Pipeline design consideration and standards

The considerations and standards guiding pipeline design insures stability and integrity in the industry.

Selecting pipe wall thickness

The fluid flow equations and formulas presented thus far enable the engineer to initiate the design of a piping or pipeline system, where the pressure drop available governs the selection of pipe size. (In addition, there may be velocity constraints that might dictate a larger pipe diameter. This is discussed below in the section on velocity considerations for pipelines.

Once the inner diameter (ID) of the piping segment has been determined, the pipe wall thickness must be calculated. There are many factors that affect the pipe-wall-thickness requirement, which include:

- The maximum and working pressures
- Maximum and working temperatures
- Chemical properties of the fluid
- The fluid velocity
- The pipe material and grade
- The safety factor or code design application

If there are no codes or standards that specifically apply to the oil and gas production facilities, the design engineer may select one of the industry codes or standards as the basis of design. The design and operation of gathering, transmission, and distribution pipeline systems are usually governed by codes, standards, and regulations. The design engineer must verify whether the particular country in which the project is located has regulations, codes, and standards that apply to facilities and/or pipelines.

The basic formula for determining pipe wall thickness is the general hoop stress formula for thin-wall cylinders, which is stated as

$$t = \frac{P d_o}{2(H_s + P)},$$ **(Eq. 1)**

where

H_s =   hoop stress in pipe wall, psi,

t =   pipe wall thickness, in.,

L =   length of pipe, ft,

P =   internal pressure of the pipe, psi,

and

d_o =   outside diameter of pipe, in.

Piping codes

The following standards from the American Natl. Standards Inst. (ANSI) and the American Soc. of Mechanical Engineers (ASME) specify wall-thickness requirements.

- ANSI/ASME Standard B31.1, Power Piping.[1] This standard applies to steam piping systems.
- ANSI/ASME Standard B31.3, Chemical Plant and Petroleum Refinery Piping.[2] This standard applies to major facilities onshore and offshore worldwide.
- ANSI/ASME Standard B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols.[3] This standard applies to onshore oil pipeline facilities.
- ANSI/ASME Standard B31.8, Gas Transmission and Distribution Piping Systems.[4] This standard applies to gas transmission, gathering, and distribution pipelines onshore.

In the U.S, piping on offshore facilities is mandated by regulation to be done in accordance with ANSI/ASME Standard B31.3. Most onshore facilities are designed in accordance with ANSI/ASME Standard B31.4 or B31.8, depending on whether it is an oil or gas facility. respectively. Some companies use the more stringent ANSI/ASME Standard B31.3 for onshore facilities.

In other countries, similar standards apply with minor variations. For simplicity, we will discuss only the U.S. standards in this chapter. The engineer should check to see if there are different standards that must be applied in the specific location of the design.

Pipe materials - basics

There are some applications where plastic, concrete, or other piping materials are both desirable and acceptable. Utility systems such as those for water, sanitary or storm water, air, draining or low-pressure oil or gas service applications often use the nonsteel piping material systems. However, for the vast majority of the "pressure" piping systems encountered, steel pipe is required.

For petroleum applications, pipe materials that meet American Petroleum Inst. (API), American Soc. for Testing and Materials (ASTM), ASME, and ANSI standards are used most often. All of these standards have very rigid design, specification, chemistry, and testing standardization and manufacturing requirements. Modern steel pipe manufactured to these exacting standards assures both high quality and safety in design.

Steel pipe is available in a variety of commercial sizes ranging from nominal 1/8 up to 60 in. or greater. **Table 1** illustrates a number ANSI pipe schedules, for reference. The "nominal" commercial pipe sizes from 1/8 through 12 in. refer to the approximate ID measurement of Schedule 40 or "standard" wall, whereas nominal 14 in. and larger sizes refer to the outside diameter. A variety of steel pipe sizes, wall thicknesses, and material grades are available for petroleum piping and pipeline applications.

 Table 1

Please note that the allowable internal pressure is the maximum pressure to which the piping system can be subjected. This could be significantly higher than the flowing pressure of the fluid in the pipe.

Wall thickness calculations - using B31.3 Code

ANSI/ASME Standard B31.3 is a very stringent code with a high safety margin. The B31.3 wall-thickness calculation formula is stated as

$$t = t_e + t_{th} + \left[\frac{Pd_o}{2(SE + PY)} \right] \left[\frac{100}{100 - T_{ol}} \right],$$ **(Eq. 2)**

where

t =   minimum design wall thickness, in.,

t_e =   corrosion allowance, in.,

t_{th} =   thread or groove depth, in. (**Table 2**),

P =   allowable internal pressure in pipe, psi,

d_o =   outside diameter of pipe, in.,

S =   allowable stress for pipe, psi (**Tables 3 and 4**),

E =   longitudinal weld-joint factor [1.0 seamless, 0.95 electric fusion weld, double butt, straight or spiral seam APL 5L, 0.85 electric resistance weld (ERW), 0.60 furnace butt weld],

Y =   derating factor (0.4 for ferrous materials operating below 900°F),

and

T_{ol} =   manufacturers allowable tolerance, % (12.5 pipe up to 20 in.-OD, 10 pipe > 20 in. OD, API 5L).

■

TABLE 9.8—THREAD ALLOWANCE CALCULATIONS FOR THREADED-PIPE-WALL THICKNESS (courtesy of AMEC Paragon)	
Nominal Pipe Size	t_{th}, in.
¼ – ⅜	0.05
½ – ¾	0.06
1 – 2	0.08
2½ – 20	0.11

Table 2

TABLE 9.9—BASIC ALLOWABLE STRESS FOR GRADE B AND X-42 SEAMLESS PIPE
(courtesy of ANSI/ASME)

Temperature, °F	ASTM A206 & API 5L, Grade B	API 5L, Grade X42
-20 to 400	20,000	20,000
500	18,900	N/A
600	17,300	N/A
650	17,000	N/A

(For additional information, see ANSI/ASME Standard B31.3,[7] Appendix A.)

Table 3

TABLE 9.10—BASIC ALLOWABLE STRESS FOR OTHER GRADES OF SEAMLESS PIPE
(courtesy of ANSI/ASME)

Grade	Minimum Temperature	Allowable Stress Minimum Temperature to 100°F
API 5L-A	-20	16,000
API 5LX-42	-20	20,000
API 5LX-46	-20	21,000
API 5LX-52	-20	22,000
ASTM A-106-B	-20	20,000
ASTM A-333-6	-50	20,000
ASTM A-369-FPA	-20	16,000
ASTM A-369-FPB	-20	20,000
ASTM A-524-I	-20	20,000
ASTM A-524-II	-20	18,300

(For additional information, see ANSI Standard B31.3, Appendix A.)

Table 4

Under ANSI/ASME Standard B31.3, the allowable pressure can be increased for certain instances. The conditions for the permissible increases in allowable pressure, according to Standard B31.3, are given next.

