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Risk-Based Inspection Methodology

Part 2—Probability of Failure Methodology

Annex 2.B—Determination of Corrosion Rates

2.B.1 Overview

2.B.1.1 Determination of Corrosion Rate

The corrosion rate should be calculated from measured thickness data available from equipment inspection(s). However, if a calculated corrosion rate is not available, estimated corrosion rates may be determined for each potential thinning mechanism using this document or as estimated by a corrosion specialist.

Screening questions are used to determine which of the thinning mechanism sections apply. These applicable sections will be entered to determine conservative estimated corrosion rates for possible thinning mechanisms. The screening questions listed in [Table 2.B.1.1](#) are used to select the applicable thinning mechanism.

2.B.1.2 Determination of Thinning Type

The results of effective inspections that have been performed on the equipment or piping should be used to designate the type of thinning (i.e. general vs localized). If this information is not known, then [Table 2.B.1.2](#) lists the type of thinning (general or localized) expected for various thinning mechanisms. If both general and localized thinning mechanisms are possible, then the type of thinning should be designated as localized. The type of thinning designated will be used to determine the effectiveness of inspection performed.

2.B.1.3 Tables

Table 2.B.1.1—Screening Questions for Corrosion Rate Calculations

Screening Questions	Action
Hydrochloric Acid (HCl) Corrosion 1. Does the process contain HCl? 2. Is free water present in the process stream (including initial condensing condition)? 3. Is the pH < 7.0?	If Yes to all, proceed to Section 2.B.2
High Temperature Sulfidic/Naphthenic Acid Corrosion 1. Does the process contain oil with sulfur compounds? 2. Is the operating temperature > 400 °F (204 °C)?	If Yes to both, proceed to Section 2.B.3
High Temperature H ₂ S/H ₂ Corrosion 1. Does the process contain H ₂ S and hydrogen? 2. Is the operating temperature > 400 °F (204 °C)?	If Yes to both, proceed to Section 2.B.4
Sulfuric Acid (H ₂ SO ₄) Corrosion Does the process contain H ₂ SO ₄ ?	If Yes, proceed to Section 2.B.5
Hydrofluoric Acid (HF) Corrosion Does the process stream contain HF?	If Yes, proceed to Section 2.B.6
Sour Water Corrosion Is free water with H ₂ S present?	If Yes, proceed to Section 2.B.7
Amine Corrosion Is equipment exposed to acid gas treating amines (MEA, DEA, DIPA, or MDEA)?	If Yes, proceed to Section 2.B.8
High Temperature Oxidation 1. Is the temperature ≥ 900 °F (482 °C)? 2. Is there oxygen present?	If Yes to both, proceed to Section 2.B.9
Acid Sour Water 1. Is free water with H ₂ S present and pH < 7.0? 2. Does the process contain < 50 ppm chlorides?	If Yes, proceed to Section 2.B.10
Cooling Water Is equipment in cooling water service?	If Yes, proceed to Section 2.B.11
Soil-side corrosion 1. Is equipment in contact with soil (buried or partially buried)? 2. Is the material of construction carbon steel?	If Yes, proceed to Section 2.B.12
CO ₂ Corrosion 1. Is free water with CO ₂ present (including consideration for dew point condensation)? 2. Is the material of construction carbon steel or < 13 % Cr?	If Yes, proceed to Section 2.B.13
AST Bottom Is the equipment item an AST tank bottom?	If Yes, proceed to Section 2.B.14

Table 2.B.1.2—Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric acid (HCl) corrosion	—	Local
High temperature sulfidic/naphthenic acid corrosion	TAN ≤ 0.5	General
	TAN > 0.5	Local
High temperature H ₂ S/H ₂ corrosion	—	General
Sulfuric acid (H ₂ SO ₄) corrosion	Low Velocity ≤ 2 ft/s (0.61 m/s) for carbon steel, ≤ 4 ft/s (1.22 m/s) for SS, and ≤ 6 ft/s (1.83 m/s) for higher alloys	General
	High Velocity ≥ 2 ft/s (0.61 m/s) for carbon steel, ≥ 4 ft/s (1.22 m/s) for SS, and ≥ 6 ft/s (1.83 m/s) for higher alloys	Local
Hydrofluoric acid (HF) corrosion	—	Local
Sour water corrosion	Low Velocity: ≤ 20 ft/s (6.1 m/s)	General
	High Velocity: > 20 ft/s (6.1 m/s)	Local
Amine corrosion	Low Velocity < 5 ft/s (1.5 m/s) rich amine < 20 ft/s (6.1 m/s) lean amine	General
	High Velocity > 5 ft/s (1.5 m/s) rich amine > 20 ft/s (6.1 m/s) lean amine	Local
High temperature oxidation	—	General
Acid sour water corrosion	< 6 ft/s (1.83 m/s)	General
	≥ 6 ft/s (1.83 m/s)	Local
Cooling water corrosion	≤ 3 ft/s (0.91 m/s)	Local
	3 to 9 ft/s (0.91 to 2.74 m/s)	General
	> 9 ft/s (2.74 m/s)	Local
Soil-side corrosion	—	Local
CO ₂ corrosion	—	Local
AST bottom	Product side	Local
	Soil side	Local

2.B.2 Hydrochloric Acid Corrosion

2.B.2.1 Description of Damage

HCl corrosion is a concern in some of the most common refining process units. HCl is aggressive to many common materials of construction across a wide range of concentrations and is often localized in nature, particularly when it is associated with localized or shock condensation or the deposition of chloride containing ammonia or amine salts. Austenitic stainless steels will often suffer pitting attack and may experience crevice corrosion and/or CISCC. Some of the nickel-based alloys may experience accelerated corrosion if oxidizing agents are present or if the alloys are not in the solution annealed heat treatment condition.

The primary refining units where HCl corrosion is a concern are crude distillation, hydrotreating, and catalytic reforming. HCl forms in crude units by the hydrolysis of magnesium and calcium chloride salts and results in dilute HCl in the overhead system. In hydrotreating units, HCl may form by hydrogenation of organic chlorides in the feed or can enter the unit with hydrocarbon feed or hydrogen and condense with water in the effluent train. In catalytic reforming units, chlorides may be stripped off of the catalyst and hydrogenate resulting in HCl corrosion in the effluent train or regeneration systems.

2.B.2.2 Basic Data

The data listed in [Table 2.B.2.1](#) are required to estimate the rate of corrosion in dilute HCl. More concentrated acid is outside the scope of this section. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.2.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.2.1](#). The HCl corrosion rate may be determined using the basic data in [Table 2.B.2.1](#) in conjunction with [Tables 2.B.2.3](#) through [2.B.2.6](#).

2.B.2.4 References

See References [46], [78], [79], [80], [92], and [93] in [Section 2.2](#).

2.B.2.5 Tables

Table 2.B.2.1—HCl—Basic Data Required for Analysis

Material of Construction	Determine the Material of Construction of the Equipment Item
pH or Cl ⁻ concentration	<p>pH is preferred for estimating the corrosion rate at dilute concentrations for carbon steel and 300 series stainless steels. Table 2.B.2.2 may be used to estimate pH from the Cl⁻ concentration if it is known. The presence of neutralizing agents may elevate the pH, however.</p> <p>For high alloy materials, Cl⁻ concentration is used to estimate the corrosion rate.</p> <p>NOTE The pH used should be of the separated acid phase within this equipment or nearest equipment downstream, e.g. the overhead accumulator boot water downstream of the overhead condenser.</p>
Maximum temperature, °F (°C)	Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating condition such as effect of the sun or heat tracing should be considered.
Presence of air or oxidants (Yes or No)	Presence of air (oxygen) may increase corrosion rates, particularly for Alloy 400 and Alloy B-2. Other oxidants such as ferric and cupric ions will have a similar effect on these alloys.

Table 2.B.2.2—HCl Corrosion—Determination of pH from Cl⁻ Concentration

Cl ⁻ Concentration (wppm)	pH
3,601 to 12,000	0.5
1,201 to 3,600	1.0
361 to 1,200	1.5
121 to 360	2.0
36 to 120	2.5
16 to 35	3.0
6 to 15	3.5
3 to 5	4.0
1 to 2	4.5
<1	5.0
NOTE Assumes no alkaline agent present (NH ₃ , neutralizing amines or caustic).	

Table 2.B.2.3—HCl Corrosion—Estimated Corrosion Rates for Carbon Steel (mpy)

pH	Temperature (°F)			
	100	125	175	200
0.5	999	999	999	999
0.80	900	999	999	999
1.25	400	999	999	999
1.75	200	700	999	999
2.25	100	300	400	560
2.75	60	130	200	280
3.25	40	70	100	140
3.75	30	50	90	125
4.25	20	40	70	100
4.75	10	30	50	70
5.25	7	20	30	40
5.75	4	15	20	30
6.25	3	10	15	20
6.80	2	5	7	10

Table 2.B.2.3M—HCl Corrosion—Estimated Corrosion Rates for Carbon Steel (mm/y)

pH	Temperature (°C)			
	38	52	79	93
0.5	25.37	25.37	25.37	25.37
0.80	22.86	25.37	25.37	25.37
1.25	10.16	25.37	25.37	25.37
1.75	5.08	17.78	25.37	25.37
2.25	2.54	7.62	10.16	14.22
2.75	1.52	3.30	5.08	7.11
3.25	1.02	1.78	2.54	3.56
3.75	0.76	1.27	2.29	3.18
4.25	0.51	1.02	1.78	2.54
4.75	0.25	0.76	1.27	1.78
5.25	0.18	0.51	0.76	1.02
5.75	0.10	0.38	0.51	0.76
6.25	0.08	0.25	0.38	0.51
6.80	0.05	0.13	0.18	0.25

Table 2.B.2.4—HCl Corrosion—Estimated Corrosion Rates for Type 304, 316, 321, 347 Series Stainless Steels (mpy)

pH	Temperature (°F)			
	100	125	175	200
0.5	900	999	999	999
0.80	500	999	999	999
1.25	300	500	700	999
1.75	150	260	400	500
2.25	80	140	200	250
2.75	50	70	100	120
3.25	30	40	50	65
3.75	20	25	30	35
4.25	10	15	20	25
4.75	5	7	10	12
5.25	4	5	6	7
5.75	3	4	5	6
6.25	2	3	4	5
6.80	1	2	3	4

NOTE These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table 2.B.2.4M—HCl Corrosion—Estimated Corrosion Rates for Type 304, 316, 321, 347 Series Stainless Steels (mm/y)

pH	Temperature (°C)			
	38	52	79	93
0.5	22.86	25.37	25.37	25.37
0.80	12.70	25.37	25.37	25.37
1.25	7.62	12.70	17.78	25.37
1.75	3.81	6.60	10.16	12.70
2.25	2.03	3.56	5.08	6.35
2.75	1.27	1.78	2.54	3.05
3.25	0.76	1.02	1.27	1.65
3.75	0.51	0.64	0.76	0.89
4.25	0.25	0.38	0.51	0.64
4.75	0.13	0.18	0.25	0.30
5.25	0.10	0.13	0.15	0.18
5.75	0.08	0.10	0.13	0.15
6.25	0.05	0.08	0.10	0.13
6.80	0.03	0.05	0.08	0.10

NOTE These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table 2.B.2.5—HCl Corrosion—Estimated Corrosion Rates for Alloys 825, 20, 625, C-276 (mpy)

Alloy	Cl ⁻ Concentration (wt%)	Temperature (°F)			
		100	125	175	200
Alloy 825 and Alloy 20	0.50	1	3	40	200
	0.75	2	5	80	400
	1.0	10	70	300	999
Alloy 625	0.50	1	2	15	75
	0.75	1	5	25	125
	1.0	2	70	200	400
Alloy C-276	0.50	1	2	8	30
	0.75	1	2	15	75
	1.0	2	10	60	300

Table 2.B.2.5M—HCl Corrosion—Estimated Corrosion Rates for Alloys 825, 20, 625, C-276 (mm/y)

Alloy	Cl ⁻ Concentration (wt%)	Temperature (°C)			
		38	52	79	93
Alloy 825 and Alloy 20	0.50	0.03	0.08	1.02	5.08
	0.75	0.05	0.13	2.03	10.16
	1.0	0.25	1.78	7.62	25.37
Alloy 625	0.50	0.03	0.05	0.38	1.91
	0.75	0.03	0.13	0.64	3.18
	1.0	0.05	1.78	5.08	10.16
Alloy C-276	0.50	0.03	0.05	0.20	0.76
	0.75	0.03	0.05	0.38	1.91
	1.0	0.05	0.25	1.52	7.62

Table 2.B.2.6—HCl Corrosion—Estimated Corrosion Rates for Alloy B-2 and Alloy 400 (mpy)

Alloy	Cl ⁻ Concentration (wt%)	Temperature (°F)							
		100		125		175		200	
		Oxygen/Oxidants Present?							
		No	Yes	No	Yes	No	Yes	No	Yes
Alloy B-2	0.50	1	4	1	4	2	8	4	16
	0.75	1	4	1	4	5	20	20	80
	1.0	2	8	5	20	10	40	25	100
Alloy 400	0.50	1	4	3	12	30	120	300	999
	0.75	2	10	5	20	80	320	800	999
	1.0	19	40	25	100	150	600	900	999

Table 2.B.2.6M—HCl Corrosion—Estimated Corrosion Rates for Alloy B-2 and Alloy 400 (mm/y)

Alloy	Cl ⁻ Concentration (wt%)	Temperature (°C)							
		38		52		79		93	
		Oxygen/Oxidants Present?							
		No	Yes	No	Yes	No	Yes	No	Yes
Alloy B-2	0.50	0.03	0.1	0.03	0.1	0.05	0.2	0.1	0.41
	0.75	0.03	0.1	0.03	0.1	0.13	0.51	0.51	2.03
	1.0	0.05	0.2	0.13	0.51	0.25	1.02	0.64	2.54
Alloy 400	0.50	0.03	0.1	0.08	0.3	0.76	3.05	7.62	25.37
	0.75	0.05	0.25	0.13	0.51	2.03	8.13	20.32	25.37
	1.0	0.48	1.02	0.64	2.54	3.81	15.24	22.86	25.37

2.B.2.6

Figures

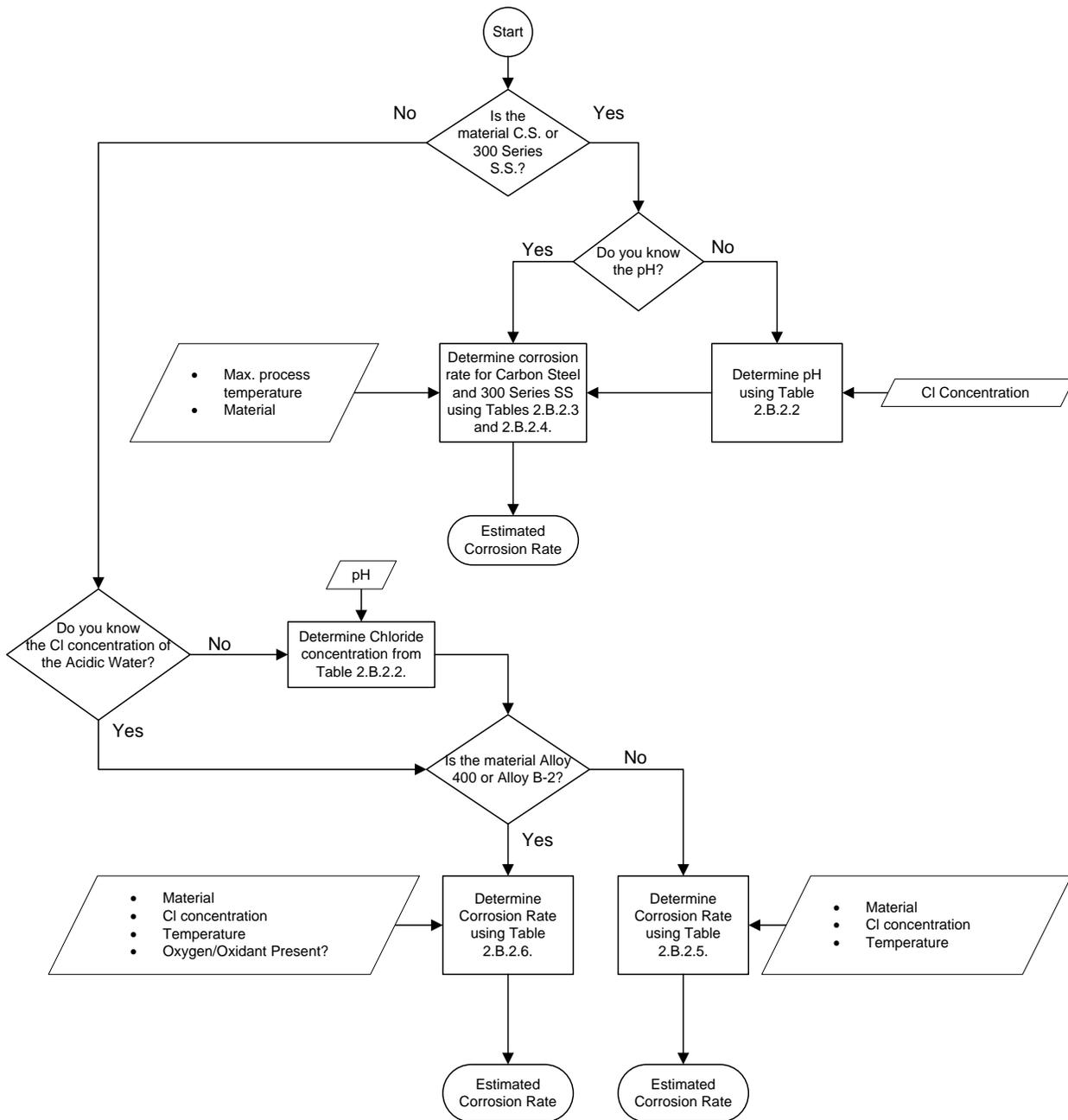


Figure 2.B.2.1—HCl Corrosion—Determination of Corrosion Rate

2.B.3 High Temperature Sulfidic and Naphthenic Acid Corrosion

2.B.3.1 Description of Damage

2.B.3.1.1 High Temperature Sulfidic Corrosion

High temperature sulfidic corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 400 °F (204 °C). This form of corrosion sometimes occurs along with naphthenic acid corrosion depending on the oil being processed. Naphthenic acid corrosion, when it occurs, is normally localized. Sulfur species occur naturally in most crude oils but their concentrations vary from crude-to-crude. These naturally occurring compounds may be corrosive themselves as well as when they are converted to hydrogen sulfide through thermal decomposition. Catalytic conversion of sulfur compounds to 2S occurs in the presence of hydrogen and a catalyst bed in hydroprocessing units. Corrosion in vapor streams containing both H₂S and hydrogen is covered in [Section 2.B.4](#).

2.B.3.1.2 Naphthenic Acid Corrosion

As with sulfur compounds, naphthenic acids occur naturally in some crude oils. During distillation, these acids tend to concentrate in higher boiling point fractions such as heavy atmospheric gas oil, atmospheric resid, and vacuum gas oils. The acids may also be present in vacuum resid, but often many of the more corrosive ones will have distilled into the vacuum side streams. Lower boiling point streams are usually low in naphthenic acids. Corrosion may appear either as pitting, more common at lower acid levels, or grooving and gouging at higher acid levels and, particularly, at higher velocities. Naphthenic acids may destabilize protective films (sulfides or oxides) on the material and thus allow a high sulfidation corrosion rate to continue or it may itself directly attack the base material.

2.B.3.1.3 Combined Corrosion Effects

The corrosion rate in high temperature sulfidic environments is a function of the material, temperature, and the concentration of the sulfur compound(s) present. The presence of naphthenic acid in sufficient amounts, however, can dramatically decrease a material's corrosion resistance where it might otherwise have suitable corrosion resistance. The following summarize the key variables in corrosion.

- a) In high temperature sulfidic environments, materials such as carbon and low alloy steels form sulfide corrosion products. The extent to which these are protective depends on the environmental factors mentioned. At high enough temperatures and/or sulfur levels, the corrosion products may become less protective so corrosion can occur at an accelerated rate.
- b) Moderate additions of chromium to carbon steel increase the material's corrosion resistance. Alloys containing 5Cr-0.5Mo, 7Cr-1Mo, and 9Cr-1Mo are often sufficient to provide acceptable material performance in these environments. Lower alloys such as 1.25Cr-0.5Mo and 2.25Cr-1Mo generally do not offer sufficient benefits over carbon steel to justify their use. Stainless steels such as 12Cr (Type 405, 410, 410S) and Type 304 may be required at higher sulfur levels and temperatures.
- c) High temperature sulfidic corrosion is related to the amount of sulfur present in the stream and is usually reported simply as wt% sulfur. Corrosion generally increases with increasing sulfur content.
- d) High temperature sulfidic corrosion occurs at temperatures greater than about 450 °F (232 °C). Naphthenic acid corrosion typically has been observed in the 450 °F to 800 °F (232 °C to 427 °C) temperature range although corrosion which exhibits naphthenic acid characteristics has been reported outside this temperature range. Above 800 °F (427 °C), the naphthenic acids either break down or distill into the vapor phase. While sulfidation will occur in both liquid and vapor phases, naphthenic acid corrosion occurs only where liquid phase is present.

- e) The materials most vulnerable to naphthenic acid corrosion are carbon steel and the iron-chrome (5 to 12 % Cr) alloys commonly used in corrosive refining services. 12Cr may experience corrosion rates greater than that of carbon steel. Type 304 stainless steel offers some resistance to naphthenic acid corrosion at lower acid levels, but normally the molybdenum containing austenitic stainless steels (Type 316 or Type 317 SS) are required for resistance to greater acid concentrations. It has been found that a minimum Mo content of 2.5 % is required in Type 316 SS to provide the best resistance to naphthenic acids.
- f) The amount of naphthenic acid present is most commonly indicated by a neutralization number or total acid number (TAN). The various acids which comprise the naphthenic acid family can have distinctly different corrosivities. The TAN is determined by an ASTM standard titration and is reported in mg KOH/g, which is the amount of potassium hydroxide (KOH) required to neutralize the acidity of one gram of oil sample. While both colorimetric and potentiometric titration methods are available, the potentiometric method covered by ASTM D664 is the more commonly used method. It should be noted that the titration neutralizes all of the acids present and not just the naphthenic acids. For example, dissolved hydrogen sulfide will be represented in the TAN of a sample. From a corrosion standpoint, the TAN of the liquid hydrocarbon stream being evaluated rather than the TAN of the whole crude is the important parameter in determining susceptibility to naphthenic acid corrosion.
- g) Another important factor in corrosion is the stream velocity, particularly where naphthenic acid is a factor in corrosion. Increased velocity increases the corrosivity by enhancing removal of protective sulfides. This effect is most pronounced in mixed liquid-vapor phase systems where velocities may be high.
- h) At particularly low sulfur levels, naphthenic acid corrosion may be more severe, even at low TAN since protective sulfides may not readily form.

2.B.3.2 Corrosion Rate Variability

There are several factors that influence the variability in the corrosion rates for sulfidation, when values obtained from the modified McConomy Curves and measured corrosion rates are compared. Factors including sulfur content, silicon content of the carbon steel, and flow regime/velocity, should be considered when determining the estimated corrosion rates, specifically when little or no information is available for the specific unit components.

In general, the stream corrosivity will increase as the sulfur content of the stream increases. Many different sulfur species exist in crude oil and can affect corrosion differently. Sulfur in the crude can be in the form of H₂S, mercaptans, elemental sulfur, polysulfides, thiophenes, aliphatic sulfides and aliphatic disulfides. Each one of these species has a different reactivity or effect on corrosion rates. As a result, different crudes with same total sulfur content can have very different corrosivity due to the sulfur species combination. Crude analysis of crude oils and its fractions is performed to identify the various sulfur species present. Predictive models can be developed based on a combination of laboratory testing and field experience.

Corrosion rates are accelerated when components are put in service due to the exposed steel surface in the sulfur containing environment. Corrosion rates slow down as a protective sulfide scale forms and reduces diffusion. The protective sulfide scale is a relative weak crystal lattice that may be removed in high velocity conditions that induces shear stress and/or by naphthenic acid. Exposing the unprotected material surface to the sulfur compounds causes accelerated corrosion. The repeated process of stripping the protective sulfide scale to expose the material and reforming the sulfide scale results in high corrosion rates. A flow velocity >100 ft/s (30.48 m/s) is known to strip the sulfide protective scale and prevent formation of the sulfide scale and result in severe corrosion.

No flow or very low flow can cause stratification of corrosive species and result in preferential corrosion attack. Silicon content of < 0.10% in carbon steel components can also result in accelerated sulfidation corrosion rates. In some applications, carbon steel may appear to be performing well with low measured corrosion rates until an unexpected failure occurs at an unidentified, low-silicon component in the circuit.

The process units where sulfidic and naphthenic acid corrosion is most commonly observed are atmospheric and vacuum crude distillation as well as the feed systems of downstream units such as hydrotreaters, catalytic crackers, and cokers. In hydrotreaters, naphthenic acid corrosion has not been reported downstream of the hydrogen addition point, even upstream of the reactor. Catalytic crackers and cokers thermally decompose naphthenic acids so this form of corrosion is also not normally reported in the fractionation sections of these units unless uncracked feed is carried in. Naphthenic acids can appear in high concentrations in lube extract oil streams when naphthenic acid containing feeds are processed. It should be noted that, where naphthenic acids may thermally decompose, lighter organic acids or carbon dioxide may form that can affect the corrosivity of condensed waters.

2.B.3.3 Basic Data

The data listed in [Table 2.B.3.1](#) are required to determine the estimated rate of corrosion in high temperature sulfidic and naphthenic acid service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.3.4 Determination of Corrosion Rate

The corrosion rate may be determined using the basic data in [Table 2.B.3.1](#) in conjunction with [Tables 2.B.3.2](#) through [2.B.3.10](#).

The corrosion rate in high temperature sulfidic environments in the absence of a naphthenic acid influence is based upon the modified McConomy curves. For components in service with no naphthenic acid, the corrosion rate follows the McConomy curves represented by the lowest TAN content ($TAN < 0.3$) in each of [Tables 2.B.3.2](#) through [2.B.2.10](#).

While various papers have been presented on naphthenic acid corrosion, no widely accepted correlations have yet been developed between corrosion rate and the various factors influencing it. Due to the lack of accurate industry tools for estimating naphthenic acid corrosion, the estimate rates provided in [Table 2.B.3.2](#) through [Table 2.B.3.10](#) should be adjusted to improve accuracy as high quality plant corrosion rate data becomes available through UT scans, RT surveys, well placed corrosion and/or ultrasonic probes, and other monitoring methods. Consequently, the corrosion rates provided in the tables for naphthenic acid is a rough estimate of the actual corrosion rate in the specific service.

Once a corrosion rate is selected from the appropriate table, it should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s).

2.B.3.4 References

See References [94], [95] (Appendix 3), [96], and [97] in [Section 2.2](#).

2.B.3.5 Tables

Table 2.B.3.1—High Temperature Sulfidic and Naphthenic Acid Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. For 316 SS, if the Mo content is not known, assume it is < 2.5 wt%.
Maximum temperature, (°F:°C)	Determine the maximum temperature of the process stream.
Sulfur content of the stream	Determine the sulfur content of the stream that is in this piece of equipment. If sulfur content is not known, contact a knowledgeable process engineer for an estimate.
Total acid number (TAN) (TAN = mg KOH/g oil sample)	The TAN of importance is that of the liquid hydrocarbon phase present in the equipment/piping being evaluated. If not known, consult a knowledgeable process engineer for an estimate.
Velocity	Determine the maximum velocity in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the velocity in flowing nozzles should be considered.

Table 2.B.3.2—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Carbon Steel (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.3	1	3	7	15	20	35	50	60
	0.65	5	15	25	35	45	55	65	75
	1.5	20	25	35	65	120	150	180	200
	3.0	30	60	60	120	150	160	240	240
	4.0	40	80	100	160	180	200	280	300
0.4	0.3	1	4	10	20	30	50	70	80
	0.65	5	10	15	25	40	60	80	90
	1.5	8	15	25	35	50	75	90	110
	3.0	10	20	35	50	70	100	120	130
	4.0	20	30	50	70	90	120	140	160
0.6	0.3	1	5	10	25	40	60	90	100
	0.65	5	10	15	30	50	80	110	130
	1.5	10	15	30	50	80	100	130	150
	3.0	15	30	50	80	100	120	140	170
	4.0	25	40	60	100	120	150	180	200
1.5	0.3	2	5	15	30	50	80	110	130
	0.65	7	10	20	35	55	100	130	150
	1.5	15	20	35	55	100	120	140	170
	3.0	20	30	55	85	110	150	170	200
	4.0	30	45	75	120	140	180	200	260
2.5	0.3	2	7	20	35	55	95	130	150
	0.65	7	10	30	45	60	120	140	170
	1.5	15	20	40	60	75	140	170	200
	3.0	20	35	60	90	120	170	200	260
	4.0	35	50	80	120	150	200	260	280
3.0	0.3	2	8	20	40	60	100	140	160
	0.65	8	15	25	45	65	120	150	170
	1.5	20	25	35	65	120	150	180	200
	3.0	30	60	60	120	150	160	240	240
	4.0	40	80	100	160	180	200	280	300

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.2M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Carbon Steel (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.3	0.03	0.08	0.18	0.38	0.51	0.89	1.27	1.52
	0.65	0.13	0.38	0.64	0.89	1.14	1.40	1.65	1.91
	1.5	0.51	0.64	0.89	1.65	3.05	3.81	4.57	5.08
	3.0	0.76	1.52	1.52	3.05	3.81	4.06	6.10	6.10
	4.0	1.02	2.03	2.54	4.06	4.57	5.08	7.11	7.62
0.4	0.3	0.03	0.10	0.25	0.51	0.76	1.27	1.78	2.03
	0.65	0.13	0.25	0.38	0.64	1.02	1.52	2.03	2.29
	1.5	0.20	0.38	0.64	0.89	1.27	1.91	2.29	2.79
	3.0	0.25	0.51	0.89	1.27	1.78	2.54	3.05	3.30
	4.0	0.51	0.76	1.27	1.78	2.29	3.05	3.56	4.06
0.6	0.3	0.03	0.13	0.25	0.64	1.02	1.52	2.29	2.54
	0.65	0.13	0.25	0.38	0.76	1.27	2.03	2.79	3.30
	1.5	0.25	0.38	0.76	1.27	2.03	2.54	3.30	3.81
	3.0	0.38	0.76	1.27	2.03	2.54	3.05	3.56	4.32
	4.0	0.64	1.02	1.52	2.54	3.05	3.81	4.57	5.08
1.5	0.3	0.05	0.13	0.38	0.76	1.27	2.03	2.79	3.30
	0.65	0.18	0.25	0.51	0.89	1.40	2.54	3.30	3.81
	1.5	0.38	0.51	0.89	1.40	2.54	3.05	3.56	4.32
	3.0	0.51	0.76	1.40	2.16	2.79	3.81	4.32	5.08
	4.0	0.76	1.14	1.91	3.05	3.56	4.57	5.08	6.60
2.5	0.3	0.05	0.18	0.51	0.89	1.40	2.41	3.30	3.81
	0.65	0.18	0.25	0.76	1.14	1.52	3.05	3.56	4.32
	1.5	0.38	0.51	1.02	1.52	1.91	3.56	4.32	5.08
	3.0	0.51	0.89	1.52	2.29	3.05	4.32	5.08	6.60
	4.0	0.89	1.27	2.03	3.05	3.81	5.08	6.60	7.11
3.0	0.3	0.05	0.20	0.51	1.02	1.52	2.54	3.56	4.06
	0.65	0.20	0.38	0.64	1.14	1.65	3.05	3.81	4.32
	1.5	0.51	0.64	0.89	1.65	3.05	3.81	4.57	5.08
	3.0	0.76	1.52	1.52	3.05	3.81	4.06	6.10	6.10
	4.0	1.02	2.03	2.54	4.06	4.57	5.08	7.11	7.62

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.3—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.3	1	1	4	7	13	21	25	30
	0.65	3	8	15	20	25	30	35	40
	1.5	10	15	20	30	60	75	90	100
	3.0	15	30	30	60	75	85	120	120
	4.0	20	40	50	80	100	120	140	160
0.4	0.3	1	2	5	10	20	30	35	40
	0.65	3	5	8	15	20	30	40	45
	1.5	4	8	15	20	25	40	45	55
	3.0	5	10	20	25	35	50	60	65
	4.0	10	15	25	35	45	60	70	80
0.8	0.3	1	3	6	15	25	40	45	50
	0.65	3	5	8	20	30	45	55	60
	1.5	5	8	15	25	40	50	65	75
	3.0	7	15	25	40	50	60	70	85
	4.0	12	20	30	50	60	75	90	100
1.5	0.3	2	3	8	15	30	50	55	65
	0.65	4	5	10	20	40	55	65	75
	1.5	6	10	20	30	50	65	70	80
	3.0	10	15	30	45	60	75	85	100
	4.0	15	20	35	60	75	90	100	130
2.5	0.3	2	4	9	20	35	55	65	75
	0.65	4	5	15	25	40	60	70	80
	1.5	7	10	20	30	45	70	80	100
	3.0	10	15	30	45	60	80	100	120
	4.0	15	25	40	60	80	100	120	140
3.0	0.3	2	4	10	20	35	60	70	80
	0.65	5	8	15	25	40	70	75	85
	1.5	10	15	20	30	60	75	90	100
	3.0	15	30	30	60	75	85	120	120
	4.0	20	40	50	80	100	120	140	160

