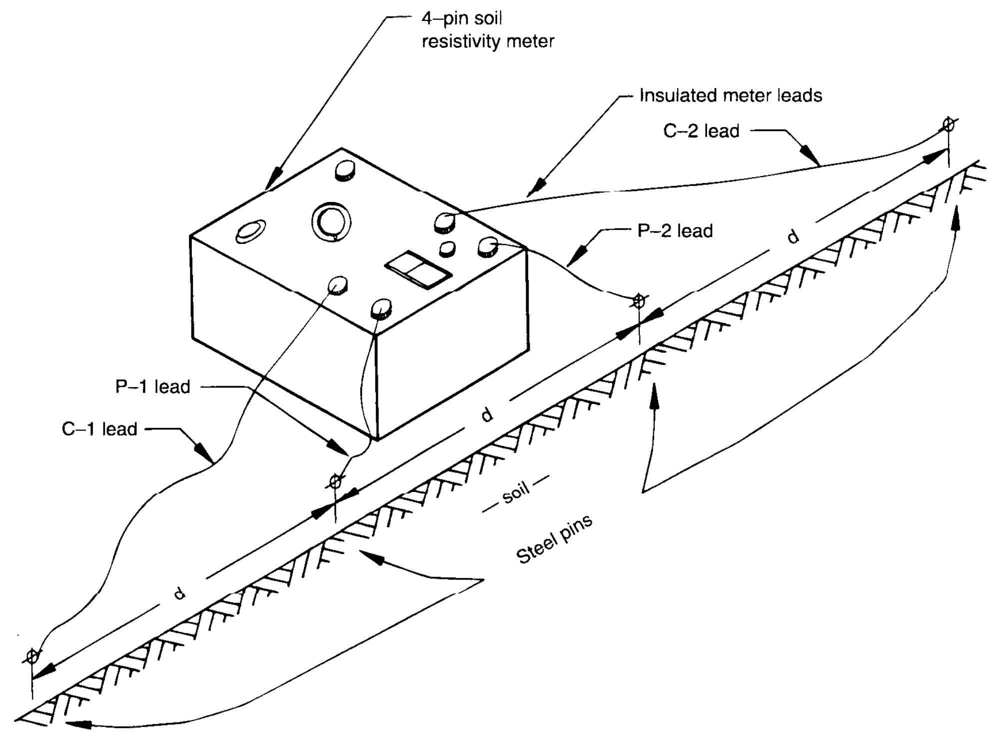


Figure 29—An Actual Chart From a Close Internal Pipe to Soil Potential Survey of Underground Piping Identifying Areas of Active Corrosion



Notes:
p="(rho)"=soil resistivity in OHM–CM
(OHM–CM=OHM–centimeters)
d–pin spacing in feet
R=meter reading after balancing
P=191.5×d×R

SOIL RESISTIVITY TESTING USING A 4–PIN SOIL RESISTIVITY METER

Figure 30—The Werner 4-Pin Soil Resistivity Test Method

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 4-pin method should be in accordance with ASTM G57. The 4-pin method uses the formula: Resistivity (ohm-cm) = 191.5 x d x 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 must be small compared to the pin spacing. See Figure 30. The following conditions should be considered in 4-pin soil resistivity measurements:

a. All underground structures must be excluded from the measurement.
b. All of the pins must 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 must be designed to exclude any effect of extraneous a-c or d-c currents.

In cases of parallel pipes or in areas of intersecting pipelines, the 4-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 31. The soil bar is typically inserted to the depth in the soil where the resistivity is to be taken. An a-c 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.

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 32 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.

10.3.1.5 Cathodic Protection Monitoring

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

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

10.3.2 Inspection Methods

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

10.3.2.1 Intelligent Pigging

This method involves the movement of a device (pig) through the piping either while it is in service or after it has been removed from service. Several types of devices are available employing different methods of inspection. The line to be evaluated must be free from restrictions that would cause the device to stick within the line, i.e., usually five diameter bends are required (standard 90° pipe ells may not pass a pig). The line must also have facilities for launching and recovering the pigs. Most plant piping systems are typically not suited to intelligent pigging.

10.3.2.2 Video Cameras

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

10.3.2.3 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. 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.

