شناسایی مکانیزم های تخریب در سیستم RBI براساس متدولوژی پتروشیمی جم

شهریور ماه ۱۴۰۳

پتروشیمی کاویان

شناسایی مکانیزم های تخریب در سیستم (RBI)

ردیف	عنوان
۱	مقدمه و شرح مفهوم RBI
۲	هزینه های خوردگی
۳	پیش نیازهای شناسایی مکانیزم های تخریب
۴	محاسبه Damage Factor بر اساس متدولوژی پتروشیمی جم
۵	شناسایی مکانیزم های تخریب API571
۶	شناسایی مکانیزم های تخریب API581
7	مثال هایی از شناسایی مکانیزم های تخریب در محیط استاندارد API581

RBI چیست؟

RBI چیست؟

بازرسی بر مبنای ریسک (RBI) ابزاری مدیریتی جهت تشخیص و اولویت‌بندی ریسک‌های مربوط به سیستم‌های تحت فشار و ارائه برنامه بازرسی بر اساس ریسک‌های محاسبه شده می‌باشد.

هزینه های خوردگی

- هزینه سالانه خوردگی برای صنعت نفت و گاز در ایالات متحده به تنهایی ۲۷ میلیارد دلار برآورد شده است مطابق (NACE International)
- یک مطالعه در کویت که به طور خاص توسط NACE در سال ۲۰۱۶ انجام شد، نشان داد که هزینه خوردگی برای بخش صنعتی این کشور ۱.۲ درصد از تولید ناخالص داخلی است که برابر ۳۴.۲ میلیارد دلار است.
- بر طبق آمارهای وال استریت جورنال هزینه خوردگی در صنعت نفت و گاز حدود ۲ بیلیون دلار است.

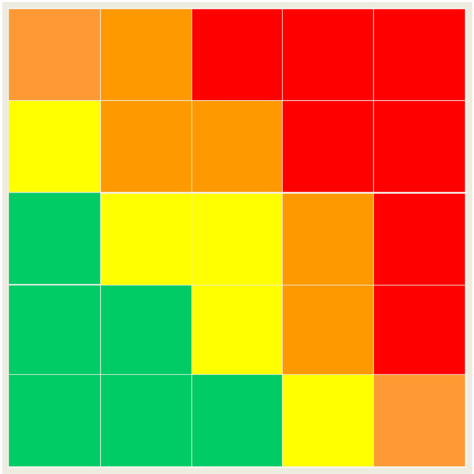
تعریف ریسک

تعریف ریسک

تعریف Failure: نشت سیال

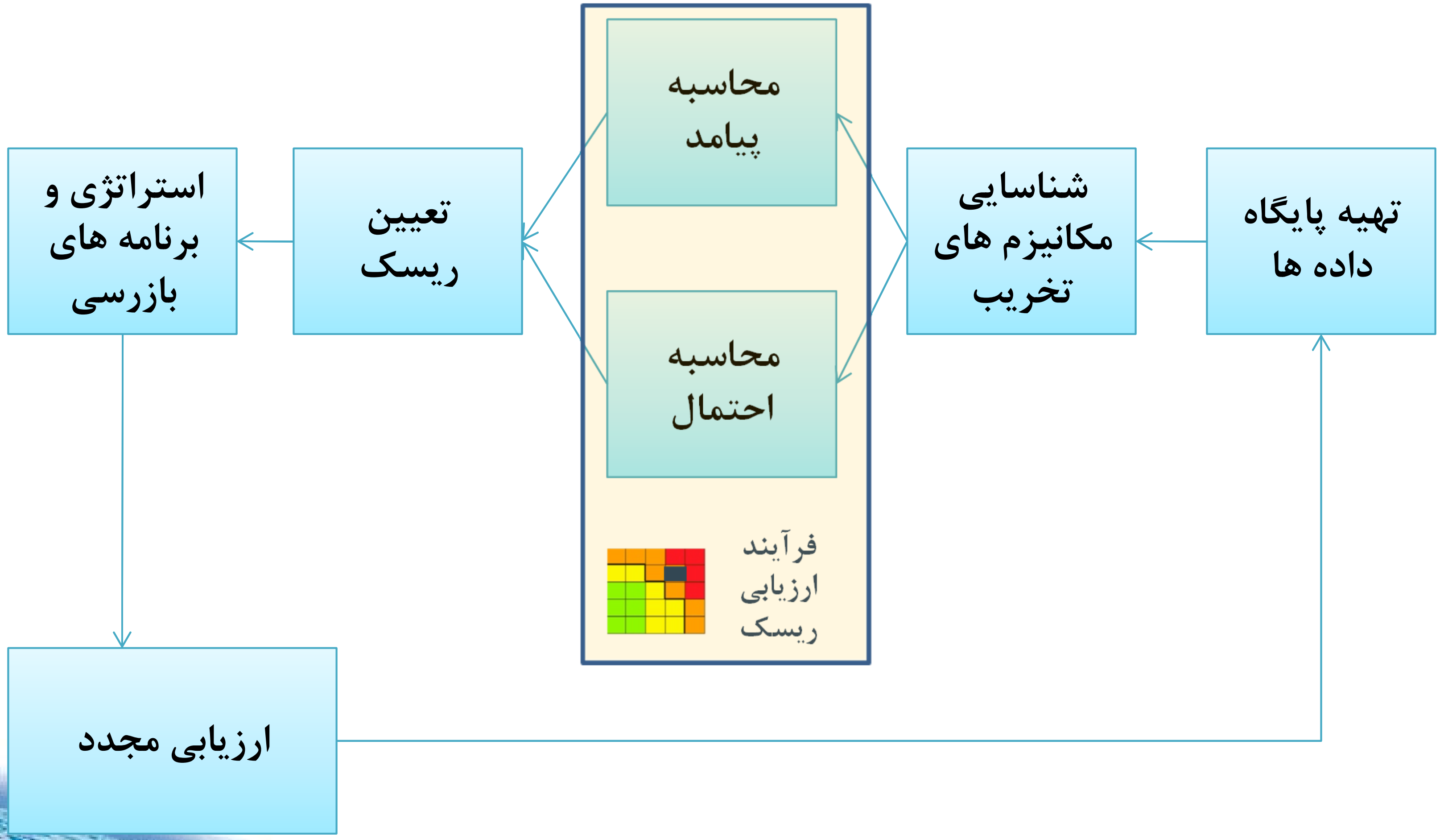
پیامد ازکارافتادگی X احتمال ازکارافتادگی (بر حسب زمان) = ریسک