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.3M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.3	0.03	0.03	0.10	0.18	0.33	0.53	0.64	0.76
	0.65	0.08	0.20	0.38	0.51	0.64	0.76	0.89	1.02
	1.5	0.25	0.38	0.51	0.76	1.52	1.91	2.29	2.54
	3.0	0.38	0.76	0.76	1.52	1.91	2.16	3.05	3.05
	4.0	0.51	1.02	1.27	2.03	2.54	3.05	3.56	4.06
0.4	0.3	0.03	0.05	0.13	0.25	0.51	0.76	0.89	1.02
	0.65	0.08	0.13	0.20	0.38	0.51	0.76	1.02	1.14
	1.5	0.10	0.20	0.38	0.51	0.64	1.02	1.14	1.40
	3.0	0.13	0.25	0.51	0.64	0.89	1.27	1.52	1.65
	4.0	0.25	0.38	0.64	0.89	1.14	1.52	1.78	2.03
0.8	0.3	0.03	0.08	0.15	0.38	0.64	1.02	1.14	1.27
	0.65	0.08	0.13	0.20	0.51	0.76	1.14	1.40	1.52
	1.5	0.13	0.20	0.38	0.64	1.02	1.27	1.65	1.91
	3.0	0.18	0.38	0.64	1.02	1.27	1.52	1.78	2.16
	4.0	0.30	0.51	0.76	1.27	1.52	1.91	2.29	2.54
1.5	0.3	0.05	0.08	0.20	0.38	0.76	1.27	1.40	1.65
	0.65	0.10	0.13	0.25	0.51	1.02	1.40	1.65	1.91
	1.5	0.15	0.25	0.51	0.76	1.27	1.65	1.78	2.03
	3.0	0.25	0.38	0.76	1.14	1.52	1.91	2.16	2.54
	4.0	0.38	0.51	0.89	1.52	1.91	2.29	2.54	3.30
2.5	0.3	0.05	0.10	0.23	0.51	0.89	1.40	1.65	1.91
	0.65	0.10	0.13	0.38	0.64	1.02	1.52	1.78	2.03
	1.5	0.18	0.25	0.51	0.76	1.14	1.78	2.03	2.54
	3.0	0.25	0.38	0.76	1.14	1.52	2.03	2.54	3.05
	4.0	0.38	0.64	1.02	1.52	2.03	2.54	3.05	3.56
3.0	0.3	0.05	0.10	0.25	0.51	0.89	1.52	1.78	2.03
	0.65	0.13	0.20	0.38	0.64	1.02	1.78	1.91	2.16
	1.5	0.25	0.38	0.51	0.76	1.52	1.91	2.29	2.54
	3.0	0.38	0.76	0.76	1.52	1.91	2.16	3.05	3.05
	4.0	0.51	1.02	1.27	2.03	2.54	3.05	3.56	4.06

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.4—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.7	1	1	2	4	6	8	10	15
	1.1	2	3	4	6	10	10	15	20
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80
0.4	0.7	1	2	3	5	8	10	15	20
	1.1	2	3	4	6	10	15	20	25
	1.75	2	4	6	8	15	20	25	30
	3.0	4	6	8	10	15	20	30	35
	4.0	6	8	10	10	20	25	35	40
0.75	0.7	1	2	4	6	10	15	23	25
	1.1	2	4	6	8	15	20	25	30
	1.75	4	6	8	10	15	20	30	35
	3.0	6	8	10	10	20	25	35	40
	4.0	8	10	10	15	20	30	40	50
1.5	0.7	1	2	5	8	15	20	30	35
	1.1	3	5	10	15	20	30	35	40
	1.75	5	10	15	20	30	35	40	45
	3.0	10	15	20	30	35	40	45	50
	4.0	15	20	30	35	40	50	60	70
2.5	0.7	1	3	6	9	15	20	35	40
	1.1	5	7	10	15	20	25	40	45
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80
3.0	0.7	2	3	6	10	15	25	35	40
	1.1	5	7	10	15	20	30	40	45
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.4M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.7	0.03	0.03	0.05	0.10	0.15	0.20	0.25	0.38
	1.1	0.05	0.08	0.10	0.15	0.25	0.25	0.38	0.51
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03
0.4	0.7	0.03	0.05	0.08	0.13	0.20	0.25	0.38	0.51
	1.1	0.05	0.08	0.10	0.15	0.25	0.38	0.51	0.64
	1.75	0.05	0.10	0.15	0.20	0.38	0.51	0.64	0.76
	3.0	0.10	0.15	0.20	0.25	0.38	0.51	0.76	0.89
	4.0	0.15	0.20	0.25	0.25	0.51	0.64	0.89	1.02
0.75	0.7	0.03	0.05	0.10	0.15	0.25	0.38	0.58	0.64
	1.1	0.05	0.10	0.15	0.20	0.38	0.51	0.64	0.76
	1.75	0.10	0.15	0.20	0.25	0.38	0.51	0.76	0.89
	3.0	0.15	0.20	0.25	0.25	0.51	0.64	0.89	1.02
	4.0	0.20	0.25	0.25	0.38	0.51	0.76	1.02	1.27
1.5	0.7	0.03	0.05	0.13	0.20	0.38	0.51	0.76	0.89
	1.1	0.08	0.13	0.25	0.38	0.51	0.76	0.89	1.02
	1.75	0.13	0.25	0.38	0.51	0.76	0.89	1.02	1.14
	3.0	0.25	0.38	0.51	0.76	0.89	1.02	1.14	1.27
	4.0	0.38	0.51	0.76	0.89	1.02	1.27	1.52	1.78
2.5	0.7	0.03	0.08	0.15	0.23	0.38	0.51	0.89	1.02
	1.1	0.13	0.18	0.25	0.38	0.51	0.64	1.02	1.14
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03
3.0	0.7	0.05	0.08	0.15	0.25	0.38	0.64	0.89	1.02
	1.1	0.13	0.18	0.25	0.38	0.51	0.76	1.02	1.14
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.5—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 7Cr-1Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.7	1	1	1	2	4	6	7	8
	1.1	1	2	3	5	7	8	10	15
	1.75	4	7	10	15	20	25	30	35
	3.0	7	10	15	20	25	30	35	45
	4.0	10	15	20	25	30	35	45	60
0.4	0.7	1	1	2	4	5	8	10	15
	1.1	1	2	4	5	8	10	15	15
	1.75	2	4	5	6	10	15	15	20
	3.0	3	5	6	9	12	15	20	20
	4.0	4	6	9	10	15	20	20	25
0.8	0.7	1	1	3	4	6	10	15	15
	1.1	2	3	4	6	10	15	15	20
	1.75	3	4	6	10	12	15	20	25
	3.0	4	6	10	12	15	20	25	30
	4.0	5	10	12	15	20	25	30	35
1.5	0.7	1	2	3	6	8	15	15	20
	1.1	2	3	6	10	15	15	20	25
	1.75	3	6	10	15	20	20	25	30
	3.0	6	10	15	20	20	25	30	35
	4.0	10	15	20	20	25	30	35	45
2.5	0.7	1	2	4	6	9	15	20	25
	1.1	6	7	9	10	15	20	25	30
	1.75	7	9	10	15	20	25	30	35
	3.0	9	10	15	20	30	35	35	40
	4.0	10	15	20	30	35	40	50	55
3.0	0.7	1	2	4	7	10	15	20	25
	1.1	2	4	7	10	15	20	25	30
	1.75	4	7	10	15	20	25	30	35
	3.0	7	10	15	20	25	30	35	45
	4.0	10	15	20	25	30	35	45	60

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.5M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 7Cr-1Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.7	0.03	0.03	0.03	0.05	0.10	0.15	0.18	0.20
	1.1	0.03	0.05	0.08	0.13	0.18	0.20	0.25	0.38
	1.75	0.10	0.18	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.18	0.25	0.38	0.51	0.64	0.76	0.89	1.14
	4.0	0.25	0.38	0.51	0.64	0.76	0.89	1.14	1.52
0.4	0.7	0.03	0.03	0.05	0.10	0.13	0.20	0.25	0.38
	1.1	0.03	0.05	0.10	0.13	0.20	0.25	0.38	0.38
	1.75	0.05	0.10	0.13	0.15	0.25	0.38	0.38	0.51
	3.0	0.08	0.13	0.15	0.23	0.30	0.38	0.51	0.51
	4.0	0.10	0.15	0.23	0.25	0.38	0.51	0.51	0.64
0.8	0.7	0.03	0.03	0.08	0.10	0.15	0.25	0.38	0.38
	1.1	0.05	0.08	0.10	0.15	0.25	0.38	0.38	0.51
	1.75	0.08	0.10	0.15	0.25	0.30	0.38	0.51	0.64
	3.0	0.10	0.15	0.25	0.30	0.38	0.51	0.64	0.76
	4.0	0.13	0.25	0.30	0.38	0.51	0.64	0.76	0.89
1.5	0.7	0.03	0.05	0.08	0.15	0.20	0.38	0.38	0.51
	1.1	0.05	0.08	0.15	0.25	0.38	0.38	0.51	0.64
	1.75	0.08	0.15	0.25	0.38	0.51	0.51	0.64	0.76
	3.0	0.15	0.25	0.38	0.51	0.51	0.64	0.76	0.89
	4.0	0.25	0.38	0.51	0.51	0.64	0.76	0.89	1.14
2.5	0.7	0.03	0.05	0.10	0.15	0.23	0.38	0.51	0.64
	1.1	0.15	0.18	0.23	0.25	0.38	0.51	0.64	0.76
	1.75	0.18	0.23	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.23	0.25	0.38	0.51	0.76	0.89	0.89	1.02
	4.0	0.25	0.38	0.51	0.76	0.89	1.02	1.27	1.40
3.0	0.7	0.03	0.05	0.10	0.18	0.25	0.38	0.51	0.64
	1.1	0.05	0.10	0.18	0.25	0.38	0.51	0.64	0.76
	1.75	0.10	0.18	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.18	0.25	0.38	0.51	0.64	0.76	0.89	1.14
	4.0	0.25	0.38	0.51	0.64	0.76	0.89	1.14	1.52

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.6—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.7	1	1	1	2	3	4	5	6
	1.1	1	2	2	4	4	5	6	8
	1.75	2	4	5	8	10	15	15	20
	3.0	3	6	10	12	15	20	20	25
	4.0	5	8	12	15	20	25	30	30
0.4	0.7	1	1	2	3	4	6	7	8
	1.1	1	1	2	4	5	7	8	10
	1.75	2	2	3	5	8	8	10	10
	3.0	3	3	5	8	10	10	12	15
	4.0	4	5	8	10	10	12	15	15
0.8	0.7	1	1	2	3	5	8	9	10
	1.1	1	2	3	5	8	10	10	10
	1.75	2	3	5	8	10	10	10	15
	3.0	3	5	8	10	10	15	15	15
	4.0	5	8	10	10	15	15	20	20
1.5	0.7	1	1	2	4	6	10	10	15
	1.1	1	2	3	5	7	10	15	15
	1.75	2	4	4	6	8	12	15	20
	3.0	3	6	5	8	10	15	20	20
	4.0	5	8	10	12	15	20	20	25
2.5	0.7	1	1	3	5	7	10	15	15
	1.1	1	2	4	6	8	10	15	15
	1.75	2	4	5	8	10	15	15	20
	3.0	3	6	10	12	15	20	20	25
	4.0	5	8	12	15	20	25	30	30
3.0	0.7	1	1	3	5	8	10	15	15
	1.1	2	3	5	8	10	15	15	20
	1.75	3	5	10	12	15	20	20	25
	3.0	5	8	12	15	20	25	30	30
	4.0	7	9	15	20	25	30	35	40

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.6M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.7	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	1.1	0.03	0.05	0.05	0.10	0.10	0.13	0.15	0.20
	1.75	0.05	0.10	0.13	0.20	0.25	0.38	0.38	0.51
	3.0	0.08	0.15	0.25	0.30	0.38	0.51	0.51	0.64
	4.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
0.4	0.7	0.03	0.03	0.05	0.08	0.10	0.15	0.18	0.20
	1.1	0.03	0.03	0.05	0.10	0.13	0.18	0.20	0.25
	1.75	0.05	0.05	0.08	0.13	0.20	0.20	0.25	0.25
	3.0	0.08	0.08	0.13	0.20	0.25	0.25	0.30	0.38
	4.0	0.10	0.13	0.20	0.25	0.25	0.30	0.38	0.38
0.8	0.7	0.03	0.03	0.05	0.08	0.13	0.20	0.23	0.25
	1.1	0.03	0.05	0.08	0.13	0.20	0.25	0.25	0.25
	1.75	0.05	0.08	0.13	0.20	0.25	0.25	0.25	0.38
	3.0	0.08	0.13	0.20	0.25	0.25	0.38	0.38	0.38
	4.0	0.13	0.20	0.25	0.25	0.38	0.38	0.51	0.51
1.5	0.7	0.03	0.03	0.05	0.10	0.15	0.25	0.25	0.38
	1.1	0.03	0.05	0.08	0.13	0.18	0.25	0.38	0.38
	1.75	0.05	0.10	0.10	0.15	0.20	0.30	0.38	0.51
	3.0	0.08	0.15	0.13	0.20	0.25	0.38	0.51	0.51
	4.0	0.13	0.20	0.25	0.30	0.38	0.51	0.51	0.64
2.5	0.7	0.03	0.03	0.08	0.13	0.18	0.25	0.38	0.38
	1.1	0.03	0.05	0.10	0.15	0.20	0.25	0.38	0.38
	1.75	0.05	0.10	0.13	0.20	0.25	0.38	0.38	0.51
	3.0	0.08	0.15	0.25	0.30	0.38	0.51	0.51	0.64
	4.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
3.0	0.7	0.03	0.03	0.08	0.13	0.20	0.25	0.38	0.38
	1.1	0.05	0.08	0.13	0.20	0.25	0.38	0.38	0.51
	1.75	0.08	0.13	0.25	0.30	0.38	0.51	0.51	0.64
	3.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
	4.0	0.18	0.23	0.38	0.51	0.64	0.76	0.89	1.02

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.7—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 12 % Cr Steel (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.7	1	1	1	1	1	1	2	2
	1.1	1	1	1	1	1	2	4	5
	1.75	2	2	2	4	4	5	8	10
	3.0	5	10	15	20	25	30	25	40
	4.0	10	15	20	25	30	25	40	45
0.4	0.7	1	1	1	1	1	2	3	3
	1.1	1	1	1	1	1	2	3	3
	1.75	1	2	2	2	2	4	5	5
	3.0	2	3	3	3	3	5	10	15
	4.0	3	4	5	8	10	12	15	20
0.8	0.7	1	1	1	1	1	2	3	4
	1.1	1	1	1	1	1	2	3	4
	1.75	2	2	4	5	6	6	7	8
	3.0	3	3	5	8	10	12	15	20
	4.0	4	5	5	8	10	15	20	25
1.5	0.7	1	1	1	1	2	3	4	5
	1.1	1	1	1	1	2	3	4	5
	1.75	2	2	3	5	7	8	10	10
	3.0	3	3	5	8	10	12	15	20
	4.0	5	8	10	12	15	20	25	30
2.5	0.7	1	1	1	1	2	3	5	6
	1.1	1	1	1	1	2	3	5	6
	1.75	2	5	7	9	10	12	15	15
	3.0	3	8	10	15	20	20	25	30
	4.0	5	10	15	20	25	30	35	40
3.0	0.7	1	1	1	1	2	4	5	6
	1.1	1	1	1	1	2	4	5	6
	1.75	3	5	7	9	10	12	15	15
	3.0	4	8	10	15	20	20	25	30
	4.0	5	10	15	20	25	30	35	40

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.7M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 12 % Cr Steel (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.7	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.10	0.13
	1.75	0.05	0.05	0.05	0.10	0.10	0.13	0.20	0.25
	3.0	0.13	0.25	0.38	0.51	0.64	0.76	0.64	1.02
	4.0	0.25	0.38	0.51	0.64	0.76	0.64	1.02	1.14
0.4	0.7	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08
	1.75	0.03	0.05	0.05	0.05	0.05	0.10	0.13	0.13
	3.0	0.05	0.08	0.08	0.08	0.08	0.13	0.25	0.38
	4.0	0.08	0.10	0.13	0.20	0.25	0.30	0.38	0.51
0.8	0.7	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.10
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.10
	1.75	0.05	0.05	0.10	0.13	0.15	0.15	0.18	0.20
	3.0	0.08	0.08	0.13	0.20	0.25	0.30	0.38	0.51
	4.0	0.10	0.13	0.13	0.20	0.25	0.38	0.51	0.64
1.5	0.7	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.13
	1.1	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.13
	1.75	0.05	0.05	0.08	0.13	0.18	0.20	0.25	0.25
	3.0	0.08	0.08	0.13	0.20	0.25	0.30	0.38	0.51
	4.0	0.13	0.20	0.25	0.30	0.38	0.51	0.64	0.76
2.5	0.7	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.15
	1.1	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.15
	1.75	0.05	0.13	0.18	0.23	0.25	0.30	0.38	0.38
	3.0	0.08	0.20	0.25	0.38	0.51	0.51	0.64	0.76
	4.0	0.13	0.25	0.38	0.51	0.64	0.76	0.89	1.02
3.0	0.7	0.03	0.03	0.03	0.03	0.05	0.10	0.13	0.15
	1.1	0.03	0.03	0.03	0.03	0.05	0.10	0.13	0.15
	1.75	0.08	0.13	0.18	0.23	0.25	0.30	0.38	0.38
	3.0	0.10	0.20	0.25	0.38	0.51	0.51	0.64	0.76
	4.0	0.13	0.25	0.38	0.51	0.64	0.76	0.89	1.02

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.8—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Austenitic SS Without Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	3	4	4
	4.0	1	1	1	2	3	4	5	6
0.4	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	3	4	4
	4.0	1	1	1	2	3	4	5	6
0.8	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	4	5	6
	4.0	1	2	2	4	6	8	10	12
1.5	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	4	5	6
	4.0	1	2	2	4	6	8	10	12
2.5	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	2	2	4	6	8	10	12
	4.0	1	2	4	7	10	14	17	20
3.0	1.0	1	1	1	1	1	1	1	2
	1.5	1	1	1	1	1	2	2	2
	3.0	1	2	2	4	6	8	10	12
	4.0	1	2	4	7	10	14	17	20

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.8M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Austenitic SS Without Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.10
	4.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
0.4	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.10
	4.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
0.8	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	4.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
1.5	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	4.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
2.5	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
	4.0	0.03	0.05	0.10	0.18	0.25	0.36	0.43	0.51
3.0	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	1.5	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05
	3.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
	4.0	0.03	0.05	0.10	0.18	0.25	0.36	0.43	0.51

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.9—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with < 2.5 % Mo (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤450	500	550	600	650	700	750	>750
0.2	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	1	2	2	2
	4.0	1	1	1	2	4	5	7	10
0.4	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	2	2	2
	4.0	1	1	2	3	4	5	7	10
0.8	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	2	2	3
	4.0	1	1	2	3	5	5	7	10
1.5	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	3	3	3	4
	4.0	1	1	3	5	5	5	7	10
2.5	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	3	4	5
	4.0	1	1	3	5	5	6	8	10
3.0	0.2	1	1	1	1	1	1	1	2
	3.0	1	1	1	2	4	5	5	6
	4.0	1	2	3	5	5	6	8	10

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.9M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with < 2.5 % Mo (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤232	260	288	315	343	371	399	>399
0.2	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05
	4.0	0.03	0.03	0.03	0.05	0.10	0.13	0.18	0.25
0.4	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05
	4.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
0.8	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.08
	4.0	0.03	0.03	0.05	0.08	0.13	0.13	0.18	0.25
1.5	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.08	0.08	0.08	0.10
	4.0	0.03	0.03	0.08	0.13	0.13	0.13	0.18	0.25
2.5	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.08	0.10	0.13
	4.0	0.03	0.03	0.08	0.13	0.13	0.15	0.20	0.25
3.0	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	3.0	0.03	0.03	0.03	0.05	0.10	0.13	0.13	0.15
	4.0	0.03	0.05	0.08	0.13	0.13	0.15	0.20	0.25

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.10—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with ≥ 2.5 % Mo and 317 SS (mpy)

Sulfur (wt%)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	>750
0.2	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	1	2	4	5
	6.0	1	1	1	2	4	5	7	10
0.4	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	4	4	5
	6.0	1	1	2	3	4	5	7	10
0.8	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	4	4	5
	6.0	1	1	2	3	4	5	7	10
1.5	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	3	5	7
	6.0	1	1	3	5	5	5	7	10
2.5	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	2	3	4	5	7
	6.0	1	1	3	5	5	6	8	10
3.0	4.0	1	1	1	1	1	1	1	2
	5.0	1	1	1	2	3	4	5	7
	6.0	1	2	3	5	5	6	8	10

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.10M—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with $\geq 2.5\%$ Mo and 317 SS (mm/y)

Sulfur (wt%)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	>399
0.2	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.03	0.05	0.10	0.13
	6.0	0.03	0.03	0.03	0.05	0.10	0.13	0.18	0.25
0.4	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.10	0.10	0.13
	6.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
0.8	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.10	0.10	0.13
	6.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
1.5	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.18
	6.0	0.03	0.03	0.08	0.13	0.13	0.13	0.18	0.25
2.5	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.18
	6.0	0.03	0.03	0.08	0.13	0.13	0.15	0.20	0.25
3.0	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	5.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.18
	6.0	0.03	0.05	0.08	0.13	0.13	0.15	0.20	0.25

NOTE: The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

2.B.3.6 Figures

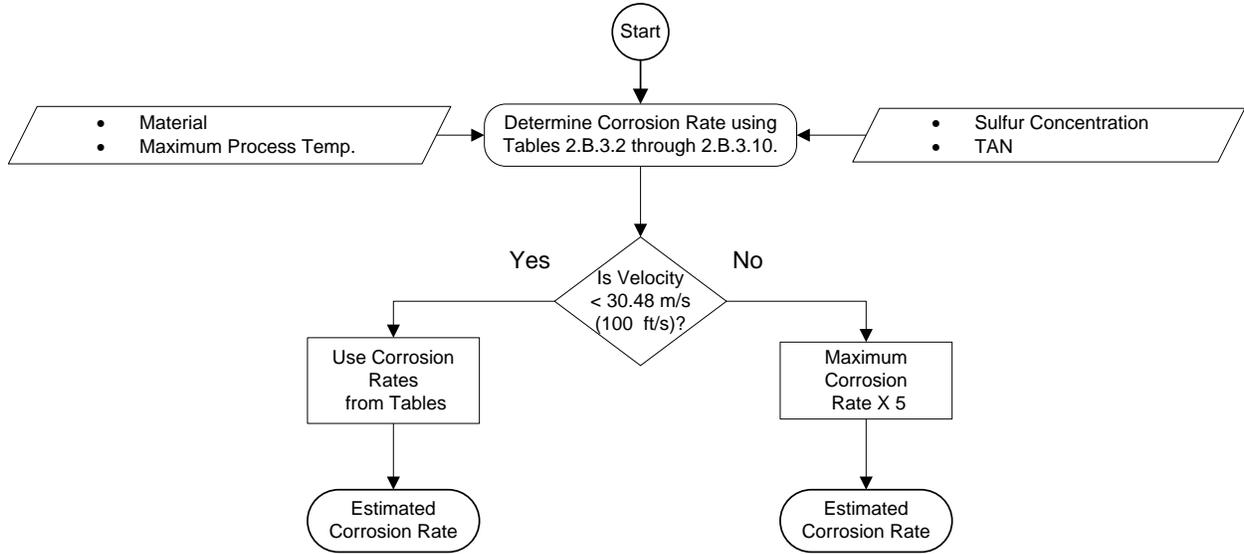


Figure 2.B.3.1—High Temperature Sulfidic and Naphthenic Acid Corrosion

2.B.4 High Temperature H₂S/H₂ Corrosion

2.B.4.1 Description of Damage

High temperature H₂S/H₂ corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 400 °F (204 °C). This form of sulfidation corrosion differs from high temperature sulfidic and naphthenic corrosion described in [Section 2.B.3](#). H₂S/H₂ corrosion occurs in hydroprocessing units, e.g. hydrodesulfurizers and hydrocrackers, once sulfur compounds are converted to hydrogen sulfide via catalytic reaction with hydrogen. Conversion of sulfur compounds to H₂S/H₂ typically does not occur to a significant extent in the presence of hydrogen, even at elevated temperatures, unless a catalyst is present. The corrosion rate is a function of the material of construction, temperature, nature of the process stream, and the concentration of H₂S.

In H₂S/H₂ environments, low levels of chromium (e.g. 5 to 9 % Cr) provide only a modest increase the corrosion resistance of steel. A minimum of 12 % Cr is needed to provide a significant decrease in corrosion rate. Further addition of chromium and nickel provides a substantial increase in corrosion resistance. The nature of the process stream is a factor in determining the corrosion rate. In H₂S/H₂ environments alone (all vapor), corrosion rates may be as much as 50 % greater than in the presence of hydrocarbons as suggested by the referenced NACE committee report. Nevertheless, the correlations developed by Couper and Gorman are used for estimating corrosion rates in both hydrocarbon-free and hydrocarbon-containing services. The predicted rates in both services are very high at high H₂S levels and temperatures, and the one set of data is satisfactory for risk-based inspection assessment purposes of either situation.

2.B.4.2 Basic Data

The data listed in [Table 2.B.4.1](#) are required to determine the rate of corrosion in high temperature H₂S/H₂ service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.4.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.4.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.4.1](#) in conjunction with [Tables 2.B.4.2](#) through [2.B.4.7](#).

The estimated corrosion rates in H₂S/H₂ environments in these tables were determined using data from the correlations developed by Couper and Gorman.

2.B.4.4 References

See References [95], [98], [99], and [100] in [Section 2.2](#).

2.B.4.5 Tables

Table 2.B.4.1—High Temperature H₂S/H₂ Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping.
Type of hydrocarbon present (naphtha or gas oil)	The Couper–Gorman corrosion rate curves are dependent on the type of hydrocarbon stream present [95, 100]. There are two categories as follows 1) Naphtha refers to those hydrocarbon streams of both light and heavy naphtha as well as light distillates (streams typically boiling at < 430 °F); 2) Gas oil refers to those hydrocarbon streams that include distillate, atmospheric gas oils, resid, and other heavier process hydrocarbons (streams typically boiling at > 430 °F).
Maximum temperature (°C:°F)	Determine the maximum process temperature.
H ₂ S content of the vapor (mole %)	Determine the H ₂ S content in the vapor. NOTE: mole% = volume % (not wt%)

Table 2.B.4.2—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Carbon Steel, 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	2	3	4	6	8	10	14	18
	Gas oil	1	1	1	2	3	5	7	10	14	20	26	34
0.0035	Naphtha	1	1	1	2	4	6	8	12	16	22	29	37
	Gas oil	1	2	3	4	7	11	16	22	31	41	55	71
0.008	Naphtha	1	1	2	3	5	7	11	15	21	29	38	50
	Gas oil	1	2	4	6	9	14	21	29	41	55	73	94
0.035	Naphtha	1	2	3	5	9	13	19	27	38	51	67	87
	Gas oil	2	4	6	10	16	25	36	51	71	96	130	170
0.08	Naphtha	1	2	4	7	10	16	23	33	46	62	82	110
	Gas oil	2	4	8	13	20	30	44	63	87	120	160	200
0.30	Naphtha	2	3	6	10	15	23	34	48	66	90	120	150
	Gas oil	3	6	11	18	29	44	64	91	130	170	230	300
0.75	Naphtha	2	4	7	11	17	26	38	54	75	100	130	170
	Gas oil	4	7	12	21	32	49	72	100	140	190	250	330
1.0	Naphtha	3	5	8	13	21	32	47	67	93	130	170	220
	Gas oil	5	9	15	26	40	61	89	130	180	240	310	410

Table 2.B.4.2M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Carbon Steel, 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mm/y)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.25	0.36	0.46
	Gas oil	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.36	0.51	0.66	0.86
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.1	0.15	0.2	0.3	0.41	0.56	0.74	0.94
	Gas oil	0.03	0.05	0.08	0.1	0.18	0.28	0.41	0.56	0.79	1.04	1.4	1.8
0.008	Naphtha	0.03	0.03	0.05	0.08	0.13	0.18	0.28	0.38	0.53	0.74	0.97	1.27
	Gas oil	0.03	0.05	0.1	0.15	0.23	0.36	0.53	0.74	1.04	1.4	1.85	2.39
0.035	Naphtha	0.03	0.05	0.08	0.13	0.23	0.33	0.48	0.69	0.97	1.3	1.7	2.21
	Gas oil	0.05	0.1	0.15	0.25	0.41	0.64	0.91	1.3	1.8	2.44	3.3	4.32
0.08	Naphtha	0.03	0.05	0.1	0.18	0.25	0.41	0.58	0.84	1.17	1.57	2.08	2.79
	Gas oil	0.05	0.1	0.2	0.33	0.51	0.76	1.12	1.6	2.21	3.05	4.06	5.08
0.30	Naphtha	0.05	0.08	0.15	0.25	0.38	0.58	0.86	1.22	1.68	2.29	3.05	3.81
	Gas oil	0.08	0.15	0.28	0.46	0.74	1.12	1.63	2.31	3.3	4.32	5.84	7.62
0.75	Naphtha	0.05	0.1	0.18	0.28	0.43	0.66	0.97	1.37	1.91	2.54	3.3	4.32
	Gas oil	0.1	0.18	0.3	0.53	0.81	1.24	1.83	2.54	3.56	4.83	6.35	8.38
1.0	Naphtha	0.08	0.13	0.2	0.33	0.53	0.81	1.19	1.7	2.36	3.3	4.32	5.59
	Gas oil	0.13	0.23	0.38	0.66	1.02	1.55	2.26	3.3	4.57	6.1	7.87	10.41

Table 2.B.4.3—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	6	8	11	14
	Gas oil	1	1	1	2	3	4	6	8	12	16	21	27
0.0035	Naphtha	1	1	1	2	3	5	7	9	13	18	23	30
	Gas oil	1	1	2	4	6	9	13	18	25	33	44	57
0.008	Naphtha	1	1	2	2	4	6	9	12	17	23	31	40
	Gas oil	1	2	3	5	7	11	17	24	33	44	58	76
0.035	Naphtha	1	2	3	4	7	10	15	22	30	41	54	70
	Gas oil	2	3	5	8	13	20	29	41	57	77	100	130
0.08	Naphtha	1	2	3	5	8	13	19	27	37	50	66	85
	Gas oil	2	4	6	10	16	24	36	51	70	94	130	160
0.30	Naphtha	1	3	5	8	12	19	27	39	53	72	95	120
	Gas oil	3	5	9	15	23	35	52	73	100	140	180	240
0.75	Naphtha	2	3	5	9	14	21	31	44	60	81	110	140
	Gas oil	3	6	10	17	26	40	58	82	110	150	200	270
1.0	Naphtha	2	4	7	11	17	26	38	54	75	100	130	170
	Gas oil	4	7	12	21	32	49	72	100	140	190	250	330

Table 2.B.4.3M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mm/y)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.28	0.36
	Gas oil	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.3	0.41	0.53	0.69
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.23	0.33	0.46	0.58	0.76
	Gas oil	0.03	0.03	0.05	0.1	0.15	0.23	0.33	0.46	0.64	0.84	1.12	1.45
0.008	Naphtha	0.03	0.03	0.05	0.05	0.1	0.15	0.23	0.3	0.43	0.58	0.79	1.02
	Gas oil	0.03	0.05	0.08	0.13	0.18	0.28	0.43	0.61	0.84	1.12	1.47	1.93
0.035	Naphtha	0.03	0.05	0.08	0.1	0.18	0.25	0.38	0.56	0.76	1.04	1.37	1.78
	Gas oil	0.05	0.08	0.13	0.2	0.33	0.51	0.74	1.04	1.45	1.96	2.54	3.3
0.08	Naphtha	0.03	0.05	0.08	0.13	0.2	0.33	0.48	0.69	0.94	1.27	1.68	2.16
	Gas oil	0.05	0.1	0.15	0.25	0.41	0.61	0.91	1.3	1.78	2.39	3.3	4.06
0.30	Naphtha	0.03	0.08	0.13	0.2	0.3	0.48	0.69	0.99	1.35	1.83	2.41	3.05
	Gas oil	0.08	0.13	0.23	0.38	0.58	0.89	1.32	1.85	2.54	3.56	4.57	6.1
0.75	Naphtha	0.05	0.08	0.13	0.23	0.36	0.53	0.79	1.12	1.52	2.06	2.79	3.56
	Gas oil	0.08	0.15	0.25	0.43	0.66	1.02	1.47	2.08	2.79	3.81	5.08	6.86
1.0	Naphtha	0.05	0.1	0.18	0.28	0.43	0.66	0.97	1.37	1.91	2.54	3.3	4.32
	Gas oil	0.1	0.18	0.3	0.53	0.81	1.24	1.83	2.54	3.56	4.83	6.35	8.38

Table 2.B.4.4—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 7Cr Steel (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	6	8	10	13
	Gas oil	1	1	1	2	2	4	5	8	11	14	19	25
0.0035	Naphtha	1	1	1	2	3	4	6	9	12	16	21	28
	Gas oil	1	1	2	3	5	8	11	16	23	30	40	52
0.008	Naphtha	1	1	1	2	4	5	8	11	16	21	28	37
	Gas oil	1	2	3	4	7	10	15	22	30	40	53	69
0.035	Naphtha	1	1	2	4	6	10	14	20	28	37	49	64
	Gas oil	1	3	5	8	12	18	27	38	52	71	94	120
0.08	Naphtha	1	2	3	5	8	12	17	24	34	46	60	78
	Gas oil	2	3	6	9	15	22	33	46	64	86	110	150
0.30	Naphtha	1	2	4	7	11	17	25	35	49	66	87	110
	Gas oil	3	5	8	13	21	32	47	67	93	130	170	220
0.75	Naphtha	2	3	5	8	13	19	28	40	55	74	98	130
	Gas oil	3	5	9	15	24	36	53	76	100	140	190	240
1.0	Naphtha	2	3	6	10	16	24	35	49	68	92	120	160
	Gas oil	4	7	11	19	30	45	66	94	130	180	230	300

Table 2.B.4.4M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 7Cr Steel (mm/y)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.25	0.33
	Gas oil	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.2	0.28	0.36	0.48	0.64
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.41	0.53	0.71
	Gas oil	0.03	0.03	0.05	0.08	0.13	0.2	0.28	0.41	0.58	0.76	1.02	1.32
0.008	Naphtha	0.03	0.03	0.03	0.05	0.1	0.13	0.2	0.28	0.41	0.53	0.71	0.94
	Gas oil	0.03	0.05	0.08	0.1	0.18	0.25	0.38	0.56	0.76	1.02	1.35	1.75
0.035	Naphtha	0.03	0.03	0.05	0.1	0.15	0.25	0.36	0.51	0.71	0.94	1.24	1.63
	Gas oil	0.03	0.08	0.13	0.2	0.3	0.46	0.69	0.97	1.32	1.8	2.39	3.05
0.08	Naphtha	0.03	0.05	0.08	0.13	0.2	0.3	0.43	0.61	0.86	1.17	1.52	1.98
	Gas oil	0.05	0.08	0.15	0.23	0.38	0.56	0.84	1.17	1.63	2.18	2.79	3.81
0.30	Naphtha	0.03	0.05	0.1	0.18	0.28	0.43	0.64	0.89	1.24	1.68	2.21	2.79
	Gas oil	0.08	0.13	0.2	0.33	0.53	0.81	1.19	1.7	2.36	3.3	4.32	5.59
0.75	Naphtha	0.05	0.08	0.13	0.2	0.33	0.48	0.71	1.02	1.4	1.88	2.49	3.3
	Gas oil	0.08	0.13	0.23	0.38	0.61	0.91	1.35	1.93	2.54	3.56	4.83	6.1
1.0	Naphtha	0.05	0.08	0.15	0.25	0.41	0.61	0.89	1.24	1.73	2.34	3.05	4.06
	Gas oil	0.1	0.18	0.28	0.48	0.76	1.14	1.68	2.39	3.3	4.57	5.84	7.62