- When the variation lasts no more than 10 hours at any one time and not more than 100 hours per year, it is permissible to exceed the pressure rating or the allowable stress for pressure design at the temperature of the increased condition by no more than 33%.
- When the variation lasts no more than 50 hours at any one time and not more than 500 hours per year, it is permissible to exceed the pressure rating or the allowable stress for pressure design at the temperature of the increased condition by not more than 20%.

Wall thickness calculations - using B31.4 Code

The ANSI/ASME Standard B31.4 code is somewhat less stringent than that of Standard B31.3 because of the lower levels of hazard associated with liquid pipelines. The code for Standard B31.4 is used often as the standard of design for crude-oil piping systems in facilities, such as pump stations, pigging facilities, measurement and regulation stations, and tank farms. The wall-thickness formula for Standard B31.4 is stated as

$$t = \frac{Pd_o}{2(FES_Y)},$$ **(Eq. 3)**

where

t = minimum design wall thickness, in.,

P = internal pressure in pipe, psi,

d_o = OD of pipe, in.,

S_Y = minimum yield stress for pipe, psi (**Table 5**),

F = derating factor, 0.72 for all locations,

and

E = longitudinal weld-joint factor [1.0 seamless, ERW, double submerged arc weld and flash weld; 0.80 electric fusion (arc) weld and electric fusion weld, 0.60 furnace butt weld].

Table 5

Table 5 (Cont'd)

Wall thickness calculations - using B31.8 code

The ANSI/ASME Standard B31.8 code is less stringent than that of Standard B31.3, but more stringent than that of Standard B13.4. The B31.8 code is often used as the standard of design for natural-gas piping systems in facilities, such as compressor stations, gas-treatment facilities, measurement and regulation stations, and tank farms. The B31.8 wall-thickness formula is stated as

$$t = \frac{Pd_o}{2FETS_Y} ,$$ **(Eq. 4)**

where

t = minimum design wall thickness, in.,

P = internal pressure in pipe, psi,

d_o = OD of pipe, in.,

S_Y = minimum yield stress for pipe, psi (**Table 6**),

F = design factor (see **Table 7** and discussion that follows),

E = longitudinal weld-joint factor (**Table 8**),

and

T = temperature derating factor (**Table 9**).

Table 6

TABLE 9.12—SPECIFIED MINIMUM YIELD STRENGTH FOR STEEL PIPE COMMONLY USED IN PIPE SYSTEMS (continued)

Spec. No.	Grade	Type [Note (1)]	SMYS, psi
ASTM A 381	Class Y-35	DSA	35,000
ASTM A 381	Class Y-42	DSA	42,000
ASTM A 381	Class Y-46	DSA	46,000
ASTM A 381	Class Y-48	DSA	48,000
ASTM A 381	Class Y-50	DSA	50,000
ASTM A 381	Class Y-52	DSA	52,000
ASTM A 381	Class Y-56	DSA	56,000
ASTM A 381	Class Y-60	DSA	60,000
ASTM A 381	Class Y-65	DSA	65,000

GENERAL NOTE:

This table is not complete. For the minimum specified yield strength of other grades and grades in other approved specifications, refer to the particular specification.

NOTES:
(1) Abbreviations: BW–furnace butt-welded; ERW–electric resistance welded; S–Seamless; FW–flash welded; EFW–electric fusion welded; DSA–double submerged-arc welded.
(2) Intermediate grades are available in API 5L.
(3) See applicable plate specification for SMYS.

(For additional information see ANSI/ASME B31.4² Appendix D)

Table 6 (Cont'd)

TABLE 9.13—BASIC DESIGN FACTOR (F) FOR STEEL-PIPE CONSTRUCTION OF NATURAL-GAS SERVICE PIPELINES (courtesy of ANSI/ASME)

Facility	Div. 1	Div. 2	2	3	4
Pipelines, mains, and service lines [see para. 840.2(c)]	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.72	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies [see para. 841.121]	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges [see para. 841.122]	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2 [see para. 840.3(b)]	0.50	0.50	0.50	0.50	0.40

For additional information, see ANSI Standard B31.8

Table 7

TABLE 9.14—BASIC DESIGN LONGITUDINAL JOINT FACTOR (E) FOR STEEL PIPELINES IN NATURAL-GAS SERVICE (courtesy of ANSI/ASME)

Spec. No.	Pipe Class	E Factor	Spec. No.	Pipe Class	E Factor
ASTM A 53	Seamless	1.00	ASTM A 671	Electric Fusion Welded	
	Electric Resistance Welded	1.00		Classes 13, 23, 33, 43, 53	0.80
	Furnace Butt Welded—			Classes 12, 22, 32, 42, 52	1.00
	Continuous Weld	0.60			
ASTM A 106	Seamless	1.00	ASTM A 672	Electric Fusion Welded	
ASTM A 134	Electric Fusion Arc Welded	0.80		Classes 13, 23, 33, 43, 53	0.80
ASTM A 135	Electric Resistance Welded	1.00		Classes 12, 22, 32, 42, 52	1.00
ASTM A 139	Electric Fusion Welded	0.80			
ASTM A 211	Spiral Welded Steel Pipe	0.80	API 5L	Seamless	1.00
ASTM A 333	Seamless	1.00		Electric Resistance Welded	1.00
	Electric Resistance Welded	1.00		Electric Flash Welded	1.00
ASTM A 381	Double Submerged-Arc-Welded	1.00		Submerged Arc Welded	1.00
				Furnace Butt Welded	0.60

GENERAL NOTE:

Definitions for the various classes of welded pipe are given in para. 804.243.
For additional information, see ANSI Standard B31.8.

Table 8

TABLE 9.15—BASIC DESIGN TEMPERATURE DERATING FACTORS (T) FOR STEEL PIPELINE IN NATURAL-GAS SERVICE (courtesy of ANSI/ASME)	
–20 to 250°F	T = 1.000
300°F	T = 0.967
350°F	T = 0.933
400°F	T = 0.900
450°F	T = 0.867

For additional information, see ANSI/ASME *Standard B31.8*.[9]

Table 9

The design factor, F, for steel pipe is a construction derating factor dependent upon the location class unit, which is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Each separate dwelling unit in a multiple-dwelling-unit building is counted as a separate building intended for human occupancy.

To determine the number of buildings intended for human occupancy for an onshore pipeline, lay out a zone 1/4-mile wide along the route of the pipeline with the pipeline on the centerline of this zone, and divide the pipeline into random sections 1 mile in length such that the individual lengths will include the maximum number of buildings intended for human occupancy. Count the number of buildings intended for human occupancy within each 1-mile zone. For this purpose, each separate dwelling unit in a multiple-dwelling-unit building is to be counted as a separate building intended for human occupancy.

It is not intended here that a full mile of lower-stress pipeline shall be installed if there are physical barriers or other factors that will limit the further expansion of the more densely populated area to a total distance of less than 1 mile. It is intended, however, that where no such barriers exist, ample allowance shall be made in determining the limits of the lower stress design to provide for probable further development in the area.