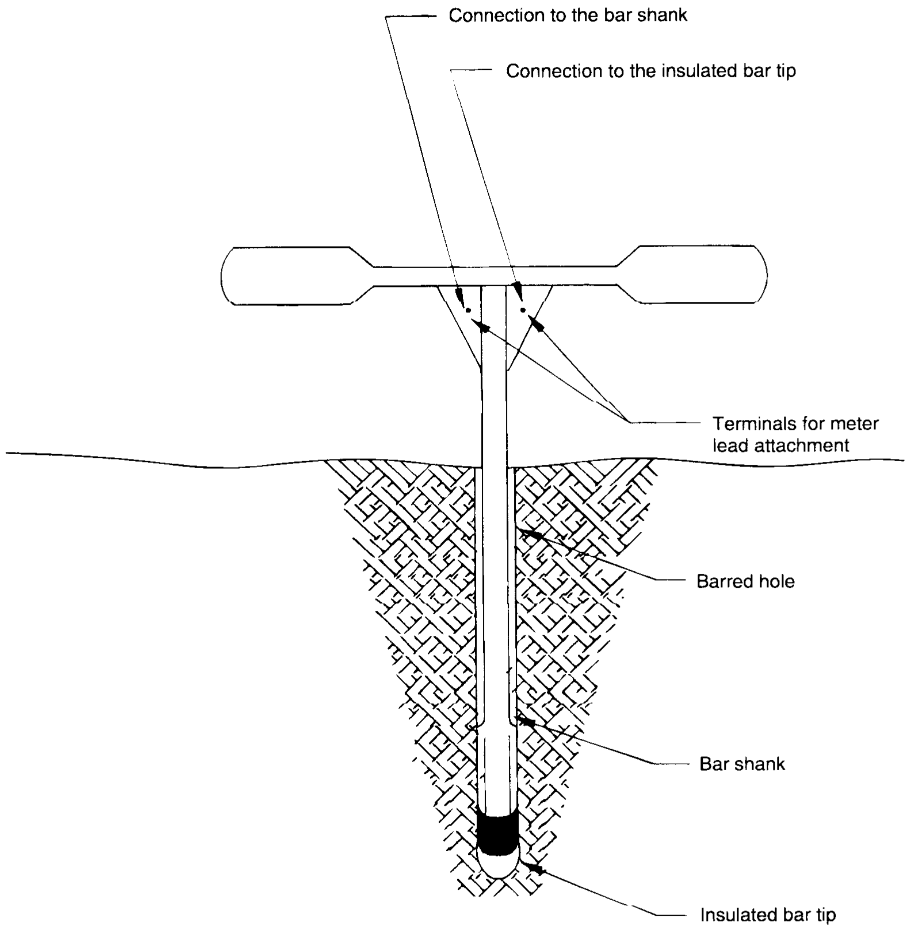


Figure 31—Soil Bar for Measuring Soil Resistivity

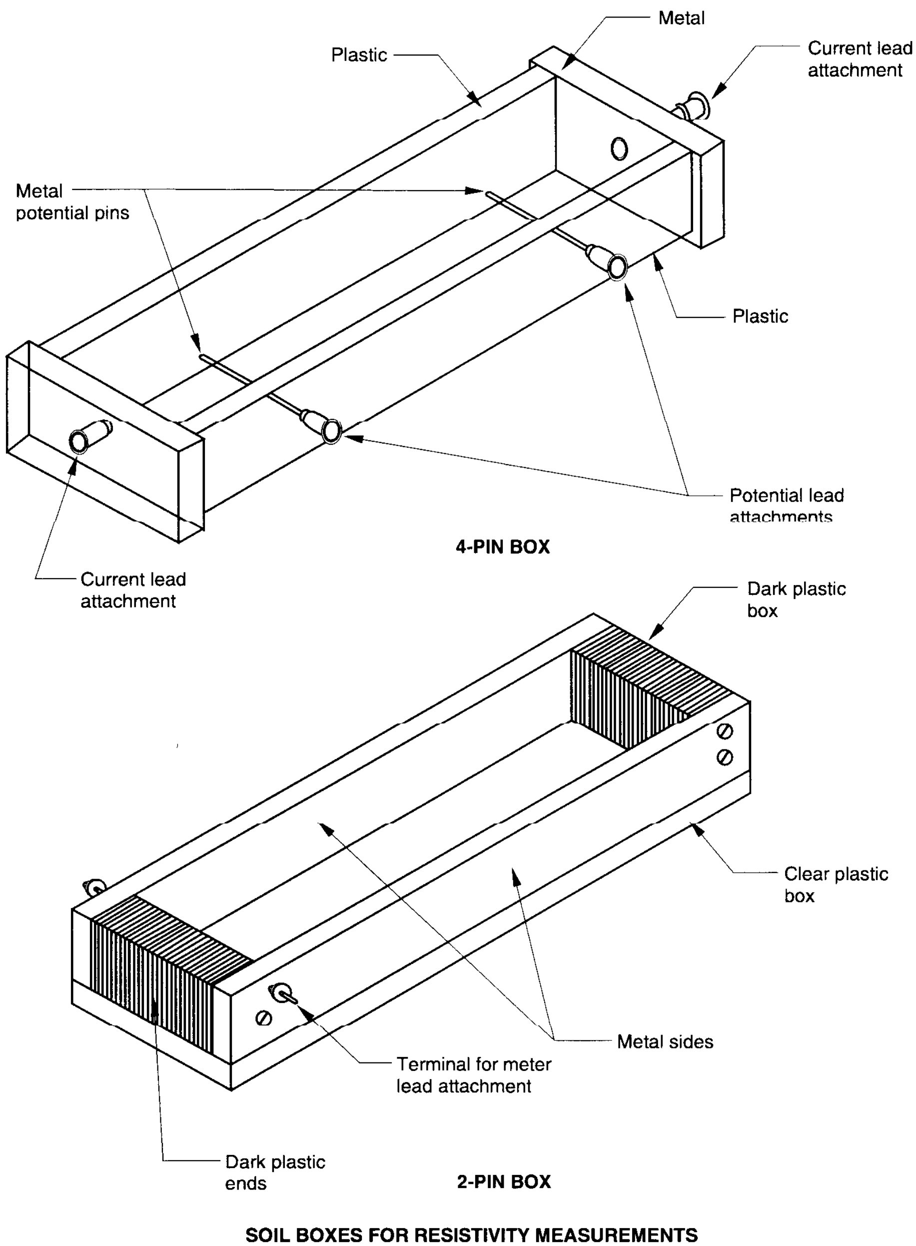


Figure 32—Two Types of Soil Boxes Used for Measuring Soil Resistivity

10.3.3 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) may affect the interpretation of results. If desired, the performance of pressure decay methods may 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 may 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 may affect the results. Again, the performance of single-point volumetric methods may be determined by a leak simulation.

d. A marker chemical (tracer) may 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 must 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 testing 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.

10.4 INSPECTION OF NEW CONSTRUCTION

10.4.1 General

All subjects covered in this section should meet ASME B31.3 requirements.

The procedures used to inspect piping systems while equipment is shut down are adaptable to the inspection of new construction. These procedures may include any number of the following activities: obtaining initial pipe wall thicknesses; 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. 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.

10.4.2 Inspection of Materials

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, may 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. 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 radiography or other special techniques is important in new construction. A representative number of welds may be checked for quality or the hardness of the weld and heat-affected zone. Liquid-penetrant or magnetic-particle inspection 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.

10.4.3 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. Any exceptions that have been accepted should be properly recorded and identified for future reference.

11 Determination of Retirement Thickness

11.1 PIPING

ASME B31.3 contains formulas and data for determining the minimum required wall thickness for new uncorroded piping. The specification relates thickness, diameter, 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 required thickness is nearly always required when items a through 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 needs to be exercised in calculating the retirement thickness for piping with branch connections reinforced per (d) above. These calculations should be performed by a piping engineer.

ASME B31.3 contains a formula for determining the required thickness of straight pipe subject to internal pressure. It also permits the use of the simple Barlow formula to determine the required wall thickness in certain cases. ASME B31.3 provides the guidance of when this formula or other equations are applicable. The Barlow formula is as follows:

$$t = PD/2SE$$

where

t = pressure design thickness for internal pressure, in inches (millimeters),

P = internal design gauge pressure of the pipe, in pounds per square inch (kilopascals),

D = outside diameter of the pipe, in inches (millimeters),

S = allowable unit stress at the design temperature, in pounds per square inch (kilopascals),

E = 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 $t > D/6$ 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.