Table 2.B.4.5—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	5	7	9	12
	Gas oil	1	1	1	1	2	3	5	7	10	13	17	23
0.0035	Naphtha	1	1	1	2	2	4	6	8	11	15	19	25
	Gas oil	1	1	2	3	5	7	11	15	21	28	37	48
0.008	Naphtha	1	1	1	2	3	5	7	10	14	20	26	34
	Gas oil	1	1	2	4	6	10	14	20	27	37	49	64
0.035	Naphtha	1	1	2	4	6	9	13	18	25	34	45	59
	Gas oil	1	2	4	7	11	17	24	35	48	65	86	110
0.08	Naphtha	1	2	3	4	7	11	16	22	31	42	55	72
	Gas oil	2	3	5	9	13	20	30	42	59	79	110	140
0.30	Naphtha	1	2	4	7	10	16	23	32	45	61	80	100
	Gas oil	2	4	7	12	19	30	43	61	85	120	150	200
0.75	Naphtha	1	3	4	7	12	18	26	37	51	68	90	120
	Gas oil	3	5	8	14	22	33	49	69	96	130	170	220
1.0	Naphtha	2	3	6	9	14	22	32	45	63	85	110	150
	Gas oil	3	6	10	17	27	41	60	86	120	160	210	280

Table 2.B.4.5M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mm/y)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.18	0.23	0.3
	Gas oil	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.43	0.58
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.05	0.1	0.15	0.2	0.28	0.38	0.48	0.64
	Gas oil	0.03	0.03	0.05	0.08	0.13	0.18	0.28	0.38	0.53	0.71	0.94	1.22
0.008	Naphtha	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.36	0.51	0.66	0.86
	Gas oil	0.03	0.03	0.05	0.1	0.15	0.25	0.36	0.51	0.69	0.94	1.24	1.63
0.035	Naphtha	0.03	0.03	0.05	0.1	0.15	0.23	0.33	0.46	0.64	0.86	1.14	1.5
	Gas oil	0.03	0.05	0.1	0.18	0.28	0.43	0.61	0.89	1.22	1.65	2.18	2.79
0.08	Naphtha	0.03	0.05	0.08	0.1	0.18	0.28	0.41	0.56	0.79	1.07	1.4	1.83
	Gas oil	0.05	0.08	0.13	0.23	0.33	0.51	0.76	1.07	1.5	2.01	2.79	3.56
0.30	Naphtha	0.03	0.05	0.1	0.18	0.25	0.41	0.58	0.81	1.14	1.55	2.03	2.54
	Gas oil	0.05	0.1	0.18	0.3	0.48	0.76	1.09	1.55	2.16	3.05	3.81	5.08
0.75	Naphtha	0.03	0.08	0.1	0.18	0.3	0.46	0.66	0.94	1.3	1.73	2.29	3.05
	Gas oil	0.08	0.13	0.2	0.36	0.56	0.84	1.24	1.75	2.44	3.3	4.32	5.59
1.0	Naphtha	0.05	0.08	0.15	0.23	0.36	0.56	0.81	1.14	1.6	2.16	2.79	3.81
	Gas oil	0.08	0.15	0.25	0.43	0.69	1.04	1.52	2.18	3.05	4.06	5.33	7.11

Table 2.B.4.6—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 12Cr Steels (mpy)

H ₂ S (mole %)	Temperature (°F)											
	425	475	525	575	625	675	725	775	825	875	925	975
0.002	1	1	1	1	2	3	4	5	6	9	11	14
0.0035	1	1	1	1	2	3	4	6	8	11	14	18
0.008	1	1	1	2	2	4	5	7	9	12	15	19
0.035	1	1	1	2	3	4	6	9	12	15	19	25
0.08	1	1	1	2	3	5	7	10	13	17	22	27
0.30	1	1	2	3	4	6	9	12	16	21	27	34
0.75	1	1	2	3	5	7	10	13	18	23	30	38
1.0	1	2	3	4	7	10	13	18	25	32	42	53

Table 2.B.4.6M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 12Cr Steels (mm/y)

H ₂ S (mole %)	Temperature (°C)											
	218	246	274	302	329	357	385	413	441	468	496	524
0.002	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.15	0.23	0.28	0.36
0.0035	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.28	0.36	0.46
0.008	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.18	0.23	0.3	0.38	0.48
0.035	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.38	0.48	0.64
0.08	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.43	0.56	0.69
0.30	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.41	0.53	0.69	0.86
0.75	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.46	0.58	0.76	0.97
1.0	0.03	0.05	0.08	0.1	0.18	0.25	0.33	0.46	0.64	0.81	1.07	1.35

Table 2.B.4.7—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mpy)

H ₂ S (mole %)	Temperature (°F)											
	425	475	525	575	625	675	725	775	825	875	925	975
0.002	1	1	1	1	1	1	1	1	1	1	2	2
0.0035	1	1	1	1	1	1	1	1	1	2	2	3
0.008	1	1	1	1	1	1	1	1	2	2	3	3
0.035	1	1	1	1	1	1	1	1	2	3	3	4
0.08	1	1	1	1	1	1	1	1	2	3	4	5
0.30	1	1	1	1	1	1	1	1	3	4	5	6
0.75	1	1	1	1	1	1	1	2	3	4	5	6
1.0	1	1	1	1	1	1	2	2	4	5	7	9

Table 2.B.4.7M—High Temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mm/y)

H ₂ S (mole %)	Temperature (°C)											
	218	246	274	302	329	357	385	413	441	468	496	524
0.002	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05
0.0035	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.08
0.008	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.08	0.08
0.035	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.1
0.08	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13
0.30	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.08	0.1	0.13	0.15
0.75	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.15
1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.18	0.23

2.B.4.6 Figures

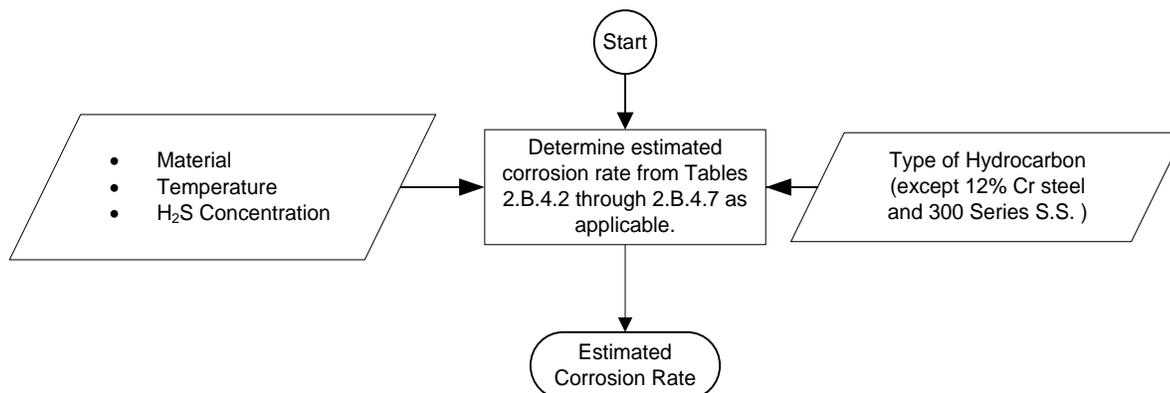


Figure 2.B.4.1—High Temperature H₂S/H₂ Corrosion—Determination of Corrosion Rate

2.B.5 Sulfuric Acid Corrosion

2.B.5.1 Description of Damage

Sulfuric acid (H_2SO_4) is one of the most widely used industrial chemicals. One common use of concentrated H_2SO_4 is as a catalyst for the alkylation process. H_2SO_4 is a very strong acid that can be extremely corrosive under certain conditions. The corrosiveness of H_2SO_4 varies widely, and depends on many factors. Acid concentration and temperature are the foremost factors that influence corrosion. In addition, velocity effects and presence of impurities in the acid, especially oxygen or oxidants, can have a significant impact on corrosion.

Although H_2SO_4 corrodes carbon steel, it is the material typically chosen for equipment and piping handling concentrated H_2SO_4 at near ambient temperatures. The corrosion rate of steel by H_2SO_4 as a function of acid concentration and temperature under stagnant conditions is provided in NACE Publication 5A151^[101]. Stagnant or low flow (< 3 ft/s or 0.91 m/s) conditions typically cause general thinning of carbon steel. The ferrous sulfate corrosion product film is somewhat protective, and as it builds on the metal surface the corrosion rate decreases. The mass transfer of ferrous sulfate away from the corroding steel surface is the rate-limiting step for the corrosion. Acid solution velocity above approximately 3 ft/s (0.91 m/s) (turbulent flow) has a significant impact on this mass transfer rate and thus the corrosion rate. Corrosion rates for steel pipelines carrying H_2SO_4 at various conditions and velocities have been calculated from a well-established mathematical model^[13]. The calculated rates were based on pure H_2SO_4 solutions with no ferrous sulfate present in the acid solution. These rates for turbulent flow in straight pipes were then multiplied by a factor of 3 (based on experience cited in reference^[13]) to account for the enhanced localized corrosion that occurs at elbows, tees, valves, and areas of internal surface roughness such as protuberances at welded joints. This provides maximum estimated corrosion rates. Actual corrosion rates could be 20 % to 50 % of these estimated maximum corrosion rates.

Although the performance of many alloys in H_2SO_4 service is primarily related to the acid concentration and temperature, velocity and the presence of an oxidant can play a significant role as well. This is because these alloys often depend upon formation of a protective oxide film to provide passivity and, therefore, corrosion resistance. The presence of an oxidant usually improves the corrosion performance in H_2SO_4 service of alloys such as stainless steel and many nickel alloys. This is not the case with Alloy B-2, which can suffer drastically high corrosion rates if an oxidant is present in the acid. The corrosion rates provided in these tables are from published literature, and the corrosion rates for non-aerated acid services are used to provide conservatism, except for Alloy B-2. This conservatism is appropriate because other acid contaminants and velocity can affect the material's passivity. The effect of velocity on corrosion rates is assumed to hold over a wide range of conditions for very little information on the effect of velocity is published.

2.B.5.2 Basic Data

The data listed in [Table 2.B.5.1](#) are required to determine the estimated corrosion rate for H_2SO_4 service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.5.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.5.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.5.1](#) in conjunction with [Tables 2.B.5.2](#) through [2.B.5.7](#).

NOTE the corrosion rates of Alloy B-2 can increase drastically in the presence of an oxidant (e.g. oxygen or ferric ions), which is not reflected in [Table 2.B.5.7](#). For this environment, a corrosion engineer should be consulted to establish an estimated corrosion rate.

2.B.5.4 References

See References [106], [101], [102], [103], and [104] in [Section 2.2](#).

2.B.5.5 Tables

Table 2.B.5.1—H₂SO₄ Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping.
Acid concentration (wt %)	Determine the concentration of the H ₂ SO ₄ present in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Maximum temperature (°F:°C)	Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating conditions such as effect of the sun or heat tracing should be considered.
Velocity of acid (ft/s: m/s)	Determine the maximum velocity of the acid in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the acid velocity in flowing nozzles (inlet, outlet, etc.) should be considered.
Oxygen/oxidant present? (Yes or No)	Determine whether the acid contains oxygen or some other oxidant. If in doubt, consult a knowledgeable process engineer. These data are only necessary if the material of construction is Alloy B-2. For carbon steel and other alloys, the corrosion rates in the tables assume the acid does not contain oxygen/oxidants.

Table 2.B.5.2—H₂SO₄ Corrosion—Estimated Corrosion Rate for Carbon Steel (mpy)

Acid Conc (wt%)	Acid Temp (°F)	Acid Velocity (ft/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
100	42	5	7	9	12	45	60	75	95	120
	59.5	12	14	17	20	65	85	110	140	170
	91	50	55	60	70	270	360	450	580	720
	122.5	100	150	200	300	999	999	999	999	999
98	42	4	6	8	10	35	45	60	75	90
	59.5	5	10	15	20	80	110	140	180	220
	91	15	25	40	60	290	390	490	640	780
	122.5	40	80	120	250	999	999	999	999	999
96	42	8	10	12	15	60	80	110	130	160
	59.5	15	20	25	40	170	220	270	350	430
	91	25	40	60	100	500	650	820	999	999
	122.5	50	100	200	500	999	999	999	999	999
93.5	42	10	15	20	25	120	160	200	260	330
	59.5	20	25	40	70	340	450	570	740	910
	91	30	40	75	130	640	850	999	999	999
	122.5	60	120	250	600	999	999	999	999	999
91	42	15	25	45	70	320	430	540	710	870
	59.5	25	40	80	120	700	940	999	999	999
	91	35	60	100	200	940	999	999	999	999
	122.5	70	150	300	800	999	999	999	999	999

Acid Conc (wt%)	Acid Temp (°F)	Acid Velocity (ft/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
87	42	20	30	50	80	380	500	630	810	999
	59.5	30	160	300	420	690	920	999	999	999
	91	45	450	850	999	999	999	999	999	999
	122.5	80	999	999	999	999	999	999	999	999
83	42	20	25	35	45	210	280	350	460	570
	59.5	30	50	100	150	680	910	999	999	999
	91	40	100	200	400	999	999	999	999	999
	122.5	80	200	400	999	999	999	999	999	999
78	42	15	20	20	25	110	150	190	250	300
	59.5	20	40	70	120	570	760	950	999	999
	91	30	60	120	250	999	999	999	999	999
	122.5	60	120	300	900	999	999	999	999	999

Table 2.B.5.2M—H₂SO₄ Corrosion—Estimated Corrosion Rate for Carbon Steel (mm/y)

Acid Conc (wt%)	Acid Temp (°C)	Acid Velocity (m/s)								
		0	.30	0.61	0.91	1.37	1.98	2.59	3.51	3.66
100	6	0.13	0.18	0.23	0.3	1.14	1.52	1.91	2.41	3.05
	15	0.3	0.36	0.43	0.51	1.65	2.16	2.79	3.56	4.32
	33	1.27	1.4	1.52	1.78	6.86	9.14	11.43	14.73	18.29
	50	2.54	3.81	5.08	7.62	25.37	25.37	25.37	25.37	25.37
98	6	0.1	0.15	0.2	0.25	0.89	1.14	1.52	1.91	2.29
	15	0.13	0.25	0.38	0.51	2.03	2.79	3.56	4.57	5.59
	33	0.38	0.64	1.02	1.52	7.37	9.91	12.45	16.26	19.81
	50	1.02	2.03	3.05	6.35	25.37	25.37	25.37	25.37	25.37
96	6	0.2	0.25	0.3	0.38	1.52	2.03	2.79	3.3	4.06
	15	0.38	0.51	0.64	1.02	4.32	5.59	6.86	8.89	10.92
	33	0.64	1.02	1.52	2.54	12.7	16.51	20.83	25.37	25.37
	50	1.27	2.54	5.08	12.7	25.37	25.37	25.37	25.37	25.37
93.5	6	0.25	0.38	0.51	0.64	3.05	4.06	5.08	6.6	8.38
	15	0.51	0.64	1.02	1.78	8.64	11.43	14.48	18.8	23.11
	33	0.76	1.02	1.91	3.3	16.26	21.59	25.37	25.37	25.37
	50	1.52	3.05	6.35	15.24	25.37	25.37	25.37	25.37	25.37
91	6	0.38	0.64	1.14	1.78	8.13	10.92	13.72	18.03	22.1
	15	0.64	1.02	2.03	3.05	17.78	23.88	25.37	25.37	25.37
	33	0.89	1.52	2.54	5.08	23.88	25.37	25.37	25.37	25.37
	50	1.78	3.81	7.62	20.32	25.37	25.37	25.37	25.37	25.37
87	6	0.51	0.76	1.27	2.03	9.65	12.7	16	20.57	25.37
	15	0.76	4.06	7.62	10.67	17.53	23.37	25.37	25.37	25.37
	33	1.14	11.43	21.59	25.37	25.37	25.37	25.37	25.37	25.37
	50	2.03	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
83	6	0.51	0.64	0.89	1.14	5.33	7.11	8.89	11.68	14.48
	15	0.76	1.27	2.54	3.81	17.27	23.11	25.37	25.37	25.37
	33	1.02	2.54	5.08	10.16	25.37	25.37	25.37	25.37	25.37
	50	2.03	5.08	10.16	25.37	25.37	25.37	25.37	25.37	25.37
78	6	0.38	0.51	0.51	0.64	2.79	3.81	4.83	6.35	7.62
	15	0.51	1.02	1.78	3.05	14.48	19.3	24.13	25.37	25.37
	33	0.76	1.52	3.05	6.35	25.37	25.37	25.37	25.37	25.37
	50	1.52	3.05	7.62	22.86	25.37	25.37	25.37	25.37	25.37

**Table 2.B.5.2M—H₂SO₄ Corrosion—Estimated Corrosion Rate for Carbon Steel (mm/y)
(Continued)**

Table 2.B.5.3—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 304 SS (mpy)

Acid Concentration (wt%)	Temperature								
	86 °F			104.5 °F			140.5 °F		
	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s
98	5	10	15	20	40	60	200	400	600
92.5	20	40	60	40	80	120	500	999	999
87	40	80	120	80	160	240	999	999	999
82	100	200	300	500	999	999	999	999	999
75	500	999	999	999	999	999	999	999	999
65	999	999	999	999	999	999	999	999	999
50	999	999	999	999	999	999	999	999	999
30	999	999	999	999	999	999	999	999	999
15	400	800	999	999	999	999	999	999	999
8	200	400	600	800	999	999	999	999	999
3.5	50	100	150	200	400	600	500	999	999
2	20	40	60	70	140	210	200	400	600

Table 2.B.5.3M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 304 SS (mm/y)

Acid Concentration (wt%)	Temperature								
	30 °C			40 °C			60 °C		
	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s
98	0.13	0.25	0.38	0.51	1.02	1.52	5.08	10.16	15.24
92.5	0.51	1.02	1.52	1.02	2.03	3.05	12.7	25.37	25.37
87	1.02	2.03	3.05	2.03	4.06	6.1	25.37	25.37	25.37
82	2.54	5.08	7.62	12.7	25.37	25.37	25.37	25.37	25.37
75	12.7	25.37	25.37	25.37	25.37	2.51	25.37	25.37	25.37
65	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
50	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
30	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
15	10.16	20.32	25.37	25.37	25.37	25.37	25.37	25.37	25.37
8	5.08	10.16	15.24	20.32	25.37	25.37	25.37	25.37	25.37
3.5	1.27	2.54	3.81	5.08	10.16	15.24	12.7	25.37	25.37
2	0.51	1.02	1.52	1.78	3.56	5.33	5.08	10.16	15.24

Table 2.B.5.4—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 316 SS (mpy)

Acid Concentration (wt%)	316 SS Corrosion Rate (mpy)								
	86 °F			104.5 °F			140.5 °F		
	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s
98	5	10	15	15	30	45	100	200	300
92.5	10	20	30	30	60	90	400	800	999
87	20	40	60	50	100	150	800	999	999
82	50	100	150	400	800	999	999	999	999
75	300	600	900	999	999	999	999	999	999
65	600	999	999	999	999	999	999	999	999
50	900	999	999	999	999	999	999	999	999
30	200	400	600	999	999	999	999	999	999
15	30	60	90	60	120	180	200	400	600
8	10	20	30	30	60	90	80	160	240
3.5	5	10	15	20	40	60	40	80	120
2	5	10	15	5	10	15	10	20	30

Table 2.B.5.4M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 316 SS (mm/y)

Acid Concentration (wt%)	Temperature								
	30 °C			40 °C			60 °C		
	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s
98	0.13	0.25	0.38	0.38	0.76	1.14	2.54	5.08	7.62
92.5	0.25	0.51	0.76	0.76	1.52	2.29	10.16	20.32	25.37
87	0.51	1.02	1.52	1.27	2.54	3.81	20.32	25.37	25.37
82	1.27	2.54	3.81	10.16	20.32	25.37	25.37	25.37	25.37
75	7.62	15.24	22.86	25.37	25.37	25.37	25.37	25.37	25.37
65	15.24	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
50	22.86	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
30	5.08	10.16	15.24	25.37	25.37	25.37	25.37	25.37	25.37
15	0.76	1.52	2.29	1.52	3.05	4.57	5.08	10.16	15.24
8	0.25	0.51	0.76	0.76	1.52	2.29	2.03	4.06	6.1
3.5	0.13	0.25	0.38	0.51	1.02	1.52	1.02	2.03	3.05
2	0.13	0.25	0.38	0.13	0.25	0.38	0.25	0.51	0.76

Table 2.B.5.5—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy 20 (mpy)

Acid Concentration (wt%)	Temperature											
	100 °F			125 °F			163.5 °F			195.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
98	2	4	6	5	10	15	15	30	45	40	80	120
92.5	3	6	9	10	20	30	25	50	75	50	100	150
85	3	6	9	10	20	30	30	60	90	60	120	180
70	3	6	9	15	30	45	50	100	150	100	200	300
55	3	6	9	10	20	30	30	60	90	60	120	180
45	3	6	9	10	20	30	30	60	90	50	100	150
35	3	6	9	10	20	30	25	50	75	40	80	120
25	2	4	6	5	10	15	20	40	60	40	80	120
15	2	4	6	5	10	15	20	40	60	35	70	105
8	2	4	6	3	6	9	5	10	15	25	50	75
5	2	4	6	3	6	9	3	6	9	20	40	60

Table 2.B.5.5M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy 20 (mm/y)

Acid Concentration (wt%)	Temperature											
	38 °C			52 °C			70 °C			91 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
98	0.05	0.1	0.15	0.13	0.25	0.38	0.38	0.76	1.14	1.02	2.03	3.05
92.5	0.08	0.15	0.23	0.25	0.51	0.76	0.64	1.27	1.91	1.27	2.54	3.81
85	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.52	3.05	4.57
70	0.08	0.15	0.23	0.38	0.76	1.14	1.27	2.54	3.81	2.54	5.08	7.62
55	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.52	3.05	4.57
45	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.27	2.54	3.81
35	0.08	0.15	0.23	0.25	0.51	0.76	0.64	1.27	1.91	1.02	2.03	3.05
25	0.05	0.1	0.15	0.13	0.25	0.38	0.51	1.02	1.52	1.02	2.03	3.05
15	0.05	0.1	0.15	0.13	0.25	0.38	0.51	1.02	1.52	0.89	1.78	2.67
8	0.05	0.1	0.15	0.08	0.15	0.23	0.13	0.25	0.38	0.64	1.27	1.91
5	0.05	0.1	0.15	0.08	0.15	0.23	0.08	0.15	0.23	0.51	1.02	1.52

Table 2.B.5.6—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy C-276 (mpy)

Acid Concentration (wt%)	Temperature											
	125 °F			137.5 °F			162.5 °F			187.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
98	3	6	9	4	8	12	5	10	15	20	40	60
92.5	4	8	12	5	10	15	20	40	60	50	100	150
85	5	10	15	10	20	30	20	40	60	60	120	180
75	5	10	15	10	20	30	20	40	60	50	100	150
55	5	10	15	10	20	30	15	30	45	40	80	120
20	4	8	12	5	10	15	15	30	45	40	80	120
8	4	8	12	5	10	15	10	20	30	30	60	90
5	3	6	9	4	8	12	5	10	15	15	30	45

Table 2.B.5.6M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy C-276 (mm/y)

Acid Concentration (wt%)	Temperature											
	52 °C			59 °C			73 °C			86 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
98	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38	0.51	1.02	1.52
92.5	0.1	0.2	0.3	0.13	0.25	0.38	0.51	1.02	1.52	1.27	2.54	3.81
85	0.13	0.25	0.38	0.25	0.51	0.76	0.51	1.02	1.52	1.52	3.05	4.57
75	0.13	0.25	0.38	0.25	0.51	0.76	0.51	1.02	1.52	1.27	2.54	3.81
55	0.13	0.25	0.38	0.25	0.51	0.76	0.38	0.76	1.14	1.02	2.03	3.05
20	0.1	0.2	0.3	0.13	0.25	0.38	0.38	0.76	1.14	1.02	2.03	3.05
8	0.1	0.2	0.3	0.13	0.25	0.38	0.25	0.51	0.76	0.76	1.52	2.29
5	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38	0.38	0.76	1.14

Table 2.B.5.7—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy B-2 (mpy)

Acid Concentration (wt%)	Temperature											
	125 °F			137.5 °F			162.5 °F			187.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
75	2	4	6	3	6	9	4	8	12	5	10	15
45	3	6	9	4	8	12	4	8	12	5	10	15
32.5	4	8	12	5	10	15	5	10	15	5	10	15
25	5	10	15	10	20	30	10	20	30	10	20	30

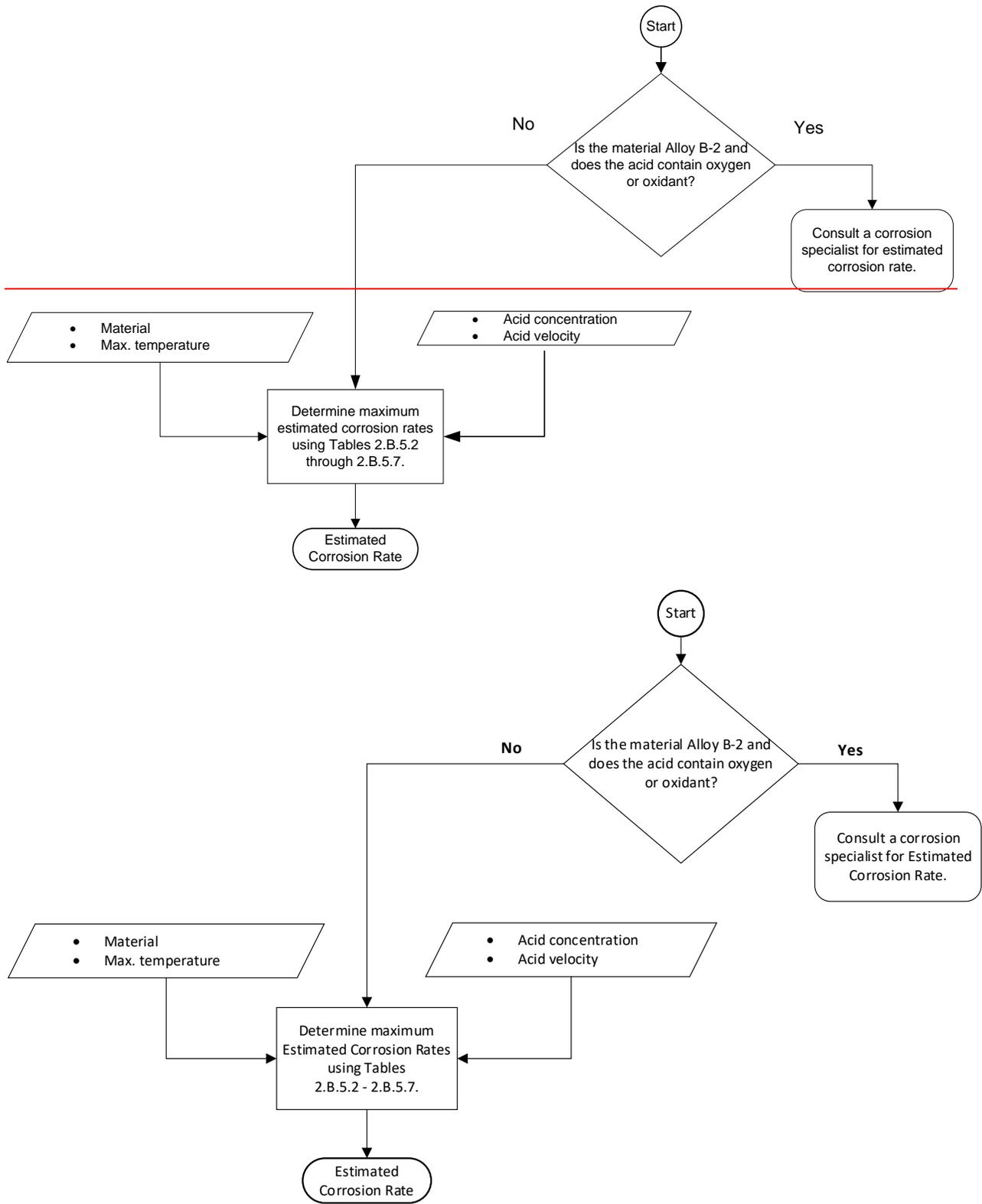
NOTE 1 Oxidants present (even in a few ppm) accelerate corrosion rates and pitting.
NOTE 2 Alloy B-2 should not be used in oxidizing conditions.

Table 2.B.5.7M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy B-2 (mm/y)

Acid Concentration (wt%)	Temperature											
	52 °C			59 °C			73 °C			86 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
75	0.05	0.1	0.15	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38
45	0.08	0.15	0.23	0.1	0.2	0.3	0.1	0.2	0.3	0.13	0.25	0.38
32.5	0.1	0.2	0.3	0.13	0.25	0.38	0.13	0.25	0.38	0.13	0.25	0.38
25	0.13	0.25	0.38	0.25	0.51	0.76	0.25	0.51	0.76	0.25	0.51	0.76

NOTE 1 Oxidants present (even in a few ppm) accelerate corrosion rates and pitting.
NOTE 2 Alloy B-2 should not be used in oxidizing conditions.

2.B.5.6 Figures

Figure 2.B.5.1—H₂SO₄ Corrosion—Determination of Corrosion Rate

2.B.6 Hydrofluoric Acid Corrosion

2.B.6.1 Description of Damage

Concentrated hydrofluoric acid (HF) is used as the acid catalyst in HF alkylation units. The alkylation reaction chemically combines an alkane (usually isobutane) with an olefin (butylene, propylene, amylene) in the presence of the acid catalyst. HF presents severe health hazards as both a liquid and vapor. If spilled, HF may form a dense, low lying, toxic cloud. Extreme caution should be exercised when using HF.

Corrosion of materials in HF primarily depends on the HF-in-water concentration and the temperature. Other variables, such as velocity, turbulence, aeration, impurities, etc., can strongly influence corrosion. Some metals will form a protective fluoride film or scale that protects the surface. Loss of this protective film, especially through high velocity or turbulence, will likely result in greatly accelerated corrosion rates. Corrosion in 80 % and stronger HF-in-water solutions is equivalent to corrosion in AHF (200 ppm H₂O). Below 80 % HF, the acid is considered aqueous, and metal corrosion is highly temperature and velocity dependent and usually accelerated. The usual HF-in-water concentrations in typical HF alkylation units are 96 % to 99+ %, and the temperatures are generally below 150 °F (66 °C). Under these conditions, carbon steel is widely used for all equipment except where close tolerances are required for operation (i.e. pumps, valves, instruments). Where close tolerances are required and at temperatures over 150 °F (66 °C) to approximately 300 °F (149 °C), Alloy 400 is typically used.

Accelerated corrosion from water dilution of the acid is often encountered in low points (bleeders, line pockets, etc.) if unit dry out leaves residual free water in these areas.

2.B.6.2 Basic Data

The data listed in [Table 2.B.6.1](#) are required to determine the estimated corrosion rate for HF acid service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.6.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.6.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.6.1](#) in conjunction with [Tables 2.B.6.2](#) through [2.B.6.3](#).

It is important to note that the corrosion rate is very high in the initial stages of exposure to HF as the protective fluoride scale is being established. Once established, the fluoride scale protects the steel resulting in low corrosion rates unless the scale is disturbed or removed.

Alloy steels have been found to exhibit higher corrosion rates than mild carbon steel in both dilute and concentrated HF and generally are not specified for this service. Higher alloys are sometimes used in HF service, and corrosion rates, if unknown, should be obtained from published literature or from the manufacturer ^[105]. It is important to consider the galvanic effects of welding carbon steel to Alloy 400 or other corrosion-resistant alloys. Accelerated and localized attack of the carbon steel may result from galvanic coupling. Increased rates of corrosion have also been reported in carbon steels that contain high levels of residual elements, notably Cu, Ni, and Cr ^[16].

Corrosion caused by HF results in general thinning except in the event of potential galvanic attack. The presence of HF may also result in hydrogen stress cracking and blistering. These degradation modes are considered in [Part 2, Section 14.1](#).

2.B.6.4 References

See References [81], [82], [106], [107], [108], and [109] in [Section 2.2](#).

2.B.6.5 Tables

Table 2.B.6.1—HF Corrosion—Basic Data Required for Analysis

Basic Data	Comments
HF-in-water concentration (wt%)	Determine the concentration of HF in the water.
Material of construction	Determine the material used to fabricate the equipment/piping.
Maximum service temperature (°F:°C)	Determine the maximum temperature of the process stream.
Velocity (ft/s:m/s)	Determine the velocity range of the process stream.
Oxygen/oxidizers present? (Yes or No)	Oxidizers can greatly accelerate corrosion of Alloy 400. No definition in terms of concentration of dissolved oxygen in the acid can be given. Acid in shipment and transfer will usually be completely air-free, and air is typically present only after opening of equipment for inspection, leaks, or improperly prepared feed to the unit.