مکانیزم های تخریب و محاسبه احتمال ازکارافتادگی



محاسبه فاکتور احتمال ازکارافتادگی

مراحل اصلی اجرای پروژه



تهیه پایگاه داده ها

شناسایی مکانیزم های تخریب

محاسبه پیامد

محاسبه احتمال

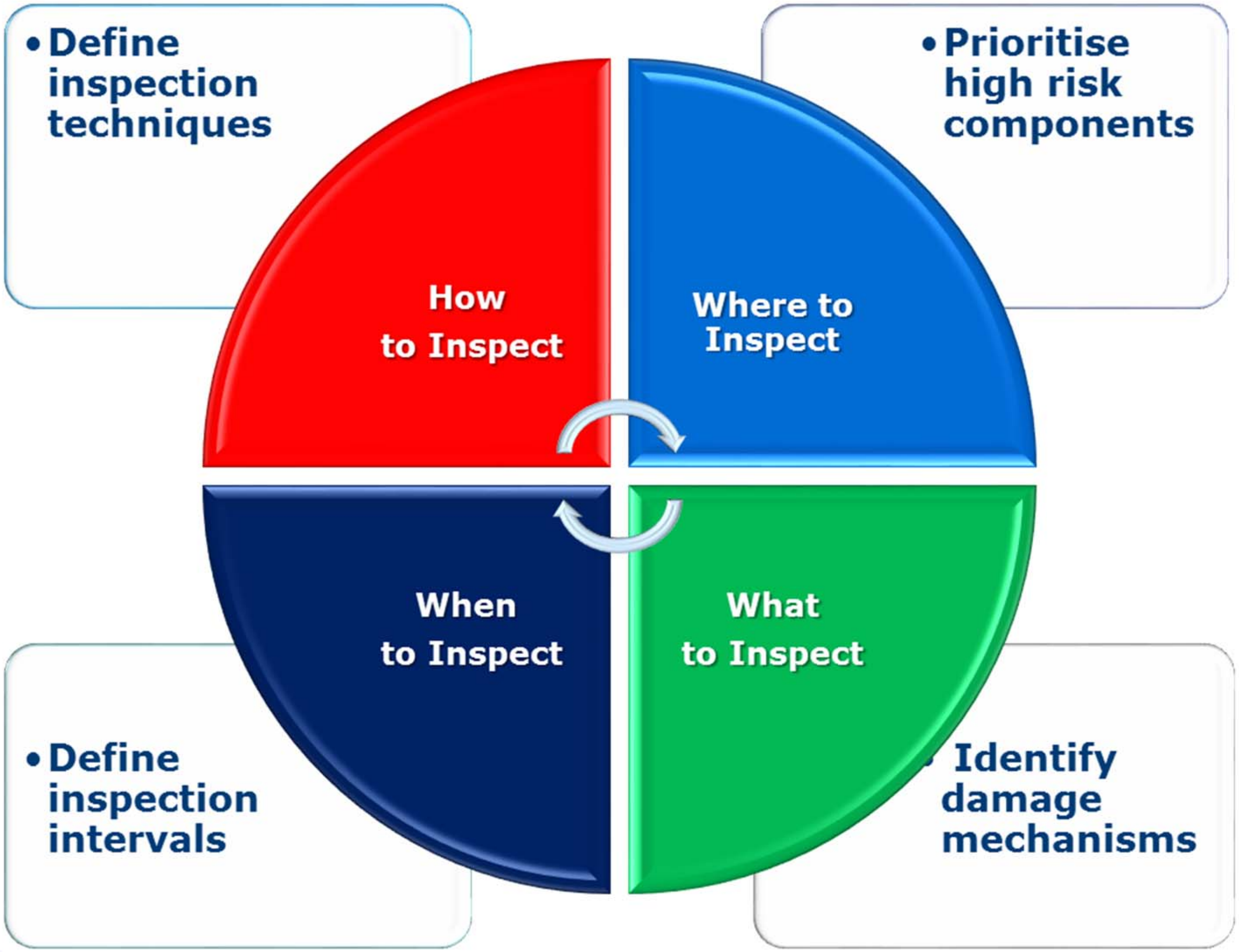
فرآیند ارزیابی ریسک

تعیین ریسک

استراتژی و برنامه های بازرسی

ارزیابی مجدد

برنامه بازرسی



- Define inspection techniques

How to Inspect

Where to Inspect

- Prioritise high risk components

When to Inspect

What to Inspect

- Define inspection intervals

- Identify damage mechanisms

Inspection Plan

- نتایج ارزیابی RBI مبنایی برای نگارش برنامه بازرسی میباشد و پس از تخمین مکانیسم‌های تخریب، تکنیک یا تکنیک‌های خاص مورد نیاز برای شناسایی این مکانیسم‌ها باید شناسایی شوند.
- تیم RBI باید رتبه ریسک، محرک های ریسک، تاریخچه تجهیز، تعداد و نتایج بازرسی، نوع و اثربخشی بازرسی ها، تجهیزات در سرویس مشابه و عمر باقی مانده را در نگارش برنامه بازرسی در نظر بگیرند.
- یک برنامه بازرسی باید شامل پاسخ سوالات زیر باشد:
- ۱) بازرسی در چه زمانی انجام خواهد شد؟ **When to inspect**
- ۲) هدف از انجام بازرسی یافتن چه عیوبی است؟ **What to inspect**
- ۳) چه بخش هایی از تجهیز باید مورد بازرسی قرار گیرد؟ **Where to inspect**
- ۴) از چه روشی برای بازرسی باید استفاده شود؟ **How to inspect**