In low pressure and temperature applications, the required pipe thicknesses determined by the Barlow formula may 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 Barlow formula.

For in-service piping subject to localized corrosion the inspector may choose to evaluate the piping strength and suitability for continued service utilizing the approach discussed in ASME B31G. Such an analysis should be performed by, or under the direction of, a piping engineer.

11.2 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 150-2500. The actual valve wall thickness requirements given in Table 3 of ASME B16.34 are approximately 0.1 inch (2.54 mm) thicker than the calculated values. Valves furnished in accordance with API Standard 600 have thickness requirements for corrosion and erosion in addition to those given in ASME B16.34.

If corrosion or erosion is anticipated, reference thickness measurements should be made when valves are installed so that the corrosion rate and metal loss can be determined.

The formula for calculating the retirement 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. In some cases, the calculated thickness will be impractical from a structural standpoint; therefore, minimum thicknesses should be established.

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.

12 Records

12.1 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 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.

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

ASTM Material Standard	Acceptable Diameter Tolerances (1)	Acceptable Thickness Tolerances (2)
A53	< OR =TO NPS $1\frac{1}{2}$ $\frac{1}{64}$ in. over $\frac{1}{32}$ in. under > NPS $1\frac{1}{2}$ ±1%	12.5% under
A106 A312 A530 A731 A790	NPS $\frac{1}{8}$-$1\frac{1}{2}$ incl. $\frac{1}{64}$ in.over $\frac{1}{32}$ in. under over NPS $1\frac{1}{2}$ to 4 incl. $\frac{1}{32}$ in. over $\frac{1}{32}$ in. under over NPS 4 to 8 incl. $\frac{1}{16}$ in. over $\frac{1}{32}$ in. under over NPS 8 to 18 incl. $\frac{3}{32}$ in. over $\frac{1}{32}$ in. under over NPS 18 to 26 incl. $\frac{1}{8}$ in. over $\frac{1}{32}$ in. under over NPS 26 to 34 incl. $\frac{5}{32}$ in. over $\frac{1}{32}$ in. under over NPS 34 to 48 incl. $\frac{3}{16}$ in. over $\frac{1}{32}$ in. under	12.5% under
A134	circumference ±0.5% of dia. specified	acceptable tolerance of plate standard
A135	+1% of nominal	12.5% under
A358	±0.5%	0.01 in. under
A409	wall under 0.188 in. thk. 0.20% wall equal to or over 0.188 in. thk. ±0.40%	0.018 in. under
A451		$\frac{1}{8}$ in. over, 0 under
A452	< 4 in. I.D. $\frac{1}{32}$ in. 4 in. incl. and over I.D. $\frac{1}{16}$ in.	22% over with $\frac{1}{8}$ in. max., 0 under
A524	NPS $\frac{1}{8}$-$1\frac{1}{2}$ incl. $\frac{1}{64}$ in. over $\frac{1}{32}$ in. under over NPS $1\frac{1}{2}$ to 4 incl. $\frac{1}{32}$ in. over $\frac{1}{32}$ in. under over NPS 4 to 8 incl. $\frac{1}{16}$ in. over $\frac{1}{32}$ in. under over NPS 8 to 18 incl. $\frac{3}{32}$ in. over $\frac{1}{32}$ in. under over NPS 18 $\frac{1}{8}$ in. over $\frac{1}{32}$ in. under	12.5% under
A587	See Table 4 in ASTM Standard	
A660		10% over specified min. wall thk. 0 under specified minimum wall thk.
A671	+0.5% of specified dia.	0.01 in. under specified thk.
A672, A691	±0.5% of specified dia.	
A813	to NPS $1\frac{1}{4}$ incl. ±0.010 in. NPS $1\frac{1}{2}$ to 6 in. incl. ±0.020 in. NPS 8 to 18 incl. ±0.030 in. NPS 20 to 24 incl. ±0.040 in. NPS 30 ±0.050 in.	=/-0.12% for wall < 0.188 in. ±0.030 in. for wall 0.0188 in. and over
A814	See Table 1 in ASTM Standard	

Note:

1. Tolerance on nominal diameter unless otherwise specified.
2. Tolerance on nominal wall thickness unless otherwise specified.