Table 2.B.6.2—HF Corrosion—Estimated Corrosion Rates (mpy) for Carbon Steel

Temp. (°F)	Velocity (ft/s)	HF-in-Water Concentration (%)									
		1	3	7	20	30	40	60	80	90	>90
70-100	<5	30	100	300	700	800	700	150	20	8	2
	≥5	60	200	600	999	999	999	300	40	15	4
130	<5	100	350	999	999	999	999	500	50	25	7
	≥5	200	700	999	999	999	999	999	100	50	15
160	<5	400	999	999	999	999	999	999	250	100	25
	≥5	800	999	999	999	999	999	999	500	200	50
190	<5	999	999	999	999	999	999	999	999	400	100
	≥5	999	999	999	999	999	999	999	999	800	200

Temp. (°C)	Velocity (m/s)	HF-in-Water Concentration (%)									
		1	3	7	20	30	40	60	80	90	>90
21.1-37.78	<1.524	0.76	2.54	7.62	17.78	20.32	17.78	3.81	0.51	0.20	0.05
	>1.524	1.52	5.08	15.24	25.37	25.37	25.37	7.62	1.02	0.38	0.10
54.44	<1.524	2.54	8.89	25.37	25.37	25.37	25.37	12.70	1.27	0.64	0.18
	>1.524	5.08	17.78	25.37	25.37	25.37	25.37	25.37	2.54	1.27	0.38
71.11	<1.524	10.16	25.37	25.37	25.37	25.37	25.37	25.37	6.35	2.54	0.64
	>1.524	20.32	25.37	25.37	25.37	25.37	25.37	25.37	12.70	5.08	1.27
87.78	<1.524	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	10.16	2.54
	>1.524	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	20.32	5.08

Table 2.B.6.3—HF Corrosion—Estimated Corrosion Rates (mpy) for Alloy 400

Temp. (°F)	Aerated?	HF-in-Water Concentration (%)							
		1	2	5	6	63	64	80	81
80	No	1	1	1	10	10	1	1	2
	Yes	10	10	10	25	25	10	10	15
125	No	1	1	1	15	15	5	5	3
	Yes	10	10	10	30	30	20	20	15
175	No	5	5	5	20	20	10	10	5
	Yes	20	20	20	100	100	50	50	20
200	No	10	10	10	20	20	20	20	10
	Yes	100	100	100	200	200	200	200	100

Table 2.B.6.3M—HF Corrosion—Estimated Corrosion Rates (mm/y) for Alloy 400

Temp (°C)	Aerated?	HF-in-Water Concentration (%)							
		1	2	5	6	63	64	80	81
27	No	0.03	0.03	0.03	0.25	0.25	0.03	0.03	0.05
	Yes	0.25	0.25	0.25	0.64	0.64	0.25	0.25	0.38
52	No	0.03	0.03	0.03	0.38	0.38	0.13	0.13	0.08
	Yes	0.25	0.25	0.25	0.76	0.76	0.51	0.51	0.38
79	No	0.13	0.13	0.13	0.51	0.51	0.25	0.25	0.13
	Yes	0.51	0.51	0.51	2.54	2.54	1.27	1.27	0.51
93	No	0.25	0.25	0.25	0.51	0.51	0.51	0.51	0.25
	Yes	2.54	2.54	2.54	5.08	5.08	5.08	5.08	2.54

2.B.6.6 Figures

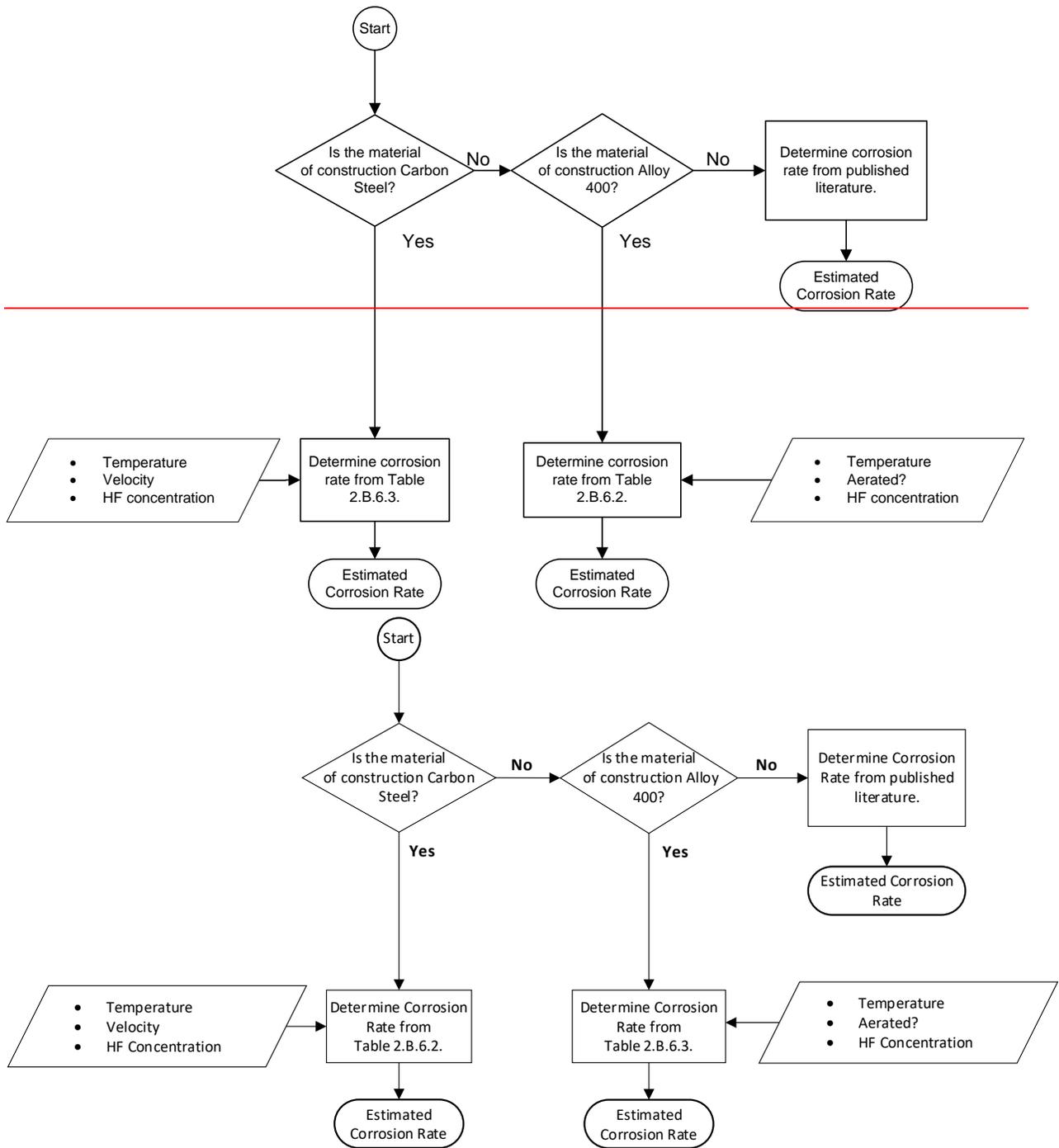


Figure 2.B.6.1—HF Corrosion—Determination of Corrosion Rate

2.B.7 Alkaline Sour Water Corrosion

2.B.7.1 Description of Damage

Alkaline sour water corrosion is broadly defined as corrosion by water containing H₂S and NH₃, and it is typically a concern for carbon steel above neutral pH. This corrosion is caused by aqueous ammonium bisulfide (NH₄HS). The primary variables that influence alkaline sour water corrosion rates are the NH₄HS concentration of the water velocity (wall shear stress) and H₂S partial pressure. Secondary variables include temperature and hydrocarbon to water ratios. Alkaline sour water corrosion is of concern across a broad range of the most common refining process units, notably hydroprocessing treating, catalytic cracking, amine treating, coking, and light ends recovery. H₂S is typically formed by thermal breakdown or catalytic conversion of sulfur compounds. NH₃ is similarly formed from nitrogen compounds. NH₄HS is formed as a result of the reaction between these two gases and precipitates out of the gas phase in the reactor effluent stream as temperatures are reduced below about 150 °F (66 °C).

2.B.7.2 Basic Data

The data listed in [Table 2.B.7.1](#) are required to determine the estimated corrosion rate for NH₄HS service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.7.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.7.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.7.1](#) in conjunction with the baseline corrosion rates and equations in [Table 2.B.7.2](#) to correct for H₂S partial pressure.

2.B.7.4 References

See References [110], [111], [112], [113], and [114] in [Section 2.2](#).

2.B.7.5 Tables

Table 2.B.7.1—Alkaline Sour Water Corrosion—Basic Data Required for Analysis

Basic Data	Comments
NH ₄ HS concentration (wt%)	Determine the NH ₄ HS concentration of the condensed water. It is suggested to determine this value with ionic process models. However, approximate values may be calculated from analyses of H ₂ S and NH ₃ as follows. — If wt% H ₂ S < 2 × (wt% NH ₃), wt% NH ₄ HS = 1.5 × (wt% H ₂ S) — If wt% H ₂ S > 2 × (wt% NH ₃), wt% NH ₄ HS = 3.0 × (wt% NH ₃)
Stream velocity, m/s (ft/s)	The vapor phase velocity should be used in a two-phase system. The liquid phase velocity should be used in a liquid full system.
H ₂ S partial pressure, psia (kPa)	Determine the partial pressure of H ₂ S by multiplying the mole% of H ₂ S in the gas phase by the total system pressure.

Table 2.B.7.2—Alkaline Sour Water Corrosion—Baseline Corrosion Rates for Carbon Steel (mpy)

NH ₄ HS (wt%)	Velocity (ft/s)				
	10	15	20	25	30
2	3	4	5	8	11
5	6	9	12	15	18
10	20	27	35	43	50
15	45	70	100	150	200

NOTE 1 For $p_{H_2S} < 50$ psia: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{25} \right) \cdot (p_{H_2S} - 50) + \text{Baseline } \cdot CR \right\}, 0 \right]$.

NOTE 2 For $p_{H_2S} \geq 50$ psia: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{40} \right) \cdot (p_{H_2S} - 50) + \text{Baseline } \cdot CR \right\}, 0 \right]$.

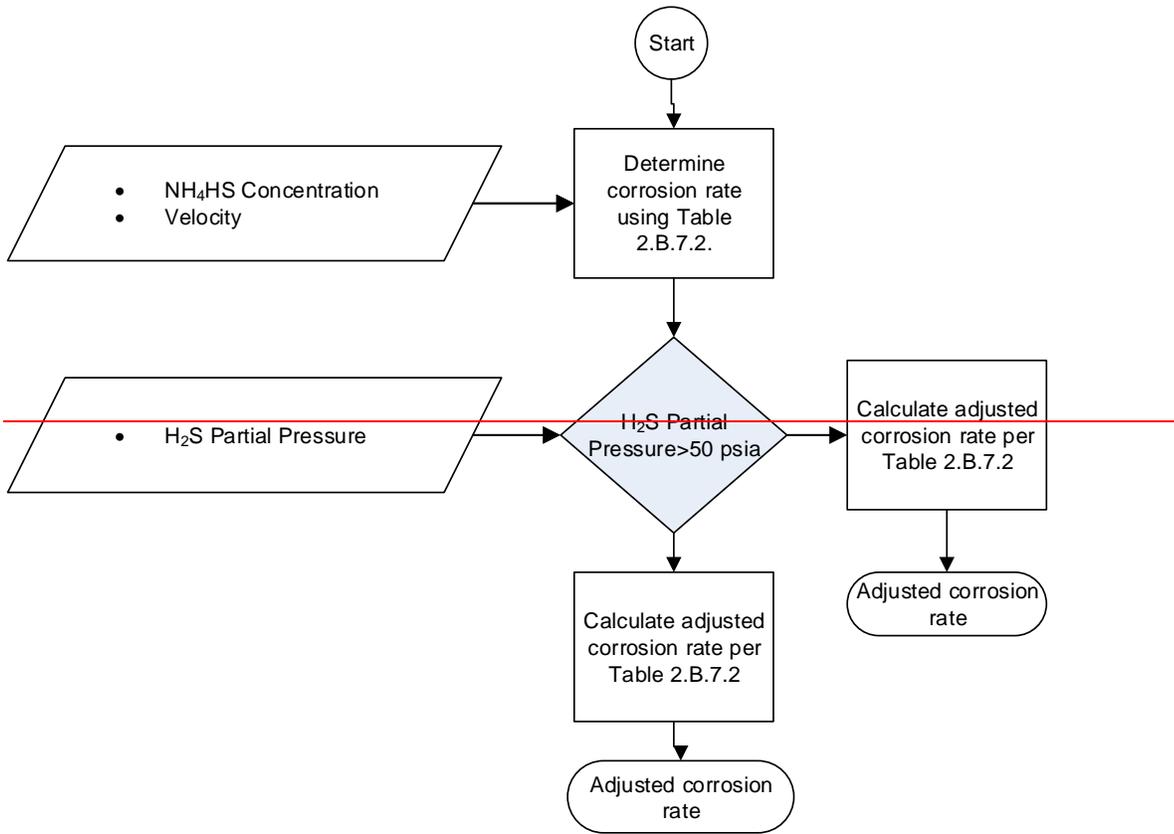
Table 2.B.7.2M—Alkaline Sour Water Corrosion—Baseline Corrosion Rates for Carbon Steel (mm/y)

NH ₄ HS (wt%)	Velocity (m/s)				
	3.05	4.57	6.10	7.62	9.14
2	0.08	0.10	0.13	0.20	0.28
5	0.15	0.23	0.30	0.38	0.46
10	0.51	0.69	0.89	1.09	1.27
15	1.14	1.78	2.54	3.81	5.08

NOTE 1 For $p_{H_2S} < 345$ kPa: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{173} \right) \cdot (p_{H_2S} - 345) + \text{Baseline } \cdot CR \right\}, 0 \right]$.

NOTE 2 For $p_{H_2S} \geq 345$ kPa: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{276} \right) \cdot (p_{H_2S} - 345) + \text{Baseline } \cdot CR \right\}, 0 \right]$.

2.B.7.6 Figures



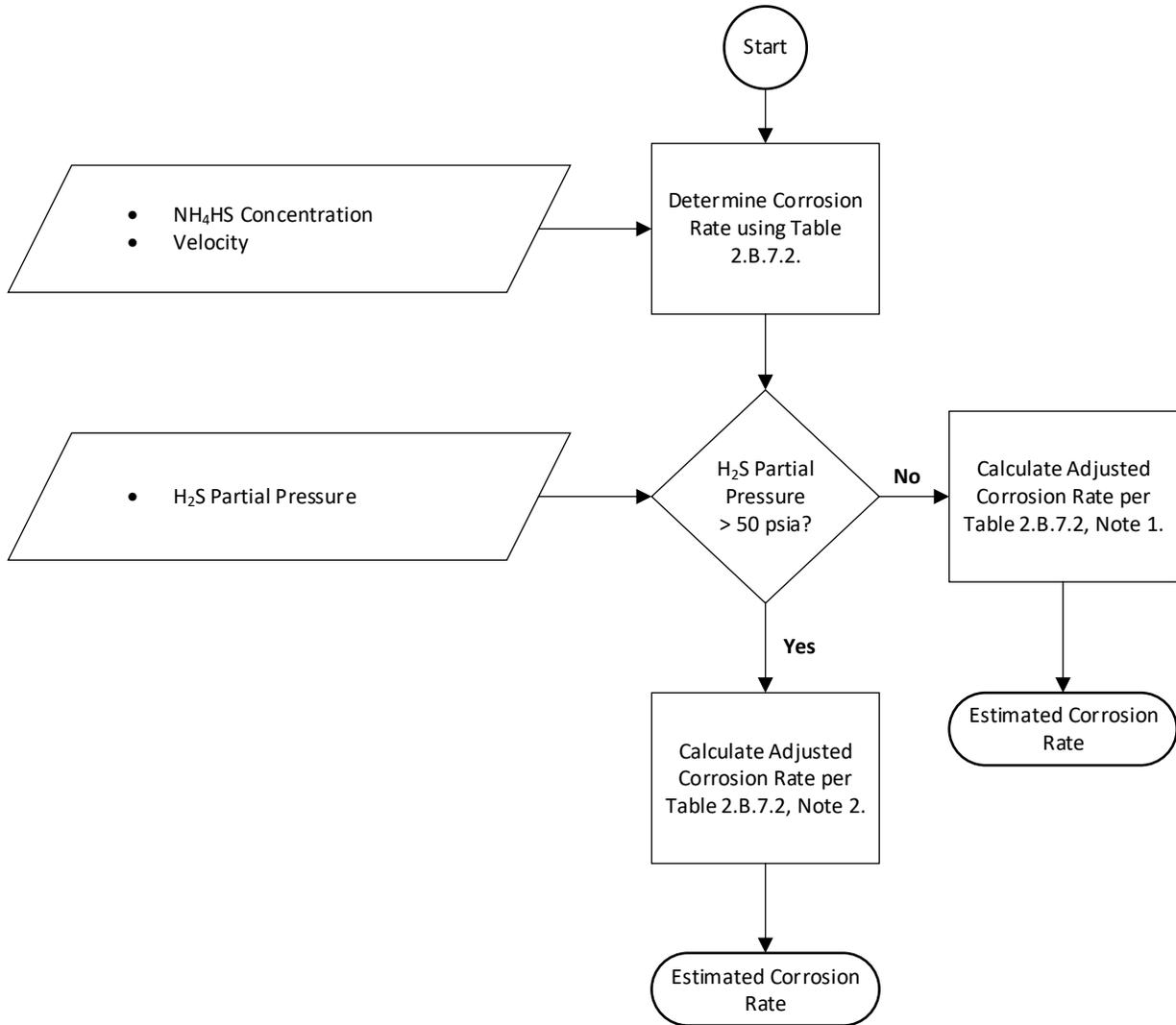


Figure 2.B.7.1—Alkaline Sour Water Corrosion—Determination of Corrosion Rate

2.B.8 Amine Corrosion

2.B.8.1 Description of Damage

Amine corrosion is a form of often-localized corrosion that occurs principally on carbon steel in some gas treating processes. Carbon steel is also vulnerable to SCC in gas treating amines if it is not postweld heat treated (see [Section 7](#)). Gas treating amines fall into two major categories—chemical solvents and physical solvents. This supplement deals with corrosion in the most common chemical solvents, MEA, DEA, and MDEA. These amines are used to remove acid gases, primarily H₂S, from plant streams. MEA and DEA will also remove CO₂, but MDEA is selective to H₂S and will remove little CO₂ if it is present. Generally, corrosion in MDEA is less than in MEA and DEA when contaminants are well controlled.

Carbon steel corrosion in amine treating processes is a function of a number of interrelated factors, the primary ones being the concentration of the amine solution, the acid gas content of the solution (“loading”), and the temperature. The most commonly used amine concentrations are 20 wt% MEA, 30 wt% DEA, and 40 to 50 wt% MDEA. At greater concentrations, corrosion rates increase.

Acid gas loading is reported in terms of moles of acid gas per mole of active amine. “Rich” solution is amine of higher acid gas loading, and “lean” solution has lower acid gas loading (typically < 0.1 mole/mole). Corrosion in poorly regenerated amine with high lean loadings is not an uncommon problem, particularly because lean solution temperatures are often greater than rich solution temperatures. Both H₂S and CO₂ must be measured to determine the acid gas loading. In addition, only the amount of available or “active” amine should be considered when calculating the loading. In H₂S-only systems, rich amine loadings up to 0.70 mole/mole have been satisfactory. In H₂S + CO₂ systems, rich loading is often limited to 0.35 to 0.45 mole/mole. In MDEA units, and particularly those used for selective H₂S removal in sulfur plant tail gas cleanup, rich loadings are often below these levels. As with most corrosion mechanisms, higher temperature increases the corrosion rate.

Another important factor in amine corrosion is the presence of amine degradation products, usually referred to as “heat stable amine salts” or HSAS. These amine degradation products act in two ways. On the one hand, they reduce the amount of active amine available to absorb acid gas, resulting in higher acid gas loadings. In addition, some amine degradation products themselves are corrosive. In MEA and DEA systems, HSAS above 0.5 wt% can begin to increase corrosion although a common operating limit is 2 wt%. Corrosion can be particularly significant, even at low acid gas loadings, at >2.0 wt% HSAS. MDEA will also form HSAS, but the primary influence on corrosion in these units is organic acid contaminants (formate, oxalate, and acetate). Thermal reclaimers are often provided in MEA units to reduce HSAS, but DEA and MDEA salts are more stable and cannot be thermally reclaimed. DEA degrades less readily than MEA and MDEA. Velocity or turbulence also influences amine corrosion. In the absence of high velocities and turbulence, amine corrosion can be fairly uniform. Higher velocities and turbulence can cause acid gas to evolve from solution, particularly at elbows and where pressure drops occur such as valves, resulting in more localized corrosion. Higher velocity and turbulence may also disrupt protective iron sulfide films that may form. Where velocity is a factor, corrosion may appear either as pitting or grooving. For carbon steel, common velocity limits are about 1.52 m/s (5 ft/s) for rich amine and about 6.01 m/s (20 ft/s) for lean amine.

Austenitic stainless steels are commonly used in areas that are corrosive to carbon steel with good success unless temperatures, amine concentration, and degradation product levels are particularly high. Common applications for stainless steels are reboiler, reclaimer, and hot rich-lean exchanger tubes as well as pressure let-down valves and downstream piping/equipment. 12 % Cr steels have been used for scrubber (absorber) tower internals successfully. Copper alloys are subject to accelerated corrosion and SCC and are normally avoided.

2.B.8.2 Basic Data

The data listed in [Table 2.B.8.1](#) are required to determine the estimated corrosion rate for amine service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.8.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.8.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.8.1](#) in conjunction with [Tables 2.B.8.2](#) through [2.B.8.5](#).

The estimated corrosion rate for carbon steel should be obtained from [Table 2.B.8.2](#) for 20 wt% MEA and 30 wt% DEA and from [Table 2.B.8.3](#) for 50 wt% MDEA. If higher amine concentrations are used, the corrosion rate obtained should be multiplied by the appropriate factor from [Table 2.B.8.4](#).

The estimated corrosion rate for stainless steel may be obtained from [Table 2.B.8.5](#).

NOTE at extreme conditions of amine concentrations, temperatures, and levels of degradation products, the corrosion rate of stainless steel can be as much as 200 times the value in the [Table 2.B.8.5](#).

2.B.8.4 References

See References [23] (Appendix B—Considerations for Corrosion Control), [115], [116], [117], [118], [119], [120], [121], [122], [123], and [124] in [Section 2.2](#).

2.B.8.5 Tables

Table 2.B.8.1—Amine Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction (CS or SS)	Determine the material of construction of equipment/piping.
Amine concentration (wt%)	Determine the amine concentration in the equipment/piping. Due to vaporization of water, a local increase in amine concentration may need to be considered in evaluating the corrosion of some reboilers and reclaimers.
Maximum process temperature (°F :°C)	Determine the maximum process temperature. In reboilers and reclaimers, tube metal temperatures may be higher than the bulk process temperature.
Acid gas loading (mole acid gas/mole active amine)	Determine the acid gas loading in the amine. If analytical results are not available, it should be estimated by a knowledgeable process engineer.
Velocity (m/s:ft/s)	Determine the maximum velocity of the amine in this equipment/piping.
HSAS concentration: MEA and DEA (≤2 wt%, 2 to 4 wt%, > 4 wt%) MDEA (<500, 500 to 4000, >4000 wppm)	In MEA and DEA, "HSAS" represents the normal family of amine degradation products In MDEA "HSAS" refers to organic acid contaminants, mainly formate, oxalate, and acetate

Table 2.B.8.2—Amine Corrosion Estimated Rate of Carbon Steel in MEA (≤ 20 wt%) and DEA (≤ 30 wt %) (mpy)

Acid Gas Loading (mol/mol)	HSAS (wt%)	Temperature (°F)											
		190		200		220		240		260		270	
		Velocity (ft/s)											
		≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20
<0.1	2	1	3	1	3	3	10	5	15	10	25	15	40
	3.0	2	6	2	6	6	20	15	40	20	45	30	80
	4.0	5	10	5	15	15	40	30	60	40	90	60	120
		Velocity (ft/s)											
		≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5
0.15	2	1	3	2	6	5	15	10	30	15	45	20	60
	3.0	2	6	4	12	10	30	20	60	30	90	40	80
	4.0	5	15	8	25	20	60	40	80	60	120	120	150
0.25	2	2	6	3	9	7	20	10	30	20	60	25	75
	3.0	4	10	6	20	15	40	20	50	40	80	50	100
	4.0	8	25	15	45	30	60	40	80	80	120	100	150
0.35	2	2	6	4	10	7	20	15	40	25	70	30	80
	3.0	4	10	8	25	15	45	30	60	50	100	100	150
	4.0	8	25	15	40	35	70	60	100	100	140	150	180
0.45	2	3	9	5	15	10	30	15	45	35	70	45	100
	3.0	6	15	10	30	20	60	45	90	70	130	90	150
	4.0	10	30	20	40	40	80	90	120	120	150	150	180
0.55	2	3	9	7	20	10	30	25	75	40	100	50	120
	3.0	6	20	15	45	20	60	50	100	80	140	100	150
	4.0	10	30	30	60	45	90	100	150	140	180	160	200
0.65	2	4	10	9	30	15	40	30	100	50	120	60	150
	3.0	8	15	20	40	30	60	60	100	90	140	100	150
	4.0	15	35	40	80	60	100	100	150	140	180	160	200
0.7	2	5	15	10	30	20	60	40	100	60	120	70	150
	3.0	10	30	20	60	40	80	70	120	100	150	120	150
	4.0	20	45	40	80	60	100	100	150	150	180	170	220

Table 2.B.8.2M—Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MEA (≤20 wt%) and DEA (≤30 wt %) (mm/y)

Acid Gas Loading (mol/mol)	HSAS (wt%)	Temperature (°C)											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1
<0.1	2	0.03	0.08	0.03	0.08	0.08	0.25	0.13	0.38	0.25	0.64	0.38	1.02
	3.0	0.05	0.15	0.05	0.15	0.15	0.51	0.38	1.02	0.51	1.14	0.76	2.03
	4.0	0.13	0.25	0.13	0.38	0.38	1.02	0.76	1.52	1.02	2.29	1.52	3.05
		Velocity m/s)											
		≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5
0.15	2	0.03	0.08	0.05	0.15	0.13	0.38	0.25	0.76	0.38	1.14	0.51	1.52
	3.0	0.05	0.15	0.1	0.3	0.25	0.76	0.51	1.52	0.76	2.29	1.02	2.03
	4.0	0.13	0.38	0.2	0.64	0.51	1.52	1.02	2.03	1.52	3.05	3.05	3.81
0.25	2	0.05	0.15	0.08	0.23	0.18	0.51	0.25	0.76	0.51	1.52	0.64	1.91
	3.0	0.1	0.25	0.15	0.51	0.38	1.02	0.51	1.27	1.02	2.03	1.27	2.54
	4.0	0.2	0.64	0.38	1.14	0.76	1.52	1.02	2.03	2.03	3.05	2.54	3.81
0.35	2	0.05	0.15	0.1	0.25	0.18	0.51	0.38	1.02	0.64	1.78	0.76	2.03
	3.0	0.1	0.25	0.2	0.64	0.38	1.14	0.76	1.52	1.27	2.54	2.54	3.81
	4.0	0.2	0.64	0.38	1.02	0.89	1.78	1.52	2.54	2.54	3.56	3.81	4.57
0.45	2	0.08	0.23	0.13	0.38	0.25	0.76	0.38	1.14	0.89	1.78	1.14	2.54
	3.0	0.15	0.38	0.25	0.76	0.51	1.52	1.14	2.29	1.78	3.3	2.29	3.81
	4.0	0.25	0.76	0.51	1.02	1.02	2.03	2.29	3.05	3.05	3.81	3.81	4.57
0.55	2	0.08	0.23	0.18	0.51	0.25	0.76	0.64	1.91	1.02	2.54	1.27	3.05
	3.0	0.15	0.51	0.38	1.14	0.51	1.52	1.27	2.54	2.03	3.56	2.54	3.81
	4.0	0.25	0.76	0.76	1.52	1.14	2.29	2.54	3.81	3.56	4.57	4.06	5.08
0.65	2	0.1	0.25	0.23	0.76	0.38	1.02	0.76	2.54	1.27	3.05	1.52	3.81
	3.0	0.2	0.38	0.51	1.02	0.76	1.52	1.52	2.54	2.29	3.56	2.54	3.81
	4.0	0.38	0.89	1.02	2.03	1.52	2.54	2.54	3.81	3.56	4.57	4.06	5.08
0.7	2	0.13	0.38	0.25	0.76	0.51	1.52	1.02	2.54	1.52	3.05	1.78	3.81
	3.0	0.25	0.76	0.51	1.52	1.02	2.03	1.78	3.05	2.54	3.81	3.05	3.81
	4.0	0.51	1.14	1.02	2.03	1.52	2.54	2.54	3.81	3.81	4.57	4.32	5.59

Table 2.B.8.3—Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤ 50 wt%) (mpy)

Acid Gas Loading (mol/mol)	HSAS (wt%)	Temperature (°F)											
		190		200		220		240		260		270	
		Velocity (ft/s)											
		≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20
< 0.1	0.5	1	3	1	3	3	10	5	15	10	25	15	40
	2.25	2	6	2	6	6	20	15	40	20	45	30	80
	4.0	5	10	5	15	15	40	30	60	40	90	60	120
		Velocity (ft/s)											
		≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	5	≤ 5	> 5	≤ 5	> 5
0.15	0.5	1	3	2	6	5	15	10	30	15	45	20	60
	2.25	2	6	4	12	10	30	20	60	30	90	40	80
	4.0	5	15	8	25	20	60	40	80	60	120	120	150
0.25	0.5	2	6	3	9	7	20	10	30	20	60	25	75
	2.25	4	10	6	20	15	40	20	50	40	80	50	100
	4.0	8	25	15	45	30	60	40	80	80	120	100	150
0.35	0.5	2	6	4	10	7	20	15	40	25	70	30	80
	2.25	4	10	8	25	15	45	30	60	50	100	100	150
	4.0	8	25	15	40	35	70	60	100	100	140	150	180
0.45	0.5	3	9	5	15	10	30	15	45	35	70	45	100
	2.25	6	15	10	30	20	60	45	90	70	130	90	150
	4.0	10	30	20	40	40	80	90	120	120	150	150	180
0.55	0.5	3	9	7	20	10	30	25	75	40	100	50	120
	2.25	6	20	15	45	20	60	50	100	80	140	100	150
	4.0	10	30	30	60	45	90	100	150	140	180	160	200
0.65	0.5	4	10	9	30	15	40	30	100	50	120	60	150
	2.25	8	15	20	40	30	60	60	100	90	140	100	150
	4.0	15	35	40	80	60	100	100	150	140	180	160	200
0.7	0.5	5	15	10	30	20	60	40	100	60	120	70	150
	2.25	10	30	20	60	40	80	70	120	100	150	120	150
	4.0	20	45	40	80	60	100	100	150	150	180	170	220

Table 2.B.8.3M—Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤50 wt%) (mm/y)

Acid Gas Loading (mol/mol)	HSAS (wt%)	Temperature (°C)											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1
<0.1	0.5	0.03	0.08	0.03	0.08	0.08	0.25	0.13	0.38	0.25	0.64	0.38	1.02
	2.25	0.05	0.15	0.05	0.15	0.15	0.51	0.38	1.02	0.51	1.14	0.76	2.03
	4.0	0.13	0.25	0.13	0.38	0.38	1.02	0.76	1.52	1.02	2.29	1.52	3.05
		Velocity (m/s)											
		≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5
0.15	0.5	0.03	0.08	0.05	0.15	0.13	0.38	0.25	0.76	0.38	1.14	0.51	1.52
	2.25	0.05	0.15	0.1	0.3	0.25	0.76	0.51	1.52	0.76	2.29	1.02	2.03
	4.0	0.13	0.38	0.2	0.64	0.51	1.52	1.02	2.03	1.52	3.05	3.05	3.81
0.25	0.5	0.05	0.15	0.08	0.23	0.18	0.51	0.25	0.76	0.51	1.52	0.64	1.91
	2.25	0.1	0.25	0.15	0.51	0.38	1.02	0.51	1.27	1.02	2.03	1.27	2.54
	4.0	0.2	0.64	0.38	1.14	0.76	1.52	1.02	2.03	2.03	3.05	2.54	3.81
0.35	0.5	0.05	0.15	0.1	0.25	0.18	0.51	0.38	1.02	0.64	1.78	0.76	2.03
	2.25	0.1	0.25	0.2	0.64	0.38	1.14	0.76	1.52	1.27	2.54	2.54	3.81
	4.0	0.2	0.64	0.38	1.02	0.89	1.78	1.52	2.54	2.54	3.56	3.81	4.57
0.45	0.5	0.08	0.23	0.13	0.38	0.25	0.76	0.38	1.14	0.89	1.78	1.14	2.54
	2.25	0.15	0.38	0.25	0.76	0.51	1.52	1.14	2.29	1.78	3.3	2.29	3.81
	4.0	0.25	0.76	0.51	1.02	1.02	2.03	2.29	3.05	3.05	3.81	3.81	4.57
0.55	0.5	0.08	0.23	0.18	0.51	0.25	0.76	0.64	1.91	1.02	2.54	1.27	3.05
	2.25	0.15	0.51	0.38	1.14	0.51	1.52	1.27	2.54	2.03	3.56	2.54	3.81
	4.0	0.25	0.76	0.76	1.52	1.14	2.29	2.54	3.81	3.56	4.57	4.06	5.08
0.65	0.5	0.1	0.25	0.23	0.76	0.38	1.02	0.76	2.54	1.27	3.05	1.52	3.81
	2.25	0.2	0.38	0.51	1.02	0.76	1.52	1.52	2.54	2.29	3.56	2.54	3.81
	4.0	0.38	0.89	1.02	2.03	1.52	2.54	2.54	3.81	3.56	4.57	4.06	5.08
0.7	0.5	0.13	0.38	0.25	0.76	0.51	1.52	1.02	2.54	1.52	3.05	1.78	3.81
	2.25	0.25	0.76	0.51	1.52	1.02	2.03	1.78	3.05	2.54	3.81	3.05	3.81
	4.0	0.51	1.14	1.02	2.03	1.52	2.54	2.54	3.81	3.81	4.57	4.32	5.59

Table 2.B.8.4—Amine Corrosion Rate Multiplier for High Amine Strengths

Type of Amine	Concentration (wt%)	Multiplier
MEA	≤20	1.0
	21 to 25	1.5
	>25	2.0
DEA	≤30	1.0
	31 to 40	1.2
	>40	1.5
MDEA	≤50	1.0

Table 2.B.8.5—Amine Corrosion Estimated Corrosion Rates for Stainless Steel for All Amines

Acid Gas Loading (mol/mol)	Temperature ≤300 °F (149 °C)	
	mm/y	mpy
0.1	0.03	1
0.15	0.03	1
0.25	0.03	1
0.35	0.05	2
0.45	0.05	2
0.55	0.08	3
0.65	0.1	4
0.7	0.13	5

2.B.8.6 Figures

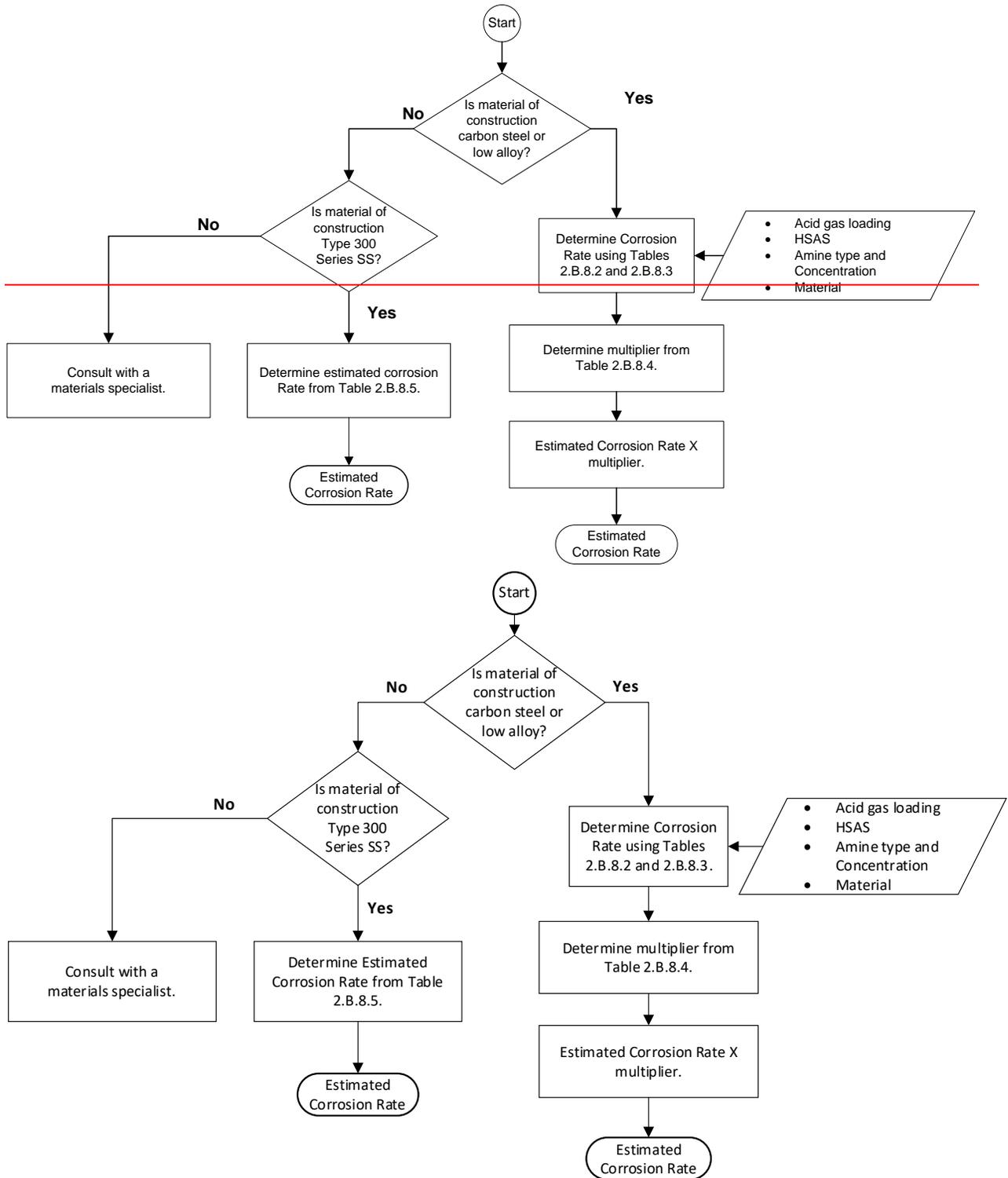


Figure 2.B.8.1—Amine Corrosion—Determination of Corrosion Rate

2.B.9 High Temperature Oxidation

2.B.9.1 Description of Damage

Corrosion due to high temperature oxidation occurs at temperatures above about 900 °F (482 °C) for carbon steel and increasing higher temperatures for alloys. The metal loss occurs as a result of the reaction of metal with oxygen in the environment. Typically, at temperatures just above the temperature where oxidation begins to occur, a dense comparatively protective oxide forms on the surface that reduces the metal loss rate. The oxide scale tends to be significantly more protective as the chromium concentration in the metal increases.