متدولوژی RBI در پتروشیمی جم

متدهای انجام پروژه RBI

- **Qualitative** (Expert judgment)
- **Semi-Quantitative** (Rule Based)
- **Fully Quantitative** (Probabilistic Logic Models)

Likelihood of Failure (LOF)

Remaining Life Factor (RLF)

Damage Factor (DF)

Inspection Factor (IF)

Condition Factor (CCF)

Process Factor (PF)

Mechanical Design Factor (MDF)

Experimental Factor (EXF)

پیش نیازهای شناسایی مکانیزم های تخریب

- سوابق ضخامت سنجی (محاسبه نرخ خوردگی، محاسبه عمر باقیمانده و تشخیص خوردگی)
- اطلاعات طراحی و ساخت تجهیزات
- اطلاعات فرایندی
- سوابق بازرسی و تخریب تجهیزات
- PFD های مارک شده توسط واحد فرایند
- استفاده از استاندارهای API571 و API581
- استفاده از آنالیزهای آزمایشگاه مرکزی
- استفاده از نفرات با پیش زمینه قوی در زمینه مکانیزم های خوردگی

Remaining Life Factor (RLF)

❖ ۱. Remaining Life Factor (RLF) :

✓ این پارامتر با استفاده از داده های ضخامت سنجی قابل محاسبه است. در صورتی که اطلاعات ضخامت سنجی وجود نداشته باشد، عمر باقیمانده باید با توجه به شرایط تجهیز و مکانیزیم های تخریب فعال تخمین زده شود.

CR=(to-ta)/T   RL= (ta-tmin)/CR

to= original thickness(mm)

ta =last actual thickness(mm)

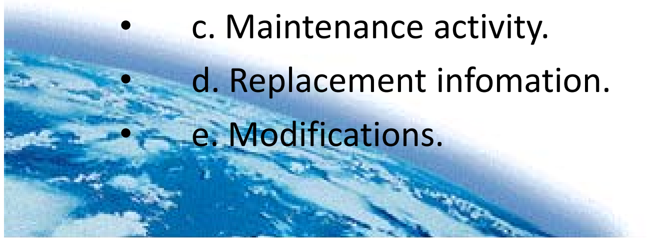
T= time between last thickness measurement and original thickness measurement (year)

tmin= minimum wall thickness(mm) or **tmin= (tn-CA)**

tn = nominal thickness , CA= Corrosion Allowance

The following basic data are necessary to identify most damage mechan

- Design and construction data:
- a. Equipment type (heat, mass, or momentum transfer) and
- function (shell and tube exchanger, trayed distillation column,
- centrifugal pump, etc.).
- b. Material of construction.
- c. Heat treatment.
- d. Thickness.
- Process data, including changes:
- a. Temperam.
- b. Pressure.
- c. Chemical service, including trace components (such as
- chlorides, CNs, ammonium salts, etc.).
- d. Flow rate.
- Equipment history:
- a. Previous inspection data
- b. Failure analysis.
- c. Maintenance activity.
- d. Replacement infomation.
- e. Modifications.



مارک آپ نقشه های PFD توسط واحد فرایند

- مشخص نمودن سيستم هاي حاوي NAOH يا KOH و مشخص نمودن مقدار آن (در صد وزني)
- مشخص نمودن سيستم هاي حاوي H_2S و در صورت وجود آب ، مشخص نمودن مقدار H_2Sدر آب (بر حسب PPM)و نيز PH مربوط به آب
- مشخص نمودن سيستم هاي حاوي آب چه همراه سيال اصلي و چه به صورت مجزا و مشخص نمودن سيستم هايي كه آب در آن ساكن يا LOW FLOW مي باشد.
- مشخص نمودن سيستم هاي حاوي CO_2 و در صورت وجود CO_2 و آب به همراه سيال اصلي مشخص نمودن مقدار CO_2 بر حسب PPM
- مشخص نمودن سيستم هاي حاوي CO
- مشخص نمودن سيستم هاي حاوي Sulfides
- مشخص نمودن سيستم هاي حاوي اكسيژن به صورت Dissolved
- مشخص نمودن سيستم هاي حاوي AMINE و مشخص نمودن تركيبات آمين Fresh Amine, Lean Amine , Rich Amine

مارک آپ نقشه های PFD توسط واحد فرایند

- مشخص نمودن سيستم هاي حاوي رطوبت (به صورت بخار)
- مشخص نمودن سيستم هاي حاوي كلر و مشخص نمودن مقدار آن (بر حسب PPM)
- مشخص نمودن سيالاتي كه احتمال رسوب گذاري در تجهيزات و خطوط پايپينگ در آنها وجود دارد.
- مشخص نمودن سيستم هاي حاوي هيدروژن و در صورت وجود هيدروژن به همراه سيال اصلي مشخص نمودن فشار جزيي آن و در صورت وجود هيدروژن به صورت اتمي مشخص نمودن آن
- مشخص نمودن سيستم هاي حاوي ذرات ساينده
- مشخص نمودن سيستم هاي حاوي پودر
- تعيين سيستم هايي كه به صورت دوفازي مايع -گاز مي باشند.
- مشخص نمودن سيستم هاي حاوي Dissolved salts, Organic compounds or Microbiological activity.
- مشخص نمودن سيستم هاي حاوي اسيدها (به عنوان مثال NH_4HS , HCL , اسيد فسفريك مخصوصا در يونيت هاي پليمري به عنوان كاتاليست و در حضور آب , اسيد سولفوريك و HFو ...) و تعيين PHمربوطه
- مشخص نمودن سيستم هاي حاوي Sour Water

