# FIXED EQUIPMENT NEWSLETTER

## VOLUME 2020, APRIL ISSUE

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ASME Pressure Vessel Criteria for preventing Brittle Fracture

Hydrostatic Testing of Pressure Vessels

Corrosion, Common Varities, and Prevention Methods

Fitness for Service Engineering Assessment

Communication Tips from Warren Buffett

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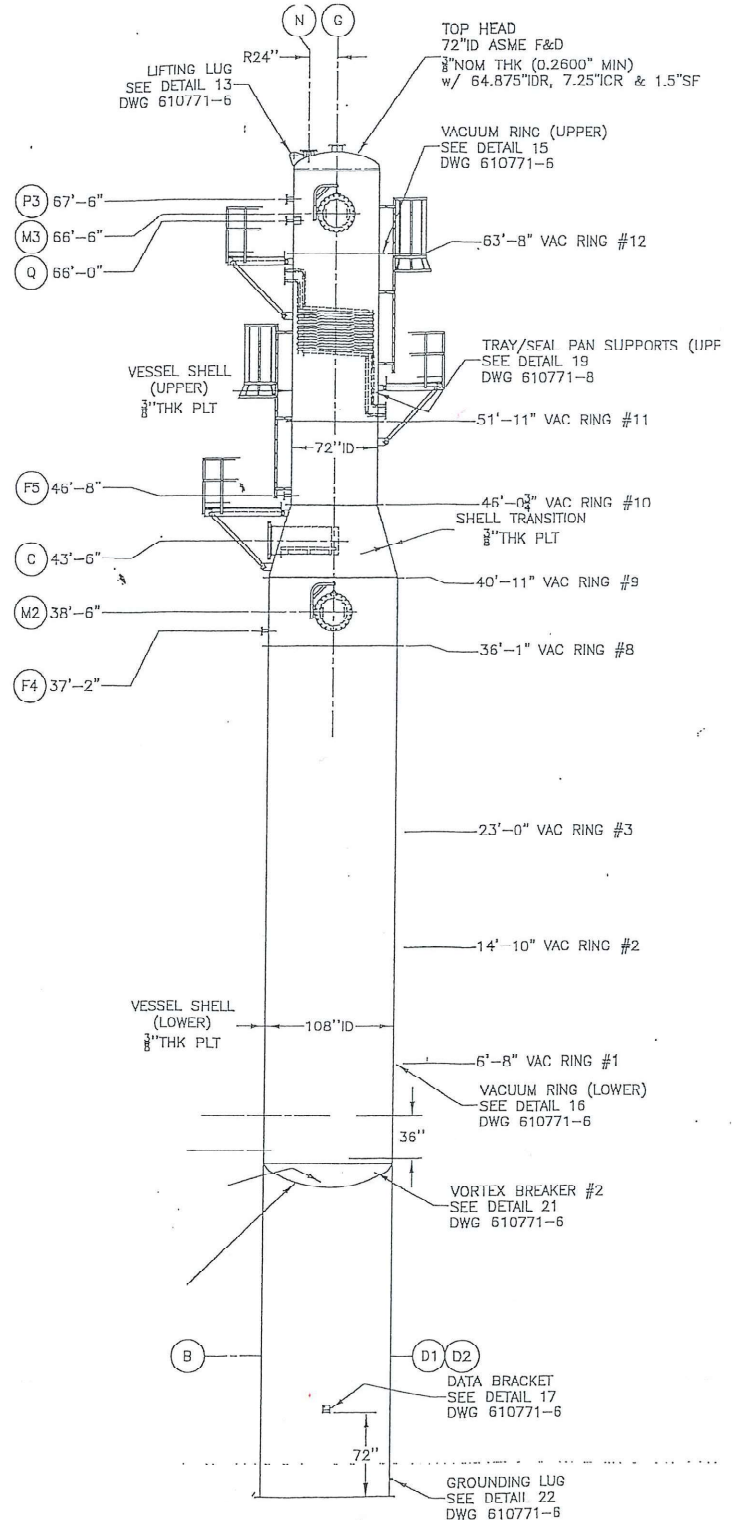
# COVID-19: Unemployment Guide

The **novel coronavirus** has leveled the American economy and has businesses of all sizes tightening their belts. Much of that pain is getting passed on to workers as businesses are forced to close because of public health orders or cut costs through layoffs and furloughs. Here's everything you need to know if you've lost your job or been furloughed because of the spread of covid-19.

**AM I ELIGIBLE FOR UNEMPLOYMENT INSURANCE?**

If you lost your job or were furloughed because of the coronavirus, you qualify for weekly unemployment payments from the state in which you worked. The payout is based on how much you earned and aims to replace about half of your previous income. It also varies by state. States also have certain requirements and conditions about who can collect unemployment benefits. Texas and Florida, for example, require recipients to be actively searching for work while they collect payments. Pennsylvania requires beneficiaries to register for employment-search services and mandates they "not refuse work when offered without good cause." You also have to meet certain wage and job duration benchmarks; you basically have to prove you were doing meaningful work before you became unemployed.

**WHAT HAPPENS TO MY HEALTH INSURANCE?**

If you're furloughed, you likely will hold on to your health insurance. If you've been laid off, your benefits usually end when you leave your job, which leaves you with two main options. You can keep your employer's plan for up to three years with a federal program called COBRA, but you have to pay for premiums yourself.

For most people, the cheaper option is purchasing insurance through the Affordable Care Act, commonly known as Obamacare. Since you've lost your job, you may get a hefty government subsidy that will make a policy purchased through Healthcare.gov or your state's health insurance marketplace more affordable.

**WHAT SHOULD I DO IF I'VE BEEN LAID OFF OR FURLOUGHED?**

Apply for unemployment insurance benefits right away. The Cares Act provides a bunch of money for states to pay out folks who lose their jobs or get furloughed. Next, assess your financial situation. Do you have money saved? Do you have any other sources of income? Take that all into account and make a new monthly budget. Use it as an opportunity to find out what expenses you can do without.

If you have a 401(k) retirement account and are younger than 59½, you can withdraw as much as $100,000 without incurring the 10 percent penalty, which has been temporarily waived under the Cares Act. You'll still be on the hook for taxes, though.

Finally, start dusting off your resume. It's never too early to start looking for your next job. Even though businesses in your field may not be hiring during the coronavirus crisis, you'll be better off when jobs do start appearing for having prepared for those openings

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## ASME PRESSURE VESSEL CRITERIA

The ASME VIII-1, uses a simplified approach for preventing brittle fracture in pressure vessels constructed with carbon steel. The code uses exemption curves (Figure 1) to determine the acceptable minimum temperature for a given material and thickness where impact testing is not required. The figure is based on experience as well as test data. The notes to the figure list only a small number of specifications that are assigned to the various exemption curves. Additional specifications are to be added as more data become available.
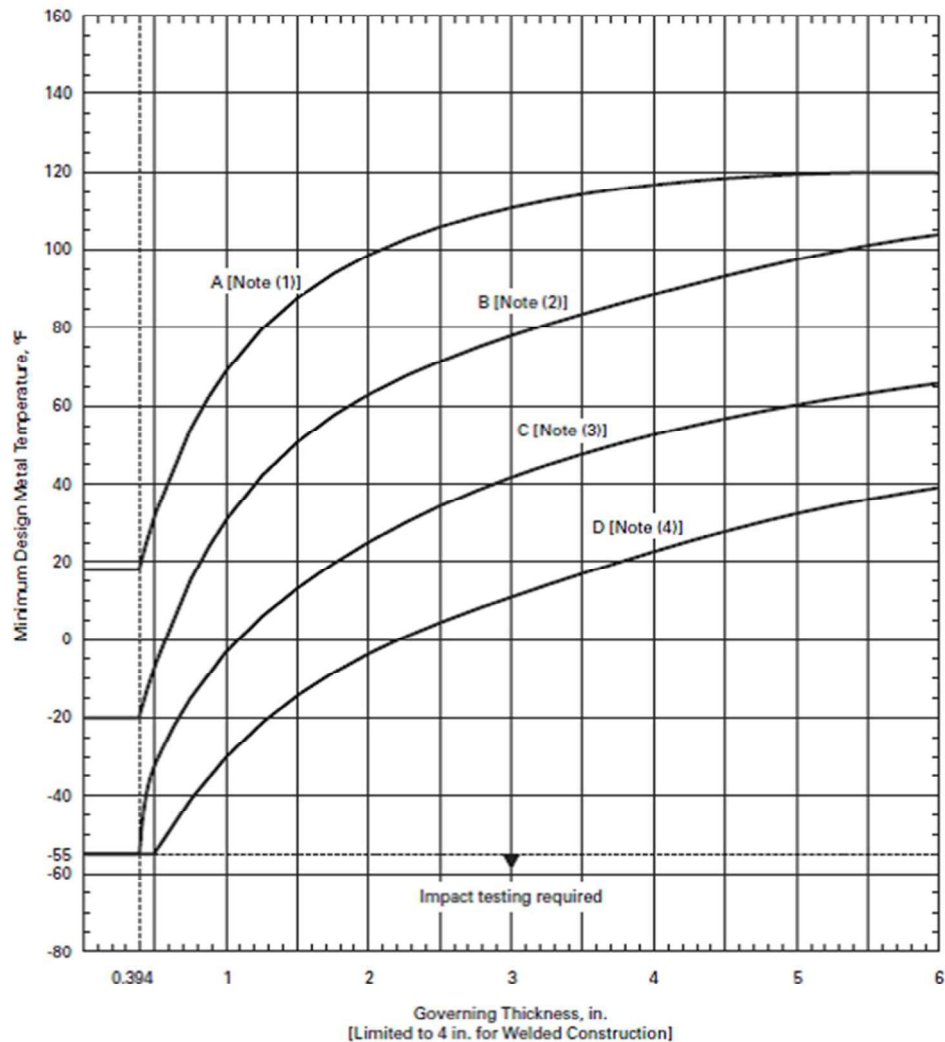