All inspection records should contain as a minimum:

a. The original date of installation.
b. The specifications and strength levels of the materials used.
c. The original thickness measurements.
d. The locations and dates of all subsequent thickness measurements.
e. The calculated retirement thickness.
f. Previous repairs/replacements.
g. Pertinent operational changes, i.e., change in service.

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.

12.2 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 at which thickness measurements are to be taken. Although original construction drawings may be used, normally separate sketches are made by, or for, the inspection department. Figure 33 is a typical isometric sketch for recording field data. Sketches have the following important functions:

a. Identify particular piping systems and circuits in terms of location, size, material specification, general process flow, and service conditions.
b. Inform the mechanical department of points to be opened for visual inspection and parts that require replacement or repair.
c. Serve as field data sheets on which can be recorded the locations of thickness measurements, serious corrosion, and sections requiring immediate replacement. These data can be transferred to continuous records at a later date.
d. Assist at future inspections in determining locations that urgently require examination.

12.3 NUMBERING SYSTEMS

The use of a coding system that uniquely identifies the process unit, the piping system, the circuit, and the TMLs is advisable.

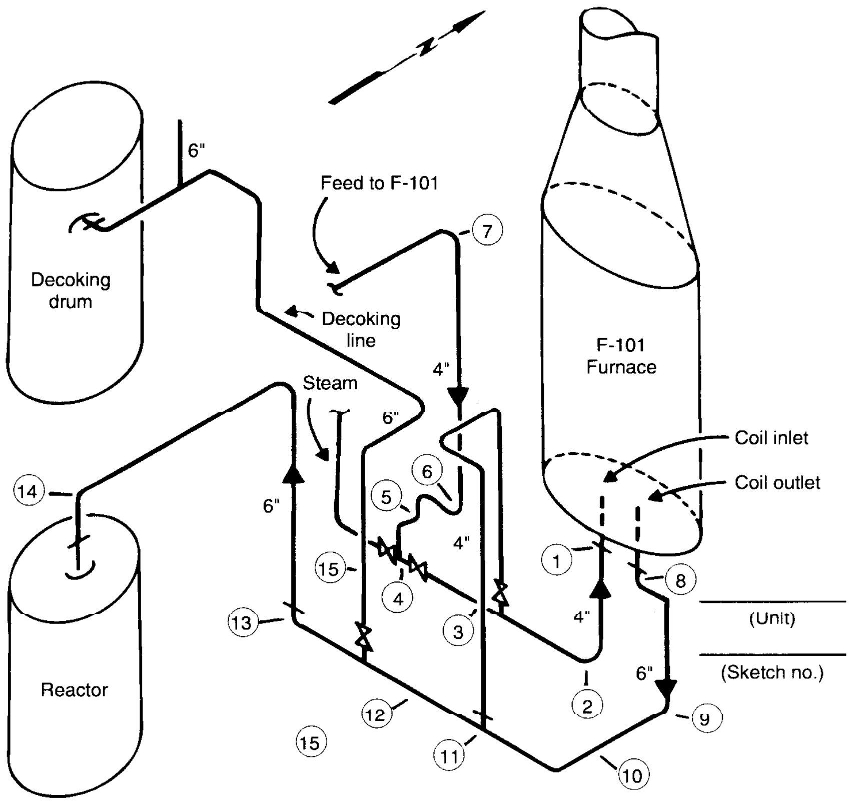
12.4 THICKNESS DATA

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 may be shown on sketches or presented as tabulated information attached to the sketches. Figure 34 shows one method of tabulating thickness readings and other information.

12.5 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, have previously shown high corrosion rates, and 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 predictable 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 shut-down period.



Note: Circled numbers indicate points at which thickness should be monitored by the inspector when the thickness data sheet is filled out.

Figure 33—Typical Isometric Sketch

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 ______

				Initial Reading					Subsequent Reading					Subsequent Reading				
Point	Reading Location	Size	Limit	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 (for example, N = nominal; U = ultrasonic; X = radiography; and C = calipers).

Figure 34—Typical Tabulation of Thickness Data

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