2.B.9.2 Basic Data

The data listed in [Table 2.B.9.1](#) are required to determine the estimated corrosion rate for high temperature oxidation service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.9.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.9.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.9.1](#) in conjunction with [Tables 2.B.9.2](#) through [2.B.9.3](#).

2.B.9.4 Tables

Table 2.B.9.1—High Temperature Oxidation—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of this equipment/piping.
Maximum metal temperature (°F :°C)	Determine the maximum metal temperature. The tube metal temperature for furnace tubes is the controlling factor.

Table 2.B.9.2—High Temperature Oxidation—Estimated Corrosion Rate (mpy)

Material	Maximum Metal Temperature (°F)											
	925	975	1025	1075	1125	1175	1225	1275	1325	1375	1425	1475
CS	2	4	6	9	14	22	33	48	—	—	—	—
1 1/4 Cr	2	3	4	7	12	18	30	46	—	—	—	—
2 1/4 Cr	1	1	2	4	9	14	24	41	—	—	—	—
5 Cr	1	1	1	2	4	6	15	35	65	—	—	—
7 Cr	1	1	1	1	1	2	3	6	17	37	60	—
9 Cr	1	1	1	1	1	1	1	2	5	11	23	40
12 Cr	1	1	1	1	1	1	1	1	3	8	15	30
304 SS	1	1	1	1	1	1	1	1	1	2	3	4
309 SS	1	1	1	1	1	1	1	1	1	1	2	3
310 SS/HK	1	1	1	1	1	1	1	1	1	1	1	2
800 H/HP	1	1	1	1	1	1	1	1	1	1	1	2

Table 2.B.9.2M—High Temperature Oxidation—Estimated Corrosion Rate (mm/y)

12 Cr	1.27	—	—	—	—	—	—	—	—	—	—	—
304 SS	0.15	0.23	0.33	0.46	0.64	0.89	1.22	—	—	—	—	—
309 SS	0.1	0.15	0.2	0.25	0.33	0.41	0.51	0.76	1.02	1.27	—	—
310 SS/HK	0.08	0.1	0.13	0.18	0.2	0.25	0.33	0.38	0.48	0.58	0.69	0.79
800 H/HP	0.08	0.1	0.15	0.2	0.25	0.33	0.43	0.53	0.69	0.84	1.04	1.27

2.B.9.5 Figures

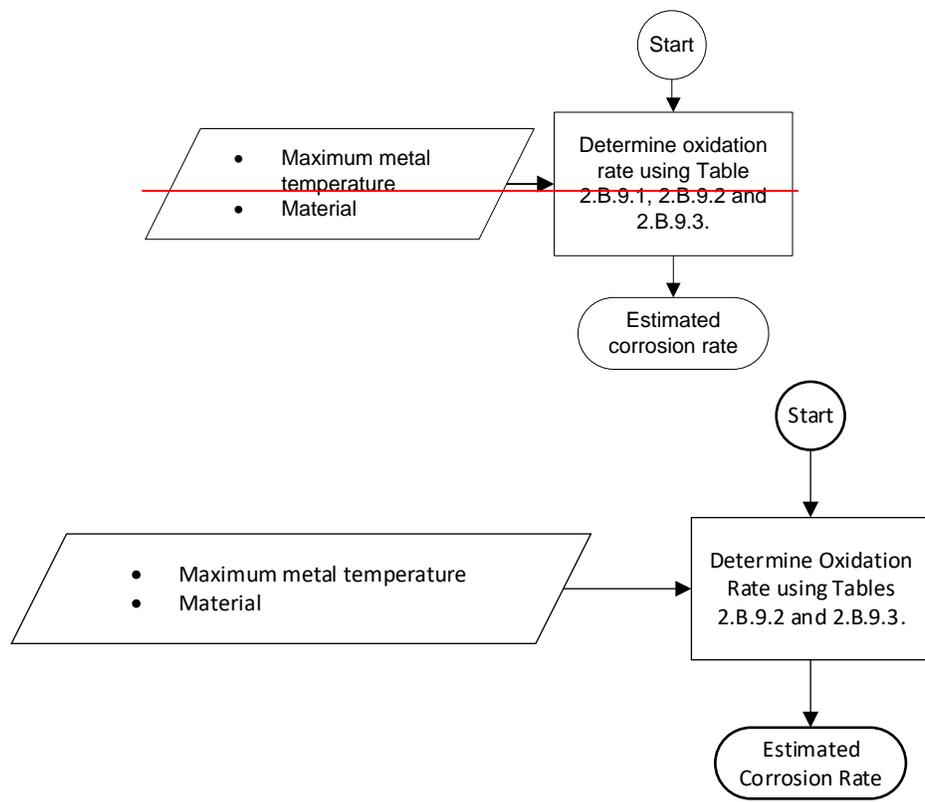


Figure 2.B.9.1—High Temperature Oxidation—Determination of Corrosion Rate

2.B.10 Acid Sour Water Corrosion

2.B.10.1 Description of Damage

2.B.10.1.1 Overview

Acid sour water is defined as water containing H₂S and with pH below neutral pH (7). The primary refining units or gas fractionator plants where acid sour water corrosion is a concern are sour distillation overhead systems in gas fractionation plants. Most other refining distillation units contain chlorides or ammonia and are covered in [Sections 2.B.2](#) and [2.B.7](#), respectively.

Corrosion damage from acid sour water is typically general thinning. Above pH of about 4.5, a protective thin iron sulfide layer limits the corrosion rate. In some instances at pH above 4.5, a thicker porous sulfide film layer can form. This can promote pitting under sulfide deposits yet generally this does not affect the general corrosion rate. Sour water condensates in equilibrium with a vapor containing H₂S at a partial pressure below 1 atm will usually have a pH between 4.5 and 7. At H₂S partial pressures greater than 1 atm, a pH < 4.5 can be achieved and are outside the scope of this paragraph.

2.B.10.1.2 Scope and Limitations

The scope of this paragraph is to give guidance in determining a conservatively estimated corrosion rate driven by acid sour water, under the following conditions and assumptions.

- a) Primary corrosive is H₂S. Assuming no significant amounts of ammonia, carbon dioxide, chlorides, or cyanides are present.
- b) The corrosion mechanism is general corrosion, with some occurrence of pitting in the presence of oxygen.
- c) This paragraph contains guidance for estimating corrosion rates of carbon steel. Copper alloys and nickel alloys (not containing chromium) can be used and are generally not susceptible to acid sour water corrosion in the refinery applications where acid sour water is found. Stainless steel can be used where the temperature is low enough that CISCC is not likely. Where the material of construction is other than carbon steel, it is assumed that the selected material is suitable for the service and that the corrosion rates will not exceed 0.05 mm/y (2 mpy).
- d) Cracking is not considered. Wet H₂S cracking mechanisms are addressed elsewhere in this document.
- e) Presence of air or oxidants may increase the corrosion. It is assumed that the normal concentration of oxygen is less than 50 ppb.
- f) A high flow velocity can have an adverse effect on the corrosion. It is assumed that the effect is negligible for velocities less than 1.83 m/s (6 ft/s). When velocities exceed 6 ft/s (1.83 m/s), higher corrosion rates and possible localized corrosion should be considered.

The base corrosion rate is estimated from the pH level and temperature. An adjustment is made for oxygen content. Other factors, such as content of chlorides, cyanides, etc., are relevant but are considered less significant for the end result in this context. The result is a conservative value for the estimated corrosion rate.

2.B.10.2 Basic Data

The data listed in [Table 2.B.10.1](#) are required to estimate the rate of corrosion rate in acid sour water. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.10.3 Determination of Corrosion Rate

The corrosion rate is determined using Equations (2.B.1) through 2.B.7 and shown in [Figure 2.B.10.1](#). If the pH is less than 4.5, then the corrosion rate shall be calculated using [Section 2.B.2](#). If the pH is greater than 7, then the corrosion rate is calculated using [Section 2.B.7](#). Otherwise, the corrosion rate of carbon steel exposed to acid sour water is computed using Equation (2.B.1).

$$CR = CR_{pH} \cdot F_o \cdot F_V \quad (2.B.1)$$

The base corrosion rate, CR_{pH} , of carbon steel exposed to acid sour water as a function of pH is provided in [Table 2.B.10.2](#). The corrosion rate can vary significantly with level of dissolved oxygen. The modification factor for the corrosion rate as a function of the oxygen content factor, F_o , is provided in [Table 2.B.10.3](#). The corrosion rate also varies with fluid velocity. The modification factor for fluid velocity is given by the following equations.

For SI units, use Equations [\(2.B.2\)](#) through [\(2.B.4\)](#):

$$F_V = 1.0 \quad \text{when velocity} < 1.83 \text{ m/s} \quad (2.B.2)$$

$$F_V = 0.82 \cdot \text{velocity} - 0.5 \quad \text{when } 1.83 \text{ m/s} \leq \text{velocity} \leq 6.10 \text{ m/s} \quad (2.B.3)$$

$$F_V = 5.0 \quad \text{when velocity} > 6.10 \text{ m/s} \quad (2.B.4)$$

For U.S. customary units, use Equations [\(2.B.5\)](#) through [\(2.B.7\)](#):

$$F_V = 1.0 \quad \text{when velocity} < 6 \text{ ft/s} \quad (2.B.5)$$

$$F_V = 0.25 \cdot \text{velocity} - 0.5 \quad \text{when } 6 \text{ ft/s} \leq \text{velocity} \leq 20 \text{ ft/s} \quad (2.B.6)$$

$$F_V = 5.0 \quad \text{when velocity} > 20 \text{ ft/s} \quad (2.B.7)$$

2.B.10.4 Nomenclature

CR	is the corrosion rate
CR_{pH}	is the base corrosion rate as a function of pH
F_o	is the corrosion rate correction for oxygen
F_V	is the corrosion rate correction for velocity
<i>velocity</i>	is the fluid velocity, m/s (ft/s)

2.B.10.5 References

See References [125], [126], [127], [128], and [129] in [Section 2.2](#).

2.B.10.6 Tables

Table 2.B.10.1—Acid Sour Water Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Carbon and low alloy steel (containing max. 6 % alloys) assumed as default.
pH	Determine the lowest pH for the equipment/piping. The pH that is used should be of the separated acid phase within this equipment or nearest equipment downstream, e.g. the overhead accumulator boot water downstream of the overhead condenser.
Water temperature, °F (°C)	Determine the maximum temperature present in the equipment/piping. This may be the maximum process temperature, but local heating condition such as effect of the sun or heat tracing should be considered.
Air or oxidants present (Yes or No)	Presence of oxygen may increase the corrosion rates. Normal oxygen concentration is ≤ 50 ppb and high is maximum > 50 ppb.
Chlorides present (Yes or No)	The present of chlorides in combination with a pH below 4.5 significantly affect the corrosion rate.

Flow velocity, ft/s (m/s)	Determine the maximum expected flow velocity.
---------------------------	---

Table 2.B.10.2—Acid Sour Water Corrosion Estimated Corrosion Rates for Carbon and Low Alloy Steel (mpy)— CR_{pH}

pH	Temperature (°F)			
	100	125	175	200
4.75	1	3	5	7
5.25	0.7	2.0	3	4
5.75	0.4	1.5	2	3
6.25	0.3	1	1.5	2
6.75	0.2	0.5	0.7	1

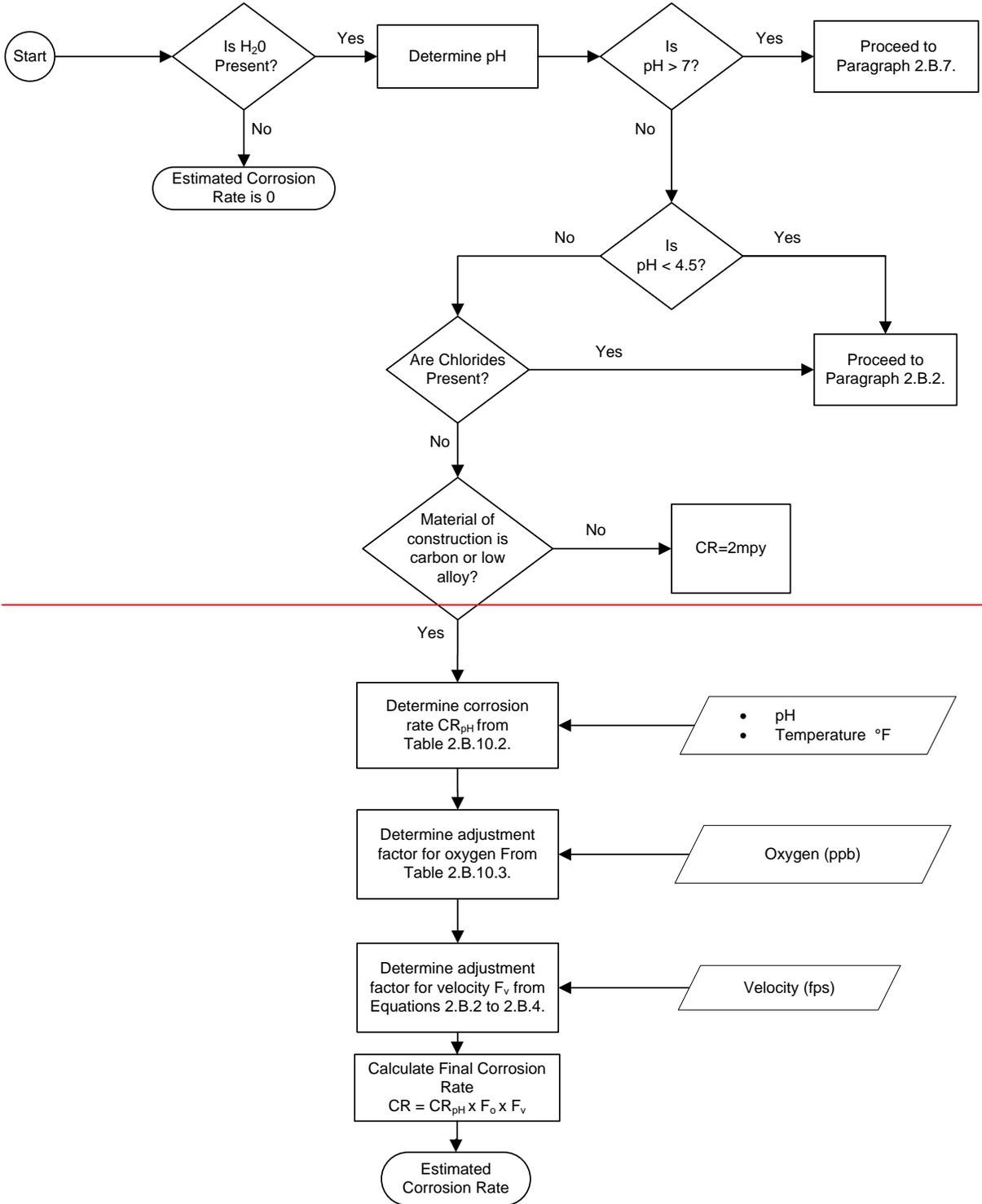
Table 2.B.10.2M—Acid Sour Water Corrosion Estimated Corrosion Rates for Carbon and Low Alloy Steel (mm/y)— CR_{pH}

pH	Temperature (°C)			
	38	52	79	93
4.75	0.03	0.08	0.13	0.18
5.25	0.02	0.05	0.08	0.1
5.75	0.01	0.04	0.05	0.08
6.25	0.01	0.03	0.04	0.05
6.75	0.01	0.01	0.02	0.03

Table 2.B.10.3—Acid Sour Water Corrosion—Basic Data Required for Analysis

Oxygen Content	Adjustment Factor—F_o
Not significant (≤ 50 ppb)	1.0
High (> 50 ppb)	2.0

2.B.10.7 Figures



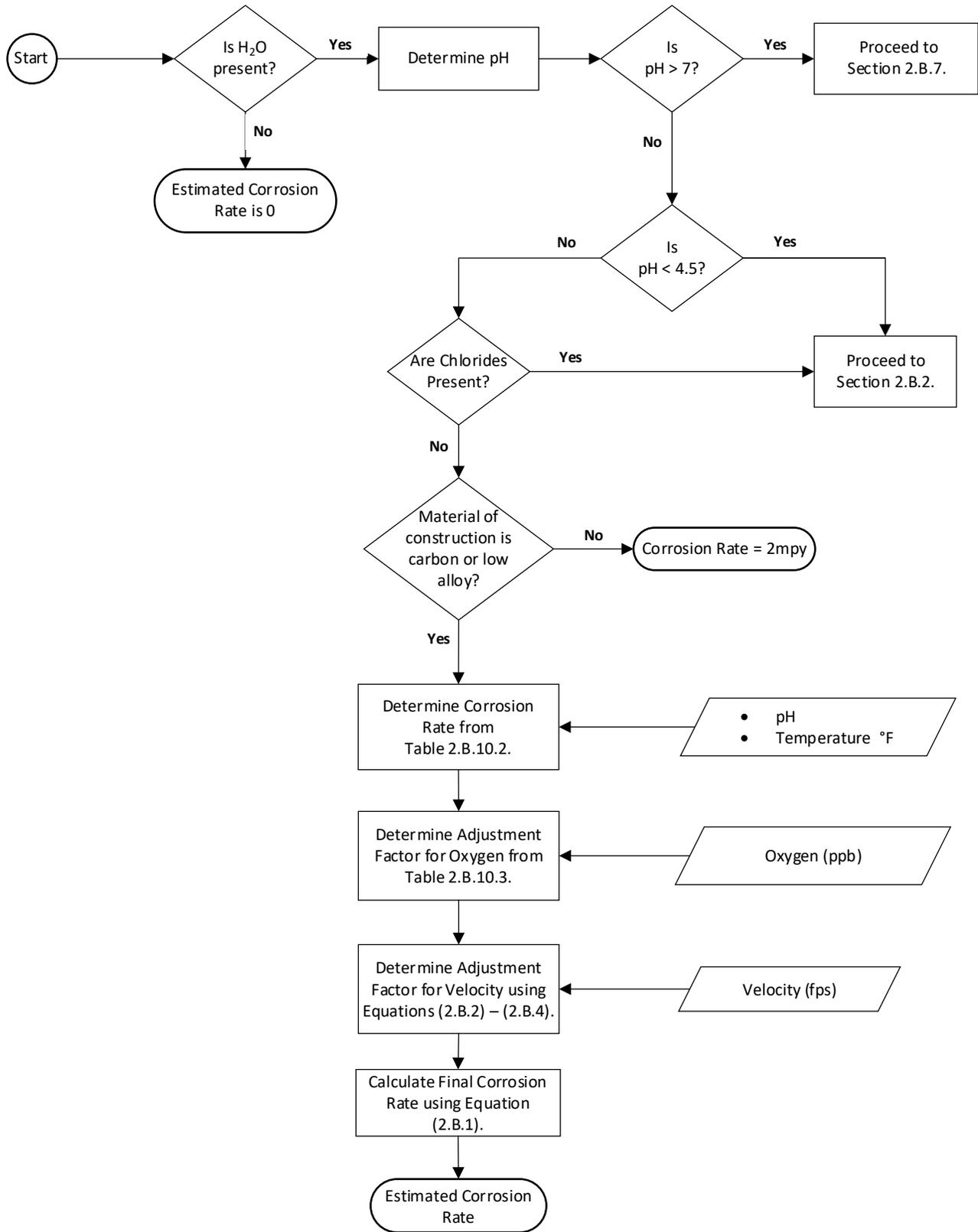


Figure 2.B.10.1—Acid Sour Water—Determination of Corrosion Rate

2.B.11 Cooling Water Corrosion

2.B.11.1 Description of Damage

2.B.11.1.1 Overview

The objective for this paragraph is to describe a conservative approach for estimating corrosion rates of carbon steel components in cooling water systems. In fresh water systems, a model uses the Ryznar Stability Index (RSI), chloride content, temperature, and flow velocity to calculate a corrosion rate. For seawater systems, a simple correlation of corrosion rate and velocity is used. Many other factors influence corrosion of the typical modern cooling water system, and this paragraph also describes qualitatively some of these considerations.

This paragraph does not attempt to account for degradation of alloys other than carbon steel or to quantify the effectiveness of water treatment. Many other alloys are used in cooling water systems. Some of these alloys and the threats that they may face are described qualitatively, but corrosion rates of these alloys are assumed to be very low. While low alloy steels are rarely used in cooling water systems, the corrosion rates given by this methodology would be reasonably accurate for low alloy steels.

The best way to assess corrosion in cooling water systems is to use a variety of monitoring techniques, but detailed use of those techniques is not described here. Most cooling water corrosion monitoring begins with the use of corrosion coupons. Other techniques have been used to monitor cooling water corrosion in situ, but they are not described. Microbiologically induced corrosion (MIC) is another common degradation mechanism in cooling water systems, and coupons are not always a reliable way to monitor this corrosion or other corrosion where there are deposits or stagnant areas. Direct monitoring and control of the microorganisms is recommended.

2.B.11.1.2 Types of Cooling Water Systems

There are three types of cooling water systems typically found in industrial operations such as refineries, as follows.

- a) Once Through Cooling—Does not reuse the heated water, which normally is pumped from a fresh water or seawater source.
- b) Closed Recirculating Cooling—Continuously reuses water that is captive in the system. No makeup after the initial water charge (except to replace accidental leakage).
- c) Open Recirculating Cooling (Cooling Tower)—Reuses water from which the heat is rejected into a cooling reservoir (tower or pond), needs continual makeup water to compensate for evaporation, blowdown, windage, and drift losses, and needs a blowdown facility to limit the concentration of impurities that are typically introduced with the makeup water.

2.B.11.1.3 Once Through Systems

Usually, the water source must be presumed corrosive since the surface waters are open to the atmosphere and contain dissolved oxygen. In a general way, corrosion of iron and steel is proportional to the chloride content when dissolved oxygen is constant, and vice versa. For seawater in particular, the flow velocity has a significant impact on the corrosion rate.

Because once through cooling water is not reused, the volume of water circulated through such a system effectively precludes chemical inhibition from a cost-effective standpoint. In some cases, a small amount of scale inhibitor is added to the influent water. However, chlorination is usually necessary to control biological growth (e.g. bacteria, slime, marine organisms).

Both fresh and saline waters are sufficiently corrosive to carbon steel that more corrosion-resistant materials must be employed. In fresh water, galvanized steel is often adequate but brackish or salt water requires more resistant materials [e.g. copper or nickel alloys; titanium; super-austenitic stainless steels (such as 6-Mo stainless steels); plastic; fiberglass reinforced plastic (FRP) or plastic-lined steel; concrete, etc.].

2.B.11.1.4 Closed Recirculated Systems

Recirculated cooling water systems are applied where water is in short supply or when the water chemistry must be rigorously controlled. Closed recirculated systems may be treated either by rendering them sterile and anaerobic or by use of inhibitors. The cost of treatment is minimal, including softening and pH control, if required or desirable. The heat is removed either in air-cooled heat exchangers or water-to-water exchangers cooled by an external cooling water system. Bactericidal treatment may be required, using non-oxidizing biocide, such as hexamethylene biguanide. If no treatment is applied, sulfate-reducing bacteria (SRB) would otherwise be a potential problem.

A successfully used strategy for preventing problems in the closed cooling water systems is to charge the system with condensate quality water and then add an effective corrosion inhibitor to prevent corrosion. Given the controlled environment, the material of construction is usually carbon steel, unless otherwise required for process reasons.

2.B.11.1.5 Open Recirculated Systems

These types of cooling systems involve constant air saturation as well as some concentration of water-borne solids in the circulating water. Such systems are corrosive to steel (unless suitably inhibited) and potentially scaling unless the hardness, pH and alkalinity are also controlled.

In a cooling tower system, the total amount of water actually used is limited to that lost by evaporation plus the blowdown established to limit the buildup of salts and solids in the system. The extent of soluble salt concentration is expressed as cycles of concentration, which is the ratio of hardness in the blowdown to that in the makeup. Water treatment chemicals need only be replaced in accordance with the blowdown rate. In most systems (water chemistry permitting), the optimum balance between water savings and salt concentration is effected at four to six cycles of concentration. The additional water savings from a higher number of cycles are usually offset by the increasing difficulty of coping with higher dissolved salt and hardness concentrations.

Because of the warm temperature and constant air scrubbing in the tower, the water is not only corrosive but also a breeding ground for slime and algae introduced from air-borne spores. Unless corrosion-resistant materials are used, open recirculated systems must usually be corrosion inhibited, treated with biocides to control biological growths, and chemically treated to control scale and deposits. The cost of such treatment must be balanced against the obvious savings in water consumption. The choice between corrosion inhibition vs resistant materials of construction is one of economics and pollution abatement considerations.

Typical corrosion-resistant materials for components in fresh-water type open recirculated systems are stainless steel, copper alloys, nickel alloys, titanium, cement lined carbon steel, FRP lined or coated steel (for vessels), etc.

2.B.11.1.6 Factors Affecting Corrosion Rate

There are several factors that affect the rate of corrosion in cooling systems. Depending on the type of system and water source, the main concerns are related to the following.

- a) Impurities in Makeup Water—Calcium, chlorides, alkalinity, silica, etc.

- b) Scale Formation—When the process side temperature is greater than 140 °F (60 °C) a scaling potential exists. The scales are minerals formed by high concentration of specific impurities, e.g. calcite (CaCO_3) formed by calcium salts and dissolved CO_2 species. Temperature, pH, and alkalinity influence the solubility limit of most minerals found in cooling water systems. Unfortunately, high temperature reduces the solubility of many important minerals, causing scale most often to appear on the hottest surfaces in the entire cooling system, which are the heat exchangers. Phosphates and zinc are two of the most common minerals used as corrosion inhibitors in water treatment programs and can form mineral scale if not properly controlled.
- c) Deposits
 - 1) Mud and Silt—Enters the cooling tower in makeup water or scrubbed from the air.
 - 2) Corrosion Products (Iron Oxide)—Formed as a result of corrosion. Forms a porous deposit that is frequently the site for pitting corrosion.
 - 3) Bio-mass—A mixture of bacterial slime and other material. Typically mud and iron oxide accumulate in low flow regions, causing a favorable environment for microorganisms to form colonies on the surface that potentially can promote accelerated pitting corrosion. Process leaks of hydrocarbon can often accelerate bacterial growth and lead to rapid formation of bio-mass.

2.B.11.1.7 Types of Corrosion

Corrosion of carbon steel in cooling water systems is dominated by pitting. The following are other more common types of corrosion that can be seen.

- a) Under-deposit Corrosion—A form of pitting corrosion that occurs beneath deposits.
- b) Crevice Corrosion—Pitting and preferential attack at a crevice such as at the tube to tubesheet crevice, etc.
- c) Galvanic Corrosion—The enhanced corrosion of one metal in electrical contact with another kind of metal in an electrolyte. This form of corrosion depends on the metals having a dissimilar corrosion potential that causes one metal to be polarized into a potential region where it corrodes more quickly. As an example, copper alloy tubes in a carbon steel tubesheet may cause more rapid corrosion of the tubesheet.
- d) Dealloying—Corrosion process that appears to selectively dissolve one of the constituents of an alloy. When admiralty brass experiences dealloying, zinc is removed leaving copper (referred to as dezincification).
- e) MIC—MIC is a complex issue. Strictly speaking, MIC is not a specific type of corrosion. Rather, it consists of both direct and indirect effects on materials by bacteria, fungi, algae, and yeasts. Many types of bacteria can be implicated involved in MIC processes. Perhaps the best known type of MIC attack is the corrosion process involving SRB. These organisms are anaerobic (cannot tolerate oxygen) and thrive beneath deposits. They metabolize sulfate creating a highly acidic local environment that leads to metal corrosion. Other types of bacteria that contribute to MIC include slime forming bacteria, nitrifying bacteria, manganese reducing bacteria, and iron reducing bacteria.
- f) SCC—SCC mechanisms require the coming together of three things—a tensile stress, a susceptible alloy, and an environment that promotes SCC in that alloy. The tensile stress may be either applied or residual, and residual stresses from welding commonly contribute to SCC. Many alloys can be susceptible to SCC in at least one environment with 300-series stainless steels and copper alloys being the most common susceptible materials used in cooling water systems. The environments most associated with SCC of these alloys are aqueous chloride environments for 300-series stainless steels and ammonia for specific copper alloys.

2.B.11.1.8 Corrosion Monitoring and Control in Cooling Water Systems

The largest potential for problems in the cooling system is associated with scaling, deposition of suspended solids, and MIC. Usually, under conditions with controlled water treatment and operating parameters, only negligible corrosion is expected. However, even with these parameters in control, MIC or buildup of solids may cause unsuspected corrosion. This fact emphasizes the need for an effective corrosion monitoring program in addition to the water treatment and process control programs.

There are several strategies for controlling corrosion. These include:

- a) keep metal surfaces free from deposits,
- b) create and maintain an environment that is not conducive to corrosion,
- c) incorporate corrosion inhibitors into the treatment program,
- d) pre-passivate new and recently cleaned equipment.

In practice it is common to simultaneously employ several of the above strategies. For example, an effective treatment program frequently incorporates corrosion inhibitors, maintenance of a benign environment, and steps to keep metal surfaces clean by using dispersants and side-stream filtration.

Many variations of basic cooling water treatment programs are being practiced. In general they all include fouling control, corrosion control and microbiological control. The most common method to control the microbiological population in a cooling system is to treat the system with one or more biocides. Biocides can be classified into oxidizing and non-oxidizing.

2.B.11.1.9 Indicators for Corrosion Issues and Their Deterrence

The following parameters might be used as indicators for potential issues in the cooling system, depending on the water treatment program in place.