**Figure 1: Impact Test Exemption Curves**

The figure requires impact testing for all welded thicknesses over 4 in. and all non-welded thicknesses over 6 in. also, the minimum acceptable temperature without impact testing is −55°F. The 0.394 in. cutoff limit on the left-hand side corresponds to 1 cm, which is the size of a Charpy V-notch specimen. In using the curves, the designer

must specify the minimum design metal temperature at which the vessel is to operate. The ASME Code does not provide minimum-temperature charts for various locations. Figure 2 can be used as a guide to minimum temperatures for vessels located in the United States and Canada.
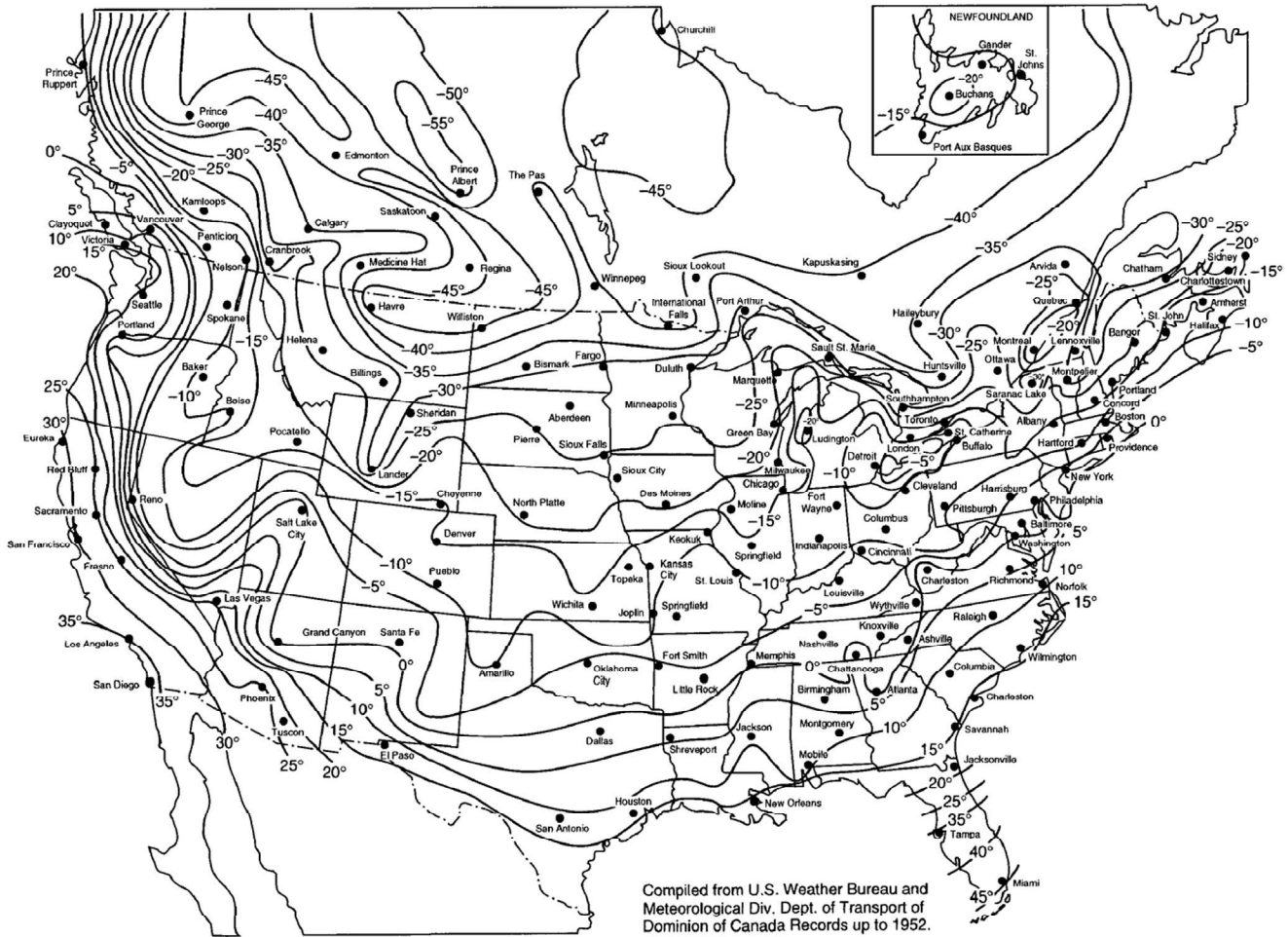


**Figure 2: Isothermal Lines of Lowest On-Day Mean Temperatures (°F)**

The exemption curves in Figure 1 can be constructed from theoretical brittle-fracture considerations. This is done by expressing the relationship between $\beta_{IC}$ and $K_{IC}$ as:

$$\beta_{IC} = \frac{1}{B}\left(\frac{K_{IC}}{\sigma_y}\right)^2 \qquad \text{[Eq. 1]}$$

where, $K_{IC}$ = Stress Intensity Factor

$B$ = Thickness

$\beta_{IC}$ = Factor

$\sigma_y$ = Yield Stress

Tests have shown that a value $\beta_{IC}$ = 1.5 represents a leak-before-failure condition in the vessel. On the other hand, a value of $\beta_{IC}$ = 0.4 represents the upper limit of small-scale yielding where the linear theory of elastic fracture mechanics is applicable. Using a conservative $\beta_{IC}$ value of 1.5, Eq. 1 becomes

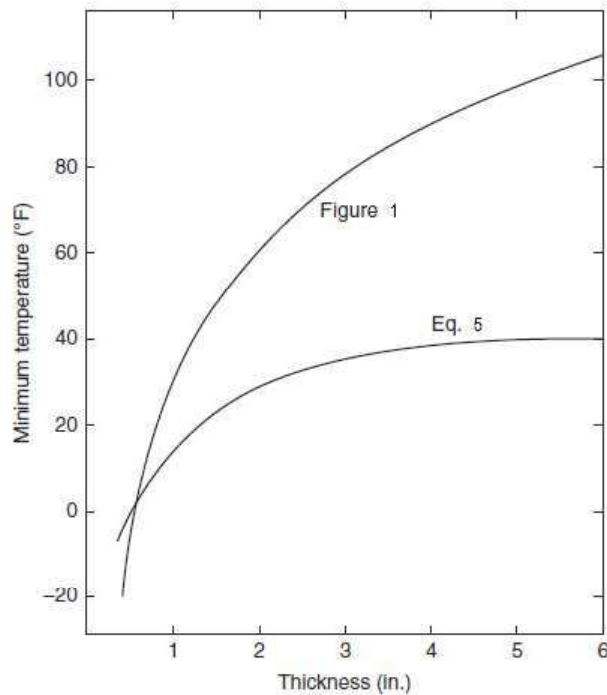$$1.5B = \left(\frac{K_{IC}}{\sigma_y}\right)^2 \qquad \text{[Eq. 2]}$$

Tests correlating $K_{IC}$ to the temperature and yield stress have shown that an approximate equation can be written as:

$$K_{IC} = \frac{\sigma_y}{C_1 - C_2 T} \qquad \text{[Eq. 3]}$$

where   $C_1, C_2$   =   Constants

   T   =   Temperature

Substituting Eq. 2 into Eq. 3 gives:

$$T = \frac{C_1}{C_2} - \frac{1}{\sqrt{1.5B}\,C_2} \qquad \text{[Eq. 4]}$$



**Figure 3: Thickness-Temperature Relationship for SA 302 Gr B Material**

Eq. 4 forms the basis for plotting various exemption curves. The constants $C_1$ and $C_2$ have to be established experimentally. For SA 302 Gr B, tests have shown that the approximate values of $C_1$ and $C_2$ are 1.15 and 0.0208 respectively and Eq. 4 becomes:

$$T = 55.3 - \frac{39.3}{\sqrt{B}} \qquad \text{[Eq. 5]}$$

A plot of this equation is shown in Figure 3. Also shown is a plot of curve B from Figure 1 which is for SA 302 Gr B material. Figure 3 shows that the theoretical solution results in lower temperature values compared to the conservative curve in ASME VIII-1. Similar equations can be developed for various materials after establishing the values of $C_1$ and $C_2$.

Notes to Figure 1:

1)   Curve A applies to:

a. All carbon and all low-alloy steel plates, structural shapes, and bars not listed in Curves B, C, and D.

b. SA-216 Grades WCB and WCC if normalized and tempered or water-quenched and tempered; SA-217 Grade WC6 if normalized and tempered or water-quenched and tempered.

2) Curve B applies to:

a. See the following:

SA-216 Grade WCA if normalized and tempered or water-quenched and tempered

SA-216 Grades WCB and WCC for thicknesses not exceeding 2 in., if produced to fine-grain practice and water-quenched and tempered

SA-217 Grade WC9 if normalized and tempered

SA-285 Grades A and B

SA-414 Grade A

SA-515 Grade 60

SA-516 Grades 65 and 70 if not normalized

SA-612 if not normalized

SA-662 Grade B if not normalized

SA/EN 10028-2 Grades P235GH, P265GH, P295GH, and P355GH as rolled

SA/AS 1548 Grades PT430NR and PT460NR;

b. Except for cast steels, all materials of Curve A if produced to fine-grain practice and normalized, which are not listed in Curves C and D;

c. All pipe, fittings, forgings, and tubing not listed for Curves C and D;

d. Parts permitted under UG-11 shall be included in Curve B even when fabricated from plate that otherwise would be assigned to a different curve.

3) Curve C applies to:

a. See the following:

SA-182 Grades F21 and F22 if normalized and tempered

SA-302 Grades C and D

SA-336 F21 and F22 if normalized and tempered, or liquid-quenched and tempered

SA-387 Grades 21 and 22 if normalized and tempered, or liquid-quenched and tempered

SA-516 Grades 55 and 60 if not normalized

SA-533 Grades B, C, and E

SA-662 Grade A

b. All materials listed in 2(a) and 2(c) for Curve B if produced to fine-grain practice and normalized, normalized and tempered, or liquid-quenched and tempered as permitted in the material specification and not listed for Curve D.

4) Curve D applies to:

SA-203

SA-508 Grade 1

SA-516 if normalized or quenched and tempered

SA-524 Classes 1 and 2

SA-537 Classes 1, 2, and 3

SA-612 if normalized

SA-662 if normalized

SA-738 Grade A

SA-738 Grade A with Cb and V deliberately added in accordance with the provisions of the material specification, not colder than −20°F

SA-738 Grade B not colder than −20°F

SA/AS 1548 Grades PT430N and PT460N.

The derivation of Eq. 5 extends the brittle-fracture theory to materials with relatively low yield strength. This produces a number of uncertainties, since the theory is intended for materials with high yield strength. Also, the brittle-fracture theory disregards numerous factors that affect the toughness of low-strength steels such as fine-grain practice, normalizing, quenching, and postweld heat treating. Because of these factors, the shape and temperature exemption of the curves in Figure 1 are based on the experience of the industry with the various materials listed in the figure rather than on theoretical equations.
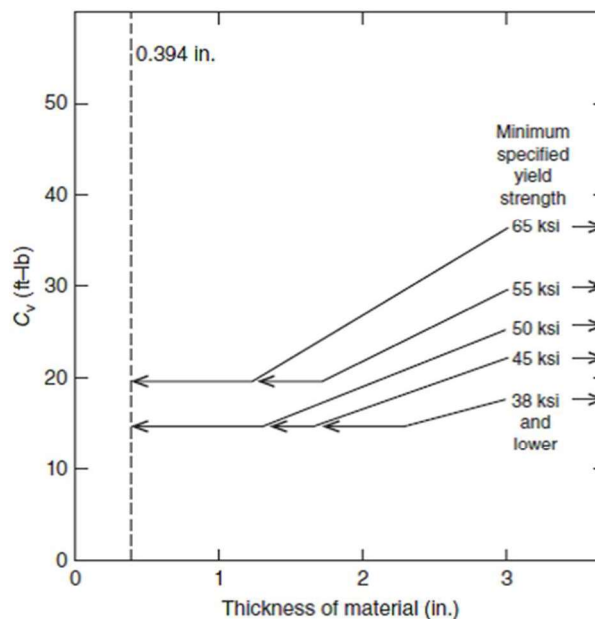


**Figure 4: Charpy V – Notch Test Requirements**

When a material is required to be impact tested in accordance with Figure 1, the specified minimum energy level is obtained from Figure 4. This figure takes into consideration the interaction between thickness, yield strength, and toughness levels. The energy level given by the figure is obtained from experience with various materials and thicknesses.