Damage Factor (DF)

❖ ۲. Damage Factor (DF)

✓ اندازه گیری خطر مرتبط با مکانیسم های تخریب فعال یا بالقوه شناخته شده و اولویت بندی بر اساس پتانسیل آنها برای ایجاد یک شکست یا خطر جدی

Logics:

1- If There are known, active damage mechanisms that can cause corrosion cracking in carbon or alloy steels

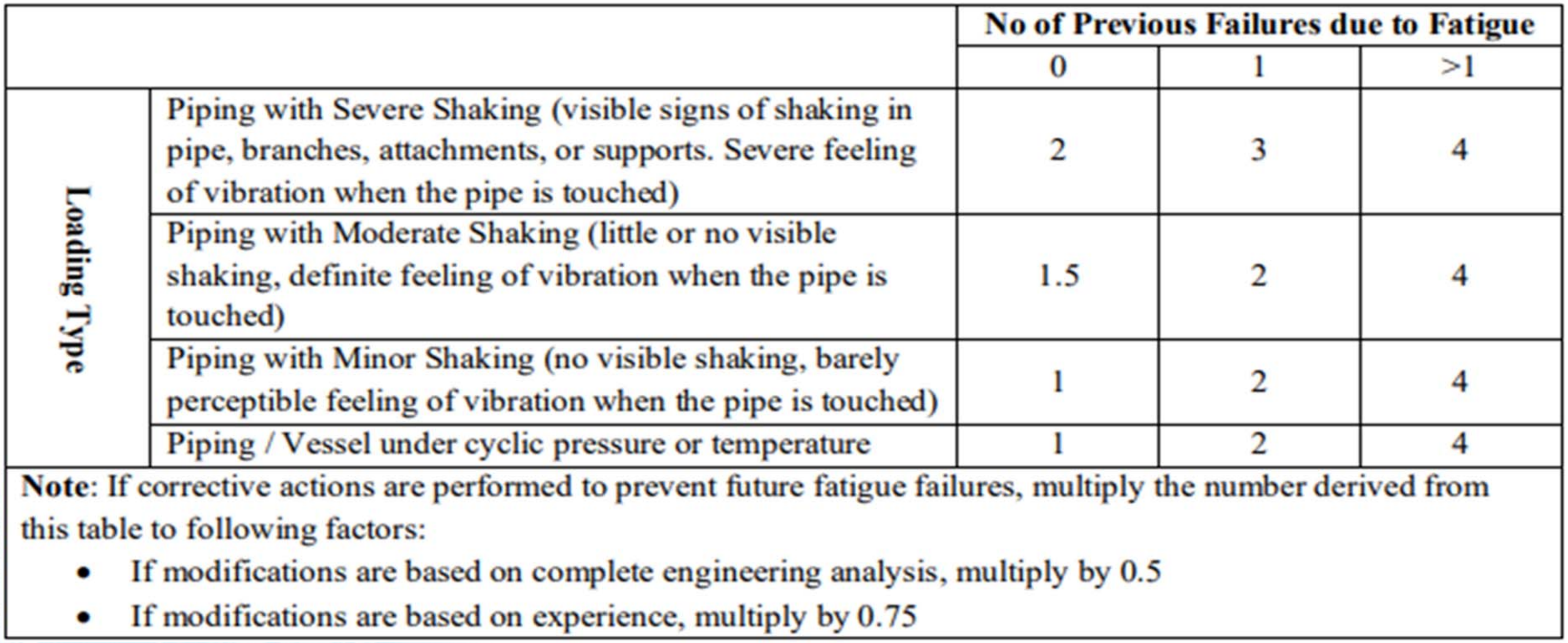
- Susceptibility of material to SCC damage is Low → DF1=2
- Susceptibility of material to SCC damage is Medium → DF1=4
- Susceptibility of material to SCC damage is High → DF1=5
- Susceptibility of material to SCC damage is Unknown → DF1=5

Damage Factor (DF)

2- If There is a potential for catastrophic brittle failure, including carbon steel materials due to low temperature operation or upset conditions, temper embrittlement, or material not adequately qualified by impact testing → DF2=4

3- If There are placed in the equipment/piping system where mechanically thermally-induces fatigue mechanism is active, determine DF3 using Table 1

Table 1: Determination of Fatigue Damage Factor



		No of Previous Failures due to Fatigue		
		0	1	>1
Loading Type	Piping with Severe Shaking (visible signs of shaking in pipe, branches, attachments, or supports. Severe feeling of vibration when the pipe is touched)	2	3	4
	Piping with Moderate Shaking (little or no visible shaking, definite feeling of vibration when the pipe is touched)	1.5	2	4
	Piping with Minor Shaking (no visible shaking, barely perceptible feeling of vibration when the pipe is touched)	1	2	4
	Piping / Vessel under cyclic pressure or temperature	1	2	4

Note: If corrective actions are performed to prevent future fatigue failures, multiply the number derived from this table to following factors:

- If modifications are based on complete engineering analysis, multiply by 0.5
- If modifications are based on experience, multiply by 0.75

Damage Factor (DF)