When a cluster of buildings intended for human occupancy indicates that a basic mile of pipeline should be identified as a Location Class 2 or Location Class 3, the Location Class 2 or Location Class 3 may be terminated 660 ft from the nearest building in the cluster. For pipelines shorter than 1 mile in length, a location class shall be assigned that is typical of the location class that would be required for 1 mile of pipeline traversing the area.

Location Classes for Design and Construction

Class 1 location

A Class 1 location is any 1-mile section of pipeline that has 10 or fewer buildings intended for human occupancy. This includes areas such as: • Wastelands • Deserts • Rugged mountains • Grazing land • Farmland • Sparsely populated areas

Class 1, division 1 location

This is a Class 1 location where the design factor, F, of the pipe is greater than 0.72 but equal to or less than 0.80 and which has been hydrostatically tested to 1.25 times the maximum operating pressure. (See Table 9.13 for exceptions to design factor.)

Class 1, division 2 location

This is a Class 1 location where the design factor, F, of the pipe is equal to or less than 0.72, and which has been tested to 1.1 times the maximum operating pressure.

Class 2 location

This is any 1-mile section of pipeline that has more than 10 but fewer than 46 buildings intended for human occupancy. This includes fringe areas around cities and towns, industrial areas, and ranch or country estates.

Class 3 location

This is any 1-mile section of pipeline that has 46 or more buildings intended for human occupancy except when a Class 4 Location prevails. This includes: • Suburban housing developments • Shopping centers • Residential areas • Industrial areas • Other populated areas not meeting Class 4 Location requirements

Class 4 location

This is any 1-mile section of pipeline where multistory buildings are prevalent, traffic is heavy or dense, and where there may be numerous other utilities underground. Multistory means four or more floors above ground including the first, or ground, floor. The depth of basements or number of basement floors is immaterial.

Comparions of the different classes

In addition to the criteria previously presented, additional consideration must be given to the possible consequences of a failure near a concentration of people, such as that found in a church, school, multiple-dwelling unit, hospital, or recreational area of an organized character in a Class 1 or 2 location. If the facility is used infrequently, the requirements of the following paragraph need not be applied.

Pipelines near places of public assembly or concentrations of people such as churches, schools, multiple-dwelling-unit buildings, hospitals, or recreational areas of an organized nature in Class 1 and 2 locations shall meet requirements for the Class 3 location.

The concentration of people previously referred to is not intended to include groups fewer than 20 people per instance or location but is intended to cover people in an outside area as well as in a building.

It should be emphasized that location class (1, 2, 3, or 4), as previously described, is the general description of a geographic area having certain characteristics as a basis for prescribing the types of design, construction, and methods of testing to be used in those locations or in areas that are respectively comparable. A numbered location class, such as Location Class 1, refers only to the geography of that location or a similar area and does not necessarily indicate that a design factor of 0.72 will suffice for all construction in that particular location or area (e.g., in Location Class 1, all crossings without casings require a design factor, F, of 0.60).

When classifying locations for the purpose of determining the design factor, F, for the pipeline construction and testing that should be prescribed, due consideration shall be given to the possibility of future development of the area. If at the time of planning a new pipeline this future development appears likely to be sufficient to change the class location, this should be taken into consideration in the design and testing of the proposed pipeline.

Wall thickness calculations - comparisons

Additional comparison of Standard B31.3 to both B31.4 and B31.8 indicates the following:

- ANSI/ASME Standard B31.3 is more conservative than either Standard B31.4 or B31.8, especially relative to API 5L, X-grade pipe and electric-resistance-welded (ERW) seam pipe.
- ANSI/ASME Standard B31.8 does not allow increases for transient conditions.
- The ANSI/ASME Standard B31.3 specification break occurs at the fence, whereas B31.8's occurs at the "first flange" upstream/downstream of the pipeline.

Using ANSI/ASME Standard B31.3 criteria for oil- and gas-facility piping will assure a very conservative design. However, the cost associated with the Standard B31.3 piping design may be substantial compared to the other codes and may not be necessary, especially for onshore facilities.

Velocity considerations

In choosing a line diameter, consideration also has to be given to maximum and minimum velocities. The line should be sized such that the maximum velocity of the fluid does not cause erosion, excess noise, or water hammer. The line should be sized such that the minimum velocity of the fluid prevents surging and keeps the line swept clear of entrained solids and liquids.

API RP14E[5] provides typical surge factors that should be considered in designing production piping systems. These are reproduced in **Table 10**.

TABLE 9.16—TYPICAL SURGE FACTORS FOR TWO-PHASE-FLOW PIPELINES
(courtesy of API)

Service	Factor, %
Facility handling primary production from its own platform	20
Facility handling primary production from another platform or remote well in less than 150 ft of water	30
Facility handling primary production from another platform or remote well in greater than 150 ft of water	40
Facility handling gas lifted production from its own platform	40
Facility handling gas lifted production from another platform or remote well	50

For additional information, see API RP14E.[10]

Table 10

Liquid line sizing

The liquid velocity can be expressed as

$$V = 0.012 \frac{Q_L}{d},$$ **(Eq. 5)**

where

Q_L =   fluid-flow rate, B/D

and

d =   pipe ID, in.

In piping systems where solids might be present or where water could settle out and create corrosion zones in low spots, a minimum velocity of 3 ft/sec is normally used. A maximum velocity of 15 ft/sec is often used to minimize the possibility of erosion by solids and water hammer caused by quickly closing a valve.

Gas line sizing

The pressure drop in gas lines is typically low in gas-producing facilities because the piping segment lengths are short. The pressure drop has a more significant impact upon longer segments such as gas-gathering pipelines, transmission pipelines, or relief or vent piping.

The velocity in gas lines should be less than 60 to 80 ft/sec to minimize noise and allow for corrosion inhibition. A lower velocity of 50 ft/sec should be used in the presence of known corrosives such as CO_2. The minimum gas velocity should be between 10 and 15 ft/sec, which minimizes liquid fallout.

Gas velocity is expressed in **Eq. 6** as

$$V_g = 60 \frac{Q_g TZ}{d^2 P},$$ (Eq. 6)

where

V_g	=	gas velocity, ft/sec,

Q_g	=	gas-flow rate, MMscf/D,

T	=	gas flowing temperature, °R,

P	=	flowing pressure, psia,

Z	=	compressibility factor, dimensionless,

and

d	=	pipe ID in.

Multiphase line sizing

The minimum fluid velocity in multiphase systems must be relatively high to keep the liquids moving and prevent or minimize slugging. The recommended minimum velocity is 10 to 15 ft/sec. The maximum recommended velocity is 60 ft/sec to inhibit noise and 50 ft/sec for CO_2 corrosion inhibition.