Curves similar to those shown in Figure 4 for the interaction between thickness, energy, and yield strength can be expressed theoretically by using the equation:

$$K_{IC}^2/E = 5C_V \qquad \text{[Eq. 6]}$$

Combining this equation with Eq. 2 gives:

$$C_V = 0.01B\sigma_y^2$$

This equation gives the required values that tend to be too high for most available low-carbon steels. Accordingly, Figure 4 was generated from experience rather than theoretical formulation.

In developing Figures 1 and 4, consideration was given to the fact that the actual relationships between $C_V$, $K_{IC}$ and $\sigma_y$ are all based on dynamic strain rates. The strain rate developed in a Charpy V-notch test specimen is about 10 (in./in.)/s, while that in a pressure vessel is significantly lower and is of the magnitude of $10^{-3}$ (in./in.)/s. Hence, a given energy level of a $C_V$ specimen at a given temperature can be acceptable in a pressure vessel of low-carbon steel with lower strain rate at a significantly lower temperature. Because of this, the ASME gives some allowance for low-strength steel to be used at a design temperature lower than the Charpy V-notch test temperature, as shown in Table 1.

**Table 1: Impact Test Temperature Differential**

| Minimum specified yield strength (ksi) | Temperature difference (°F)[a] |
|---|---|
| ≤ 40 | 10 |
| ≤ 55 | 5 |
| > 55 | 0 |

a) Impact test temperature may be higher than the MDMT by the amount shown.

It has been shown that vessels constructed of low-carbon steel having a stress level below 6000 psi do not fail in brittle fracture. Accordingly, the ASME Code permits materials to be used at temperatures below those given in Figure 2 if the stress in a component is decreased below the allowable stress level. The amount of decrease in temperature as the stress level decreases is based on many theoretical considerations. The first is the intensity factor, which is defined as:

$$K_I = \sqrt{\frac{\pi a}{Q}}(S_m M_m + S_b M_b) \qquad \text{[Eq. 7]}$$

where

| | | |
|---|---|---|
| $K_I$ | = | Stress intensity factor, $ksi\sqrt{in}$ |
| $S_m$, $S_b$ | = | Membrane and bending stress respectively, ksi |
| $Q$ | = | Flow shape factor |
| $a$ | = | Depth of a surface flaw or one-half the minor diameter of an embedded flaw |
| $M_m$, $M_b$ | = | Corrections factors for membrane and bending stress |

ASME VIII-1 assumes a maximum flaw size of a = t/4 and l/a = 6, where l = major diameter of flaw (in.) and t = vessel wall thickness (in.). Based on these assumptions, the values of $M_m$ and $M_b$ are obtained from Figures 5 and 6, and are given by $M_m$ = 1.18 and $M_b$ = 0.80.
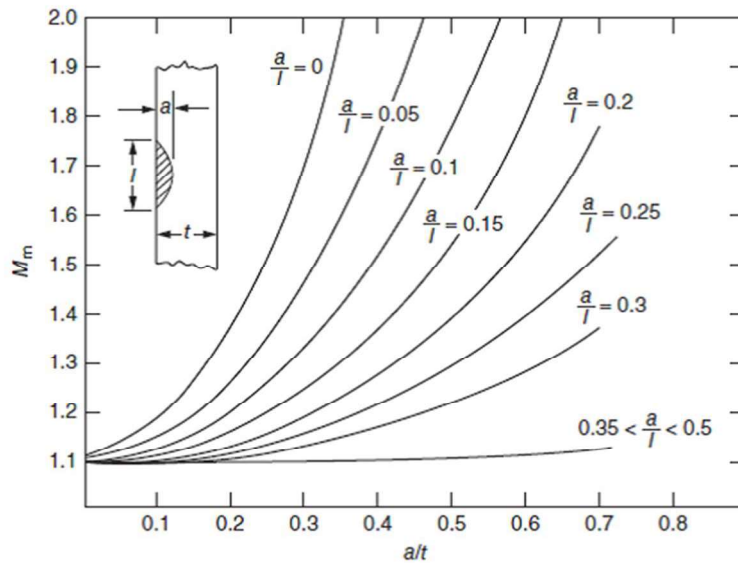
These values are based on surface flaw and are higher than those obtained from subsurface flaws. It is also assumed that the total stress is expressed as:

$$S_m + S_b \leq S_y$$

Letting $S_m = {}^{2/3}S_y$ and $S_b = {}^{1/3}S_y$, Eq. 7 reduces to:

$$K_I = 1.867 S_y \sqrt{a/Q}$$

**Figure 5: Membrane-Stress Correction Factor**
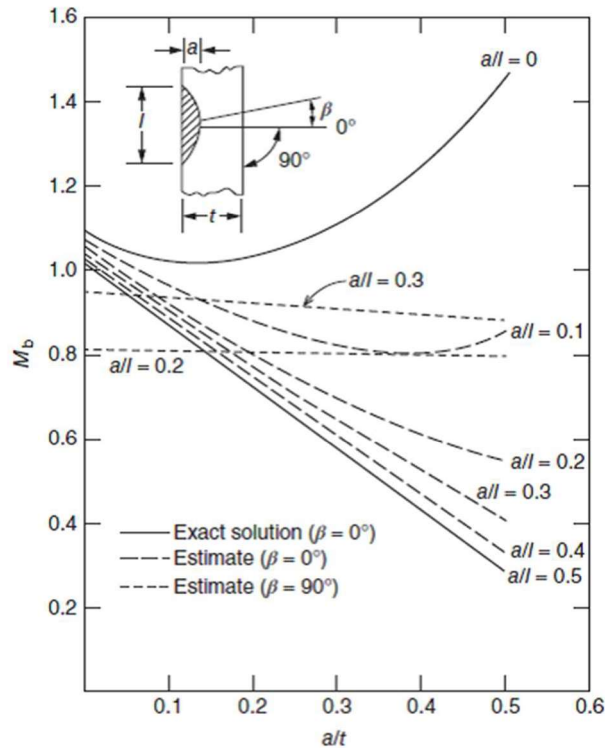
**Figure 6: Bending-Stress Correction Factor**

$K_I$ in Eq. 8 is a function of $S_y$, $Q$, and a. The value of $S_y$ is assumed to be 40 ksi, which is an average value for the majority of materials used in pressure vessel construction. The value of $Q$ is obtained from Figure 7 and is a function of the stress level. The actual value of a in Eq. 8 depends on the thickness of the vessel wall. Table 2 lists values of $K_I$ as a function of stress level using Eq. 8, different wall thicknesses, and Figure 7. The table also gives the ratio of the $K_I$ values at reduced stress levels to that at the full stress level of 40 ksi.

The $K_I$ ratios calculated in Table 2 are used to obtain temperature-reduction values from an actual $K_I$ curve. One such curve is shown in Figure 8 for SA-533 Gr. B class 1 and SA-508 class 2 and 3 steels. The $K_I$ value at NDT+60°F is used as a basis for establishing the temperature reduction shown in Figure 8. The temperature reduction is given in Table 3 and is plotted in Figure 9. This figure is used by the ASME for determining the reduction in minimum allowable temperature for various stress levels without impact testing.
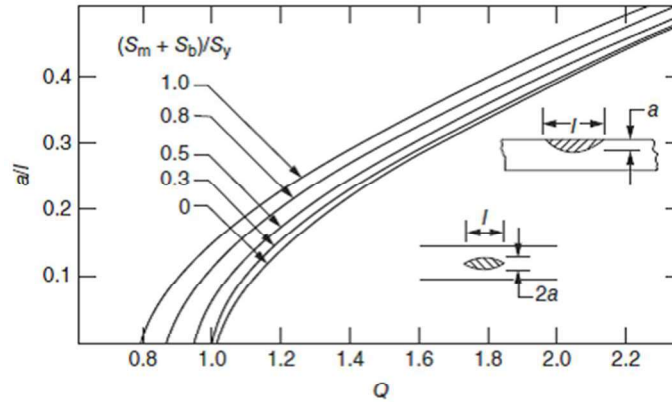


**Figure 7: Shape Factors**

**Table 2: $K_{IC}$ Values and Ratios** ($S_y$ = yield stress, ksi)

| | | $S/S_y$ = 1.0 | | 0.8 | | 0.5 | | 0.4 |
|---|---|---|---|---|---|---|---|---|
| | | Q = 1.045 | | 1.105 | | 1.18 | | 1.20 |
| Thickness (in) | a (in) | $K_c$ (1) | $K_{IC}$ (2) | (2)/(1) | $K_{IC}$ (3) | (3)/(1) | $K_{IC}$ (4) | (4)/(1) |
| 6 | 1.5 | 89 | 70 | 0.79 | 42 | 0.47 | 33 | 0.37 |
| 4 | 1.00 | 73 | 57 | 0.78 | 34 | 0.47 | 27 | 0.37 |
| 2 | 0.50 | 52 | 40 | 0.77 | 24 | 0.46 | 19 | 0.37 |
| 1 | 0.25 | 37 | 28 | 0.76 | 17 | 0.46 | 14 | 0.38 |
| 0.5 | 0.125 | 26 | 20 | 0.77 | 12 | 0.46 | 10 | 0.38 |
| Average | | | | 0.77 | | 0.47 | | 0.37 |
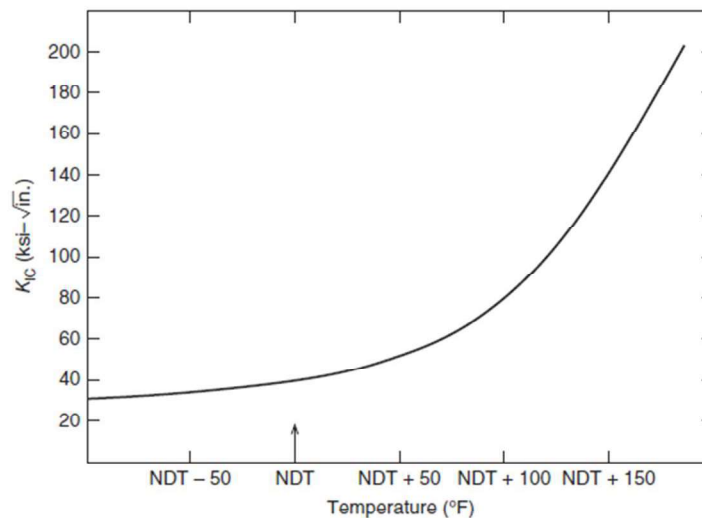