4-If There is known high temperature hydrogen attack occurring → DF4=3

5-If There is known corrosion cracking of austenitic stainless steels occurring as a result of process,

and

- Susceptibility of material to SCC damage is Low → DF1=1
- Susceptibility of material to SCC damage is Medium → DF1=2
- Susceptibility of material to SCC damage is High → DF1=3
- Susceptibility of material to SCC damage is Unknown → DF1=3

6-If Localized corrosion is occurring → DF6=4

7-If General Corrosion is occurring → DF7=2

Damage Factor (DF)

8-If Creep Damage is known to be occurring in high temperature process, including furnaces and heaters → DF8=1

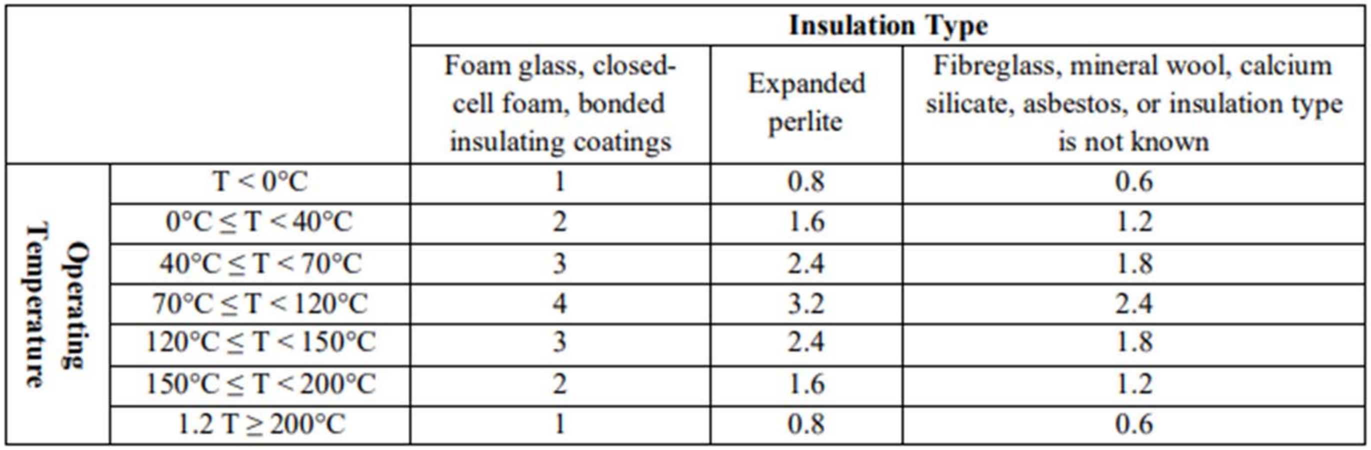
9-If Material degradation is known to be occurring, with such mechanism as sigma phase formation, carburization, spheroidization, etc → DF9=1

10-If the equipment/piping has insulation, and

- Material of Construction is Carbon or Low Alloy Steel, Determine DF10 from Table 2
- Material of Construction is 300 series stainless steel, Determine DF10 from Table 3
- Material of Construction is duplex or super duplex stainless steel, Determine DF10 from Table 4

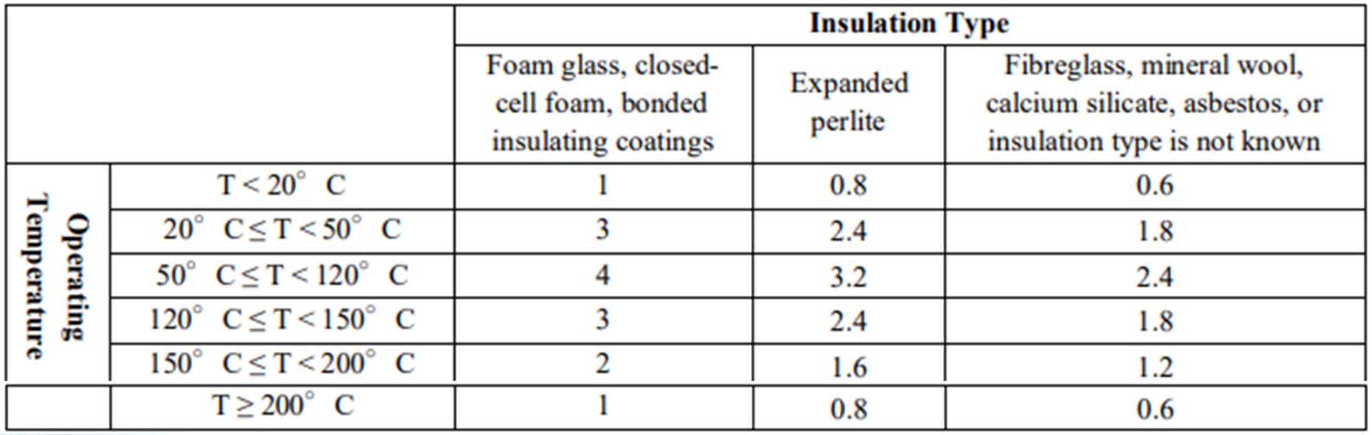
Damage Factor (DF)

Table 2: Corrosion Under Insulation Damage Factor for Carbon and Low Alloy Steels



		Insulation Type		
		Foam glass, closed-cell foam, bonded insulating coatings	Expanded perlite	Fibreglass, mineral wool, calcium silicate, asbestos, or insulation type is not known
Operating Temperature	T < 0°C	1	0.8	0.6
	0°C ≤ T < 40°C	2	1.6	1.2
	40°C ≤ T < 70°C	3	2.4	1.8
	70°C ≤ T < 120°C	4	3.2	2.4
	120°C ≤ T < 150°C	3	2.4	1.8
	150°C ≤ T < 200°C	2	1.6	1.2
	1.2 T ≥ 200°C	1	0.8	0.6