In two-phase flow, it is possible that liquid droplets in the flow stream will impact on the wall of the pipe causing erosion of the products of corrosion. This is called erosion/corrosion. Erosion of the pipe wall itself could occur if solid particles, particularly sand, are entrained in the flow stream. The following guidelines from API RP14E[5] should be used to protect against erosion/corrosion.

Calculate the erosional velocity of the mixture with **Eq. 7**.

$$V_e = \frac{C}{\rho_M^{1/2}},$$ (Eq. 7)

where C = empirical constant. ρ_M is the average density of the mixture at flowing conditions. It can be calculated from

$$\rho_M = \frac{(12409)(SG)P + (2.7)RSP}{(198.7)P + ZRT},$$ (Eq. 8)

where

SG	=	specific gravity of the liquid (relative to water),

and

S	=	specific gravity of the gas relative to air.

Industry experience to date indicates that for solids-free fluids, values of $C = 100$ for continuous service and $C = 125$ for intermittent service are conservative. For solids-free fluids where corrosion is not anticipated or when corrosion is controlled by inhibition or by employing corrosion-resistant alloys, values of $C = 150$ to 200 may be used for continuous service; values up to 250 have been used successfully for intermittent service. If solids production is anticipated, fluid velocities should be significantly reduced. Different values of C may be used where specific application studies have shown them to be appropriate.

Where solids and/or corrosive contaminants are present or where c values higher than 100 for continuous service are used, periodic surveys to assess pipe wall thickness should be considered. The design of any piping system where solids are anticipated should consider the installation of sand probes, cushion flow tees, and a minimum of 3 ft of straight piping downstream of choke outlets.

Once a design velocity is chosen, to determine the pipe size, **Eq. 9** can be used.

$$d = \left[\frac{\left(11.9 + \frac{ZTR}{16.7P}\right)Q_L}{1,000V} \right]^{1/2},$$

(Eq. 9)

where

d = pipe ID, in.,

Z = compressibility factor, dimensionless,

R = gas/liquid ratio, ft^3/bbl,

P = flowing pressure, psia,

T = gas/liquid flowing temperature, °R,

V = maximum allowable velocity, ft/sec,

and

Q_L = liquid-flow rate, B/D.

Valve, fitting, and flange pressure ratings

Pipe fittings, valves, and flanges are designed and manufactured in accordance several industry standards including API, ASTM, ANSI/ASME and Manufacturer's Standardization Soc. (MSS) (large-diameter pipeline fittings/flanges). The piping components are designed and manufactured to the industry standards to:

- Ensure the consistency of the material properties and specifications
- Set uniform dimensional standards and tolerances; specify methods of production and quality control
- Specify service ratings and allowable pressure and temperature ratings for fittings manufactured to the standards
- Provide interchangeability between fittings and valves manufactured to the standards

Piping materials manufactured to these standards can be traced to the source foundry and the material composition verified. Material traceability is another important feature of standardization. Each fitting, valve, and flange can be certified as to the material, specification, and grade.

Pressure ratings

ANSI Standard B16.5, Steel Pipe Flanges and Flanged Fittings,[6] has seven pressure classes: ANSI 150, 300, 400, 600, 900, 1500, and 2500. **Table 11** illustrates the maximum, nonshock working pressures for Material Group 1.1, which is the working group for most oil and gas piping and pipeline applications.

TABLE 9.17—PRESSURE RATINGS VS. TEMPERATURE FOR MATERIALS GROUP 1.1-27, CLASS 150, 300, 400, 600, 900, 1500, AND 2500 (courtesy of ANSI/ASME)

Class	−20 to 100°F	200°F
150	285	260
300	740	675
400	990	900
600	1,480	1,350
900	2,220	2,025
1500	3,705	3,375
2500	6,170	5,625

Pressure ratings for temperatures between 100 and 200°F should be interpolated between the values at 100 and 200°F.

(Refer to ANSI/ASME B16.5[11] for definition of material groups and for specific pressure ratings for other material groups and temperatures.)

Table 11

API Spec. 6A[7] prescribes seven pressure classes: 2,000, 3,000, 5,000, 10,000, 15,000, 20,000, and 30,000. API 2,000, 3,000, and 5,000 lbf have the same dimensions as ANSI 600, ANSI 900, and ANSI 1,500, respectively. When the API flange is bolted to an ANSI flange, the connection must be rated for the ANSI pressure rating. **Table 12** shows the temperature and pressure ratings for API-specification fittings.

TABLE 9.17—PRESSURE RATINGS VS. TEMPERATURE FOR MATERIALS GROUP 1.1-27, CLASS 150, 300, 400, 600, 900, 1500, AND 2500 (courtesy of ANSI/ASME)

Class	−20 to 100°F	200°F
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600	1,480	1,350
900	2,220	2,025
1500	3,705	3,375
2500	6,170	5,625

Pressure ratings for temperatures between 100 and 200°F should be interpolated between the values at 100 and 200°F.

(Refer to ANSI/ASME B16.5[11] for definition of material groups and for specific pressure ratings for other material groups and temperatures.)

Table 12

API flanges are required for extreme high pressures and are typically used for wellheads. ANSI flanges are less costly and more available than the API flanges and are used in the production facility. Typically, API flanges are used in the flowline near the wellhead, but ANSI flanges are used downstream. Manifolds and production headers may be API or ANSI, depending upon the operating pressures.

Flange types

Flanges come in a variety of neck connection configurations and face designs. Flange connections may be slip-on, threaded, socket weld, or weld neck. Slip-on, socket-weld, and threaded-neck flanges should not be used in most high-pressure applications, especially for pipe larger than 3- to 4-in. nominal pipe size. ANSI Standard B31.3[2] specifically recommends that slip-on flanges not be used where mechanical vibration or large temperature cycles are encountered. Weld-neck flanges are typically better in the higher-pressure oil and gas and pipeline applications.

The flange face, or the part of the flange that makes the physical connection, comes in several classifications, as shown in **Fig. 1**:

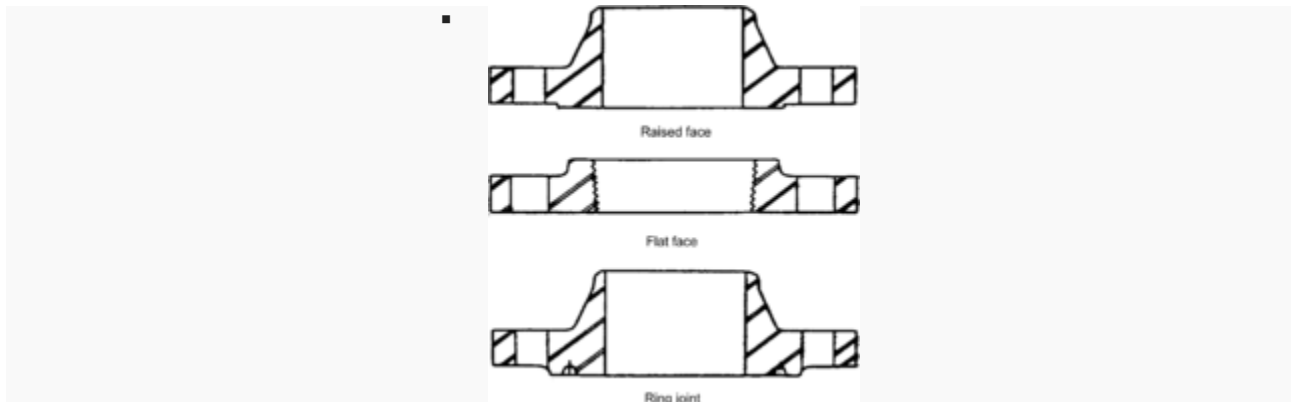- Flat face
- Raised face (RF)
- Ring-type joint (RTJ)