**Figure 8: $K_{IC}$ Test Data**
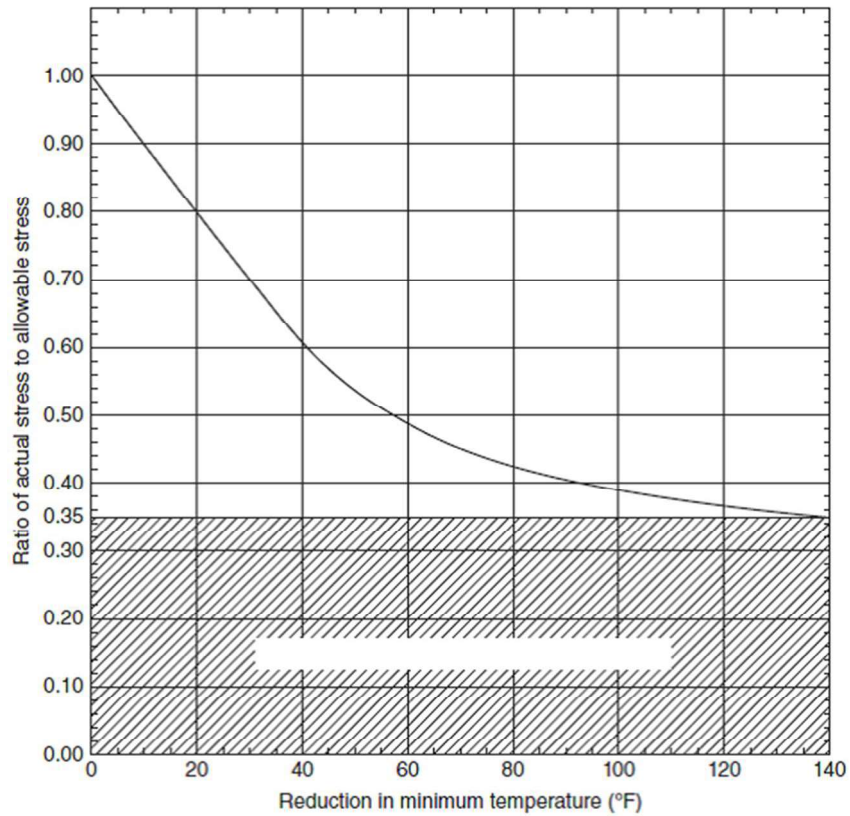
**Figure 9: ASME VIII-1 Temperature Reduction**

**Table 3: Temperature Reduction Values**

| $K_{IC}$ ratio average from Table 2 | $K_{IC}$ from Figure 8 (ksi $\sqrt{in.}$ | Temperature | Temperature difference (°F) |
|---|---|---|---|
| 1.0 | 114 [a] | NDT + 60°F | 0 |
| 0.77 | 88 | NDT + 41°F | 19 |
| 0.47 | 54 | NDT + 0°F | 60 |
| 0.37 | 42 | NDT - 46°F | 106 |

**References:**

Structural Analysis and Design of Process Equipment – Maan H. Jawad and James R. Farr

# HYDROSTATIC TESTING OF PRESSURE VESSELS

ASME Section VIII, Div. 1 (ASME Code) sets out the general requirements for inspection and testing for pressure vessels. One of the requirements is that either hydrostatic test or pneumatic test must be performed, and vessel must be inspected during the test. The test is done after all fabrication has been completed and all examinations have been performed. For most pressure vessels, hydrostatic test in accordance with UG-99 is done with water. For pressure vessels that cannot be safely filled with water, or where even traces of the testing liquid cannot be tolerated, a pneumatic test may be done in accordance with UG-100. This article looks at the ASME Code requirements for the hydrostatic testing of pressure vessels.



**Figure 1: Pressure Vessels after Completion of Hydrostatic Tests**
[*Courtesy of Fourinox, Geen Bay WI*]

**Hydrostatic Test Procedure**

Before the hydrostatic test is performed, the pressure vessel should be properly blocked to permit examination of all parts during the test. Large, thin-walled vessels may require extra blocking to guard against undue strains caused by the water load. Adequate venting must be provided to ensure that all parts of the pressure vessel can be filled with water.

Pressure vessels designed for internal pressure are subjected to a hydrostatic test pressure that, at every point in the vessel, is at least equal to 1.3 times the maximum allowable working pressure (MAWP) multiplied by the lowest stress ratio (LSR) for the material of which the pressure vessel is constructed. The LSR for the pressure vessel material is the ratio of the stress value at its test temperature to the stress value at the design temperature. The hydrostatic test pressure reading is adjusted to account for any static head conditions depending on the difference in elevation between the chamber being tested and the pressure gauge. Two gauges should be used to provide a double check on the pressure. If only one gauge is used and it is incorrect, the pressure vessel can be damaged by overpressure.

The ASME Code does not specify an upper limit for the hydrostatic test pressure. However, if it is allowed to exceed the required test pressure to the degree that the pressure vessel is subjected to visible permanent distortion, then the Inspector has the right to reject the pressure vessel.

If postweld heat treatment (PWHT) of the pressure vessel is required, it is done before the hydrostatic test. A preliminary hydrostatic test to reveal leaks prior to PWHT is permitted.
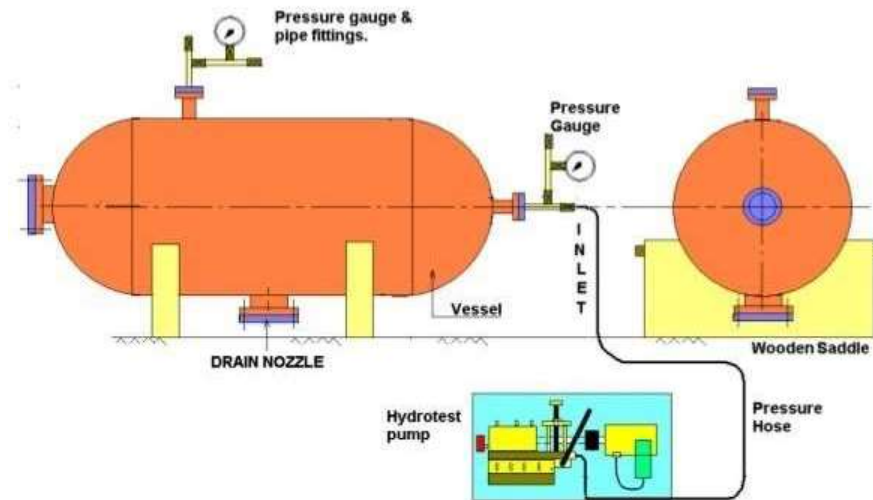
**Figure 2: Sketch for Hydrostatic Test**

**Combination of Units**

When the pressure chambers of combination units are designed to operate independently (as in the case of a shell-and-tube heat exchanger, for example), they are hydro-tested as separate pressure vessels. If the common elements are designed for a larger differential pressure than the higher of the design pressures of the adjacent chambers, then the hydrostatic test for the common element is based on at least their differential pressure. Following the hydrostatic tests of the independent chambers and the common elements, the adjacent chambers are hydro-tested simultaneously.

**Inspection of Pressure Vessel during Hydrostatic Test**

Following the application of the hydrostatic test pressure for a specific amount of time (usually from 10 minutes to half-hour), the pressure is reduced to a value not less than the test pressure divided by 1.3. Visual inspection is then made of all joints and connection. Other than the leakage that might occur at temporary test closures for those openings intended for welded connections, there should be no leakage at the time of visual inspection.

Once the inspection is complete and the pressure vessel has been drained, a final examination should be made of internal and external surface, the alignment, and the circularity.

**Hydrostatic Test Liquid**

Although water is mostly used for hydrostatic test, any non-hazardous liquid may be used provided it is below its boiling point. A fluorescent dye may be added to water to make leaks easier to detect. It is recommended that the metal temperature during the hydrostatic test be maintained at least 30°F above the MDMT to minimize the risk of brittle fracture, but need not exceed 120°F. If the test temperature exceeds 120°F, it is recommended that inspection of the pressure vessel should be delayed until the temperature is reduced to 120°F or less. Also the test pressure should not be applied until after the pressure vessel and its contents are at about the same temperature.

**Relief Valve**

It is recommended to have a small relief valve set to $1\frac{1}{3}$ times the test pressure for the pressure test system, in case the pressure vessel, while under hydrostatic test, is likely to be warmed up with personnel absent.

### Painting and Coating

Pressure-retaining welds of the pressure vessel should not be coated prior to the hydrostatic test. If coating these welds is absolutely necessary, they should first be leak tested in accordance with ASME Section V, Article 10. When the pressure vessels are intended for lethal service, coating of these welds prior to the hydrostatic test is not permitted.

### An Observation of the Hydrostatic Test Pressure

If the fluid head exists in the vessel only during hydrostatic testing, the primary membrane stress from the combination of the hydrostatic test pressure and the fluid-head pressure may go as high as the yield strength of the vessel material at the test temperature. However, if the resulting minimum required thickness from the combination is indicated as more than the thickness required for the normal design conditions, substitution of a pneumatic test or a combination hydrostatic-pneumatic test should be considered. In general, the minimum required thickness of a vessel should never be set by the requirements of the hydrostatic head unless it is impossible to test it any other way. Also, remember that a hydrostatic test may use fluids other than water if water causes a problem such as corrosion.

### Post Hydrostatic Test

The Authorized Inspector (AI), after witnessing the final hydrostatic tests and carrying out the examinations that are necessary, will check the pressure vessel data report sheets to make sure they are properly filled out and signed by the manufacturer. AI will then allow the Code Certification mark (Figure 3) to be applied in accordance with the Code requirements. If everything is in order, the datasheets are signed by the AI.
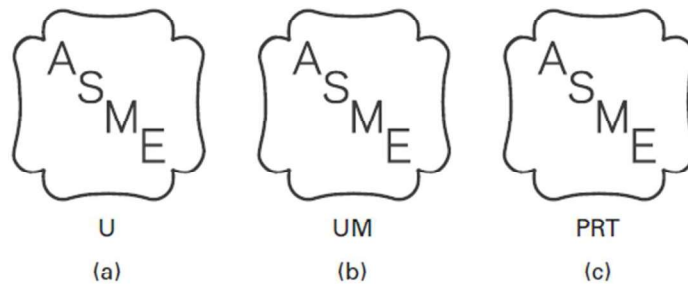


**Figure 3: ASME Section VIII, Division 1 Certification Marks**

**References:**

ASME Section VIII, Division 1 – 2019 Edition

Structural Analysis and Design of Process Equipment – Maan H. Jawad and James R. Farr

Pressure Vessels: The ASME Code Simplified – J. Phillip Ellenberger, Robert Chuse and Bryce Carson, Sr.

# SHELL-AND-TUBE HEAT EXCHANGERS: GENERAL DESIGN PRACTICES

## TUBE SIDE

- High pressure stream should be located on tube side.
- Stream requiring special metallurgy should be on tube side.
- Stream exhibiting highest fouling should be on tube side.

## SHELL SIDE

- More viscous fluid should be on shell side.
- Lower flowrate stream should be on shell side.

## FINNED TUBES

- Consider finned tube when shell side heat transfer coefficient is less than 30% of tube side heat transfer coefficient.
- Do not use finned tubes when shell side fouling is high.

## THERMAL DESIGN

- Do not provide thermal overdesign by increasing fouling factors.
- Provide thermal overdesign by increasing tube bundle length, not its diameter.

## OTHER CONSIDERATIONS

- Design heat exchanger for maximum utilization of pressure drop.
- Do not design heat exchanger for operation in transition flow.
- Vertical shell side condensation should be in down flow.
- Vertical tube side boiling should be in up flow.

**Note about typical heat transfer coefficients provided in literature:**

- Where a range of coefficients is given for liquids, the lower values are for cooling and the higher values are for heating.
- Tube side coefficients are usually based on ¾-in diameter tubes. Adjustment to other diameters may be made by multiplying by 0.75/ actual outside diameter.

**TEMA Shell Configurations:**

- Single shell-pass, TEMA "E" shells are preferred for most single-phase and condensing applications.
- Two shell-pass, TEMA "F" shells with two tube-pass bundles are preferred where pure counterflow conditions and maximum MTD are required.
- TEMA "G" and "H" split-flow shells are preferred only for horizontal shell-side thermosiphon reboilers.
- Divided-flow TEMA "J" shells with RODbaffle tube-bundles are preferred for low-pressure drop, single phase and condensing services.
- TEMA "K" shells are used exclusively for horizontal kettle reboilers.