Table 3: Corrosion Under Insulation Damage Factor for 300 Series Austenitic Stainless Steels



		Insulation Type		
		Foam glass, closed-cell foam, bonded insulating coatings	Expanded perlite	Fibreglass, mineral wool, calcium silicate, asbestos, or insulation type is not known
Operating Temperature	T < 20° C	1	0.8	0.6
	20° C ≤ T < 50° C	3	2.4	1.8
	50° C ≤ T < 120° C	4	3.2	2.4
	120° C ≤ T < 150° C	3	2.4	1.8
	150° C ≤ T < 200° C	2	1.6	1.2
	T ≥ 200° C	1	0.8	0.6

Damage Factor (DF)

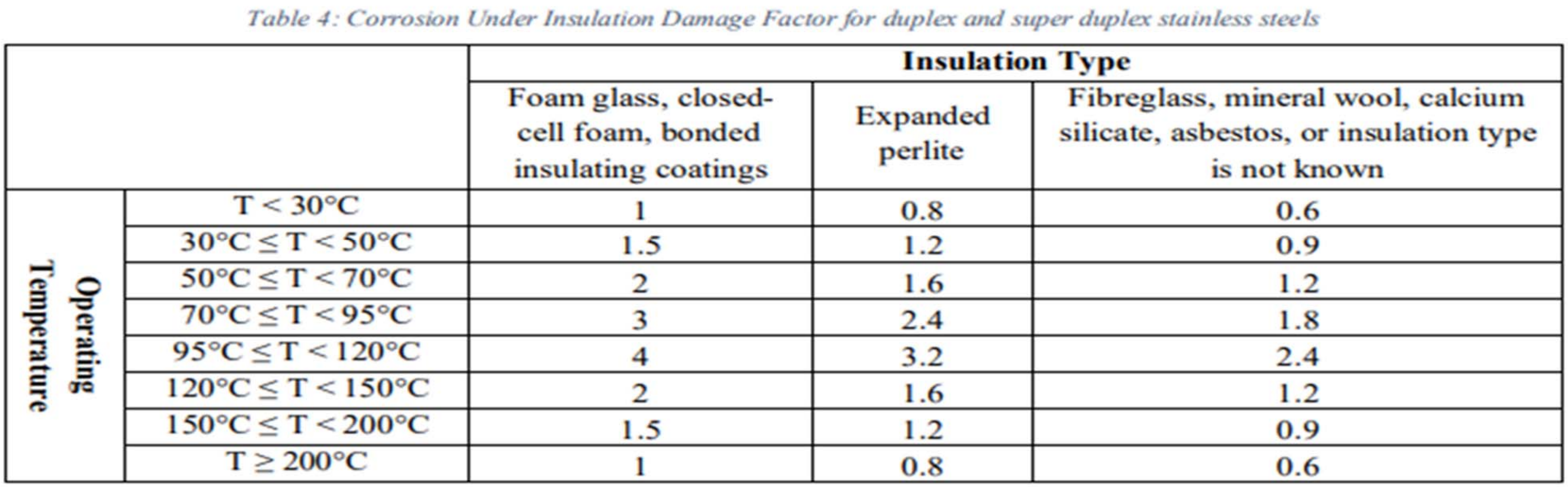


Table 4: Corrosion Under Insulation Damage Factor for duplex and super duplex stainless steels

		Insulation Type		
		Foam glass, closed-cell foam, bonded insulating coatings	Expanded perlite	Fibreglass, mineral wool, calcium silicate, asbestos, or insulation type is not known
Operating Temperature	T < 30°C	1	0.8	0.6
	30°C ≤ T < 50°C	1.5	1.2	0.9
	50°C ≤ T < 70°C	2	1.6	1.2
	70°C ≤ T < 95°C	3	2.4	1.8
	95°C ≤ T < 120°C	4	3.2	2.4
	120°C ≤ T < 150°C	2	1.6	1.2
	150°C ≤ T < 200°C	1.5	1.2	0.9
	T ≥ 200°C	1	0.8	0.6

11-If Other active damage mechanism has been identified → DF11=1

12-If Potential damage mechanism in the equipment/piping system have not been evaluated and are not being periodically reviewed by a qualified material engineer → DF12= 10

The overall DF will be sum of the lines 1 through 12, up to maximum of 30

API 571 : Damage Mechanisms

- **Uniform or Localized Loss of Thickness (Thinning)**
- Galvanic Corrosion
- Atmospheric Corrosion
- Corrosion Under Insulation (CUI)
- Cooling Water Corrosion
- Boiler Water Condensate Corrosion
- CO2 Corrosion
- Flue Gas Dew Point Corrosion
- Microbiologically Induced Corrosion (MIC)
- Soil Corrosion
- Caustic Corrosion
- Dealloying
- Graphitic Corrosion
- Amine Corrosion
- Ammonium Bisulfide Corrosion (Alkaline Sour Water)
- Ammonium Chloride Corrosion
- Hydrochloric Acid (HCl) Corrosion
- High Temp H2/H2S Corrosion
- Hydrofluoric (HF) Acid Corrosion
- Naphthenic Acid Corrosion (NAC)
- Phenol (Carbonic Acid) Corrosion
- Phosphoric Acid Corrosion
- Sour Water Corrosion (Acidic)
- Sulfuric Acid Corrosion

Mechanical and Metallurgical Failure Mechanisms

- Graphitization
- Softening (Spheroidization)
- Temper Embrittlement
- Strain Aging
- 885oF Embrittlement
- Sigma Phase Embrittlement
- Brittle Fracture
- Creep / Stress Rupture
- Thermal Fatigue
- Short Term Overheating – Stress Rupture
- Steam Blanketing
- Dissimilar Metal Weld (DMW) Cracking
- Thermal Shock
- Erosion / Erosion-Corrosion
- Cavitation
- Mechanical Fatigue
- Vibration-Induced Fatigue
- Refractory Degradation
- Reheat Cracking