- a) If process-side temperature is greater than 140 °F (60 °C), then a scaling potential exists. However, at the measured pH, one can calculate the temperature at which the water begins to scale, by solving for the value of C_2 in [Equation \(2.B.11\)](#) using the coefficients provided in [Table 2.B.11.3](#).
- b) Dissolved Solids—The higher the level of dissolved solids, typically an indicator of chlorides, the higher the corrosion rate.
- c) Velocity should be maintained at minimum 1 m/s (3 ft/s) through all parts of the system. For example, if cooling water is on the shell-side of a shell-and-tube exchanger, some regions within the shell will have a low velocity.
- d) Iron levels greater than 5 ppm in the recirculating water could be an indication that the applied dispersants and flocculating agents are insufficient to keep the formation of deposits at an acceptable level. Other means of deposit control may be required.
- e) In open recirculated systems, suspended solids above 100 ppm will cause settlement in heat exchanger equipment and become a site for under-deposit corrosion.
- f) Chlorine content may be dissolved intentionally in water as a biocide. It has little effect on carbon steel if pH is maintained above 7 to suppress formation of acid hydrolysis products by $\text{Cl}_2 + \text{H}_2\text{O} \rightarrow \text{HClO} + \text{HCl}$. However, chlorine will attack copper alloys, even at higher pH, presumably by reaction with the Cu_2O surface film.

- g) Ammonia Content—Results primarily from contamination by process leaks. Could also be present if NH_4OH is used as an acid neutralizer; however, this is not recommended due to the volatility of ammonia and its use as a food source by microorganisms. It has little effect on iron and steel but has a strong effect on copper alloys. Ammonia forms complexes with copper that can cause rapid general corrosion and/or SCC of copper alloys. For example, admiralty brass is very susceptible to ammonia SCC and might experience SCC with only trace amount of ammonia present.

With fresh waters, corrosion of steel is governed by dissolved oxygen over a broad pH range (4.5 to 9.5) at relatively low temperatures. Below pH 4.5, the corrosion is controlled by hydrogen evolution under acid conditions. Above pH 9.5, an insoluble film of ferric hydroxide suppresses corrosion. In buffered solutions, where ionic concentrations are high without a corresponding drop in pH (as with carbonic and other weakly ionized acids), corrosion with hydrogen evolution may occur in the pH 5.0 to 5.5 range. In the intermediate pH range of 4.5 through 9.5, a loose, porous, ferrous-oxide deposit shelters the surface and maintains the steel surface pH at about 9.5. The corrosion rate remains nearly constant and is determined by uniform diffusion of dissolved oxygen through the deposit. At the metal surface under the deposit, oxygen is reduced cathodically. Cathodic reduction of dissolved oxygen produces a slightly alkaline surface condition, which precipitates calcium carbonate (CaCO_3). These precipitates in turn inhibit further cathodic reduction and corrosion.

The corrosive effect from the water in closed recirculating cooling water systems is easily mitigated. These systems may be treated either by rendering them sterile and anaerobic or by either oxidizing or non-oxidizing inhibitors.

Corrosion control in open recirculating cooling water systems can be achieved through the continuous use of treatment chemicals containing scale and corrosion inhibitors and polymeric dispersants. The regular use of broad spectrum microbiocides is typically used for controlling microbiological populations.

Once through cooling water systems present special problems because chemical treatment of the water may not be possible or practical. In addition, such systems often use seawater or other inherently corrosive water. Corrosion control in once through systems is principally achieved by proper alloy selection, CP, and/or the use of epoxy-phenolic coatings.

2.B.11.1.10 Assumptions

Cooling water systems can be very complex, and this risk-based inspection model does not attempt to address every issue that must be considered. For the purposes of this model, the following assumptions have been made.

- a) Low alloy steels are rarely used in cooling water systems and will not be addressed in the remainder of this paragraph. However, most of the content for carbon steel applies to low alloy steels.
- b) This model does not consider degradation of alloys other than carbon steel. Beyond some general comments, SCC and pitting of stainless steels and dealloying of copper alloys are not considered.
- c) If coupon measurement results are available, these should be used instead of this model. As a rule of thumb for carbon steel, the pitting rate is a factor of 5 to 10 times the coupon general corrosion rate, (calculated by weight loss).
- d) If corrosion inhibitors are being used, it is assumed that the program is designed and operated to adequately control corrosion of carbon steel and alloy materials.
- e) An effective microbiological control program is in place, and corrosion driven by MIC is negligible, i.e. can be set to < 0.13 mm/y (5 mpy), pitting.
- f) Water pH is kept within the range 6.5 to 9.5. Outside this pH range, the corrosion is assumed caused by other means than what is covered in this paragraph.
- g) In the event the RSI value is < 6 , it is assumed that corrosion is retarded by scale formation, but can still be estimated on the basis of the chloride content, temperature and flow velocity.

h) There is no deposition and no local low flow areas.

2.B.11.1.1 Corrosion Rates for Copper Alloys Components

This paragraph is not intended to cover material of construction other than carbon steel. The introduction of other materials such as stainless steel, copper, nickel, zinc, or aluminum-based alloys, etc. might introduce other types of degradation mechanisms. It is virtually impossible to model the complexity of the various materials and interrelation with various chemical and contaminants in the water. Thus, it has been assumed that, in general, the selection of appropriate alloy material combined with “correct” chemical treatment and process control will render a negligible corrosion rate in the cooling water system.

In general, copper and its alloys are the most reliable and cost effective alloys for many water services, although dezincification needs to be specifically inhibited for brasses containing more than 15 % zinc. Copper, red brass, inhibited admiralty brasses, aluminum brass, aluminum bronze, and cupronickels, in that order, are used for water of increasing salinity and/or velocity. In the presence of dissolved oxygen, soft waters can be highly corrosive to copper alloys. Also copper can suffer pitting under some conditions, which for fresh waters can be described as three types of pitting:

- a) Type 1 pitting is apparently caused by residual carbonaceous films from the manufacturing process;
- b) Type 2 pitting is associated with hot soft waters [>140 °F (60 °C)], and
- c) Type 3 pitting may occur in cold water or high pH and low salt concentrations, for unknown reasons.

Another issue related to copper alloys is cracking. Admiralty brass is very susceptible to ammonia SCC and might experience SCC with only a trace amount of ammonia present.

An important factor for copper-based alloys is maintaining operation within design velocity limits. Velocities under the lower limit can lead to increased deposition and under-deposit corrosion, and velocities exceeding the upper limit can cause damage to the protective surface film resulting in impingement attack.

2.B.11.2 Basic Data

2.B.11.2.1 Recirculating Cooling Water Systems

The data listed in [Table 2.B.11.1](#) are required for determining the estimated corrosion rate for recirculating cooling water service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.11.2.2 Once Through Cooling Water Systems

The data listed in [Table 2.B.11.2](#) are required for determining the estimated corrosion rate for once through cooling water service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.11.3 Determination of Corrosion Rate

2.B.11.3.1 Recirculating Cooling Water Systems

2.B.11.3.1.1 Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.11.1](#). The corrosion rate is calculated using [Equation \(2.B.8\)](#). In this equation, the base corrosion rate, CR_B , is adjusted for temperature and flow velocity for each component in the system to calculate a final representative corrosion rate.

$$CR = CR_B \cdot F_T \cdot F_V \quad (2.B.8)$$

The estimated corrosion rates need further adjustments in case construction material is other than carbon steel. This has not been addressed within this paragraph.

2.B.11.3.1.2 Base Corrosion Rate

The base corrosion rate, CR_B , is an estimated corrosion rate that is determined from the water scale tendency, chloride concentration, and a threshold for flow velocity [i.e. higher or lower than 8 ft/s (2.44 m/s)].

The concept of RSIs is used to predict whether water variables in the pH range of 6.5 to 9.5 will produce conditions that are scaling or corrosive to carbon steel. The expected tendencies are increased scaling conditions at higher temperatures, higher Ca hardness, and higher MO alkalinity and seeing corrosive conditions at lower temperatures, lower Ca hardness, or lower MO alkalinity. MO alkalinity refers to the methyl orange and the test used to measure the total alkalinity of water.

For given values of calcium hardness, MO alkalinity and total dissolved salt concentration, a value of pH, pH_s , exists at which the water is in equilibrium with solid CaCO_3 . The deposit of CaCO_3 is thermodynamically possible when the pH of water is higher than pH_s , i.e. higher than the pH at saturation of calcium carbonate. The difference between the actual pH, pH_a , of a sample of water and the pH for CaCO_3 saturated water, pH_s , is called the Langelier Saturation Index (LSI) and is computed using [Equation \(2.B.9\)](#).

$$LSI = pH_a - pH_s \quad (2.B.9)$$

The LSI is used to predict the tendency for CaCO_3 to either dissolve or precipitate and provide corrosion resistance in fresh water, under varying conditions.

While the concept of the Langelier index is correct and helpful, however, it should be emphasized that a positive value of the index can result from waters of totally different quality. As the pH increases, the Ca^{2+} concentration decreases drastically. The corrosion protection characteristics of the resulting CaCO_3 film differ accordingly. In other words, waters of different pH, Ca hardness, and MO alkalinity that give the same value of the index have different corrosivity.

The Langelier index alone cannot be used to do any quantitative assessment. However when used along with the RSI determined using [Equation \(2.B.10\)](#), a relatively good prediction of the scaling or corrosive tendencies of a water is obtained.

$$RSI = 2 \cdot pH_s - pH_a \quad (2.B.10)$$

This RSI was developed based on actual operating results for waters with different saturation indexes and is used in practice for estimating corrosivity of water. The value of pH in [Equation \(2.B.10\)](#) is calculated using [Equation \(2.B.11\)](#) and the parameters in [Table 2.B.11.3](#).

$$pH_s = (9.3 + C_1 + C_2) - (C_3 + C_4) \quad (2.B.11)$$

All values of the Stability Index can be expected to be positive. At the value of 6, the CaCO_3 is in equilibrium. The deposition of CaCO_3 increases proportionally (increased tendency of forming scale) as the index drops to below 6, and corrosivity increases as the index rises above 6. Values of 10 or above indicate extreme corrosivity. Corrosion can still take place with < 6 RSI. However, in general, low corrosion rates are obtained in scale-forming waters.

Even though the RSI indicates that CaCO_3 precipitation takes place, the corrosion rate may remain high if the water contains colloidal silica or organic particles, such as algae, because CaCO_3 precipitates on them instead of on the steel surface. For waters high in dissolved salt (such as seawater) or at high temperature, the CaCO_3 film is less protective.

Once the RSI has been determined, the base corrosion rate is calculated based on the chloride concentration and flow velocity of the water using [Table 2.B.11.4](#). In case where the velocity is larger than 8 ft/s, the effect from scaling is assumed not protective against corrosion.

Corrosion of steel increases with chloride content of the water and reaches a maximum at approximately 6000 ppm. Above that level the chloride effect is offset by diminishing solubility of dissolved oxygen.

2.B.11.3.1.3 Temperature Factor

The corrosion rate of carbon steel has shown to increase almost linearly with temperature from 80 °F to 175 °F (27 °C to 79 °C). This classical correlation has been used to adjust the calculated corrosion rates. Therefore, to calculate the temperature adjustment, the ΔT is calculated by subtracting 75 °F (24 °C) from the actual metal temperature, T_{OP} , or:

$$\Delta T = T_{OP} - T_{adjust} \quad (2.B.12)$$

This ΔT is used to determine the temperature correction factor, F_T , using [Table 2.B.11.5](#). The F_T values are different between open and closed systems at high temperatures. In an open system, heating above room temperature initially increases corrosion rate for steel but also reduces solubility of dissolved oxygen, which allows oxygen to escape. Therefore, at temperatures of 175 °F (79 °C) and greater, the corrosion rate decreases. However, in a closed system, the corrosion rate increases with temperature because of retention of small amounts of dissolved oxygen under pressure.

2.B.11.3.1.4 Flow Velocity Factor

Velocity is one of the prime variables influencing waterside corrosion. At very low velocity, biofouling or deposit buildup can occur promoting under-deposit type of attack or MIC. Even if fouling deposits do not occur, low velocity encourages higher metal temperatures that results in an increase in the corrosion rate. For carbon steel there is a range of flow velocities [see [Equation \(2.B.14\)](#)] where temperature does not have an effect on the corrosion rate. If flow velocities are outside these limits the velocity factor may be determined from [Table 2.B.11.6](#) or calculated using the following equations where V_a is the actual velocity.

For SI units, use Equations [\(2.B.13\)](#) through [\(2.B.15\)](#):

$$F_V = 1 + 1.64 \cdot (0.914 - V_a) \quad \text{for } V_a < 0.914 \text{ m/s} \quad (2.B.13)$$

$$F_V = 1 \quad \text{for } 0.914 \text{ m/s} \leq V_a \leq 2.44 \text{ m/s} \quad (2.B.14)$$

$$F_V = 1 + 0.82 \cdot (V_a - 2.44) \quad \text{for } V_a > 2.44 \text{ m/s} \quad (2.B.15)$$

For U.S. customary units, use Equations [\(2.B.16\)](#) through [\(2.B.18\)](#):

$$F_V = 1 + 0.50 \cdot (3 - V_a) \quad \text{for } V_a < 3 \text{ ft/s} \quad (2.B.16)$$

$$F_V = 1 \quad \text{for } 3 \text{ ft/s} \leq V_a \leq 8 \text{ ft/s} \quad (2.B.17)$$

$$F_V = 1 + 0.25 \cdot (V_a - 8) \quad \text{for } V_a > 8 \text{ ft/s} \quad (2.B.18)$$

This represents a fairly coarse and conservative way of factoring in the velocity effect in the corrosion rate prediction model. In reality this effect is a product of a much more sophisticated interrelation between temperature, dissolved oxygen, pH, and velocity. However, the trend shown in [Table 2.B.11.6](#) does comply with actual testing described in Reference^[37] for velocities up to 7 ft/s (2.13 m/s). For carbon steel in seawater, the velocity is even more a governing factor for the corrosion rate.

2.B.11.3.2 Once Through Cooling Water Systems

2.B.11.3.2.1 Overview

The steps required to determine the corrosion rate are shown in [Figure 2.B.11.1](#). Once through cooling water systems are much less common in the U.S. refinery industry than recirculation systems. Once through systems may be economical where there is an abundance of surface water, but the effects of thermal pollution may be too great to allow their use in some locations. Chemical treatment is normally environmentally unacceptable and/or uneconomical. These systems rarely use anything but chlorination, which controls biological growth.

It is assumed in this paragraph that chemical treatment is not applied and that the material of construction is carbon steel. In practice, the materials of construction in once through systems may be copper alloys, titanium alloys, stainless steels, polyvinyl chloride (PVC), cement-lined, or coated (organic) steel, or even galvanized carbon steel where the supply source is known to be fairly clean fresh water.

The main concern for a once through cooling water system is the quality of the supply water, i.e. type of water (sea or salt, brackish or fresh water) and level of contaminants (such as solids, phosphates, iron, ammonia, bugs, and bacteria, etc.). In total there are a large number of factors that ultimately affect damage to the equipment in a once through cooling water system.

For simplicity of this corrosion model for once through systems, these systems are considered either as seawater systems or fresh water systems, and the corrosion rates are determined as a function of temperature, water flow velocity, dissolved oxygen, and content of chlorides.

2.B.11.3.2.2 Fresh Water Once Through System

Fresh water comprises natural surface water with chloride content less than 1000 ppm. The corrosion rate is estimated in the same manner as an open recirculating system, with no chemical treatment or corrosion inhibition, except for biocide.

2.B.11.3.2.3 Seawater Once Through Systems

Seawater comprises brackish or seawater with a chloride content of more than 1000 ppm. The salts found in seawater do not appreciably alter the pH value when dissolved in water. The main type of dissolved salt in seawater is sodium chloride (NaCl).

Seawater typically contains about 3 % sodium chloride with approximately 19,000 ppm chloride ion (and 11,000 ppm sodium). The chloride ions comprise about 55 % of the total dissolved solids (TDS). Dissolved oxygen is typically present at normal saturated values of 6 to 8 ppm at 75 °F to 85 °F (24 °C to 29 °C). The pH of seawater is usually 7.7 to 8.3 in surface waters ^[29]. Seawater always contains SRB and a level of sulfate ion concentration (2 to 3,000 ppm) conducive to SRB growth under anaerobic conditions. Anaerobic conditions will exist under deposits (organic or inorganic), in crevices, and under the influence of biological oxygen demand (BOD) or chemical oxygen demand (COD). One of the most important properties of seawater is its ratios of concentrations of the major constituents are remarkably constant worldwide, including the level of chloride and oxygen.

The temperatures encountered in once through seawater systems usually preclude scale formation by inverse solubility effects, which normally would initiate at about 190 °F (88 °C). Obviously deposits can occur under extreme conditions of temperature in condensers, but this is an exceptional circumstance. Deposition of sand and silt is primarily controlled by establishing a minimum flow and by mechanical cleaning as required. Biofouling can be caused by soft organisms (slimes, algae, and hydroids) and hard organisms (barnacles, mussels, oysters, tubeworms, and sea squirts). The degree of fouling depends to some extent on the material of construction. Metals and alloys that produce toxic salts (e.g. copper, lead, and zinc) are more resistant. Both fouling and bacterial effects are controlled largely by chlorination.

Corrosion of carbon steel in seawater is controlled by the availability of oxygen to the metal surface. Under static conditions (zero velocity), carbon steel corrodes at rates between 4 and 8 mpy (0.10 and 0.20 mm/y), depending on the local oxygen and temperature variations. As the velocity causes a mass flow of oxygen to the metal surface, corrosion is very dependent on flow rate and can increase by a factor of 100 in moving from static condition to a velocity of about 130 ft/s (39.6 m/s). Galvanizing confers only limited benefit under flow conditions, as corrosion of zinc also increases with velocity. For the thickness normally used in seawater piping, it will extend the life of the pipe for about 6 months only.

Thus, velocity is the most important single factor influencing design of carbon steel components in seawater systems. The chosen design velocity controls the dimensions of many components, such as piping and valves. When the corrosion rate is subject to mass transfer control, flow velocity at the metal surface becomes the rate-determining factor.

Based on test results reported^[30, 35, 36], [Equations \(2.B.19\)](#) and [\(2.B.20\)](#) may be used to calculate the corrosion rates on carbon steel in seawater systems as a function of the velocity, V_a . Values for the corrosion rate as a function of velocity using this equation are shown in [Table 2.B.11.7](#).

For SI units, use [Equation \(2.B.19\)](#):

$$CR = 0.1318 + 0.3108 \cdot V_a - 0.0579 \cdot V_a^2 + 0.01208 \cdot V_a^{2.5} \quad (2.B.19)$$

For U.S. customary units, use [Equation \(2.B.20\)](#):

$$CR = 5.1885 + 3.7293 \cdot V_a - 0.21181 \cdot V_a^2 + 0.02439 \cdot V_a^{2.5} \quad (2.B.20)$$

[Equations \(2.B.19\)](#) and [\(2.B.20\)](#) were developed based on the data specified in reference [35], assuming seawater temperature of about 70 °F (21 °C) and an oxygen concentration of 6 to 8 ppm.

With high flow rates, the corrosion rate increases up to around 40 ft/s (12.2 m/s), where the attack changes to erosion-corrosion. However, it is assumed that cooling water systems in the refining industry will not experience water flow velocities in excess of 20 ft/s (6.1 m/s).

2.B.11.3.3 Groundwater

Groundwaters are not specifically addressed in this paragraph. However, the following can be a quick guideline for determining the level of corrosivity for such waters. The assessment needs to be made by a competent person for water corrosivity issues.

Groundwaters may contain well water, geothermal springs, or produced water (i.e. waters of brines co-produced with oil or gas). Although groundwaters can be considered one category, they might vary largely in chemistry. Groundwaters are often characterized in terms of total key species (TKS), which is a sum of chloride, sulfate, dissolved CO₂, bicarbonate, carbonate, sulfide, and ammonia concentrations. TKS is a measure of corrosivity. Depending on the TKS value, the corrosivity towards steel can be rated as follows.

- a) Low [< 1 mpy (0.03 mm/y)] corrosion rate.
- b) Medium [1 to 10 mpy (0.03 to 0.25 mm/y)].
- c) High [10 to 50 mpy (0.25 to 1.27 mm/y)].
- d) Very High [> 50 mpy (1.27 mm/y)].

The subject of specific TKS values vs corrosivity has not been addressed in this paragraph.

2.B.11.4 Nomenclature

CR	is the corrosion rate, mpy (mm/yr)
CR_B	is the base corrosion rate, mpy (mm/yr)
$C_1 \rightarrow C_4$	are the pH_s calculation parameters
F_T	is the corrosion rate temperature correction
F_V	is the corrosion rate velocity correction
LSI	is the Langelier Saturation Index
pH_a	is the actual pH
pH_s	is the pH of the sample
RSI	is the Ryznar Stability Index
T_{adjust}	is used to calculate the temperature adjustment = 75 °F (24 °C)
T_{op}	is the corrosion operating temperature, °F (°C)
V_a	is the actual velocity, ft/s (m/s)
ΔT	is the temperature difference, °F (°C)

2.B.11.5 References

See References [130], [131], [132], [133], [134], [135], [136], [137], and [138] in [Section 2.2](#).

2.B.11.6 Tables

Table 2.B.11.1—Cooling Water Corrosion—Basic Data Required for Analysis: Recirculating Cooling Water Systems and Once Through Cooling Water System with Fresh Water

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Only carbon steel components are covered.
Actual corrosion rates	Corrosion coupon data on this system or similar systems or actual rates at the facility. Caution is warranted when using corrosion rates as determined from corrosion coupons or actual measured rates from system measurements. These measurements may not be representative or indicators of worst case. Example would be coupons placed in flowing streams that could not provide data on for deposits or no flow areas.
Metal temperature of cooling or condenser surfaces, (°F:°C)	Determine the estimated metal temperature exposed to the cooling water, i.e. water-side metal surface temperature.
pH_a	Experimentally measured pH of the water.
pH_s	pH value at which the water is in equilibrium with solid calcium carbonate (CaCO_3).
TDS (mg/L)	Determine if TDS is in the range of: a) 50 to 400 mg/L, or b) 401 to 1000 mg/L Determine to what degree the TDS consist of salts (incl. ammonia), phosphates, Cu, etc. that potentially effect under-deposit corrosion.
Ca (mg/L) as CaCO_3	Determine calcium hardness as calcium carbonate (CaCO_3).
Methyl orange alkalinity (mg/L) as CaCO_3	Corresponds to the concentration of bicarbonate (HCO_3^-), commonly expressed as parts per million or mg/L of CaCO_3 (calcium carbonate).
Flow velocity (ft/s: m/s)	Determine the maximum and minimum expected water velocities.
Chlorides (ppm Cl^-)	Determine parts per million of chlorides.
MIC observed or suspected? (Yes or No)	Indicate if MIC has been observed in the cooling water system, or if MIC is considered likely.
DO (ppm O_2)	Dissolved oxygen.

Table 2.B.11.2—Cooling Water Corrosion—Basic Data Required for Analysis: Once Through Cooling Water System with Salt Water

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Only carbon steel components are covered.
Actual corrosion rates	Corrosion coupon data on this system or similar systems or actual rates at the facility.
Flow velocity (ft/s: m/s)	Determine the maximum and minimum expected water velocities.

Table 2.B.11.3—pH Calculation Parameters

C₁ Factor			C₃ Factor		C₄ Factor	
Total Solids (mg/L)		C₁	Calcium Hardness (mg/L CaCO₃)	C₃	M.O. Alkalinity (mg/L CaCO₃)	C₄
50 to 400		0.1	10.5	0.6	10.5	1.0
>400 to 1000		0.2	12.5	0.7	12.5	1.1
C₂ Factor			15.5	0.8	15.5	1.2
			20	0.9	20	1.3
Temperature (°C)	Temperature (°F)	C₂	25	1.0	25	1.4
			31	1.1	31	1.5
1	33	2.6	39	1.2	40	1.6
4	39	2.5	49.5	1.3	50	1.7
8	46	2.4	62.5	1.4	62.5	1.8
12	53	2.3	78.5	1.5	79	1.9
16	60	2.2	99	1.6	99.5	2.0
19	67	2.1	124.5	1.7	125	2.1
24	76	2.0	156.5	1.8	158	2.2
29	85	1.9	197.5	1.9	197.5	2.3
34	94	1.8	250	2.0	250	2.4
41	105	1.7	310	2.1	315	2.5
47	117	1.6	390	2.2	400	2.6
53	128	1.5	495	2.3	500	2.7
60	140	1.4	625	2.4	625	2.8
68	154	1.3	785	2.5	790	2.9
77	170	1.2	940	2.6	945	3.0

Table 2.B.11.4— CR_B Base Corrosion Rate Calculation

Chloride Content (ppm)	Base Corrosion Rate, CR_B (mpy)	
	RSI > 6 or Velocity > 8 ft/s	RSI ≤ 6 and Velocity ≤ 8 ft/s
5	1	0.3
10	2	0.6
50	4	1.4
100	6	2
250	9	3
500	13	4.3
750	15	5
1,000	17	5.7
2,000	17	5.6
3,000	16	5.4
5,000	15	4.9
10,000	13	4.3

NOTE 1 RSI < 4—Heavy scale forming, non-aggressive.
NOTE 2 RSI 5 to 6—Slightly scale forming and mildly aggressive.
NOTE 3 RSI 6 to 6.5—Balanced or at CaCO₃ saturation.
NOTE 4 RSI 6.5 to 7—Non-scaling and slightly aggressive.
NOTE 5 RSI > 8—Under-saturated, very aggressive.

Table 2.B.11.4M— CR_B Base Corrosion Rate Calculation

Chloride Content (ppm)	Base Corrosion Rate, CR_B (mm/y)	
	RSI > 6 and Velocity > 2.4 m/s	RSI > 6 and Velocity ≤ 2.4 m/s
5	0.03	0.01
10	0.05	0.02
50	0.1	0.04
100	0.15	0.05
250	0.23	0.08
500	0.33	0.11
750	0.38	0.13
1,000	0.43	0.14
2,000	0.43	0.14
3,000	0.41	0.14
5,000	0.38	0.12
10,000	0.33	0.11

NOTE 1 RSI < 4—Heavy scale forming, non-aggressive.
NOTE 2 RSI 5 to 6—Slightly scale forming and mildly aggressive.
NOTE 3 RSI 6 to 6.5—Balanced or at CaCO₃ saturation.
NOTE 4 RSI 6.5 to 7—Non-scaling and slightly aggressive.
NOTE 5 RSI > 8—Under-saturated, very aggressive.

Table 2.B.11.5—Temperature Adjustment Factor, F_T , as a Function of the Operating Temperature

Operating Temperature (°F)		F_T for Closed Systems	F_T for Open Systems
°C	°F		
24	75	0.1	0.1
27	80	0.3	0.3
29	85	0.4	0.4
32	90	0.6	0.6
35	95	0.8	0.8
38	100	0.9	0.9
41	105	1.1	1.1
43	110	1.2	1.2
46	115	1.4	1.4
49	120	1.6	1.6
52	125	1.7	1.7
54	130	1.9	1.9
57	135	2.1	2.1
60	140	2.2	2.2
63	145	2.4	2.4
66	150	2.5	2.5
68	155	2.7	2.7
71	160	2.9	2.9
74	165	3.0	3.0
77	170	3.2	3.2
79	175	3.4	3.3
82	180	3.5	3.3
85	185	3.7	3.3
88	190	3.8	3.3
91	195	4.0	3.1
93	200	4.2	2.9
96	205	4.3	2.5
99	210	4.5	1.7

Table 2.B.11.6—Flow Velocity Adjustment Factor (F_V) As a Function of the Flow Velocity

Flow Velocity		F_V —Flow Velocity Factor
m/s	ft/s	
0.15	0.5	2.25
0.3	1	2
0.61	2	1.5
0.91	3	1
1.22	4	1
1.52	5	1
1.83	6	1
2.13	7	1
2.44	8	1
2.74	9	1.25
3.05	10	1.5
3.35	11	1.75
3.66	12	2
3.96	13	2.25
4.27	14	2.5
4.57	15	2.75
4.88	16	3
5.18	17	3.25
5.49	18	3.5
5.79	19	3.75
6.1	20	4

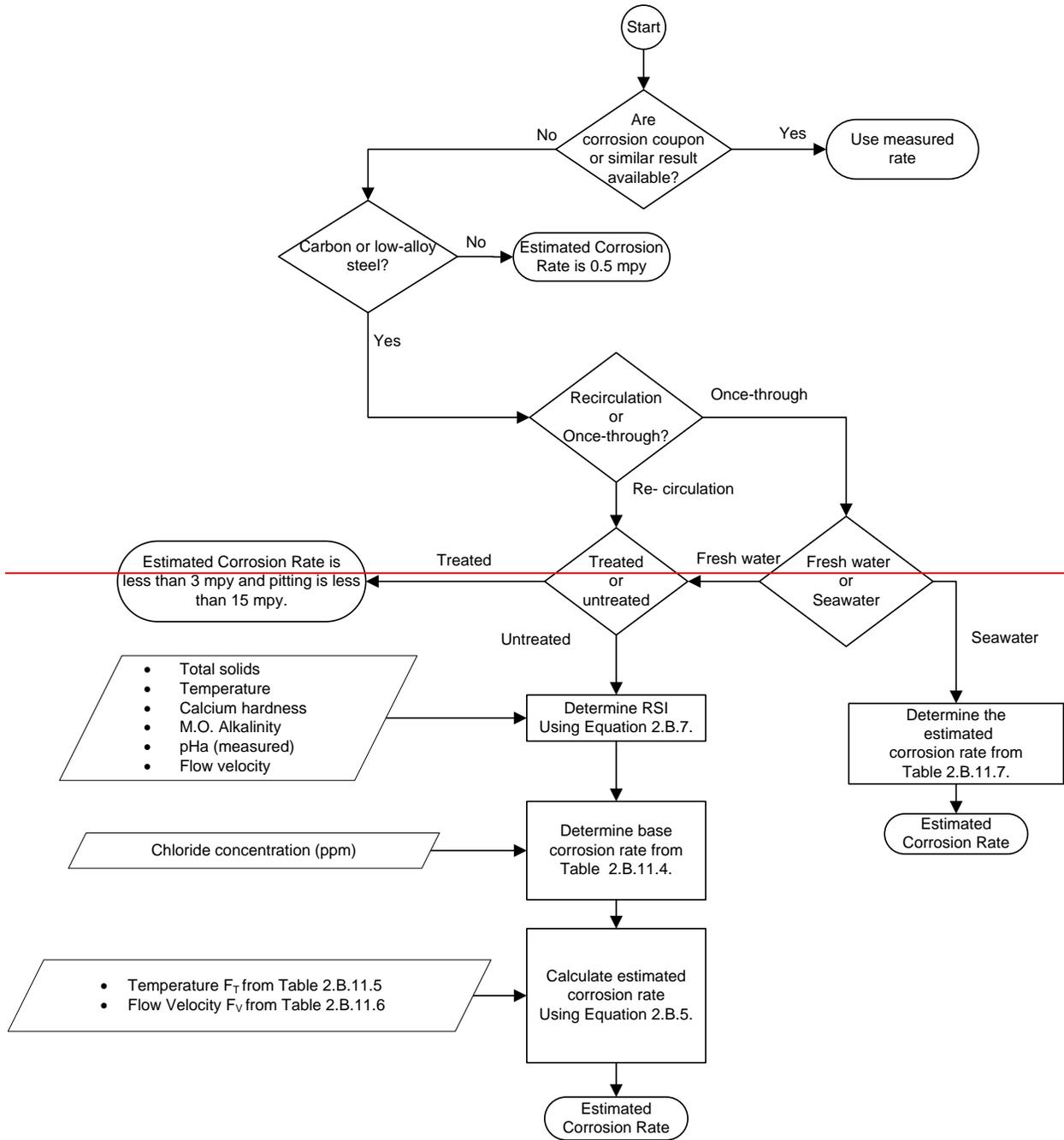
Table 2.B.11.7—Cooling Water Corrosion Estimated Corrosion Rate for Carbon and Low Alloy Steels in Seawater As a Function of Flow Velocity

Flow Velocity (ft/s)	Corrosion Rate (mpy)
0	5.2
1	8.7
2	11.9
3	14.9
4	17.5
5	19.9
6	22.1
7	24.1
8	25.9
9	27.5
10	29.0
11	30.4
12	31.6
13	32.7
14	33.8
15	34.7
16	35.6
17	36.4
18	37.2
19	38.0

Table 2.B.11.7M—Cooling Water Corrosion Estimated Corrosion Rate for Carbon and Low Alloy Steels in Seawater As a Function of Flow Velocity

Flow Velocity (m/s)	Corrosion Rate (mm/y)
0	0.13
0.3	0.22
0.61	0.3
0.91	0.38
1.22	0.44
1.52	0.51
1.83	0.56
2.13	0.61
2.44	0.66
2.74	0.7
3.05	0.74
3.35	0.77
3.66	0.8
3.96	0.83
4.27	0.86
4.57	0.88
4.88	0.9
5.18	0.92
5.49	0.94
5.79	0.97

2.B.11.7 Figures



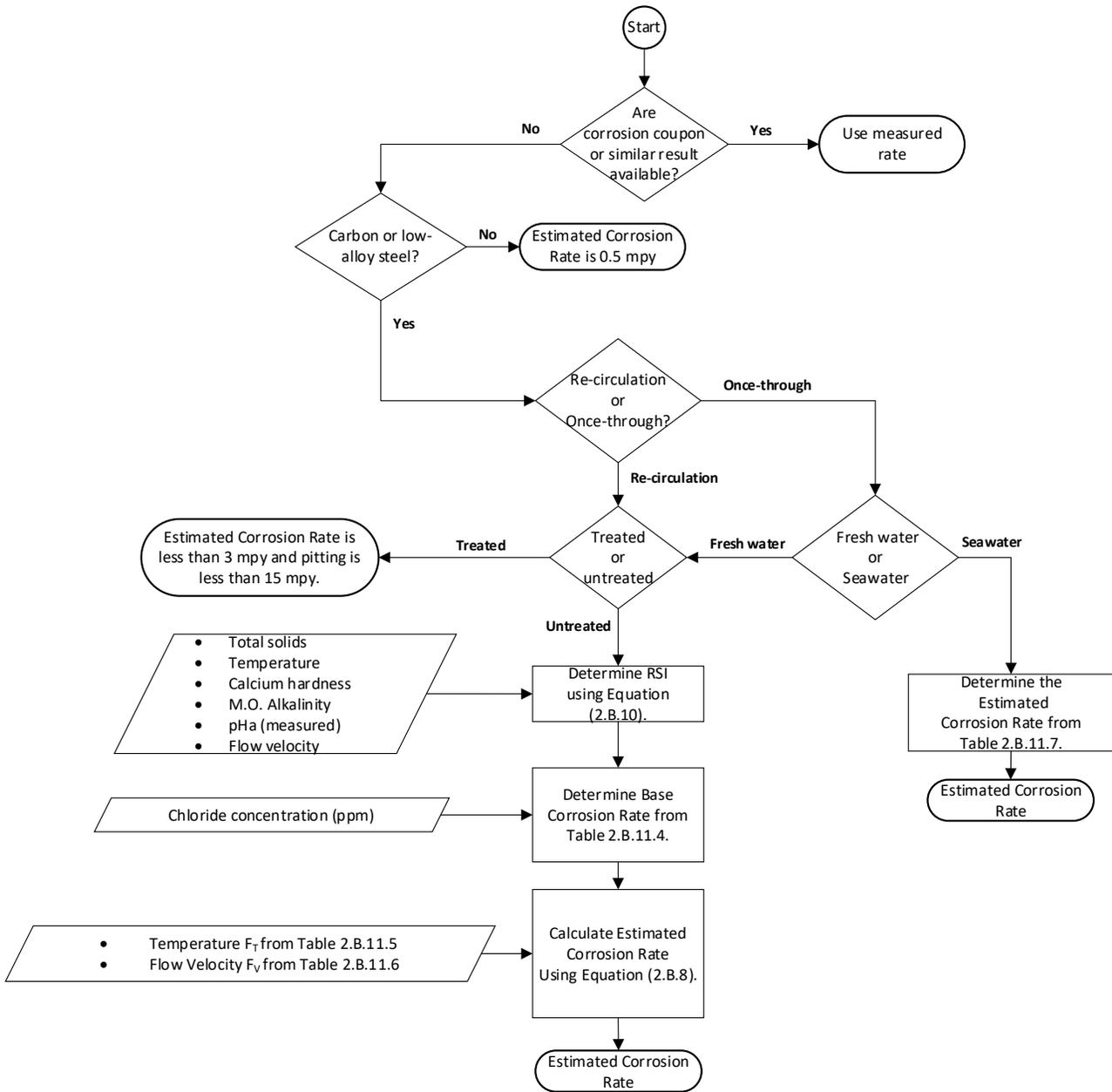


Figure 2.B.11.1—Cooling Water—Determination of Corrosion Rate

2.B.12 Soil-Side Corrosion

2.B.12.1 Description of Damage

2.B.12.1.1 Overview

The objective for this supplement is to give a conservative approach for assessing the potential for soil corrosion and determining appropriate mitigation measures, while taking the most significant factors for soil corrosion into account.