 Fig. 1—Typical ASME/ANSI *B16.5* **and MSS** *SP 44* **flange faces (courtesy of AMEC Paragon).**

Flat-face flanges are typically available only in low-pressure ANSI 150 flanges and are not used in high-pressure applications. RF and RTJ flanges are commonly used in the oil and gas and pipeline applications.

RF flanges are less expensive and easier to make up where tight clearances make it difficult to spread the flanges apart so that the ring may be inserted. RTJ flanges tend to seal better at higher pressures. API RP14E[5] recommends RTJ faced flanges in ANSI class 900 and higher. Onshore applications often use RF flanges in pressure class ratings as high as ANSI 2500. ANSI Standard B16.5[6] places no limitations on the application of RF flanges in pressure service.

Gasket materials

Gasket materials for flat-face gaskets normally are 1/16 in. thick and made of composite materials. Asbestos was formerly used for gasket materials for both flat-faced and RF gaskets, but asbestos has been replaced because it is a hazardous material.

Spiral-wound gaskets, composed of a metal ring with wound internal composite rings, are typically used. The composite materials may include stainless steel and Teflon or other polytetrafluoroethylene (PTFE) type materials. A wide selection of winding materials is commercially available for a number of different fluids and applications. RTJ "ring" gaskets are typically made of cadmium-plated soft iron or low-carbon steel for ANSI 600 and ANSI 900 class flanges. 304 and 316 stainless-steel rings are frequently used in the higher-class ratings as well as for corrosive-service applications (such as H_2S and CO_2 service).

Bolting materials

The typical carbon-steel bolt materials used in most flange bolting applications is ASTM A-193, Grade B-7. The companion nuts are typically ASTM A-194, Grade 2H. ASTM has specifications and grades for carbon-steel and alloy bolts and nuts for high-temperature, low-temperature, and extreme-service applications.

Pipe fittings

Pipe fittings generally are categorized as threaded, socket weld, or butt weld. The threaded and socket-weld fittings are typically forged steel and are ASTM A-105 material and manufactured as per ANSI *B16.11, Forged Steel Fittings, Socket Welding, and Threaded*. [8] Socket-weld fittings have a groove where the pipe is inserted and weld material is used to fill the void and seal the connection. The pressure class ratings of forged-steel threaded and socket-weld fittings are 2,000 lbf (also known as standard); 3,000 lbf [also known as extra strong (XS)]; and 6,000 lbf [also known as double extra strong (XXS)], which refers to their allowable operating pressure at 100°F. The fittings are rated up to 700°F, where the rating effectively reduces the fitting operating pressures by 1/3. Generally, threaded fittings should not be used in piping systems for pipe larger in size than 2-in. nominal.

API *RP14E*[5] recommends that 1 1/2-in. size fittings should be socket welded for hydrocarbon service above ANSI 600, hydrocarbon service above 200°F, hydrocarbon service subject to vibration, and glycol service. It also recommends that 2-in. and larger piping should be flanged with butt-weld fittings when in hydrocarbon or glycol service. Threaded fittings should be avoided in all applications where mechanical vibration (pumps and compressors) or cyclic thermal variations occur.

For most hydrocarbon service, ASTM A-106 Grade B seamless pipe or API 5L Grade B pipe is used with ASTM A105 flanges and threaded/socket-weld fittings; ASTM A-234 Grade WPB seamless, butt-weld fittings; ASTM A-193 Grade B-7 and A-354 Grade BC flange stud bolts; and ASTM A-194 Grade 2H nuts. In higher pressure where the pipe and fitting wall-thickness requirements become a cost factor (because of the extra weight of the steel), pipe and fittings manufactured to higher-strength steel specification and grade may be used. For example, if a design would require that 0.500-in. wall, A-106 Grade B pipe be used with A-234 Grade WPB seamless fittings, an API 5L Grade X65 pipe (say with a design wall thickness of 0.250 in. and companion grade butt-weld fittings) could be used to save wall thickness and weight, which would save cost for the materials. (Note: the higher-grade steel butt-weld fittings may cost slightly more than the more commonly available A-234 Grade WPB, but any cost differential is usually offset by the difference in physical weight saved—the price for carbon-steel pipe and fittings is essentially based on the weight of the steel.)

Most of the common Grade B steels are safe to operate down to –20°F. For colder-service conditions, A-106 and API 5L Grade B can operate to –50°F, if the maximum operating pressure is less than 25% of the maximum allowable design pressure, and if the combined longitudinal stress because of pressure, dead weight, and displacement strain is less than 6,000 psi. The common Grade B steels can be used in service to –50°F if the pipe and fittings are heat treated and Charpy impact tested. However, a number of other commonly available steel specifications and grades for pipe, flanges, valves, and fittings are available for low-temperature service without special testing. Some common steels available include ASTM A-333 Grade 1 (–50°F), A-334 Grade 1(–50° F), A-312 TP 304L (stainless steel, –425°F), and A-312 TP 316L (stainless steel, –325°F).

Pipe and butt-weld fittings in ASTM A-53 Grade B, A-106 Grade B, A-333 Grade1, and API 5L Grade B and the "X" grades (X42 through X65) are acceptable for H_2S service. Natl. Assn. of Corrosion Engineers (NACE) Standard MR-01-75, Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment, [9] Secs. 3 and 5, prescribes the requirements for steel pipe, valves, and fittings in such service.

Minimum wall thickness - pipe and fittings

The pressure and temperature requirements, and the chosen wall-thickness calculation formula, dictate the resulting pipe wall thickness required for the piping or pipeline design. The specification and grade of pipe and fitting materials selected for the design must be compatible with each other chemically (e.g., carbon content) so that the fittings can be welded to the pipe. In Sec. IX of the ASME Codes for Welding,[10] base metals (pipe and fittings) have been assigned P-numbers and group numbers. Within the P-number groupings, ferrous base metals, which have specified impact test requirements, are classified in groups. The assigned P-numbers and group numbers are based essentially on comparable base-metal characteristics, such as:

- Composition
- Weldability
- Brazeability
- Mechanical properties

The ASME/ANSI and ASTM material specifications for pipe and fittings will list the P-numbers and group numbers within the data. The group number and P-numbers for the materials to be welded should be compatible (see ASME Sec. IX, QW-420[10] to verify material compatibility). Typically, for most oil and gas production-facility and pipeline applications (Group 1), P-1 materials will be required. The various codes and standards may prescribe allowable tolerances for pipe-to-fitting thickness variances. The allowable operating pressure and temperature and wall thickness of the fitting must be compatible with the pipe design. The maximum allowable operating pressure and temperature of the weakest piping-system component will determine the maximum allowable operating pressure for the system.