- **Environment – Assisted Cracking**
- Chloride Stress Corrosion Cracking (Cl–SCC)
- Corrosion Fatigue
- Caustic Stress Corrosion Cracking (Caustic Embrittlement)
- Ammonia Stress Corrosion Cracking
- Liquid Metal Embrittlement (LME)
- Hydrogen Embrittlement (HE)
- Polythionic Acid Stress Corrosion Cracking (PASCC)
- Amine Stress Corrosion Cracking
- Wet H2S Damage (Blistering / HIC / SOHIC / SCC)
- Hydrogen Stress Cracking – HF
- Carbonate Stress Corrosion Cracking
- Ethanol/methanol Stress Corrosion Cracking

- **High Temperature Corrosion [400oF (204oC)]**

- Oxidation
- Sulfidation
- Carburization
- Decarburization
- Metal Dusting
- Fuel Ash Corrosion
- Nitriding

- **Other Mechanisms**
- High Temperature Hydrogen Attack (HTHA)
- Titanium Hydriding

Damage types

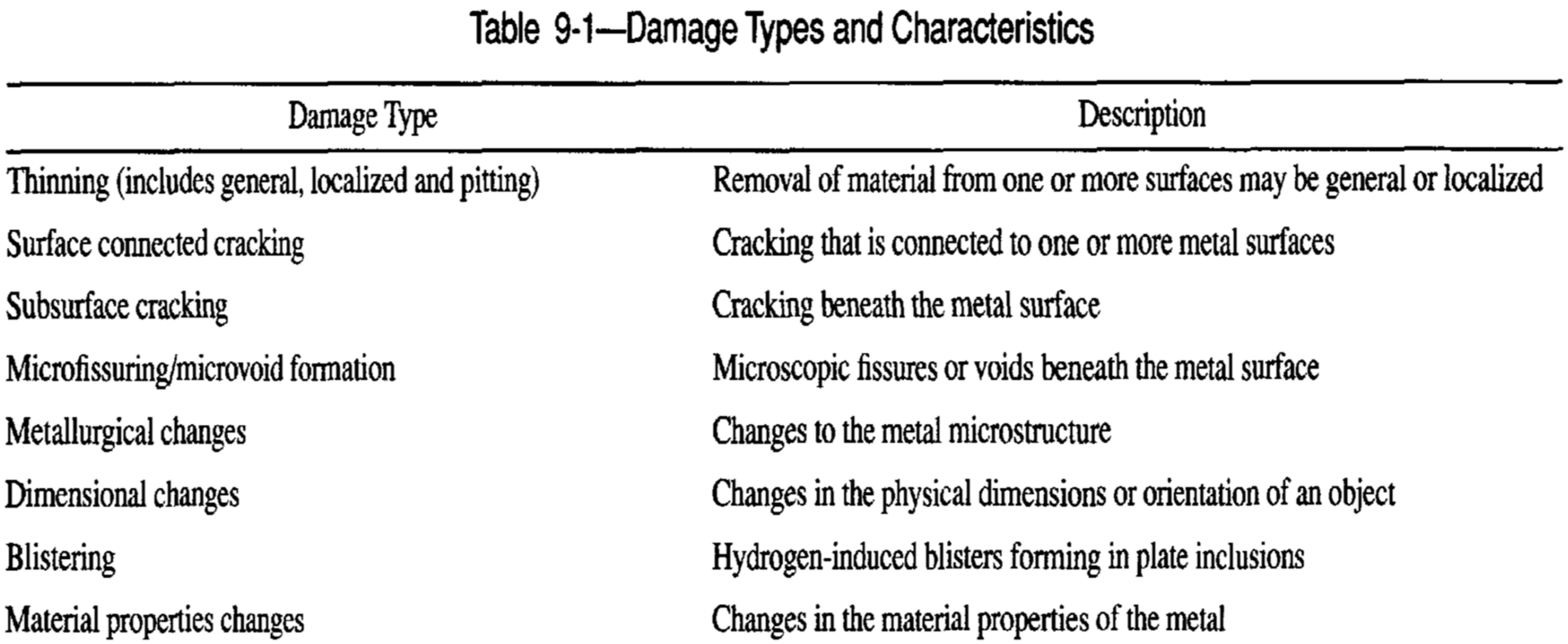


Table 9-1—Damage Types and Characteristics

Damage Type	Description
Thinning (includes general, localized and pitting)	Removal of material from one or more surfaces may be general or localized
Surface connected cracking	Cracking that is connected to one or more metal surfaces
Subsurface cracking	Cracking beneath the metal surface
Microfissuring/microvoid formation	Microscopic fissures or voids beneath the metal surface
Metallurgical changes	Changes to the metal microstructure
Dimensional changes	Changes in the physical dimensions or orientation of an object
Blistering	Hydrogen-induced blisters forming in plate inclusions
Material properties changes	Changes in the material properties of the metal