Taken from "*Rules of Thumb for Process Engineers*" by H.R. Hunt.

# CORROSION, COMMON VARIETIES, AND PREVENTION METHODS

## CORROSION SCIENCE



Corrosion is a natural phenomenon, a chemical process rooted in science. Metals have a tendency after production and shaping to revert back to their lower energy, more natural state of ore (e.g. iron ore). The tendency is known as the Law of Entropy. It is very rare to find metals in their pure state naturally, more commonly, they are combined with other elements to form ores. In the steel industry, great efforts are expended to turn naturally occurring iron ore into steel.

Corrosion is the reverse process of metallurgy. In other words, the energy used to transform ore into a metal is reversed as the metal is exposed to oxygen and water. As the metal is exposed to these elements, the corrosion process begins oxides are formed on the steel surface and in some cases combine with sulfides and carbonates.

## CORROSION PROCESS

Elements are rarely found in a pure metal state. Rather they are found in chemical combinations with one or more nonmetallic elements. These chemical combinations are commonly known as ore. Iron, copper, and zinc ore are three of the most common ores found in the earth's crust.

Significant energy must be expended to reduce the ore to pure metal. This energy can be applied via metallurgical or chemical means and is done so in the process called smelting and refining. Additional energy also may be used in the form of cold-working or heating and casting the pure metal into a working shape. Corrosion, which can be simply defined as rust, is the tendency for metals to revert to their natural, lower energy state of ore.



Metallic corrosion includes exposure to oxygen in the environment and electrochemical processes, meaning the metal forms corrosion cells on its surface that greatly accelerate the transformation of metal back to the ore state, and involves both chemical reactions and the flow of electrons. A basic electrochemical process that drives the corrosion of metals is galvanic action, where current is generated internally by physical and chemical reactions occurring among the components of the cell.

TYPES OF CORROSION

There are several types of corrosion and the science and understanding of these processes are constantly evolving. Here is a brief overview of some common types of corrosion:

### Galvanic Corrosion

Galvanic corrosion is the most common and impactful form of corrosion. It occurs when two dissimilar (different) metals are in contact in the presence of an electrolyte. In a galvanic cell (bimetallic couple), the more active metal (anode) corrodes and the more noble metal (cathode) is protected. There are a number of factors that affect the galvanic corrosion including types of metals, relative size of anode, and environment (temperature, humidity, salinity, etc.)

### Pitting Corrosion

Pitting Corrosion occurs under certain conditions, which leads to accelerated corrosion in certain areas rather than uniform corrosion throughout the piece. Such conditions include low concentrations of oxygen or high concentrations of chlorides (anions) that interfere with the alloys ability to reform a passivating film. In the worst cases, most of the surface remains protected, but tiny fluctuations degrade the film in a few critical areas. Corrosion at these points is amplified and can cause pits.

### Microbial Corrosion

Microbial corrosion, commonly referred to as microbiologically influenced corrosion (MIC) is caused by microorganisms. It applies to both metallic and non-metallic materials with or without oxygen. When oxygen is absent, sulfate-reducing bacteria are active and produce hydrogen sulfide causing sulfide stress cracking. When oxygen is present, some bacteria may directly oxidize iron to iron oxides and hydroxides. Concentration cells can form in the deposits of corrosion products, leading to localized corrosion.

### High Temperature Corrosion

High-temperature corrosion, as its name suggest, is deterioration of a metal due to heating. This can occur when a metal is subjected to a hot atmosphere in the presence of oxygen, sulfur, or other compound capable of oxidizing the material.

### Crevice Corrosion

Crevice corrosion occurs in confined spaces where access of fluid from the environment is limited such as gaps and contact areas between parts, under gaskets or seals, inside cracks and seams and spaces filled with deposits.

CORROSION RATE



Approximately 85% of all steel produced is carbon steel and therefore susceptible to natural oxidation and galvanic corrosion. The rate of corrosion is well understood in typical atmospheric conditions, but for the design engineer, the precise localized or micro-environment conditions must be well understood for him/her to have confidence in the ultimate durability of the design. Other micro-environments include exposure to fresh and salt water (in or very near) or in soil.

Corrosion of carbon steel and even alloy steels in micro-environments can be very complex. For example, the pH, moisture content, and chloride level are just three of the variables determining the corrosion rate of galvanized steel in soil.

Corrosion charts are difficult to develop because of the many variables present in any given micro-environment. For example, corrosion in water must consider factors such as oxygen content, the extent of agitation, wave action, temperature, chloride levels and more. This makes developing a chart predictive of corrosion rates for any specific location extensive and sometimes costly, and why many corrosion rate charts exist, but only for unique locations and conditions.

Here is a little more detail about steel corrosion rates in various environments:

**Atmospheric**

The most common exposure environment for metallic corrosion is atmospheric. As steel, copper, magnesium, aluminum, et al are exposed to the atmosphere, they react with free flowing air and moisture to develop oxides. The performance of atmospherically exposed metals depends on five main factors: temperature, humidity, rainfall, sulfur dioxide (pollution) concentration in the air, and air salinity. None of these factors can be singled out as the main contributor to corrosion. Extensive studies have been conducted on these metals and a predictable corrosion rate for each is available.

Corrosion of carbon steel occurs when the relative humidity of the air is 70% to 80% and the air temperature is above 32 F. Corrosion rates may be accelerated by air impurities that dissolve in condensed water or rain water and by dust and dirt settling on the metal surface.

General corrosion rates of carbon steel in different atmospheres are provided in the following table. It should be noted corrosion rates in micro-environments can greatly exceed the corrosion rates given in the table.

The (uniform) corrosion rate of steel in different atmospheres:

| Atmosphere | Corrosion Rate (μm/year) |
|---|---|
| Rural | 4 - 60 |
| Urban | 30 - 70 |
| Industrial | 40 - 160 |
| Marine | 60 - 170 |

**In Soil**

Steel in soil is subjected to a range of corrosive forces quite unlike those experienced in atmospheric exposure conditions, and the performance of steel in-ground is not as well understood as is the durability in above-ground applications. With more than 200 different types of soil identified in North America, corrosion rate in soils is varied and hard to predict. Steel requires oxygen, moisture and the presence of dissolved salts to corrode. If any one of these is absent, the corrosion reaction will cease or proceed very slowly. Steel corrodes quickly in acidic environments and slowly or not at all as alkalinity is increased. The corrosion rate of steel in soil can range from less than 0.2 microns per year in favorable conditions to 20 microns per year or more in very aggressive soils.

Corrosion of metals in soil is extremely variable and while the soil environment is complex, it is possible to make some generalizations about soil types and corrosion. The main factors that dictate the corrosivity of the soil are moisture content, pH level, and chlorides. These soil conditions are affected by additional characteristics such as aeration, temperature, resistivity, and texture or particle size. Any given soil is a very heterogeneous material consisting of three phases: solid, gaseous, and aqueous.

The solid phase consists of soil particles that vary in size, in chemical composition, and the level of entrained organic material. The solid phase of soils are classified according to their average particle size and chemistry. Traditionally, particles between 0.07 mm to 2 mm are considered sand, particles from 0.0005 mm to 0.07 mm are silts, and 0.005 mm and smaller are clays. Because of the smaller particle size and their ability to absorb water readily, clay soils present a higher corrosion rate than sandy soils.

The gaseous phase consists of air entrained in the soils pores. Access of gas (air) into the soil depends on its permeability. Drier soils or coarser grained soils will allow more oxygen access to the sub-surface and increase the rate of steel corrosion relative to the areas with less oxygen.

The aqueous phase, or the soil moisture is the vehicle that allows corrosion to proceed. The relative acidity of the aqueous solution is the most important factor in the corrosion rate. At low pH the evolution of hydrogen tends to eliminate the possibility of protective film formation, so steel corrosion continues, but in alkaline solutions, protective films are created and reduce the corrosion rate. The greater alkalinity, the slower the rate of attack becomes. In neutral solutions, other factors such as aeration become more important, so generalizations are more difficult to develop.

**Marine (Water)**



A less common environment for metal is submerged in or exposed to water. Moisture is highly corrosive to most metals including steel, aluminum, and zinc. There are many different types of water (pure water, natural fresh water, potable water (treated drinking water), and seawater) and each has different mechanisms that determine the corrosion rate. The parameters that affect corrosion of metals in water include pH level, oxygen content, water temperature, agitation, the presence of inhibitors, and tide conditions.

Onshore areas of marine corrosion include docks, harbors, naval yards, where sacrificial anodes providing cathodic protection may be employed, as well as protective coatings such as marine paints and galvanizing. Offshore oil and gas platforms are exposed to particularly aggressive corrosion from sea salt spray and immersion.

**Pipeline**

Depending on the nature of the product being carried, exposure conditions, operating conditions (24/7 v. sporadic), and commitment to maintenance, pipeline corrosion may mean a useful life of one year or more than 50. In North America the cost of pipeline corrosion is approximately $9 billion annually with 10% apportioned to cost of failure, 38% to capital requirements, and 52% to operations and maintenance.



Although technology and monitoring equipment investment has increased significantly in the past few years, including risk assessment and pipeline integrity management programs, several high profile failures brings into question the effectiveness of such commitment to safety.

One of the challenges to pipeline corrosion is that it typically starts on the inside of the pipe, making detection difficult. Pervasive within the pipeline industry is the mentality to wait until a failure occurs to fix it. This is because the cost to implement effective inspection such as smart pigs is very high. This myopic strategy may save money in the near term, but surely has a higher cost to the environment and future capital requirements.

STEEL CORROSION

The corrosion process that takes place on a piece of uncoated steel is very complex. Factors such as variations in the composition/structure of the steel, presence of impurities due to the higher instance of recycled steel, uneven internal stress, and/or exposure to non-uniform environment all affect the corrosion process.

It is very easy for microscopic areas of the exposed steel to become relatively anodic or cathodic to one another. A large number of such areas can develop in a small section of the exposed steel. Further, it is highly possible

several different types of galvanic corrosion cells are present in the same small area of an actively corroding piece of steel.

As the corrosion process progresses, corrosion products tend to build up in certain areas of the metal. These corrosion products have different elemental compositions than the original state. The new compositions exposed on the surface lead to changes in the anodic and cathodic areas. As the change in anodic and cathodic areas occur, previously uncorroded areas of the metal can be attacked and corrode. This will accelerate the overall corrosion of the steel surface.

| Mosaic of anodes and cathodes, electrically connected by the underlying steel. | Moisture in the air provides the electrical path between anodes and cathodes. Due to differences in potential, electric current begins to flow as the anodic areas are consumed. Iron ions produced at the anode combine with the environment to form the flaky iron oxide known as rust. | As anodic areas corrode, new material of different composition and structure is exposed. This results in a change of electrical potentials and changes the location of anodic and cathodic sites. Over time, previously uncorroded areas are attacked and uniform surface corrosion results. This continues until the steel is entirely consumed. |
|---|---|---|

The corrosion products of steel are oxide particles and have a distinctive brown/red (rust) color. Just a small amount of these particles can cause an uncoated steel surface to appear corroded. Steel corrodes naturally when exposed to the atmosphere, but the corrosion process accelerates when electrochemical corrosion cells are active on the surface.