In small diameter threaded piping systems, for mechanical strength, impact resistance, and corrosion resistance, the pipe should have at least a 0.25-in. wall thickness. For smaller pipe, it is recommended that 3/4-in. and smaller pipe be Schedule 160, 2 to 3 in. Schedule 80, and 4 to 6 in. Schedule 40. ANSI/ASME B31.3[2] recommends that 1 1/2-in. and smaller threaded pipe use a minimum Schedule 80 and 2 in. and larger use Schedule 40.

Branch connections

Branch connections in piping systems must be designed for both pressure/temperature requirements and mechanical strength. Typically, a tee fitting should be used for branch connections unless the nominal branch pipe diameter is less than 1/2 of the nominal, main "run" pipe diameter. If a connection, other than a tee, is used for the branch, ANSI/ASME B31.3[2] requires that the branch connection be reinforced; a pipe coupling is used if the branch size is 2 in. or less and the branch is less than 1/4 of the diameter of the pipe run, or an integrally reinforced, pressure-tested branch fitting (such as a weld-o-let, thread-o-let, or socket-o-let) is used. **Table 13** is an example branch-connection schedule that could be used to specify the proper choice of branch connection.

 Table 13

Valves

There are several types of isolation valves that are used in hydrocarbon service applications, including:

- Ball valves
- Gate valves
- Plug valves
- Globe valves

- Butterfly valves
- Diaphragm valves
- Needle valves

Table 14 describes some of the characteristics of the various isolation valves. Valves are designed and manufactured under many industry standards. For most hydrocarbon service, valves manufactured under API Spec. 6F[11] standards are used. Valves are designed and manufactured with a variety of end connections, body and trim materials, seat and seal materials, and operators. Valves are rated in accordance with the ANSI and API pressure class systems:

- ANSI

  - 150

    - 300
    - 400
    - 600
    - 900
    - 1,500
    - 2,500

    - API 6A

      - 2,000

    - 3,000
    - 5,000
    - 10,000
    - 15,000
    - 20,000
    - 30,000

TABLE 9.20—VARIOUS VALVE TYPES AND CHARACTERISTICS (courtesy of AMEC Paragon)

Ball Valves	Plug Valves	Gate Valves	Butterfly Valves	Globe Valves	Diaphragm (Bladder) Valves	Needle Valves
1/4 turn	1/4 turn	Many turns	1/4 turn	Many turns	Suitable for throttling slurry service	Miniature globe valves used for instrumentation systems
Temperature limited by elastomer	Temperature limited by elastomer seal	May vibrate from normal position	Not leak tight	Suitable for throttling	Temperature limited	Used for throttling small volumes
Not suitable for throttling	May need to be lubricated often	Unprotected rising stem can be hard to operate	Vibrate open unless lock on handle	Metal-to-metal seat	Metal-to-metal seat	Metal-to-metal seat
	Torque varies—hard to automate	Not suitable for throttling	Inexpensive	Small stem movement—easy to automate		Easy to plug small passages
	Not suitable for throttling	Easy to automate with power piston	Can use to throttle where tight shutoff not required			
	Usually cheaper than ball	In high pressures or large sizes usually cheaper than ball or plug				

Table 14

Valves used on the wellhead are typically API valves built to the same pressure ratings as the API flanges, whereas valves used in the production facility and pipelines are most commonly ANSI flange rated.

The options specified for isolation valves include:

- End connections: weld end, threaded (or screw) end, and flanged end (RF or RTJ).

- Body and trim: cast iron, ductile iron, carbon steel, stainless steel, and NACE.
- Seat and seal materials: PTFE, Fluroelastomer, Buna-N, Viton, Nylon, and others.
- Operator: lever, hand-wheel, gear, and automatic (extensions if needed).
- Fire safe rating: per API Spec. 6FA.[12]
- Pressure rating: ANSI/ASME or API.
- Mounting: floating or trunion (ball and plug valves).
- Port configuration: full, reduced, or regular port (ball, gate, and plug valve).
- Seating: double or single seat (ball and gate valve).
- Double block and bleed: ball and gate.
- Sealant fittings: ball and plug valves.
- Rising or nonrising stem and inside or outside yoke: gate valves.

Refer to manufacturer's literature for the various options available for specific valve types and their intended use.

The other type of valve commonly used is the check valve, which allows flow in one direction only. There are four types of check valves:

- Swing
- Split disk
- Lift plug/piston
- Ball

The swing check valve is suitable for nonpulsating flow and is not good for vertical-flow applications. The split-disk check valves are mounted between flanges (wafer configuration), but the operating springs are easily subject to failure. The lift-plug and piston check valves are good for pulsating-flow conditions—an orifice controls the plug or piston movement, and they are excellent in vertical flow conditions; however, the lift-plug/piston check valve can easily be cut out in sandy service and is subject to fouling with paraffin and debris. The ball check valve is typically used in 2-in. and smaller lines and can be used in vertical-flow applications, but it does have a characteristic of slamming shut upon flow reversal. Check valves are designed and manufactured under the same codes and standards as isolation valves. The pressure ratings, end connections, body materials, seals, etc. are the same as for isolation valves. Note: Check valves should never be substituted for a positive-shutoff isolation valve in any piping-system application. Under ideal service conditions, the best check valve in the perfect application will not guarantee a positive shutoff.

Control valves and pressure - relief/safety devices

Automatic control valves and pressure-relief devices are an integral part of oil and gas facility and pipeline-system piping. Control valves typically are used to regulate pressure, temperature, and flow rate. Pressure-relief valves and devices prevent the piping system from exceeding the maximum allowable pressure. As piping-system components, control valves and pressure-relief valves come in a variety of configurations and materials and are rated in accordance with the ANSI and API pressure classes, flange ratings, and end connections. As with isolation and check valves, control valves and pressure-relief valves must be rated for the maximum allowable pressure of the interconnecting piping system.

Specification pressure breaks

Fluid flowing through a piping system can undergo pressure decreases by flowing through chokes and/or control valves. However, if flow were to stop, the pressure in the line would increase to the upstream pressure.

When fluid flows from a high-pressure source into a lower-pressure system, there is a distinct point where the system could be subjected to the higher pressure by activation of an

isolation valve. This distinct point is called a specification "pressure break" point. Pipe valves and fittings upstream of this point must be designed to withstand the higher pressure.