This supplement pertains to any carbon steel equipment or structure having surface metal exposed to soil, with the exception of the soil side of aboveground storage tanks, which are covered in [Section 2.B.14](#). The most typical equipment exposed to soil corrosion is buried or partly buried carbon steel vessels/drums and piping, with some type of coating.

The method described in this paragraph may be used to establish an estimate of the corrosion rate that would be expected in a given environment. If actual corrosion rates are known for particular pieces of equipment or other similar equipment in similar service, that data may be used in lieu of this method.

2.B.12.1.2 Soil Corrosivity

The damage to the exterior of metals exposed to soils is usually referred to as soil corrosion and is often attributed to soil characteristics. Soils having high moisture content, high dissolved salt concentrations, and high acidity are expected to be the most corrosive. However, soil composition alone has been found to have little correlation with soil corrosivity.

There is no single easily measured soil parameter that can be used to determine soil corrosivity. Instead, a number of characteristics must be combined to estimate the corrosion that may be expected on a steel structure from a particular soil. According to ASTM STP 741, soil corrosivity classes can be characterized by total acidity, resistivity, conductivity, drainage (soil texture), and aeration (water–air permeability). The most significant causes for soil corrosion are described in [Section 2.B.12.2](#).

Soils frequently have characteristics of which some indicate that the soil is corrosive and others indicate just the opposite. By virtue of water and related water-soluble salts being present, soil becomes an effective electrolyte for completing the corrosion circuit between anode and cathode. This can be true even if the soil is fairly dry and nonconductive (high resistivity). The water content in the soils relates to drainage, which is defined as the ability to allow water percolation. In the long term, the residence time for water or moisture on the metal surface will control the degree of corrosion in soil. Measuring this residence time is difficult or impossible in practice. Therefore, it becomes necessary to use more easily measured soil characteristics, which have a less certain correlation with soil corrosivity. The parameters usually considered include soil resistivity, pH, chloride content, redox potential, and type of soil.

Soil resistivity is frequently used to estimate soil corrosivity, mainly because it is easy to measure (commonly measured by the 4-pin Werner technique as described in ASME G57, or electromagnetic non-contacting methods, Geonics). In practice, the conditions around the equipment surface are likely to be different than in the surrounding native soil, due to different compaction and possibly also different soil type and texture (especially where sand is used for backfill). Furthermore, the conditions probably vary along the equipment surface as well. These variations will cause local effects that are not easily predicted by bulk resistivity measurements, and these local effects again make a direct correlation solely between soil resistivity and soil corrosivity of questionable value.

2.B.12.1.3 Preventing Soil Corrosion

The common prevention methods for soil corrosion of carbon steel equipment are special backfill, coating, and CP. The most effective corrosion protection is achieved by a combination of a corrosion-resistant coating and an effective CP system. With an effective CP system in place, the corrosion rate can be maintained at a level close to zero. However, maintaining and managing an effective CP system can be complex and should involve personnel competent in this field. An effective CP system will normally be maintained in compliance with a recognized standard, such as NACE RP0169.

Partially buried equipment must be handled in three ways. The portion under the soil will be treated as a piece of buried equipment. The portion exposed to air will be treated as any other outdoor equipment and often requires little attention. The soil-to-air interface is unique for the location and alloy, and soil-to-air interface corrosion may present a higher corrosion concern than underground corrosion.

Equipment that is fully encased in concrete is not normally in need of additional corrosion protection provided that a chloride-free concrete mix is used and moisture content is stable, and it is not subject to chloride intrusion.

2.B.12.2 Description of Damage

The soil corrosion damage morphology is generally expected to be localized external corrosion, i.e. pitting at the anode. The severity of corrosion depends on the local soil conditions and changes in the immediate environment along the equipment metal surface. The following are the main theoretical causes of soil and underground corrosion.

- a) **Equipment Temperature**—For a moist environment containing dissolved oxygen, an increase in the equipment temperature (operating temperature for piping or pipelines) can significantly increase the external corrosion rate. Theoretically corrosion by oxygen (oxidation) ceases when all the dissolved oxygen is consumed. Oxygen can be replenished by drain water or from the air (especially at the soil-to-air interface). The corrosion reaction is primarily controlled by diffusion of oxygen to the corroding surface. Any process that slows oxygen diffusion slows the reaction, and ultimately reduce the corrosion rate. As corrosion products accumulate on the corroding surface, oxygen diffusion is slowed. Corrosion due to oxidation of steel doubles for every 20 °C to 30 °C (35 °F to 55 °F) rise in temperature, beginning at room temperature. Corrosion is nearly proportional to temperature up to about 80 °C (180 °F) when oxygen is replenished unrestricted to the corroding surface. With the increase in temperature, dissolved oxygen is driven from the water solution, resulting in a decrease in the rate of corrosion by oxygen.
- b) **Galvanic Corrosion (Dissimilar Metal Corrosion)**—This occurs when two different metals are joined in the soil, such as steel and copper. Electrical current will flow from the steel into the soil and back into the copper resulting in corrosion of the steel. A less recognized but similar phenomenon occurs when new steel is connected to old steel in the soil, such as when replacing a section of corroded pipe. The new steel that is not cathodically protected will frequently experience a higher corrosion rate.
- c) **Corrosion Resulting from Dissimilar Soils**—In much the same manner as dissimilar metals, a structure that contacts two or more different types of soil will have different electrical potentials between the metal and each respective soil. Hence, variations in soil density and porosity can be a common cause of corrosion in buried equipment, with more dense soil areas promoting an anodic reaction and lighter soil cover promoting a cathodic reaction. The resultant pitting at the anode can lead to swift penetration of the wall. The phenomena can occur even over long distances. For example, on a buried pipeline, the anodic areas and cathodic areas may be considerable distances apart, e.g. where a pipeline crosses a marshy area near a river and then runs through much drier sandy soil. The differences in the native pipe-to-soil potential can be sufficient to set up a corrosion cell with anode and cathode many hundreds of yards apart.

- d) Corrosion by Stray Current Drainage—This corrosion differs from other corrosion damage types in that the current, which causes the corrosion, has a source external to the affected structure. The stray current source can be AC power lines, telephone lines, adjacent CP systems, or any electrically driven equipment, most notably rail systems. Stray currents flow from an external source onto a pipeline or structure and then flow along it to some other area(s) where they leave to reenter the earth causing localized corrosion. Where stray current corrosion is a factor, CP may not be the best method of controlling corrosion. The majority of stray current corrosion problems result from the interacting CP systems where nearby equipment provides the low-resistance paths for the current from the impressed-current CP system to pass before returning to the protected equipment. This disturbance in current distribution makes the CP system incomplete and causes localized corrosion on the interfering equipment. One solution to stray current problems is electrical bonding of nearby equipment. However, the appropriate solution needs to be evaluated on a case by case basis.
- e) Differential Aeration Corrosion Cells—Local differences in the packing of the soil and in its moisture content may develop oxygen concentration cells where the area with the least oxygen is anodic to the area in which oxygen is more readily available. Aeration corrosion cells are similar to the corrosion cells that produce pitting in waters, when one area of the metal has more ready access to oxygen than other areas. The areas with less access to oxygen will corrode preferentially. This sometimes occurs when a pipe passes beneath a roadbed or crosses deep underneath a river.
- f) MIC—Microbacterial action can also promote local corrosion. Corrosion enhanced by SRB is well documented. These microbes reduce the commonly available sulfate ions in the soil to produce hydrogen sulfide. This, in turn, results in increased acidity and acceleration of anodic dissolution. Coating types, age, and condition are significant factors in preventing microbiologically influenced corrosion.

2.B.12.3 Basic Data

The data listed in [Table 2.B.12.1](#) are required to determine the estimated corrosion rate for soil-side corrosion. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.12.4 Determination of Corrosion Rate

2.B.12.4.1 Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.12.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.12.1](#) in conjunction with Equation. (2.B.21):

$$CR = CR_B \cdot F_{SR} \cdot F_T \cdot F_{CP} \cdot F_{CE} \quad (2.B.21)$$

In this equation, the base corrosion rate, CR_B , is adjusted for soil resistivity, F_{SR} , temperature, F_T , cathodic protection, F_{CP} , and coating effectiveness, F_{CE} . Determination of the base corrosion rate and each of these factors is discussed in the following paragraphs.

2.B.12.4.2 Establishing the Base Corrosion Rate

The base corrosion rate is the expected or observed corrosion rate for the buried equipment or structure. Estimating a corrosion rate based on soil properties is difficult without extensive physical and chemical analyses. Corrosion rates will be estimated based on rather easily established general characteristics, as shown in [Table 2.B.12.2](#). There are numerous possible combinations of these variables, with possible offsetting or compounding effects on the expected corrosion rate. The user should use a corrosion rate that is based on the actual conditions of the soil in contact with the structure. Corrosion rates should be extrapolated between those values shown in the table to account for the expected effects of the various factors. For example, if a soil had all the characteristics of those in row 2 of the table, then a corrosion rate of 5 mpy (0.13 mm/y) would be estimated. If, however, the soil was primarily clay, in an industrial setting (moderate chemical contaminants), with a mixture of some other soil types and sizes and the soil is normally saturated, a corrosion rate between 5 and 10 mpy (0.13 and 0.25 mm/y), or as an average 7 mpy (0.178 mm/y), would be estimated. If actual corrosion rates are known for the particular piece of equipment or other similar equipment in similar service, that data should be used.

2.B.12.4.3 Adjustment Factor for Soil Resistivity (Optional)

The soil resistivity factor might be considered as input information when estimating the base corrosion and as such discarded as an adjustment factor. However, for a couple of cases, the soil resistivity factor should be included as an adjustment factor for the base corrosion rate, i.e. where:

- a) estimation of the base corrosion rate is determined by intuitive settings for the sub-factors in [Table 2.B.12.2](#), and
- b) regular measurements of soil resistivity are part of the inspection program and variation in soil resistivity might be the only indicative variable for monitoring changes in the soil characteristics (an example would be monitoring soil resistivity around a cooling tower basin with adjacent chemical treating facilities).

Soil resistivity gives a composite measure of moisture content of soil and dissolved electrolytes in the soil water, i.e. an indication for soil condition. Soil resistivity has often been used as a broad indicator of soil corrosivity. Because ionic current flow is associated with soil corrosion reactions, high resistivity will arguably slow down corrosion reactions although a high soil resistivity alone will not guarantee absence of serious corrosion. Soil resistivity generally decreases with increasing water content and concentration of ionic species. Variations in soil resistivity along the length of the structure are highly undesirable, as this will lead to the formation of macro corrosion cells. Thus, the merit of a corrosion risk classification based on an absolute value of soil resistivity is limited.

Resistivity of native undisturbed earth and the soil adjacent to the pipe (looser) may be very different. However, over time the less compacted and possibly higher resistivity soil near the structure will assume the characteristics of the native soil, i.e. the high resistivity soil might become contaminated by capillary action. While the soil resistivity against the pipe or structure cannot be measured accurately, bulk measurements can be taken for soil resistivity in the vicinity of the buried equipment. Given the above theory and assuming several measurements will be taken, these resistivity measurements can be considered representative for the soil adjacent to the structure.

Normal soil resistivity is 3,000 to 5,000 Ω -cm, although 20,000 Ω -cm is not uncommon. Corrosion rate adjustment factors for soil resistivities are provided in [Table 2.B.12.3](#). The ranges in this table are consistent with API 651 (general classification of resistivity, based on NACE 51011). API 570 (1997) only stipulates 3 ranges (<2,000; 2,000 to 10,000; >10,000) for determining the recommended inspection frequencies of 5, 10, and 15 years, respectively, for buried piping without CP.

2.B.12.4.4 Adjustment Factor for Temperature

The base corrosion rate is adjusted for the operating temperature in accordance with [Table 2.B.12.4](#). See ASM Handbook 13 (Corrosion) for temperature effect on external corrosion.

2.B.12.4.5 Adjustment Factor for CP and Stray Current Drainage

CP is the primary method used to avoid corrosion of buried structures from the soil corrosion. However, the system must be installed and maintained properly. In [Table 2.B.12.5](#) corrosion rate adjustment factors are given for CP system coverage and expected efficiency of protection. “Hot spot” protection is the practice of installing sacrificial anodes (aluminum, zinc, or magnesium) at locations of suspected anodic activity, as determined by surveys of structure-to-soil potential. Complete protection is achieved by installation of sacrificial anodes or impressed current protection systems sufficient to cover the entire surface of the buried equipment. Anodic protection is not an applicable method for protection of buried equipment. NACE RP0169 establishes three criteria for protection. One common reference level is a structure-to-soil potential measurement of -0.85 volts with reference to a copper/copper sulfate reference electrode. This criterion is considered less effective than the other two criteria commonly known as 100 mV polarization and -0.85 volt polarized structure-to-soil potential.

As discussed earlier, stray current can originate from various external sources such as power lines, electrically driven equipment, and impressed current CP systems in the environs. Except for the few cases where AC stray current is present from inductively coupled situations such as paralleling high tension lines, stray current would not occur if electrical systems were entirely insulated from earth. At the same time, proper grounding of electrical power circuits is necessary to reduce electric shock hazards. Hence the stray current corrosion problem will probably never be eliminated.

A low-level, steady state current may be controlled with CP systems. But a larger stray current that may be dynamic would require special analysis and corrective measures. The corrosion potential from these larger stray current problems is of a much higher magnitude than the other corrosion causes discussed. Therefore, they should be addressed first before considering any other effects on the corrosion potential of the equipment or structure being addressed. An effective CP system will include testing and mitigating the effect of stray currents on a routine basis.

Adjustment factors for CP systems, based on the effectiveness of the system, are provided in [Table 2.B.12.5](#). It shall be noted that the effectiveness of the CP system depends on the continuity of operation of impressed current sources, the system complies to NACE RP0169 and managed by NACE certified personal.

For structures which are only partly protected by a CP system, the unprotected areas will have corrosion rates that are determined by the prevailing conditions.

2.B.12.4.6 Adjustment Factor for Coating Effectiveness

The primary effect that a coating has on the corrosion rate is related to the potential for the coating to shield the CP current in the event that the coating becomes disbonded from the structure. This is a complicated relationship between many factors but is primarily related to how well coating adheres to the pipe and how age, temperature extremes, and maintenance practices affect the dielectric properties of the coating. Each factor is considered to be independent of each other. All of multiplying factors that apply to the coating in question should be used to determine the total coating effectiveness factor, F_{CE} .

[Table 2.B.12.6](#) is used for calculating the adjustment factor for a coating. When the multiplying factors criterion does not apply, substitute factor with 1.0. For example, for a mill applied polyethelene (PE) tape that is 30 years old, has been occasionally subjected to temperatures over the maximum, and there is never any coating inspection or maintenance, the total coating effectiveness factor would be:

$$F_{CE} = 1.5 \cdot 1.2 \cdot 3.0 \cdot 1.5 = 13.5 \quad (2.B.22)$$

For a bare pipe or structure, $F_{CE} = 1.0$. For a pipe that does not have CP, the coating effectiveness factors should still be used since holidays in the coating may allow concentrated corrosion to occur in the damaged area.

2.B.12.5 Nomenclature

CR is the corrosion rate

CR_B is the base corrosion rate

F_{CE} is the corrosion rate correction factor for coating effectiveness

F_{CP} is the corrosion rate correction factor for CP

F_{SR} is the corrosion rate correction factor for soil resistivity

F_T is the corrosion rate correction factor for temperature

2.B.12.6 References

See References [134], [138], [139], [140], [141], [142], [143], and [144] in [Section 2.2](#).

2.B.12.7 Tables

Table 2.B.12.1—Soil-Side Corrosion—Basic Data Required for Analysis

Basic Data		Comments
Base corrosion rate, mpy (mm/yr)		The expected or observed corrosion rate for the buried structure, or a “similar” structure under “similar” service and conditions.
Equipment temperature, °F (°C)		Equipment temperature (operating temperature for piping and pipelines).
Soil resistivity, Ω -cm		Soil characteristics in the vicinity of the buried structure.
Cathodic protection (CP)		Specify whether or not a CP system is installed and how effective it is.
Coating		Type of coating, age, temperature abuse, and inspection and maintenance history, if a coating is installed.
Equipment age, years		The time since installation of the buried equipment—used to determine accumulated corrosion over time since buried.

Table 2.B.12.2—Base Corrosion Rate

Factors Affecting Base Corrosion Rate				Base Corrosion Rate	
Primary Soil Type	Level of Chemical Contaminants	Particle Size and Uniformity	Moisture Level	mm/y	mpy
Sand	Low chlorides (inland, non-industrial)	Homogeneous, fine silt or sand	Dry, desert-like	0.03	1
Silt	Moderate (industrial)	Mixed	Variable moisture	0.13	5
Clay	High chlorides (coastal areas)	>50 % gravel	Normally saturated	0.25	10

Table 2.B.12.3—Soil Resistivity Adjustment

Resistivity (Ω -cm)	Corrosiveness	Multiplying Factor
<500	Very Corrosive	1.50
500 to 1,000	Corrosive	1.25
1,000 to 2,000	Moderately Corrosive	1.00
2,000 to 10,000	Mildly Corrosive	0.83
>10,000	Progressively Less Corrosive	0.60

Table 2.B.12.4—Equipment Temperature Adjustment

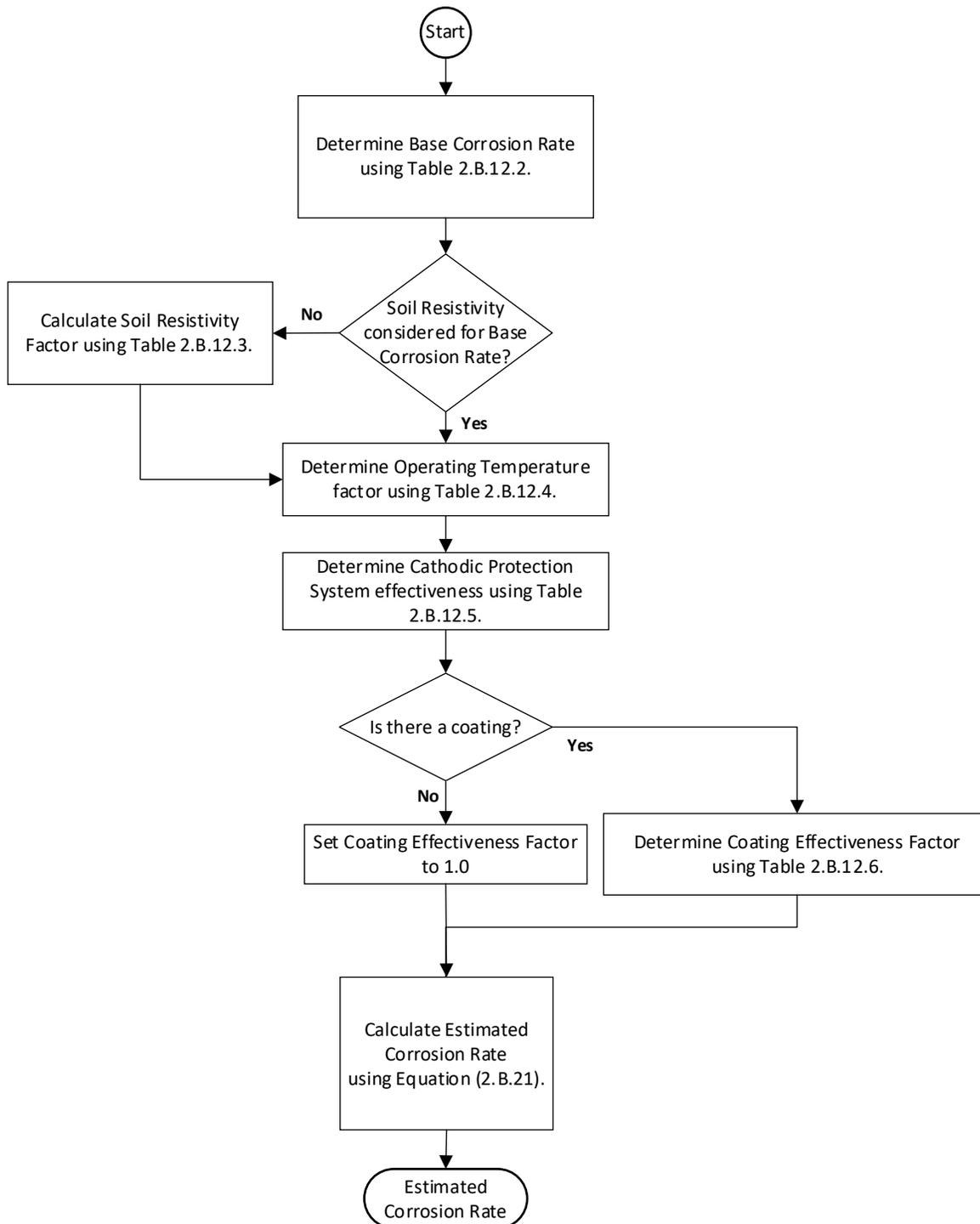
Temperature		Multiplying Factor
°C	°F	
<49	<120	1.00
49 to 104	120 to 220	2.00
>104	>220	1.00

Table 2.B.12.5—CP Effectiveness Factors

CP Measurement Practices	Multiplying Factor
No CP on structure (or CP exists but is not regularly tested per NACE RP0169) and CP on an adjacent structure could cause stray current corrosion	10.0
No CP	1.0
CP exists, but is not tested each year or part of the structure is not in accordance with any NACE RP0169 criteria	0.8
CP is tested annually and is in accordance with NACE RP0169 "on" potential criteria over entire structure	0.4
CP is tested annually and is in accordance with NACE RP0169 polarized or "instant-off" potential criteria over entire structure	0.05

Table 2.B.12.6—Calculating the Total Coating Effectiveness Factor

Coating Type	Base Factor for Coating Type	Multiplying Factors		
		Age > 20 years	Maximum Rated Temperature Is Occasionally Exceeded	Coating Maintenance Is Rare or None
Fusion bonded epoxy	1.0	1.1	1.5	1.1
Liquid epoxy				
Asphalt enamel				
Asphalt mastic				
Coal tar enamel	1.0	1.2	2.0	1.5
Extruded polyethylene with mastic or rubber	1.0	1.2	3.0	1.5
Mill applied PE tape with mastic	1.5	1.2	3.0	1.5
Field applied PE tape with mastic	2.0	2.0	3.0	1.5
Three-layer PE or PP	1.0	1.2	2.0	1.2

2.B.12.8 Figures**Figure 2.B.12.1—Soil-side Corrosion—Determination of Corrosion Rate**

2.B.13 CO₂ Corrosion

2.B.13.1 Description of Damage

Carbon dioxide is a weakly acidic gas. In streams with carbon dioxide and free water, the CO₂ dissolves in water producing carbonic acid (H₂CO₃). The carbonic acid then dissolves the steel producing iron carbonate and hydrogen (Fe+H₂CO₃→FeCO₃+H₂). Despite being a weak acid, carbonic acid can be extremely corrosive to carbon steel. CO₂ is commonly found in upstream sections before treatment. CO₂ corrosion requires the presence of free water in order to produce the Carbonic acid. The primary variables that influence CO₂ corrosion rates are the CO₂ concentration, operating pressure, operating temperature, application of inhibitors, flow rate, and presence of hydrocarbon fluids, and contaminants in the system.

Aqueous CO₂ corrosion of carbon and low alloy steels is an electrochemical process involving the anodic dissolution of iron and the cathodic evolution of hydrogen. The electrochemical reactions are often accompanied by the formation of films of FeCO₃ (and/or Fe₃O₄), which can be protective or non-protective depending on the conditions under which these are formed.

NORSOK Standard M-506 has been used as the main reference for the developing the corrosion rate calculation model described in this section.

2.B.13.2 Basic Data

The data listed in [Table 2.B.13.1](#) are required to determine the estimated corrosion rate for carbonic acid service. If precise data have not been measured, a knowledgeable process specialist should be consulted. Entering only the data marked required will result in a conservative estimate of the corrosion rate. The calculation for the corrosion rate is more refined as more optional data are entered.

2.B.13.3 Determination of Corrosion Rate

2.B.13.3.1 Calculation of the Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.13.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.13.1](#) in conjunction with Equation (2.B.23).

$$CR = CR_B \cdot \min \left[F_{glycol}, F_{inhib} \right] \quad (2.B.23)$$

The calculation of the base corrosion rate, CR_B , is most complex; it depends on the temperature, the partial pressure of CO₂, the fluid flow velocity, and the pH of the fluid. The following paragraphs detail how these can be estimated for RBI purposes for some simple mixtures of crude oil, water, and natural gas mixtures. In order to estimate corrosion rates for situations outside this simple mixture, the analyst should refer to NORSOK Standard M-506. In cases where the equipment is not associated with upstream production, the analyst should also be prepared to adjust or estimate corrosion rates for fluids that are not mixtures of crude, water and natural gas.

2.B.13.3.2 Relative Humidity

In order for corrosion to occur, there must be liquid water present in the equipment. In a system transporting gas, liquid water exists only if the temperature is below the dew point and the relative humidity in the stream is greater than 100 %. When a mixture of water vapor and natural gas behaves approximately as ideal gases, the relative humidity in a gas is 100 % when the partial pressure of the water vapor is equal to the saturation pressure. This result in the simplified formula for the relative humidity,

$$RH = \left(\frac{x \cdot P}{P_{sat}(T)} \right) \left(\frac{1}{0.622 + x} \right) \quad (2.B.24)$$

In Equation (2.B.24), x is the ratio of the mass of water to the mass of dry gas, or $\%w/(100-\%w)$, where $\%w$ is the percent water by weight in the stream. The parameter P is the pressure and $P_{sat}(T)$ is the saturation pressure for water at temperature, T , which can be obtained from steam tables. The 0.622 is the ratio of the molecular weight of water (≈ 18) to the average molecular weight of air (≈ 29). Using Equation (2.B.24) and standard steam tables, an approximate equation for the dew point temperature T_d ($^{\circ}\text{F}$) can be derived; see Equation (2.B.25):

$$\log_{10}T_d = 2.0866 + 0.2088 \cdot \log_{10} \left[\frac{\%w}{100} \right] + 0.2242 \cdot \log_{10} [P] \quad (2.B.25)$$

In Equation (2.B.25), P is the pressure in psia, and $\%w$ is the percent water by weight in the stream (lbm/100lbm), between 0 and 30.

2.B.13.3.3 Base Corrosion Rate

The base corrosion rate in mm/y is calculated from Equation (2.B.26). To obtain mpy, multiply the result in mm/y by 39.4.

$$CR_{base} = f(T, pH) \cdot f_{CO_2}^{0.62} \cdot \left(\frac{S}{19} \right)^{0.146 + 0.0324 f_{CO_2}} \quad (2.B.26)$$

In Equation (2.B.26), $f(T, pH)$ is the temperature-pH function that is tabulated in Table 2.B.13.2. This tabulated function was calculated by combining the M-506 temperature and temperature dependent function pH function into a single quantity. It should be noted that the $f(T, pH)$ function jumps sharply between 176 $^{\circ}\text{F}$ and 194 $^{\circ}\text{F}$ (80 $^{\circ}\text{C}$ and 90 $^{\circ}\text{C}$).

The CO_2 fugacity, f_{CO_2} in bar, pH, and the shear stress from the flow S in Pa needed to calculate the basic corrosion rate are discussed in the following paragraphs.

2.B.13.3.4 Determining the pH

For RBI purposes, the pH term in temperature-pH function tabulated in Table 2.B.13.2 may be calculated using one of the following approximations. For condensation:

$$pH = 2.8686 + 0.7931 \cdot \log_{10} [T] - 0.57 \cdot \log_{10} [p_{CO_2}] \quad (2.B.27)$$

for Fe^{++} saturated water:

$$pH = 2.5907 + 0.8668 \cdot \log_{10} [T] - 0.49 \cdot \log_{10} [p_{CO_2}] \quad (2.B.28)$$

and for water with salinity slightly greater than seawater (salinity = 46 g/l):

$$pH = 2.7137 + 0.8002 \cdot \log_{10} [T] - 0.57 \cdot \log_{10} [p_{CO_2}] \quad (2.B.29)$$

In Equations (2.B.27), (2.B.28), and (2.B.29), T is the temperature in $^{\circ}\text{F}$, and p_{CO_2} is the CO_2 partial pressure in psi. These approximations were developed from Monte Carlo simulations. These simulation studies used the equilibrium equations recommended and by M-506 to calculate the concentration of hydrogen cation and then the pH for a wide range of temperatures, pressures, and CO_2 mole fractions.

Equations (2.B.27), (2.B.28), and (2.B.29) apply to water, seawater, and Fe⁺⁺ saturated water and do not account for the buffering action of bicarbonate ions or for the increase acidity caused by salinity levels higher than 45 g/l. In cases where these factors are significant, the analyst should consider using an alternative analysis such as direct application of the provisions in M-506 for salinity and dissolved bicarbonate.

2.B.13.3.5 Determining the CO₂ Fugacity

Fugacity has units of pressure. It is used in place of the pressure—or partial pressure—in calculations concerning the equilibrium of real gas mixtures. When the fugacity is used in place of the pressure, real gases can be modeled using the equations for ideal gases. M-506 uses the following equation for modeling the fugacity, f_{CO_2} .

$$\log_{10} [f_{CO_2}] = \log_{10} [p_{CO_2}] + \min [250, p_{CO_2}] \cdot \left(0.0031 - \frac{1.4}{T + 273} \right) \quad (2.B.30)$$

$$\log_{10} [f_{CO_2}] = \log_{10} [p_{CO_2}] + \log_{10} [a] \quad (2.B.31)$$

In Equations (2.B.30) and (2.B.31), p_{CO_2} is the CO₂ partial pressure in bar and T is the temperature in °C. NOTE the fugacity coefficient, a , is the ratio between CO₂ fugacity and the partial pressure, or:

$$f_{CO_2} = p_{CO_2} \cdot a \quad (2.B.32)$$

2.B.13.3.6 Determining the Flow Velocity

M-506 uses the fluid flow shear stress to model the effect of flow velocity on the base corrosion rate. M-506 recommends the Equation (2.B.33) to calculate the stress, S , in units of Pa. In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

$$S = \frac{f \cdot \rho_m \cdot u_m^2}{2} \quad (2.B.33)$$

In Equation (2.B.33), f is the friction factor, u_m is the mixture flow velocity in m/s, and ρ_m is the mixture mass density in kg/m³. The friction coefficient may be approximated for turbulent flow ($Re > 2300$) by using Equation (2.B.34):

$$f = 0.001375 \left[1 + \left(20000 \left(\frac{e}{D} \right) + \frac{10^6}{Re} \right)^{0.33} \right] \quad (2.B.34)$$

The term e/D is the relative roughness and Re is the Reynolds Number of the mixture given by Equation (2.B.35):

$$Re = \frac{D \rho_m u_m}{\mu_m} = \frac{\dot{m} D}{A \mu_m} \quad (2.B.35)$$

In Equation (2.B.35), D is the diameter in meters, and μ_m is viscosity of the mixture in Pa·s (0.001cP = Pa·s). This equation also shows that the Reynolds number can be calculated using the mass flux, \dot{m} , and the cross-sectional area, A .

M-506 gives some guidance on the calculation of the two-phase viscosity, density, and fluid velocity. These factors depend on the volumetric ratio of the liquid flow to the flow, sometimes known as the liquid holdup, the amount of water in the liquid fraction, the gas water and oil viscosities at the temperature and pressure. These calculations are complex and go beyond the scope of an RBI study. If required, the analyst can refer to the recommendations in NORSOK or use the software provided by NORSOK to perform the calculations recommended in M-506 to approximate the two-phase flow characteristics. While M-506 provides some guidelines for the calculation of bulk fluid properties, they do not explicitly account for the solubility of natural gas in oil, which can also affect the all of these properties.