GALVANIC CORROSION
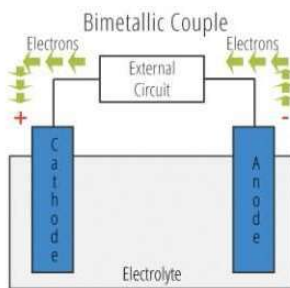
There are two primary types of galvanic cells that cause corrosion: the bi-metallic couple and the concentration cell. A bi-metallic couple is like a battery, consisting of two dissimilar metals immersed in an electrolyte solution. An electric current (flow of electrons) is generated when the two electrodes are connected by an external, conductive path.

A concentration cell consists of an anode and cathode of the same metal or alloy and a return current path. The electromotive force is provided by a difference in concentration of the surfaces through the external path.

There are four elements necessary for corrosion to occur in a galvanic cell:

- **Anode** - The electrode where galvanic reaction(s) generate electrons - negative ions are discharged and positive ions are formed. Corrosion occurs at the anode.

- **Cathode** - The electrode that receives electrons - positive ions are discharged, negative ions are formed. The cathode is protected from corrosion.

- **Electrolyte**The conductor through which current is carried.. Electrolytes include aqueous solutions or other liquids.

- **Return Current Path** - The metallic pathway connecting the anode to the cathode. It is often the underlying metal substrate.

All four elements (anode, cathode, electryolyte, and return current path) are necessary for corrosion to occur. Removing any one of these elements will stop the current flow and galvanic corrosion will not occur. Substituting a different metal for the anode or cathode may cause the direction of the current to reverse, resulting in a switch to the electrode experiencing corrosion.

The Galvanic Series of Metals (right) lists metals and alloys in decreasing order of electrical activity. Metals nearer the top of the table are less noble metals and have a greater tendency to lose electrons than the more noble metals found lower on the list.

```
CORRODED END
(Anodic or less noble)
Magnesium
Zinc
Aluminum
Steel
Lead
Tin
Nickel
Brass
Bronzes
Copper
Stainless Steel (passive)
Silver
Gold
Platinum
(Cathodic or more noble)
PROTECTED END
```

## CORROSION PROTECTION FOR STEEL

Steel is a proven durable and efficient building material that has been used since the Industrial Revolution. It is cost effective, aesthetically pleasing, sustainable, and strong. However, like all metals, steel corrodes when exposed to the atmosphere. Therefore, it is important to consider corrosion protection methods when constructing projects with exposed steel. There are a number of different corrosion protection systems to consider including:

HOT-DIP GALVANIZING

Hot-dip galvanizing (HDG) is the process of immersing fabricated steel or iron into a kettle (bath) of molten zinc. While in the kettle, iron in the steel metallurgically reacts with the zinc to form a tightly-bonded alloy coating. Hot-dip galvanizing resists corrosion by providing barrier and cathodic protection, as well as through the development of the zinc patina. These three levels of corrosion protection provide galvanized steel with maintenance-free longevity for decades.

DUPLEX SYSTEMS

A duplex system is formed by painting or powder coating over hot-dip galvanized steel. Used for decades as a means to enhance corrosion protection, the synergy between the two systems provides protection far superior to either system used independently.

Duplex systems are most commonly specified for aesthetic reasons. However, paint or powder coating can also be added to galvanizing in very aggressive environments or for color coding as well as to extend the life of existing galvanized structures. The key to a successful duplex system is to properly prepare the galvanized surface for paint or powder according to ASTM D6386 and ASTM D7803.

When hot-dip galvanized steel is painted or powder coated, the duplex coating provides a more sophisticated manner of corrosion protection known as the synergistic effect. The exterior layer of paint or powder coating acts as an additional barrier and slows down the rate at which the zinc is consumed, greatly extending the life of the galvanized steel. In return, the underlying galvanized coating acts as a noble primer eliminating the pinhole corrosion and peeling effect often seen on bare steel. Once the exterior layer has been weathered down or damaged, the zinc beneath is still available to provide cathodic and barrier protection.

As a result of this synergistic effect, the substrate steel is afforded corrosion protection for 1.5 to 2.3 times the sum of the expected life of each system alone. For example, if a galvanized coating alone on black steel would provide 70 years of maintenance-free protection and a paint coating would not require any maintenance for 10 years, the combination duplex system would provide maintenance-free protection for 120 to 184 years in the same environment.

This is not to suggest the original paint or powder coating will last more than a century. Rather this lifetime assumes no maintenance will be performed and the paint or powder coating would naturally wear way, and then the galvanizing would provide corrosion protection for the remainder of the life. However, the owner will likely want to maintain the paint/powder system for aesthetics. So in practice, the synergistic effect is realized in the delayed maintenance cycle (touch-up, maintenance paint, and full repaint) of the paint/powder coating of the duplex system. The maintenance cycle paint/powder on galvanized steel is 1.5 to 2 times the cycle for paint/powder on bare steel.

ZINC COATINGS

Zinc metal has a number of characteristics that make it a well-suited corrosion protective coating for iron and steel products. Zinc's excellent corrosion resistance in most environments accounts for its successful use as a protective coating on a variety of products and in many exposure conditions.

This proven corrosion resistance is a result of zincs ability to form dense, adherent corrosion byproducts, which leads to a rate of corrosion considerably lower than ferrous materials 10 to 100 times slower, depending on the environment. While a fresh zinc surface is quite reactive when exposed to the atmosphere, zinc corrosion products develop rapidly on the surface as the coating is exposed to natural wet and dry cycles in the atmosphere. These corrosion products, collectively known as the zinc patina, act as an additional barrier between the steel and the environment.

PROTECTIVE COATINGS

Protective coatings, such as paint and powder coatings, applied to steel provide barrier protection. As barrier protection is dependent on the integrity of the coating, the selection, application, and handling of painted and powder coated materials is very important. It is imperative these coatings are handled with care during installation and if damaged are repaired to ensure they are as durable as planned.

All organic forms of barrier protection are permeable to some degree, and once the protective coating is penetrated, the corrosion resistance is compromised. Most paints and powders are porous and easily damaged, allowing electrolytes (moisture, humidity) to reach the underlying steel. If regular maintenance is not performed, under-film corrosion begins and the coating can fail in a relatively short period of time. There is no cathodic protection provided by paints and powder coatings, which limits their time to first maintenance to ten years or less in most environments.

Both paint and powder coatings can be used in conjunction with hot-dip galvanizing, known as a duplex system. The two coatings work in synergy to provide superior corrosion protection, while allowing a specifier to suit any aesthetic preference.

SPECIAL STEELS

Special steels such as stainless and weathering provide corrosion protection by taking advantage of specific chemistries and elements. Weathering and stainless steel tend to work best in narrowly defined environments or applications and each has its own limitations.

**Stainless Steel**

Stainless steel is an alloy steel containing iron and chromium. Because of the chromium content, usually 12-20 percent of the alloy, stainless steel has excellent resistance to stain and rust. There are more than 50 types of stainless steel identified by the microstructure. Austenitic stainless steels contain at least 6% nickel and austenite and provide good corrosion resistance and high ductility. Ferretic stainless steels have better resistance to stress corrosion than austenitic, but are more difficult to weld. The US Department of Commerce estimates approximately 1 million tons of stainless steel was produced in 2012, and about 200,000 tons of nickel-containing steel is used each year by the food processing industry in North America.

Stainless is durable for many decades in most applications, as it is incredibly passive. It is often paired with hot-dip galvanized steel in applications. However, there are a number of limitations to its widespread use, including cost, size, and difficulty in installation. Stainless steel is sold at a premium compared to coated (painted or galvanized) carbon steel, weathering steel and other building materials. Additionally, it is only readily available in certain sizes and shapes, ages with an uneven appearance, and is difficult to weld. For these reasons, its application tends to be in cases where small quantities make an OEM product superior to one that has no stainless or in specific sectors such as food and beverage.

**Weathering Steel**

Weathering steel, which contains copper, develops a natural iron-oxide (rust) patina that is stable once formed, exhibiting increased corrosion resistance compared to carbon steel. The corrosion-retarding effect of the protective layer is produced by the particular distribution and concentration of alloying elements present. The layer protecting the surface develops and regenerates continuously when subjected to the influence of the weather. In other words, the steel is allowed to rust in order to form the patina, or protective layer.

Weathering steel is often marketed as a no-maintenance steel to the bridge and highway market specifically. However, in the last several years, the limitations of weathering steel have stifled its use. The development of the rust patina is fragile, and requires a balanced wet-dry cycle and it does not perform well in damp areas or where vegetation comes in contact with the steel. Though the rustic look is sometimes favored by designers, the issues of rust runoff and staining of concrete bases of poles and bridge columns is unappealing and has limited the use of weathering steel.

## EFFECTS OF CORROSION

Steel corrosion is a costly problem in fact the annual direct cost of metallic corrosion worldwide is $2.2 Trillion USD. North America is a large contributor to these annual costs, as the annual cost of corrosion in the US is $423 Billion the equivalent of 3.1% of the Gross Domestic Product (GDP). Though steel corrosion, whether in atmospheric, soil, water, or other exposures, is a natural phenomenon, estimates show 25-30% could be stymied if proper corrosion protection methods were employed.

Unfortunately, one of the biggest corrosion offenders is public infrastructure which means we all pay (taxes) for the lack of adequate planning. The long-held attitude in public construction of cheapest bid wins has been proven flawed. Building with the cheapest method initially often means greater costs in the future costs public budgets rarely account for nor have the means to consume.

However, the cost of corrosion is not just financial. Beyond the huge direct outlay of funds to repair and/or replace corroded and/or decaying structures are the indirect costs (natural resources, potential hazards, and lost opportunity). When a project is constructed with a building material not able to survive its environment for the length of the design life, natural resources are needlessly consumed to continually repair and maintain the structure. Wasting natural resources is a direct contradiction to the growing focus and desire for sustainable development to benefit future generations.

In addition to the waste of natural resources, building structures that cannot sustain their environment can lead to hazardous situations.  Accidents caused by corroded structures can lead to huge safety concerns, loss of life, resources, and more.  One failed pipeline, bridge collapse, or other catastrophe is one too many and leads to huge indirect costs (more traffic delays, loss of business, etc.) and public outcry. Depending on which market sector (industrial, infrastructure, commercial, etc.) is being considered, these indirect costs may be as high as five to ten times the direct cost.

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**References:**

Corrosion – American Galvanizers Association

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# FITNESS-FOR-SERVICE ENGINEERING ASSESSMENT

## INTRODUCTION

The ASME and API new construction codes and standards for pressurized equipment provide rules for the design, fabrication, inspection and testing of new pressure vessels, piping systems, and storage tanks. These codes do not provide rules to evaluate equipment that degrades while in-service and deficiencies due to degradation or from original fabrication that may be found during subsequent inspections. API 510, API 570, API 653, and NB-23 Codes/Standards for the inspection, repair, alteration, and rerating of in-service pressure vessels, piping systems, and storage tanks do address the fact that equipment degrades while in service.

Fitness-For-Service (FFS) assessments are quantitative engineering evaluations that are performed to demonstrate the structural integrity of an in-service component that may contain a flaw or damage. They provide guidance for conducting FFS assessments using methodologies specifically prepared for pressurized equipment. The guidelines can be used to make run-repair-replace decisions to help determine if pressurized equipment containing flaws that have been identified by inspection can continue to operate safely for some period of time. These FFS assessments are currently recognized and referenced by the API Codes and Standards (510, 570, & 653), and by NB-23 as suitable means for evaluating the structural integrity of pressure vessels, piping systems and storage tanks where inspection has revealed degradation and flaws in the equipment.