The piping and equipment must be designed for the maximum possible source pressure that the system might experience. This means that any segment that can be isolated either intentionally or accidentally from a downstream relief device must be designed for the maximum upstream pressure to which it can be subjected. Typically, this "design" pressure will be set by the set pressure of an upstream relief device, or the maximum pressure that can be developed by the upstream source (pump, compressor, or wellhead). Because pressure breaks occur at isolation valves, careful placement of isolation valves must be considered in multipressure piping-system designs.

API RP14J, *Design and Hazards Analysis for Offshore Production Facilities*[13] provides the following guidance for determining the proper maximum allowable pressure to use in designing a segment of a piping system and the location of specification breaks.

- Check valves may leak or fail open and allow communication of pressure from the high side to the low side. (Check valves should still be used to minimize backflow in case of a leak, but cannot be relied upon to prevent overpressure.)
- Control valves, including self-contained regulators, can be in either the open or closed position, whichever allows the piping segment to be exposed to the maximum pressure.
- Block valves can be positioned in either the open or closed position, whichever position creates the highest pressure.
- Locked open (or closed) valves can be considered always open (or closed), if the lock and key are maintained in accordance with a proper lockout and tagout procedure. A hazards analysis should be performed to determine if the risk associated with relying on the lockout/tagout procedure is justified.

High-pressure sensors alone do not provide sufficient protection from overpressure. The one exception is that API RP 14C[14]allows the use of two independent isolation valves on production flowline segments (see the page on Safety systems). This should be approached with caution after thorough consideration of other alternatives.

Pressure-relief valves and rupture discs will always work because of the high reliability of their design. (In critical service, some operators require a backup relief valve or rupture disc to the primary relief device to increase reliability or to provide a spare).

In checking for spec-break locations, it is easiest to start at a primary pressure-relief valve (one designed for blocked discharge) and trace the upstream piping (including all branches) to the first block valve or control valve. It is then assumed the valve is closed, and the line is followed further upstream (including all branches) to the next pressure-relief valve or the source of pressure. The piping from the first block valve to the upstream pressure relief valve or source of pressure should be rated for the setting of the pressure-relief valve or maximum pressure of the source if no pressure-relief valves are present. Each branch upstream of the first block valve should be pressure rated at this highest pressure at every location, where it can be isolated from any downstream pressure-relief valve.

Fig. 2 shows an example of spec-break locations determined in this manner. **Fig. 3** shows how the spec breaks change if Valve 5 is added on the inlet to the low-pressure (LP) separator. Note: this changes the ratings of Valves B, D, and F in the manifold, as well as that of Valves 1 through 4 on the liquid outlet of the high pressure (HP) separator. **Fig. 4** shows that the pressure rating of Valves 1 through 4 do not need to be changed if the location of Valve 5 is changed. **Fig. 5** shows an alternative pressure rating scheme brought about by adding a relief valve upstream of Valve 5.
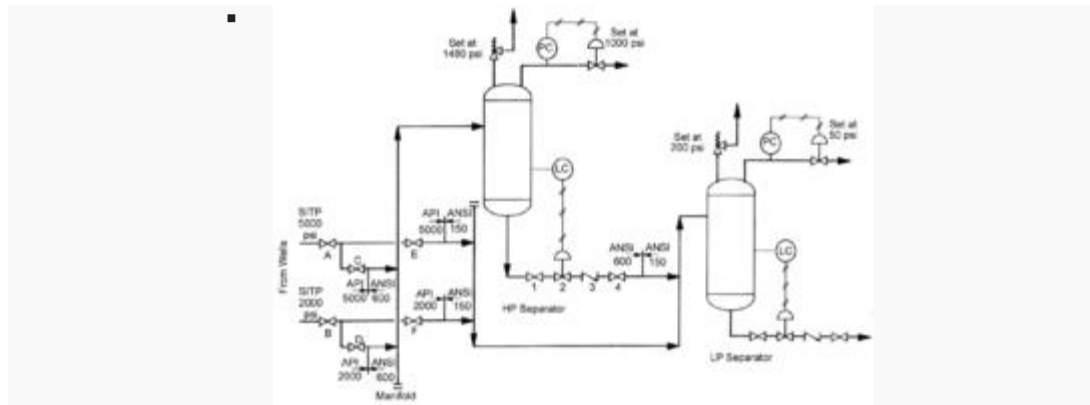
Fig. 2—Determination of pressure breaks. Example of spec break in accordance with API *RP14J* (courtesy of API).
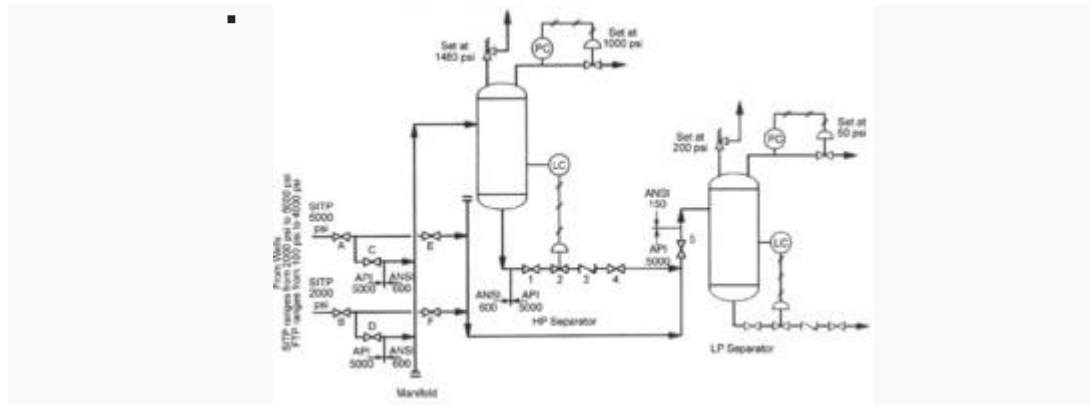

Fig. 3—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig 9.14 except Valve 5 has been added on the inlet to the low-pressure separator and down-stream of the high-pressure dump line, which changes the ratings of Valves B, D, and F on the inlet manifold as well as Valves 1 through 4 on the liquid outlet of the high-pressure separator (courtesy of API).
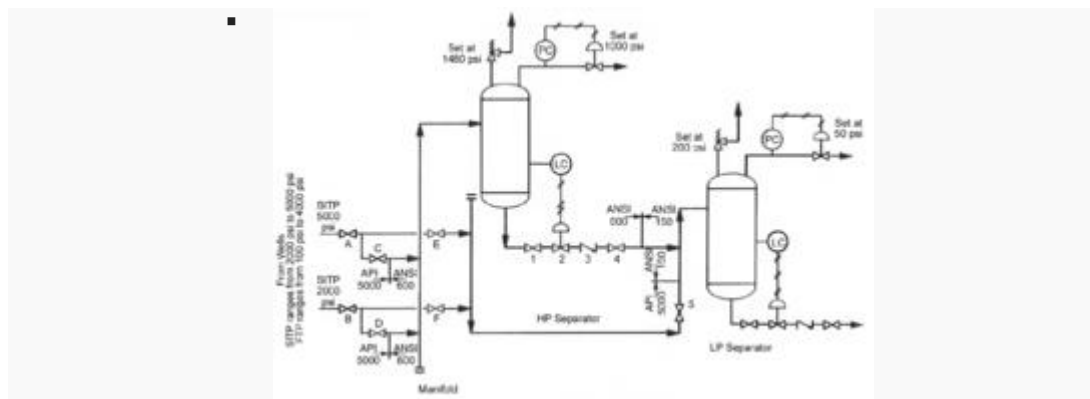