2.B.13.3.7 Adjustment for Inhibitors or Glycol

The addition of glycol reduces the CO₂ corrosion rate. M-506 accounts for this by simply reducing the corrosion rate by applying a factor of the form:

$$\log_{10} [F_{glycol}] = 1.6 \cdot (\log[100 - G] - 2) \quad (2.B.36)$$

In Equation (2.B.36), G is the percent weight of glycol as a percent of water in the system. F_{glycol} is limited to a minimum value of 0.008. The base corrosion rate is multiplied by the factor F_{glycol} to account for the corrosion reduction due to glycol.

For other types of corrosion inhibitors added to the stream, M-506 requires that its effectiveness must be independently determined and used directly as a reduction factor, F_{inhib} . If both glycol and an inhibitor are used, the minimum of F_{inhib} and F_{glycol} should be used as shown in Equation (2.B.23).

2.B.13.4 Nomenclature

a	is the fugacity coefficient
A	is the pipe cross-sectional area, ft ² (m ²)
CR	is the corrosion rate
CR_B	is the base corrosion rate
D	is the pipe diameter, ft (m)
e/D	is the relative roughness
f	is the fraction factor
f_{CO_2}	is the CO ₂ fugacity, bar
$f(T, pH)$	is the temperature-pH function
F_{glycol}	is the corrosion rate correction factor for glycol
F_{inhib}	is the corrosion rate correction factor for the inhibitor
G	is the percent weight of glycol as a percent of water in the system
\dot{m}	is the calculated using the mass flux, lb/(ft ² -s) (kg/(m ² -s))
P	is the pressure, psia

p_{CO_2}	is the CO ₂ partial pressure, psi (bar)
$P_{sat}(T)$	is the saturation pressure for water at temperature T , psia
$\%w$	is the percent water by weight in the stream
Re	is the Reynolds Number
RH	is the relative humidity
S	is the shear stress, Pa
T	is the temperature, °F (°C)
T_d	is dew point temperature, °F (°C)
u_m	is the mixture flow velocity, m/s
x	is the ratio of the mass of water to the mass of dry gas
ρ_m	is the mixture mass density, kg/m ³
μ_m	is the viscosity of the mixture, cP

2.B.13.5 Tables

Table 2.B.13.1—CO₂ Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Temperature—Required	The corrosion phenomenon is highly temperature dependent. The maximum temperature of the process is required. Temperatures above 284 °F (140 °C) are not considered.
Pressure—Required	Total pressure of the system. The total pressure of the gas is a big contributor in the corrosion rate up to about 250 psig.
CO ₂ concentration (mole %)—Required	Determine the CO ₂ partial pressure (p_{CO_2}) = (mol fraction of CO ₂ × total pressure), a maximum 580 psi (4 MPa) partial CO ₂ pressure is considered.
p_{CO_2} —Required, if CO ₂ concentration is not given	CO ₂ partial pressure, which is converted to CO ₂ fugacity to account for non-ideal behavior.
Material of construction—Required	Determine the material of construction of equipment/piping. Stainless steels and copper alloys are assumed to be resistant to CO ₂ corrosion.
pH—Required	If known explicitly, the pH of the stream should be used; otherwise Equations (2.B.27) , (2.B.28) , and (2.B.29) can be used to estimate the pH based on the CO ₂ partial pressure, whether the water in the stream is Fe ⁺⁺ saturated or water with salinity slightly larger than seawater.
Stream properties: bulk density, ρ_m , viscosity, μ_m , gas to liquid ratios—Required	Guidance with respect to typical values properties expected in natural gas–oil mixtures (i.e. reservoir fluids) is provided. Estimation of densities can be made on the basis of the oil density (°API), gas–oil ratio (GOR), pressure, P , and temperature, T . For other streams, a process engineer should assess these parameters.
For systems with liquids: Water cut—Optional	Determine the percentage of water in the system. The default for this field is 30 %.
For gas systems: Relative humidity, RH or the dew point temperature, T_d —Optional	Determine the dew point temperature, T_d , based on the water content. Equation (2.B.25) is provided for guidance, but should not be assumed to be accurate within ±10 °F. If not provided, the gas stream temperature is assumed to be below the dew point.
Glycol/water mix—Optional	Water content of glycol/water mix in %weight (%water in the total glycol/water mix). The default value would assume no glycol added in the system.
Inhibition efficiency—Optional	Requires %efficiency of the inhibitor. No inhibitor injected as a default value.

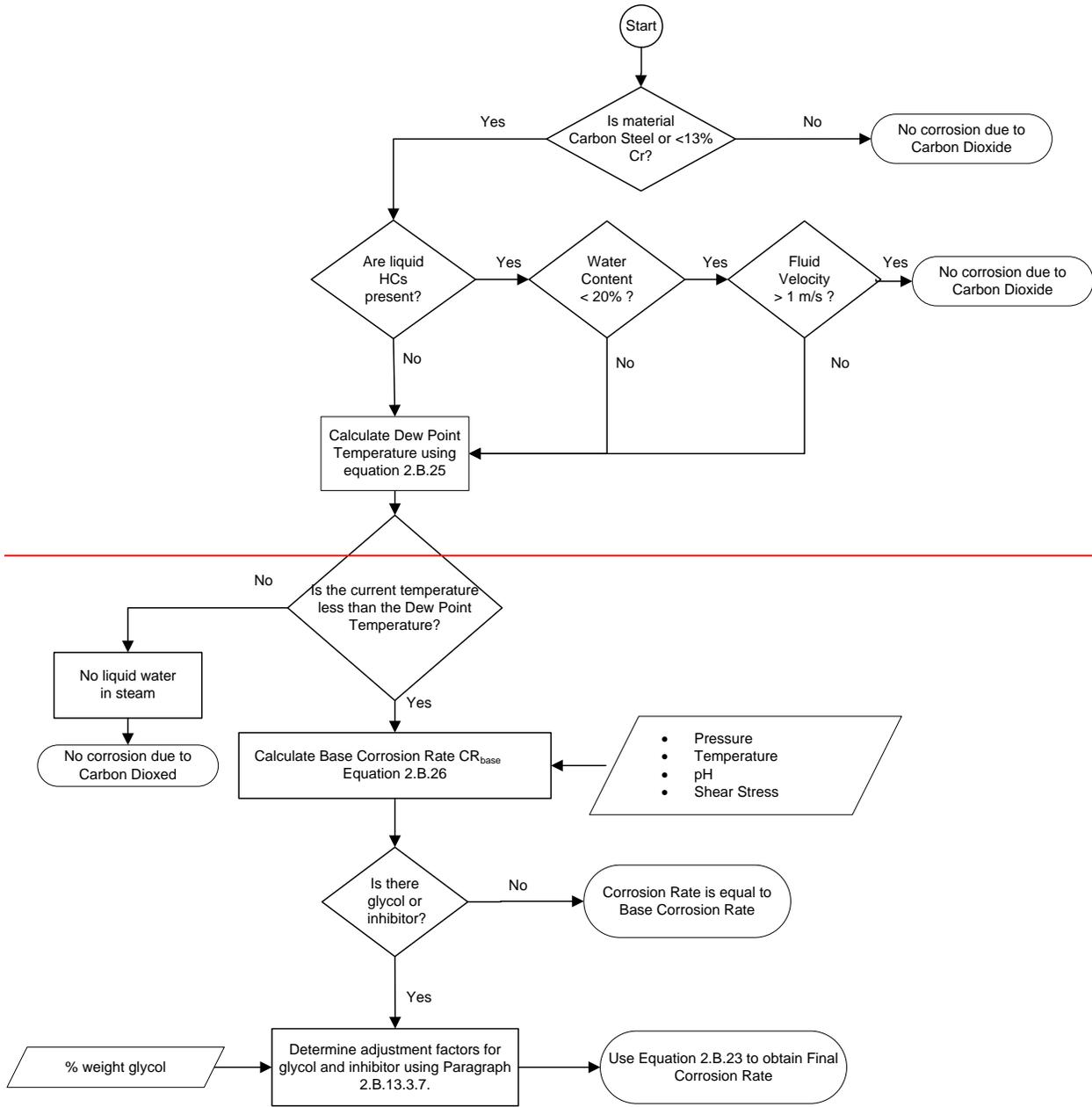
Table 2.B.13.2—pH Temperature Function

Temperature (°F)	pH						
	3.5	4.0	4.5	5.0	5.5	6.0	6.5
68	6.00	5.45	4.9	3.72	2.55	1.55	0.72
86	8.52	7.77	7.02	5.16	3.40	2.00	0.91
104	10.98	10.06	9.13	6.49	4.08	2.30	1.02
122	11.92	10.96	10.01	6.86	4.10	2.20	0.94
140	12.83	11.86	10.89	7.18	4.05	2.03	0.84
158	13.42	12.01	10.6	6.58	3.61	1.86	0.87
176	13.93	12.12	10.31	6.01	3.20	1.70	0.90
194	9.37	7.91	6.45	2.44	0.82	0.49	0.32
212	9.23	8.04	6.38	2.19	0.94	0.62	0.42
230	8.96	8.09	6.22	1.87	1.07	0.77	0.53
248	8.55	8.06	5.98	1.48	1.20	0.92	0.65
266	7.38	6.39	3.98	0.96	0.80	0.63	0.47
284	6.26	4.91	2.31	0.53	0.46	0.39	0.32
302	5.20	3.62	0.98	0.19	0.19	0.19	0.19

Table 2.B.13.2M—pH Temperature Function

Temperature (°C)	pH						
	3.5	4.0	4.5	5.0	5.5	6.0	6.5
20	6.00	5.45	4.9	3.72	2.55	1.55	0.72
30	8.52	7.77	7.02	5.16	3.40	2.00	0.91
40	10.98	10.06	9.13	6.49	4.08	2.30	1.02
50	11.92	10.96	10.01	6.86	4.10	2.20	0.94
60	12.83	11.86	10.89	7.18	4.05	2.03	0.84
70	13.42	12.01	10.6	6.58	3.61	1.86	0.87
80	13.93	12.12	10.31	6.01	3.20	1.70	0.90
90	9.37	7.91	6.45	2.44	0.82	0.49	0.32
100	9.23	8.04	6.38	2.19	0.94	0.62	0.42
110	8.96	8.09	6.22	1.87	1.07	0.77	0.53
120	8.55	8.06	5.98	1.48	1.20	0.92	0.65
130	7.38	6.39	3.98	0.96	0.80	0.63	0.47
140	6.26	4.91	2.31	0.53	0.46	0.39	0.32
150	5.20	3.62	0.98	0.19	0.19	0.19	0.19

2.B.13.6 Figures



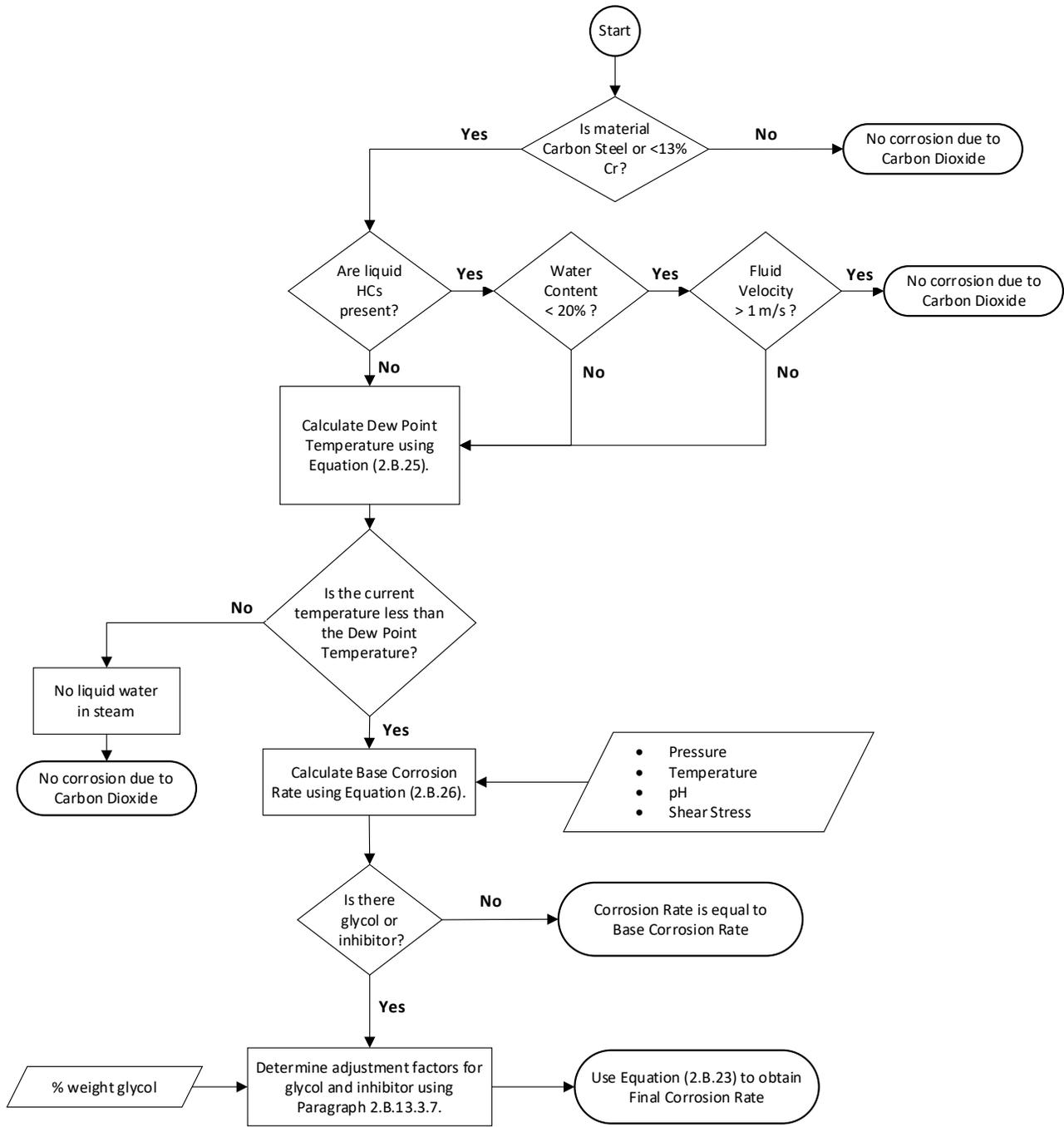


Figure 2.B.13.1—CO₂ Corrosion—Determination of Corrosion Rate

2.B.14 Atmospheric Storage Tank Bottom Corrosion

2.B.14.1 Description of Damage

Corrosion occurs from the product side (internal corrosion) and soil side (external corrosion) of AST bottoms constructed of carbon steel. Product-side corrosion can result in general or localized thinning. Factors affecting product-side corrosion is the stored product corrosivity characteristics, operating temperature, steam coil practices, and the presence of water in the AST. Soil-side corrosion results in localized thinning. Factors affecting soil-side corrosion are soil type, pad type, water draining, CP, AST bottom design, and operating temperature of the process stored.

2.B.14.2 Basic Data

2.B.14.2.1 Soil-Side Corrosion Rate Equation

The data listed in [Table 2.B.14.1](#) are required to determine the estimated corrosion rate for soil-side service. If precise data have not been measured, a knowledgeable corrosion specialist should be consulted.

2.B.14.2.2 Product-Side Corrosion Rate Equation

The data listed in [Table 2.B.14.2](#) are required to determine the estimated corrosion rate for product-side service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.14.3 Determination of Corrosion Rate

2.B.14.3.1 Soil-Side Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.14.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.14.1](#) in conjunction with [Equation \(2.B.37\)](#).

$$CR_S = CR_{SB} \cdot F_{SR} \cdot F_{PA} \cdot F_{TD} \cdot F_{CP} \cdot F_{TB} \cdot F_{ST} \quad (2.B.37)$$

The base soil-side base corrosion rate, CR_{SB} , should be determined based on actual inspection data. If these data are not available, then the base soil-side corrosion rate may be assumed to be 5 mpy (0.13 mm/y). This base corrosion rate is the expected or observed corrosion rate for a typical AST under average conditions (see [Table 2.B.14.3](#)), neither highly susceptible to corrosion nor especially resistant to corrosion.

The adjustment factors in [Equation \(2.B.37\)](#) are determined as described below.

- a) Adjustment Factor for Soil Conditions, F_{SR} —The corrosion rate adjustment factor is given in [Table 2.B.14.4](#). The resistivity of the native soil beneath the AST pad can affect the corrosion rate of the AST bottom. The resistivity of the AST pad material may be higher than the existing surrounding soil. However, corrosive soil beneath the high resistivity AST pad material may contaminate the AST pad fill by capillary action (see API 651, 1997, Section 5.3.1). Therefore, resistivity of the surrounding native soil may be used to determine the likelihood of corrosion on the AST bottom. A common method of measuring soil resistivity is described in ASTM G57. If the soil resistivity is not known, then assume Moderately Corrosive soil (adjustment factor equals 1).

NOTE an adjustment factor of 1 is used for ASTs with RPBs, since RPBs effectively prevent the contamination of the AST pad material by the native soil.

- b) Adjustment Factor for AST Pad, F_{PA} —The corrosion rate adjustment factor is given in [Table 2.B.14.5](#). The type of pad or foundation that the AST rests upon will influence the corrosion rate. The adjustment factors are assigned in a similar manner to those for the native soil beneath the AST pad.

- c) Adjustment Factor for Drainage, F_{TD} —The corrosion rate adjustment factor is given in [Table 2.B.14.6](#). Rainwater collecting around the base of the AST can greatly increase corrosion. The adjustment is made so that storm water collecting around a AST will cause the base corrosion rate to increase by a factor of 2. If the drainage is so poor that more than one-third of the circumference of the bottom edge of the AST is underwater for extended periods of time, then the base corrosion rate is increased by a factor of 3. Good drainage is considered normal, so the multiplier is set to 1 if water does not normally collect around the base of the AST.
- d) Adjust for CP, F_{CP} —The corrosion rate adjustment factor is given in [Table 2.B.14.7](#). CP is one of the primary methods used to avoid corrosion of AST bottoms from the soil side. However, the system must be installed and maintained properly. The factor is established so that the most credit is given for a properly functioning CP system in accordance with API 651, but no penalty is assessed for lack of CP. This assumes that the base corrosion rate is for systems without CP. Unless a High Level inspection can verify that the CP system is effective (verified by inspection in compliance with NACE RP0169 or equivalent), no credit is obtained for the CP system.
- e) Adjust for AST Bottom Type, F_{TB} —The corrosion rate adjustment factor is given in [Table 2.B.14.8](#). ASTs with properly installed RPBs tend to have bottom corrosion rates comparable to those with a single bottom.
- f) Adjustment for Operating Temperature, F_{ST} —The corrosion rate adjustment factor is given in [Table 2.B.14.9](#). The operating temperature of the AST may influence external corrosion.

2.B.14.3.2 Product-Side Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.14.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.14.2](#) in conjunction with [Equation \(2.B.38\)](#).

$$CR_P = CR_{PB} \cdot F_{PC} \cdot F_{PT} \cdot F_{SC} \cdot F_{WD} \quad (2.B.38)$$

The product-side base corrosion rate, CR_{PB} , should be determined based on actual inspection data. If these data are not available, then the base product-side corrosion rate may be assumed to be 2 mpy (0.05 mm/y). The base corrosion rate is founded on the conditions stated in [Table 2.B.14.10](#).

The adjustment factors in [Equation \(2.B.38\)](#) are determined as described below.

- a) Adjustment for Product Condition, F_{PC} —The corrosion rate adjustment factor is given in [Table 2.B.14.11](#). Wet conditions should be used if significant bottom sediments and water are present.
- b) Adjustment for Operating temperature, F_{PT} —The corrosion rate adjustment factor is given in [Table 2.B.14.12](#).
- c) Adjustment for Steam Coil, F_{SC} —The corrosion rate adjustment factor is given in [Table 2.B.14.13](#). If a steam coil heater is present, the internal corrosion rate is adjusted upwards slightly due to extra heat, and the possibility of steam leaks from the internal coil
- d) Adjustment for Water Draw-off, F_{WD} —The corrosion rate adjustment factor is given in [Table 2.B.14.14](#). Water draws, when consistently used, can greatly reduce the damaging effects of water at the bottom of the AST. To receive the full benefit, water must be drawn weekly or after every receipt.

2.B.14.3.3 Combined Atmospheric Storage Tank Floor Corrosion Rate

The internal and external corrosion rates are estimated by multiplying the base corrosion rate by the respective adjustment factors. This will produce two separate corrosion rates that are combined as described below. It is assumed that the soil-side corrosion will be localized in nature while the product-side corrosion will be either generalized or localized. To avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.

- a) Option 1—If the internal corrosion is generalized in nature, the corrosion areas will likely overlap such that the bottom thickness is simultaneously reduced by both internal and external influences. In this case, the internal and external rates are additive.
- b) Option 2—For pitting and localized corrosion, the chances are low that internal and external rates can combine to produce an additive effect on wall loss. In this case, the user chooses the greater of the two corrosion rates as the governing rate for the proceeding step.

2.B.14.4 Nomenclature

CR_P	is the product-side corrosion rate
CR_{PB}	is the product-side base corrosion rate
CR_S	is the soil-side corrosion rate
CR_{SB}	is the soil-side base corrosion rate
F_{CP}	is the soil-side corrosion rate correction factor for CP
F_{PA}	is the soil-side corrosion rate correction factor for AST pad type
F_{PC}	is the product-side corrosion rate correction factor for product condition
F_{PT}	is the product-side corrosion rate correction factor for temperature
F_{SC}	is the soil-side corrosion rate correction factor for temperature
F_{SR}	is the soil-side corrosion rate correction factor for soil conditions
F_{ST}	is the product-side corrosion rate correction factor for temperature
F_{TB}	is the soil-side corrosion rate correction factor for AST bottom type
F_{TD}	is the soil-side corrosion rate correction factor for drainage
F_{WD}	is the product-side corrosion rate correction factor for water draw-off

2.B.14.5 Tables

Table 2.B.14.1—Soil-Side Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Measured or estimated corrosion rate (mpy: mm/y)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 5 mpy (0.13 mm/y).
Soil condition (Ω -cm)	Soil resistivity of native soil underneath and around the AST or dike area. A common method of measuring soil resistivity is described in ASTM G57.
AST pad	The type of AST pad material (soil, sand, etc.) upon which the tank rests. In the case of an AST supported on a ring wall, it is the material used for filling inside the wall.
AST drainage	The effectiveness with which rainwater is drained away from the AST and prevented from collecting under the AST bottom.
CP	The existence of a CP system for the AST bottom, and the proper installation and operation of such a system, based on API 651.
Bottom type	Single bottom or bottom with RPB. The RPB can be a textile or plastic type barrier, or a second floor.
Operating temperature ($^{\circ}$ F: $^{\circ}$ C)	The highest operating temperature expected during operation (considering both normal and unusual operating conditions).

Table 2.B.14.2—Product-Side Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Measured or estimated corrosion rate (mpy)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 2 mpy (0.05 mm/y).
Product-side condition	Dry or wet, wet conditions should be used if significant bottom sediments and water are present.
Operating temperature ($^{\circ}$ F)	The highest operating temperature expected during operation (considering both normal and unusual operating conditions).
AST steam coil heater	Yes or No. If a steam coil heater is utilized, the internal corrosion is adjusted upwards slightly due to extra heat, and the possibility of steam leaks.
Water draws	Water draws when consistently used can greatly reduce the damaging effects of water at the bottom of the AST.

Table 2.B.14.3—Summary of Conditions for Soil-Side Base Corrosion Rate

Factor	Base Corrosion Rate Conditions
Soil resistivity	Moderately corrosive (1000 to 2000 Ω -cm)
AST pad material	Continuous asphalt or concrete
AST drainage	Storm water does not collect around base of AST
CP	None or not functioning
Bottom type	Single bottom
Bulk fluid temperature	Below 75 $^{\circ}$ F (24 $^{\circ}$ C)

Table 2.B.14.4—Soil-Side Soil Resistivity Adjustment Factor

Resistivity (ohm-cm)	Potential Corrosion Activity	Multiplying Factor— F_{SR}
<500	Very corrosive	1.5
500 to 1,000	corrosive	1.25
1,000 to 2,000	Moderately corrosive	1.0
2,000 to 10,000	Mildly corrosive	0.83
>10,000	Progressively less corrosive	0.66
AST with RPB		1.0

Table 2.B.14.5—Soil-Side AST Pad Adjustment Factor

AST Pad Type	Multiplying Factor— F_{PA}
Soil with high salt	1.5
Crushed limestone	1.4
Native soil	1.3
Construction grade sand	1.15
Continuous asphalt	1.0
Continuous concrete	1.0
Oil sand	0.7
High resistivity low chloride sand	0.7

Table 2.B.14.6—Soil-Side AST Drainage Adjustment Factor

AST Drainage Type	Multiplying Factor— F_{TD}
One-third frequently underwater	3
Storm water collects at AST base	2
Storm water does not collect at AST base	1

Table 2.B.14.7—Soil-Side CP Adjustment Factor

CP Type	Multiplying Factor— F_{CP}
None	1.0
Yes not per API 651	0.66
Yes per API 651	0.33

Table 2.B.14.8—Soil-Side AST Bottom Type Adjustment

AST Pad Type	Multiplying Factor— F_{TB}
RPB not per API 650	1.4
RPB per API 650	1.0
Single bottom	1.0

Table 2.B.14.9—Soil-Side Temperature Adjustment

Soil-Side Temperature		Multiplying Factor— F_{ST}
°C	°F	
Temp ≤ 24	Temp ≤ 75	1.0
24 < Temp ≤ 66	75 < Temp ≤ 150	1.1
66 < Temp ≤ 93	150 < Temp ≤ 200	1.3
93 < Temp ≤ 121	200 < Temp ≤ 250	1.4
>121	>250	1.0

Table 2.B.14.10—Summary of Conditions for Product-Side Base Corrosion Rate

Factor	Base Corrosion Rate Conditions
Internal coating	Internal coating not needed for corrosion protection and none applied
Bulk fluid temperature	Below 75 °F (24 °C)
Steam coil heater	No
Water draws	No (water draws conducted neither weekly nor after every receipt)

Table 2.B.14.11—Product-Side Product Condition Adjustment

Product-Side Condition	Multiplying Factor— F_{PC}
Wet	2.5
Dry	1.0

Table 2.B.14.12—Product-Side Temperature Adjustment

Product-Side Temperature		Multiplying Factor— F_{PT}
°C	°F	
Temp ≤ 24	Temp ≤ 75	1.0
24 < Temp ≤ 66	75 < Temp ≤ 150	1.1
66 < Temp ≤ 93	150 < Temp ≤ 200	1.3
93 < Temp ≤ 121	200 < Temp ≤ 250	1.4
>121	>250	1.0

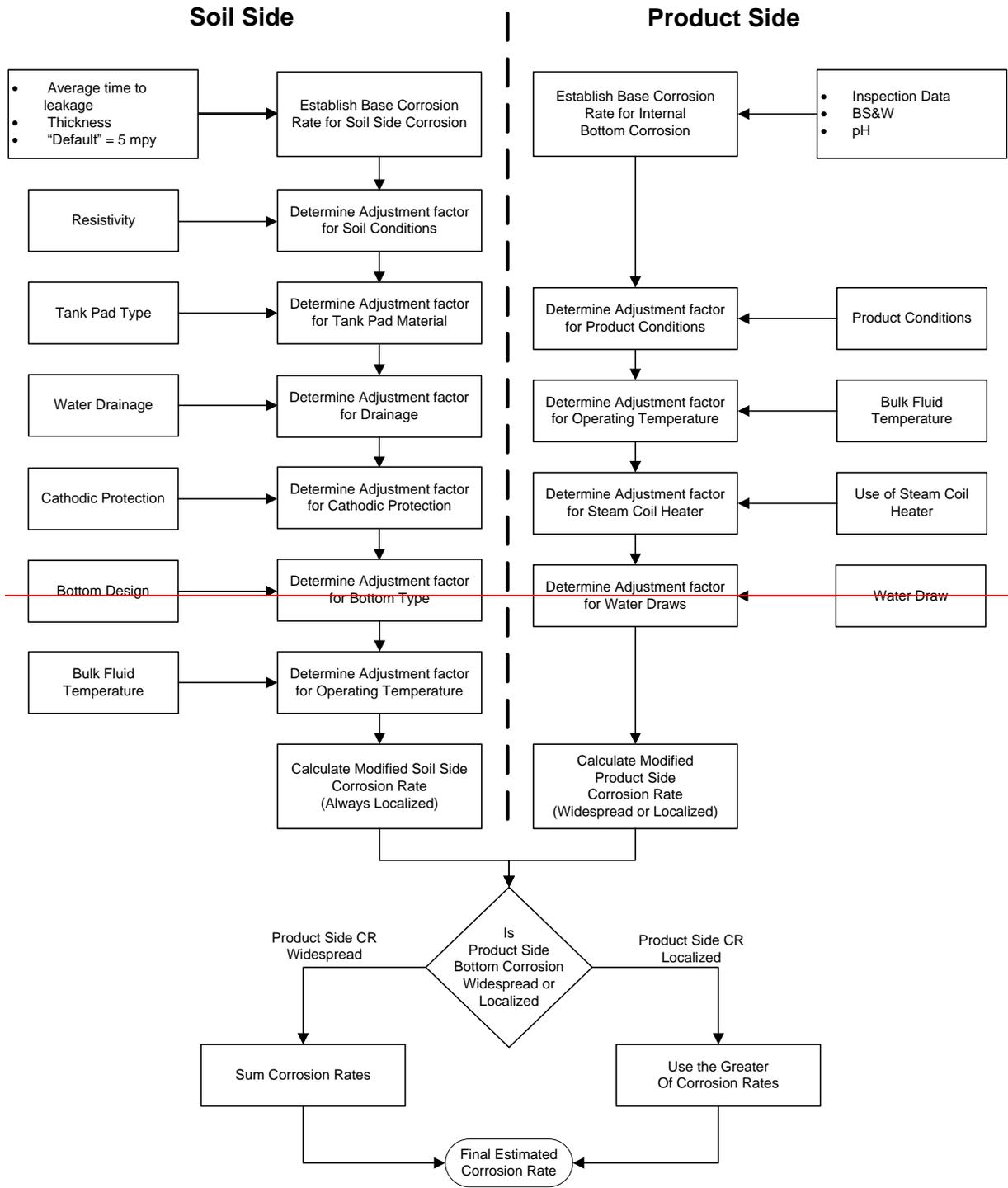
Table 2.B.14.13—Product-Side Steam Coil Adjustment

Steam Coil	Multiplying Factor— F_{SC}
No	1.0
Yes	1.15

Table 2.B.14.14—Product-Side Water Draw-off Adjustment

Water Draw-off	Multiplying Factor—F_{WD}
No	1.0
Yes	0.7

2.B.14.6 Figures



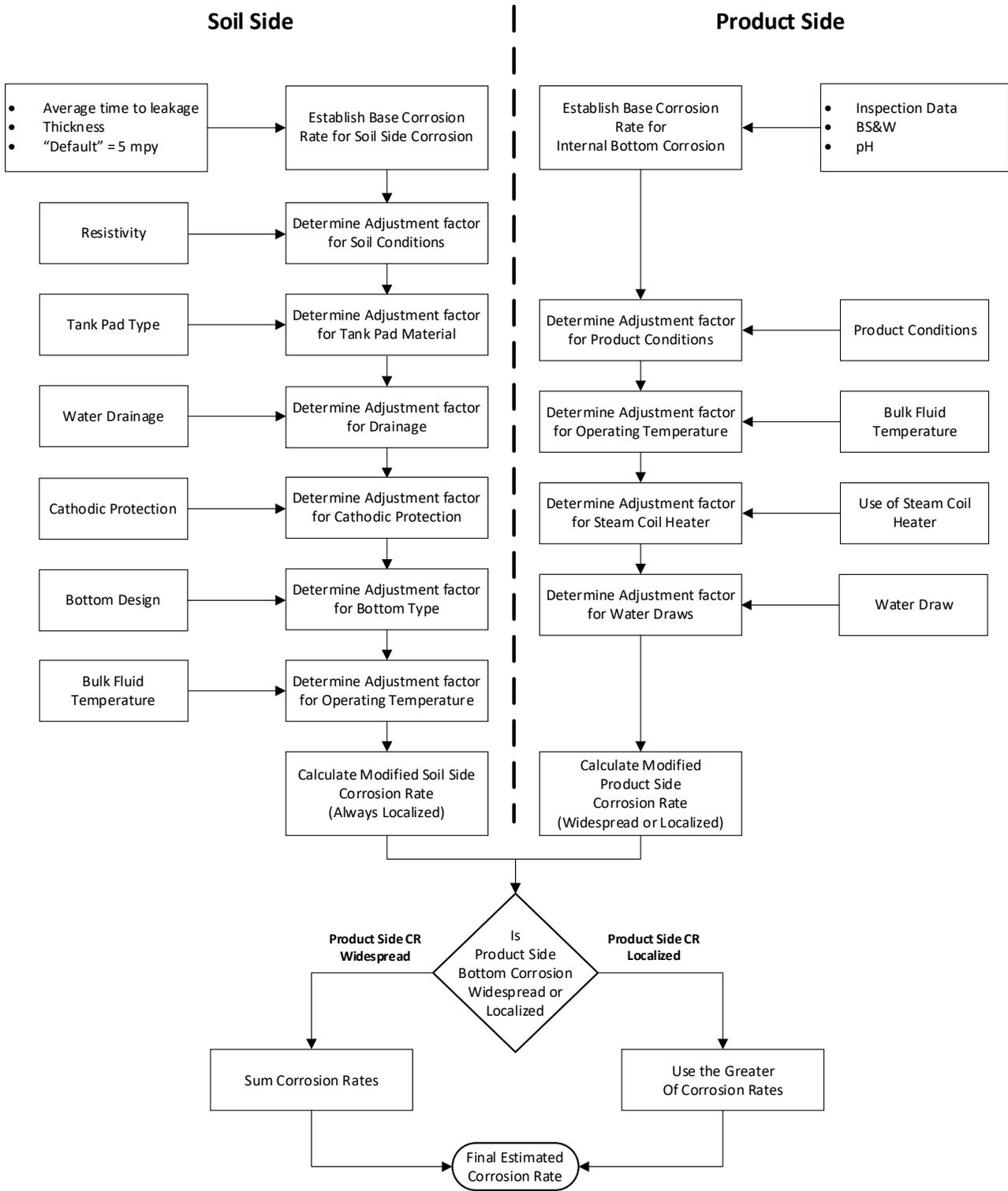


Figure 2.B.14.1—AST Bottom Corrosion—Determination of Soil-Side and Product-Side Corrosion Rates