This article provides an overview of the API 579-1/ASME FFS-1 standard that contains the FFS assessments. Further articles in upcoming issues of the newsletter will provide in-depth analysis of this standard.

## SCOPE

API 579-1/ ASME FFS-1 is the FFS standard that contains methods and procedures that are intended to supplement and augment the requirements in API 510, API 570, API 563, and other post-construction codes that reference FFS evaluations such as NB-23. This standard can be used for FFS assessments and/or rerating of equipment designed and constructed to the following codes:

- a) ASME B&PV Code, Section VIII, Division 1
- b) ASME B&PV Code, Section VIII, Division 2
- c) ASME B&PV Code, Section I
- d) ASME B31.1 Piping Code
- e) ASME B31.3 Piping Code
- f) API 650
- g) API 620

The assessment procedures in this Standard may also be applied to pressure containing equipment constructed to other recognized codes and standards, including international and internal corporate standards. This Standard has broad application since the assessment procedures are based on allowable stress methods and plastic collapse loads for non-crack-like flaws, and the Failure Assessment Diagram (FAD) Approach for crack-like flaws. When evaluating other codes and standards the following attributes of the ASME and API design codes should be considered:

1) Material specifications
2) Upper and/or lower temperature limits for specific materials

3)  Material strength properties and the design allowable stress basis

4)  Material fracture toughness requirements

5)  Design rules for shell sections

6)  Design rules for shell discontinuities such as nozzles and conical transitions

7)  Design requirements for cyclic loads

8)  Design requirements for operation in the creep range

9)  Weld joint efficiency or quality factors

10) Fabrication details and quality of workmanship

11) Inspection requirements, particularly for welded joints

The FFS assessment procedures cover both the present integrity of the component given a current state of damage and the projected remaining life. Assessment techniques include evaluation of flaws including: general and localized corrosion, widespread and localized pitting, blisters and hydrogen damage, weld misalignment and shell distortions, crack-like flaws including environmental cracking, laminations, dents and gouges, and remaining life assessment procedures for components operating in the creep range. In addition, evaluation techniques provide for condition assessment of equipment including resistance to brittle fracture, long-term creep damage, and fire damage.

Analytical procedures, material properties including environmental effects, NDE guidelines and documentation requirements are included in the FFS assessment. In addition, both qualitative and quantitative guidance for establishing remaining life and in-service margins for continued operation of equipment are provided in regards to future operating conditions and environmental compatibility.

The FFS assessment procedures can be used to evaluate flaws commonly encountered in pressure vessels, piping and tankage. The procedures do not provide a definitive guideline for every possible situation that may be encountered. However, flexibility is provided to the user in the form of an advanced assessment level to handle uncommon situations that may require a more detailed analysis.

## RESPONSIBILITIES

### OWNER-USER

The Owner-User of pressurized equipment has the overall responsibility for FFS assessments completed using the required procedures, including compliance with appropriate jurisdictional and insurance requirements. The Owner-User ensures that the results of the assessment are documented and filed with the appropriate permanent equipment records. Many of the Owner-User responsibilities are given to the Plant Engineer.

The Owner-User shall understand the overall process, the importance of each piece of equipment to that process, and the failure consequences of each piece of equipment such that the Owner-User can assume overall responsibility for the results of the FFS assessment performed. The Owner-User shall have the ability and experience to recognize potentially damaging operations or equipment conditions and to take remedial steps.

### INSPECTOR

The Inspector, working in conjunction with the NDE engineer, is responsible to the Owner-User for determining that the requirements for inspection and testing are met. In addition, the Inspector provides all necessary inspection data required for a FFS assessment, and is responsible for controlling the overall accuracy of the flaw detection and sizing activities. In some instances, as determined by the Owner-User, the Inspector may also be responsible for the FFS assessment (Level 1 Assessment).

The Inspector is qualified and certified in accordance with the applicable post-construction Code (API 510, API 570, API 653, ANSI/NB-23, or other post-construction code or standard) required by the jurisdiction. Nondestructive examination personnel responsible for data used in a FFS assessment shall be certified to at least Level II in accordance with industry standards such as the American Society for Nondestructive Testing (ANST) SNT-TC-1A, CP-189, ACCP, or equivalent. The Inspector shall have experience in the inspection, examination, or both, of the type of equipment and associated process that is the subject of the FFS assessment.

ENGINEER

The Engineer is responsible to the Owner-User for most types of FFS assessments, documentation, and resulting recommendations. The exception is that a Level 1 Assessment may be performed by an Inspector or other non-degreed specialist; however, in these cases the Engineer should review the analysis. A FFS assessment may require input from multiple engineering disciplines as described below:

a) *Materials or Metallurgical Engineering* – Identification of the material damage mechanisms, establishment of corrosion/erosion rates, determination of material properties including strength parameters and crack-like flaw growth parameters, development of suitable remediation methods and monitoring programs, and documentation.

b) *Mechanical or Structural Engineering* – Computations of the minimum required thickness and/or MAWP (MFH) for a component, performance of any required thermal and stress analysis, and knowledge in the design of and the practices relating to pressure containing equipment including pressure vessel, piping, and tankage codes and standards.

c) *Inspection Engineering* – Establishment of an inspection plan that is capable of detecting, characterizing, sizing flaws or damage, and selection and execution of examination procedures in conjunction with available NDE expertise.

d) *Fracture Mechanics Engineering* – Assessment of crack-like flaws using the principles of fracture mechanics.

e) *Non-Destructive Examination (NDE) Engineering* – Selection and development of methods to detect, characterize, and size flaws or quantify the amount of damage, and the analysis and interpretation of inspection data.

f) *Process Engineering* – Documentation of past and future operating conditions, including normal and upset conditions, and identification of the contained fluid and its contaminant levels that may affect degradation of the component being evaluated.

**Plant Engineer:** The term Plant Engineer applies to an engineer with knowledge of the equipment containing the component requiring the FFS Assessment. The Plant Engineer may perform both a Level 1 Assessment and Level 2 Assessment and typically has certain knowledge of the engineering disciplines, or access to personnel with the necessary engineering disciplines knowledge required for the FFS Assessment to be performed.

## ASSESSMENT PROCEDURE

API 579-1/ASME FFS-1 FFS contains assessment procedures that can be used to evaluate pressurized components containing flaws or damage. If the results of the FFS assessment indicate that the equipment is suitable for the current operating conditions, then the equipment can continue to be operated at these conditions provided suitable monitoring/inspection programs are established. If the results of the FFS assessment indicate that the equipment is not suitable for the current operating conditions, then the equipment can be rerated using the calculation methods in this Standard. These calculation methods can be used to find a reduced Maximum Allowable Working Pressure (MAWP) and/or coincident temperature for pressurized components (e.g. pressure vessels drums, headers, tubing, and piping).

The FFS assessment procedures are organized by flaw type and/or damage mechanism. A list of flaw types and damage mechanisms and the corresponding Part in the Standard that provides the FFS assessment methodology is shown in Table 1. In some cases, it may be necessary to use the assessment procedures from multiple Parts if the primary type of damage is not evident. For example, the metal loss in a component may be associated with general corrosion, local corrosion and pitting. If multiple damage mechanisms are present, a damage class, e.g., corrosion/erosion, can be identified to assist in the evaluation. An overview of damage classes in this Standard is shown in Figure 1. As indicated in this figure, several flaw types and damage mechanisms may need to be evaluated to determine the FFS of a component. Each Part referenced within a damage class includes guidance on how to perform an assessment when multiple damage mechanisms are present.

**Table 1: Overview of Flaw and Damage Assessment Procedures**

| Flow or Damage Mechanism | Part in API 579-1/ ASME FFS-1 | Overview |
|---|---|---|
| Brittle Fracture | Part 3 | Assessment procedures are provided for evaluating the resistance to brittle fracture of existing carbon and low alloy steel pressure vessels, piping, and storage tanks. Criteria are provided to evaluate normal operating, start-up, upset, and shut-down conditions. |
| General Metal Loss | Part 4 | Assessment procedures are provided to evaluate general corrosion. Thickness data used for the assessment can be either point thickness readings or detailed thickness profiles. A methodology is provided to utilize the assessment procedures of Part 5 when the thickness data indicates that the metal loss can be treated as localized. |
| Local Metal Loss | Part 5 | Assessment techniques are provided to evaluate single and networks of Local Thin Areas and groove-like flaws in pressurized components. Detailed thickness profiles are required for the assessment. The assessment procedures can also be utilized to evaluate individual pits or blisters as provided for in Part 6 and Part 7, respectively. |
| Pitting Corrosion | Part 6 | Assessment procedures are provided to evaluate widely scattered pitting, localized pitting, pitting which occurs within a region of local metal loss, and a region of localized metal loss located within a region of widely scattered pitting. The assessment procedures can also be utilized to evaluate a network of closely spaced blisters as provided for in Part 7. |
| Blisters and HIC/SOHIC Damage | Part 7 | Assessment procedures are provided to evaluate isolated and networks of blisters and HIC/SOHIC Damage. The assessment guidelines include provisions for blisters and HIC/SOHIC damage located at weld joints and structural discontinuities such as shell transitions, stiffening rings, and nozzles. |
| Weld Misalignment and Shell Distortions | Part 8 | Assessment procedures are provided to evaluate stresses resulting from geometric discontinuities in shell type structures including weld misalignment and shell distortions (e.g. out-of-roundness and bulges). |
| Crack-like Flaws | Part 9 | Assessment procedures are provided to evaluate crack-like flaws. Solutions for stress intensity factors and reference stress (limit load) are included in Annex C and Annex D, respectively. Methods to evaluate residual stress as required by the assessment procedure are described in Annex E. Material properties required for the assessment are provided in Annex F. Recommendations |

| | | for evaluating crack growth including environmental concerns are also covered. |
|---|---|---|
| High Temperature Operation and Creep | Part 10 | Assessment procedures are provided to determine the remaining life of a component operating in the creep regime. Material properties required for the assessment are provided in Annex F. Analysis methods for evaluating crack growth including environmental concerns are also covered. |
| Fire Damage | Part 11 | Assessment procedures are provided to evaluate equipment subject to fire damage. A methodology is provided to rank and screen components for evaluation based on the heat exposure experienced during the fire. The assessment procedures of the other Parts of this publication are utilized to evaluate component damage. |
| Dent, Gouge, and Dent Gouge Combinations | Part 12 | Assessment techniques are provided to evaluate dent, gouge, and dent gouge combinations in components. |
| Lamination | Part 13 | Assessment procedures are provided to evaluate laminations. The assessment guidelines include provisions for laminations located at weld joints and structural discontinuities such as shell transitions, stiffening rings, and nozzles. |

The general FFS assessment procedure for all flaw types and damage mechanisms is provided in this Part. An overview of the procedure is provided in the following eight steps. The remaining Parts in this Standard utilize this assessment methodology for a specific flaw type or damage mechanism and provide specific details covering Steps 2 through 8 of this procedure.

STEP 1    Flaw and Damage Mechanism Identification: The first step in a FFS assessment is to identify the flaw type and cause of damage. The original design and fabrication practices, the material of construction, and the service history and environmental conditions can be used to ascertain the likely cause of the damage. An overview of damage mechanisms that can assist in identifying likely causes of damage, is provided in Annex G. Once the flaw type is identified, the appropriate Part of this Standard can be selected for the assessment.