Fig. 4—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig. 9.14 except this shows that the pressure ratings of Valves 1 through 4

do not need to be changed if Valve 5 is located upstream of the dump line from the high-pressure separator (courtesy of API).
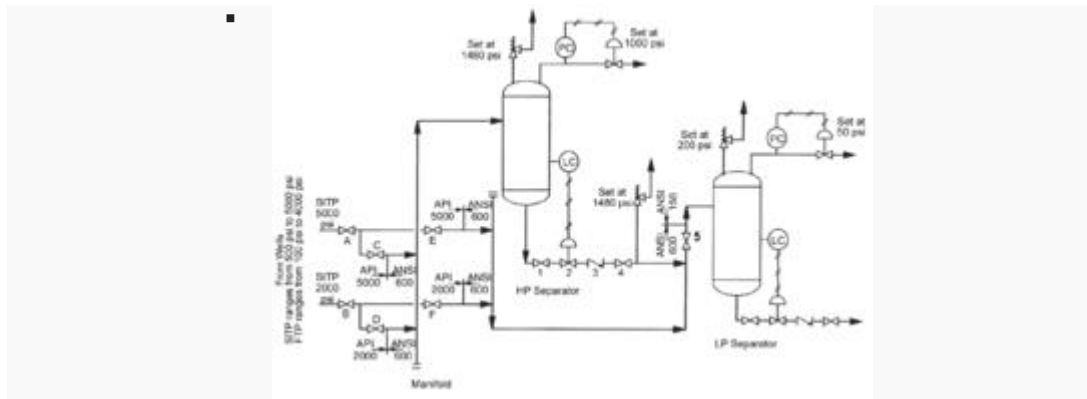

Fig. 5—Determination of pressure breaks. Same example of spec break in accordance with API *RP14J* as Fig. 9.14 except this shows an alternative spec-break scheme by adding a relief valve upstream of Valve 5 (courtesy of API).

Pipe expansion and supports

Pipe expansion

Steel piping systems are subject to movement because of thermal expansion/contraction and mechanical forces. Piping systems subjected to temperature changes greater than 50°F or temperature changes greater than 75°F, where the distance between piping turns is greater than 12 times the pipe diameter, may require expansion loops. ANSI/ASME B31.3[2] addresses the design requirements related to displacement strain because of thermal expansion, longitudinal sustained stresses, and computed displacement stress range.

Screening for expansion loops is not required by ANSI/ASME B31.3[2] if the piping system duplicates an existing system and can be readily judged as adequate by comparison to other piping systems and DY/(L–U) 2 ≤ 0.03, where D is the nominal pipe size in inches, Y is the expansion to be absorbed by the piping in inches, L is the length of the pipe segment in feet, and U is the straight-line distance between anchors).

In the majority of oil and gas facility and pipeline applications, pipe expansion is not critical, as normal piping arrangements contain the numerous elbows and changes of direction. These make the piping system relatively flexible and allow the pipe to absorb the expansion; however, if the flowing temperatures are high or there is a significant variation in temperature, the normal piping configuration may not be adequate to handle the expansion and contraction of the piping systems. The design must be checked to verify that the piping configuration will absorb the expansion and, if not, that expansion loop will be incorporated as needed.

The calculation of both actual and allowable stresses in piping systems subject to movement and large temperature changes is complex and requires special expertise. There are a number of good computer programs that calculate stresses in piping systems and compare them to the stresses allowed by the specific piping code.

Pipe support spacing

The proper location and spacing of above-ground-pipe supports can be determined as follows:

1. Assume that the hoop stress in the pipe is equal to the allowable stress, S_h, for the material at the design temperature.
2. According to Poisson's law, the axial stress can be no more than 0.3 S_h. The stress available for the bending moment is then 0.7 S_h.
3. As an approximation, assume 0.25 S_h is used for the moment caused by the pipe to allow for stress concentrations and occasional loads.
4. Assuming the pipe can be modeled as a fixed beam,

$$L = \left[\frac{0.2 S_h Z}{W}\right]^{1/2},$$

(Eq. 10)

where

L =   length between supports, ft,

S_h =   allowable stress, psi,

Z =   pipe-section modulus, in.^{3},

and

W =   weight of pipe filled with water, lbm/ft.

Eq. 10 is merely a conservative approximation. A more liberal spacing can be determined by using one of the many pipe stress calculation programs.

Nomenclature

H_s =   hoop stress in pipe wall, psi,

t =   pipe wall thickness, in.,

L =   length of pipe, ft,

P =   internal pressure of the pipe, psi,

t_e =   corrosion allowance, in.,

t_{th} = thread or groove depth, in. (**Table 2**),

P = allowable internal pressure in pipe, psi,

d_o = outside diameter of pipe, in.,

S = allowable stress for pipe, psi (**Tables 3 and 4**),

E = longitudinal weld-joint factor [1.0 seamless, 0.95 electric fusion weld, double butt, straight or spiral seam APL 5L, 0.85 electric resistance weld (ERW), 0.60 furnace butt weld],

Y = derating factor (0.4 for ferrous materials operating below 900°F),

T_{ol} = manufacturers allowable tolerance, % (12.5 pipe up to 20 in.-OD, 10 pipe > 20 in. OD, API 5L).

t = minimum design wall thickness, in.,

P = internal pressure in pipe, psi,

S_Y = minimum yield stress for pipe, psi (**Table 5**),

F = derating factor, 0.72 for all locations,

E = longitudinal weld-joint factor [1.0 seamless, ERW, double submerged arc weld and flash weld; 0.80 electric fusion (arc) weld and electric fusion weld, 0.60 furnace butt weld].

t = minimum design wall thickness, in.,

P = internal pressure in pipe, psi,

d_o = OD of pipe, in.,

S_Y = minimum yield stress for pipe, psi (**Table 6**),

F = design factor (see **Table 7** and discussion that follows),

E = longitudinal weld-joint factor (**Table 8**),

T = temperature derating factor (**Table 9**).

Q_L =   fluid-flow rate, B/D

V_g =   gas velocity, ft/sec,

Q_g =   gas-flow rate, MMscf/D,

T =   gas flowing temperature, °R,

P =   flowing pressure, psia,

Z =   compressibility factor, dimensionless,

d =   pipe ID in.

SG =   specific gravity of the liquid (relative to water),

S =   specific gravity of the gas relative to air