STEP 2    Applicability and Limitations of the FFS Assessment Procedures: The applicability and limitations of the assessment procedure are described in each Part, and a decision on whether to proceed with an assessment can be made.

STEP 3    Data Requirements: The data required for a FFS assessment depend on the flaw type or damage mechanism being evaluated. Data requirements may include: original equipment design data, information pertaining to maintenance and operational history, expected future service, and data specific to the FFS assessment such as flaw size, state of stress in the component at the location of the flaw, and material properties. Data requirements common to all FFS assessment procedures are covered in this Part. Data requirements specific to a damage mechanism or flaw type are covered in the Part containing the corresponding assessment procedures.

STEP 4    Assessment Techniques and Acceptance Criteria: Assessment techniques and acceptance criteria are provided in each Part. If multiple damage mechanisms are present, more than one Part may have to be used for the evaluation.

STEP 5    Remaining Life Evaluation: An estimate of the remaining life or limiting flaw size should be made for establishing an inspection interval. The remaining life is established using the FFS assessment procedures with an estimate of future damage. The remaining life can be used in conjunction with an inspection code to establish an inspection interval.

STEP 6    Remediation: Remediation methods are provided in each Part based on the damage mechanism or flaw type. In some cases, remediation techniques may be used to control future damage associated with flaw growth and/or material deterioration.

STEP 7    In-Service Monitoring: Methods for in-service monitoring are provided in each Part based on the damage mechanism or flaw type. In-service monitoring may be used for those cases where a remaining life and inspection interval cannot adequately be established because of the complexities associated with the service environment.

STEP 8    Documentation: Documentation should include a record of all information and decisions made in each of the previous steps to qualify the component for continued operation. Documentation requirements common to all FFS assessment procedures are covered in this Part. Documentation requirements specific to a damage mechanism or flaw type are covered in the Part containing the corresponding assessment procedures.
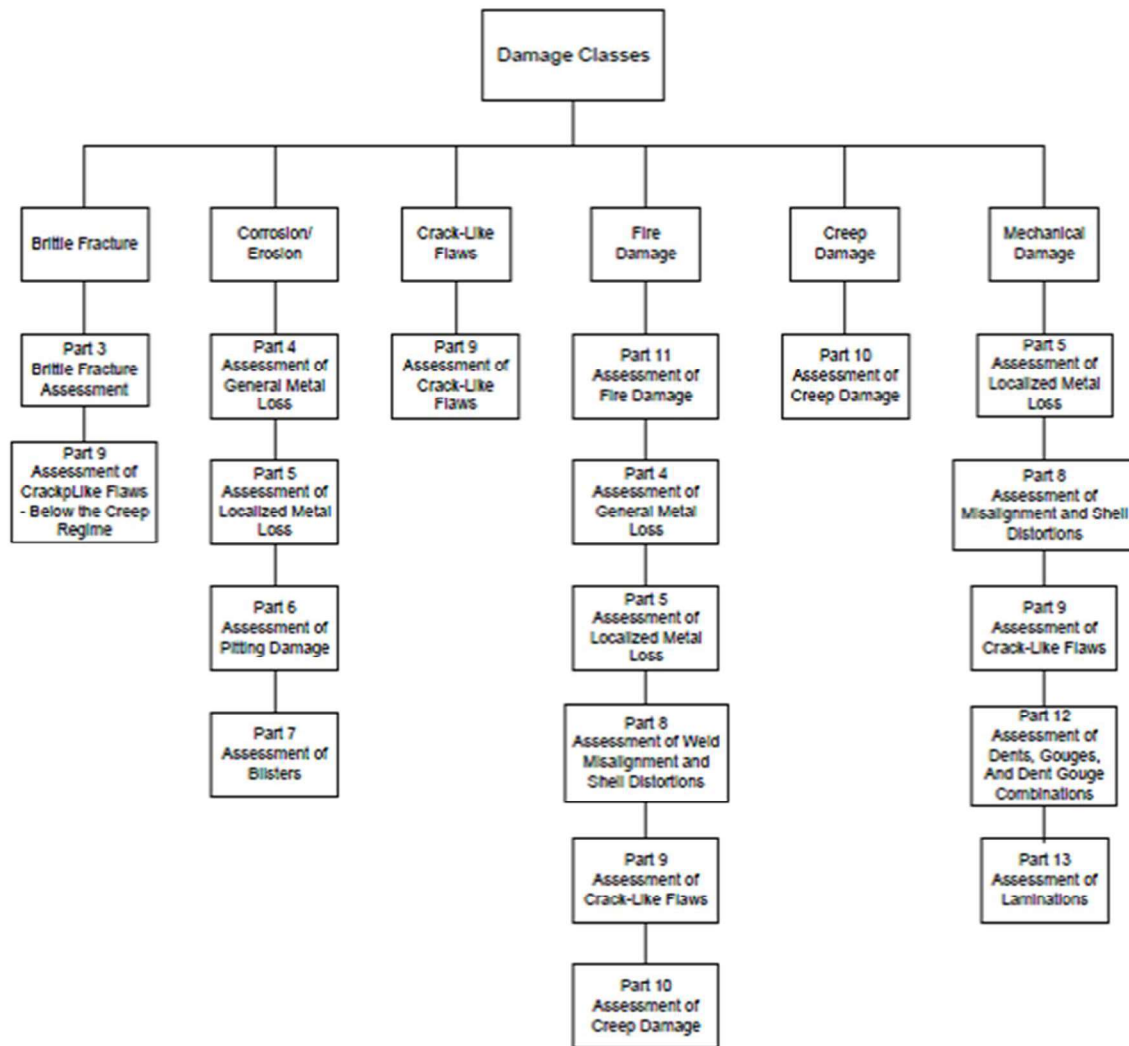


**Figure 1: FFS Assessment Procedures for Various Damage Classes**

## LEVELS OF ASSESSMENT

Three Levels of assessment are provided in each Part of the Standard that cover FFS assessment procedures. A logic diagram is included in each Part to illustrate how these assessment levels are interrelated. In general, each assessment level provides a balance between conservatism, the amount of information required for the evaluation, the skill of the personnel performing the assessment, and the complexity of analysis being performed. Level 1 is the most conservative, but is easiest to use. Practitioners usually proceed sequentially from a Level 1 to a Level 3 analysis (unless otherwise directed by the assessment techniques) if the current assessment level does not provide an acceptable result, or a clear course of action cannot be determined. A general overview of each assessment level and its intended use are described below.

### LEVEL 1 ASSESSMENT

The assessment procedures included in this level are intended to provide conservative screening criteria that can be utilized with a minimum amount of inspection or component information. A Level 1 assessment may be performed either by plant inspection or engineering personnel.

### LEVEL 2 ASSESSMENT

The assessment procedures included in this level are intended to provide a more detailed evaluation that produces results that are more precise than those from a Level 1 assessment. In a Level 2 Assessment, inspection information similar to that required for a Level 1 assessment are needed; however, more detailed calculations are used in the evaluation. Level 2 assessments would typically be conducted by plant engineers, or engineering specialists experienced and knowledgeable in performing FFS assessments.

### LEVEL 3 ASSESSMENT

The assessment procedures included in this level are intended to provide the most detailed evaluation which produces results that are more precise than those from a Level 2 assessment. In a Level 3 Assessment, the most detailed inspection and component information is typically required, and the recommended analysis is based on numerical techniques such as the finite element method or experimental techniques when appropriate. A Level 3 assessment is primarily intended for use by engineering specialists experienced and knowledgeable in performing FFS assessments.

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**References:**

API 579-1/ASME FFS-1 Fitness-For-Service, Second Edition (June 5, 2007)

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# COMMUNICATION TIPS FROM WARREN BUFFETT

Warren Buffett, one of the wealthiest and most successful investors in the world, recently shared some excellent advice for those who are looking to improve their value in the work world. He was asked what advice he'd give to new graduates about to enter the workplace.

Buffett initially responded with a simple, three-word sentence:

"Invest in yourself."

The famous investor continued:

"The one easy way to become worth 50% more than you are now at least is to hone your communication skills--both written and verbal. If you can't communicate, it's like winking at a girl in the dark--nothing happens. You can have all the brainpower in the world but you have to be able to transmit it. And the transmission is communication."

Buffett's advice is so on point, especially considering that we live in a time where communication skills are more important than ever. Remote workers live and operate in different time zones and on different schedules, increasing the need to communicate effectively via the written word. Additionally, if you use modern technology to communicate, your potential audience has transformed from a few people to a few thousand, or a few million. Poor communication skills will affect how that audience perceives not only your message, but you as well.

So, how can you follow Buffett's advice and invest in your communication skills?

Here are four tips you can put into practice today:

**1. Listen first.**

Communication is a two-way street. By listening first, you demonstrate humility and a willingness to learn, which will encourage colleagues and clients and make them feel valued.

To accomplish this, resist the urge to interrupt, or to dismiss new ideas or techniques. Instead, dignify those you work with by asking for their opinions and perspectives. Then, make sure you pay attention when they speak--rather than concentrate on what you're going to say next.

By showing your audience that you value what they have to say, they'll be more willing to share what they really think.

**2. Remember, it's not just what you say; it's how you say it.**

Many people feel that respect must be earned, rather than given. But taking the initiative to show respect to others will drastically increase the power of your message.

- Respectful communication includes:
- Remembering and using people's names whenever possible
- Acknowledging others and their viewpoints
- Showing personal interest, by asking your audience questions and determining what's important to them
- Getting the full story before jumping to conclusions

Respect begets respect. If you show consideration and dignity in the way you speak to others, they'll be more willing to listen to what you have to say.

### 3. Think before you speak (or write).

In a world ruled by convenience and speed, it takes major self-discipline to think before speaking. But responding too quickly can cause you to say something out of emotion that you later regret--like sending an angry email or text, or agreeing to something that you don't really want to follow through on.

Instead of responding immediately to every question or message, take time to think about your response. When speaking, this may be a matter of just a few seconds. When writing, it may be a few hours, or even a day.

By thinking before responding, you can communicate in a way that's both effective *and* in harmony with your core principles and values.

### 4. Strive for clarity.

You rarely achieve great communication on the first try, especially if the topic is complex.

Speaking face-to-face (or over the phone) is often preferable to written communication, because you can include emotional cues like tone of voice, facial expressions, and gestures. You can also ask follow up questions to make sure the other party understands and is on the same page.

But if you're communicating through writing about something serious, you should take time to re-read what you've read and check for proper:

- Capitalization
- Punctuation
- Spelling
- Grammar
- Syntax

Remember, conversational and authentic doesn't have to mean sloppy. Paying closer attention to your writing will allow you to convey your thoughts more clearly. Additionally, by paying attention to detail you'll stand out among peers and leave a better impression.

Warren Buffett didn't develop his reputation by chance. He did so by investing in himself, first.

You can do the same--by learning to communicate effectively.

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**References:**

*Business Insider* article dated December 25, 2018.

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It is becoming less practical for many companies to maintain in-house engineering staff. That is where we come in – whenever you need us, either for one-time projects, or for recurring engineering services. We understand the codes and standards, and can offer a range of services related to pressure vessels, tanks and heat exchangers.

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