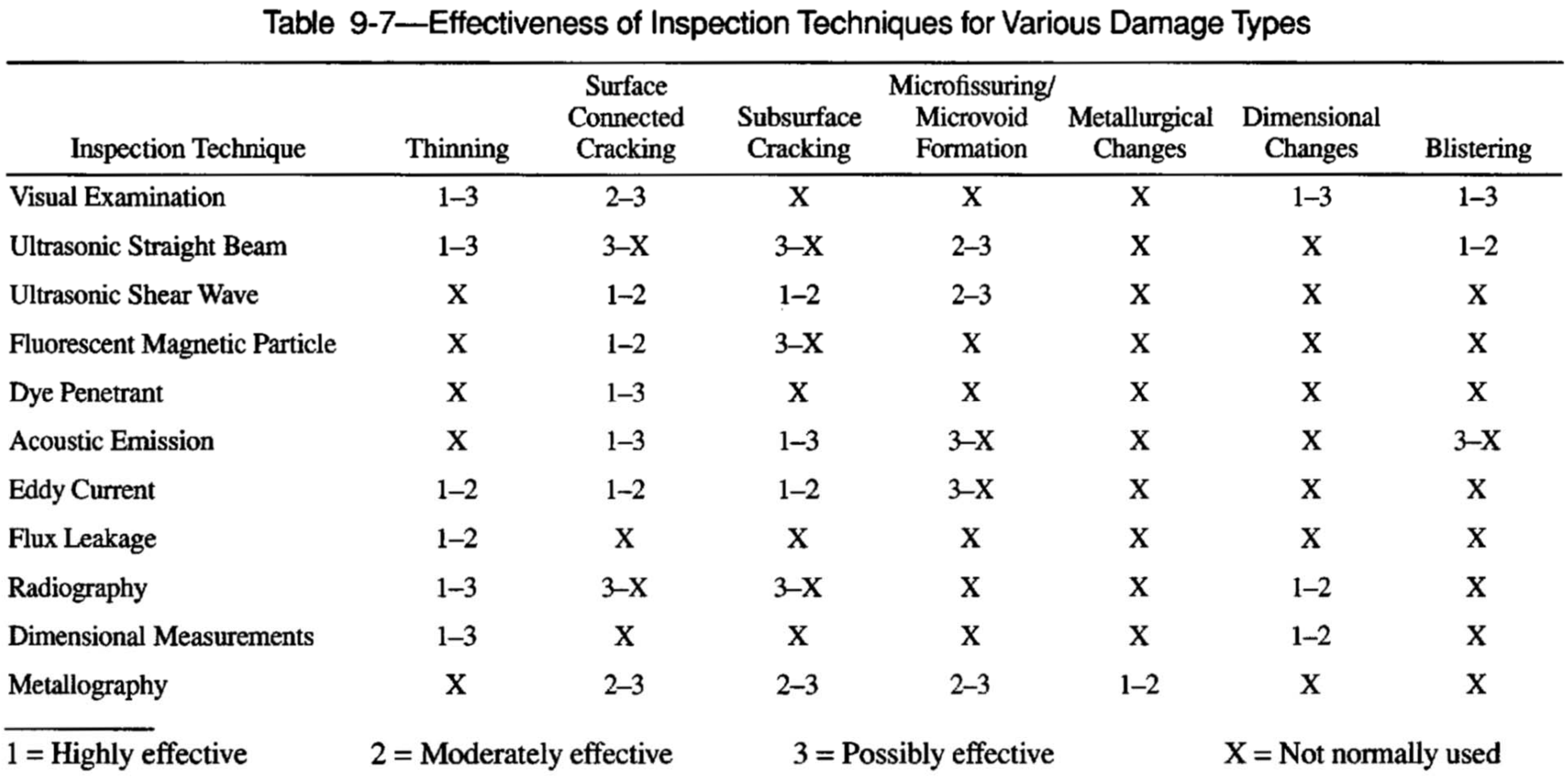


Table 9-7—Effectiveness of Inspection Techniques for Various Damage Types

Inspection Technique	Thinning	Surface Connected Cracking	Subsurface Cracking	Microfissuring/ Microvoid Formation	Metallurgical Changes	Dimensional Changes	Blistering
Visual Examination	1–3	2–3	X	X	X	1–3	1–3
Ultrasonic Straight Beam	1–3	3–X	3–X	2–3	X	X	1–2
Ultrasonic Shear Wave	X	1–2	1–2	2–3	X	X	X
Fluorescent Magnetic Particle	X	1–2	3–X	X	X	X	X
Dye Penetrant	X	1–3	X	X	X	X	X
Acoustic Emission	X	1–3	1–3	3–X	X	X	3–X
Eddy Current	1–2	1–2	1–2	3–X	X	X	X
Flux Leakage	1–2	X	X	X	X	X	X
Radiography	1–3	3–X	3–X	X	X	1–2	X
Dimensional Measurements	1–3	X	X	X	X	1–2	X
Metallography	X	2–3	2–3	2–3	1–2	X	X

1 = Highly effective 2 = Moderately effective 3 = Possibly effective X = Not normally used

Table 9-2—Corrosion Damage Mechanisms

Damage Mechanism	
HCl corrosion	Corrosion under insulation/fireproofing
Organic chlorides corrosion	Cooling water corrosion
Inorganic chlorides corrosion	Atmospheric corrosion
Organic sulfur corrosion	Soil corrosion
H_2/H_2S Sulfidation	High temperature oxidation
CO_2 corrosion	Hot corrosion
Naphthenic acid corrosion	Flue gas corrosion
Sour water corrosion	Dealloying
Sulfuric acid corrosion	Galvanic corrosion
Hydrofluoric acid corrosion	Crevice/underdeposit corrosion
Phenol/NMP corrosion	Biological corrosion
Phosphoric acid corrosion	Injection point corrosion
Caustic corrosion	Boiler water/condensate corrosion
Ammonia corrosion	Flue gas dewpoint corrosion
Chlorine/sodium hypochlorite corrosion	

Note: All of the following damage mechanisms relate to thinning of metals by corrosion. The damage type for all of these mechanisms is thinning.

Table 9-3—Stress Corrosion Cracking Damage Mechanisms

Damage Mechanism
Amine
Ammonia
Caustic
Carbonate
Chloride
Polythionic acid
Liquid metal embrittlement
Hydrofluoric acid
Corrosion fatigue

Note: All of the following damage mechanisms relate to surface connected cracking of metals.

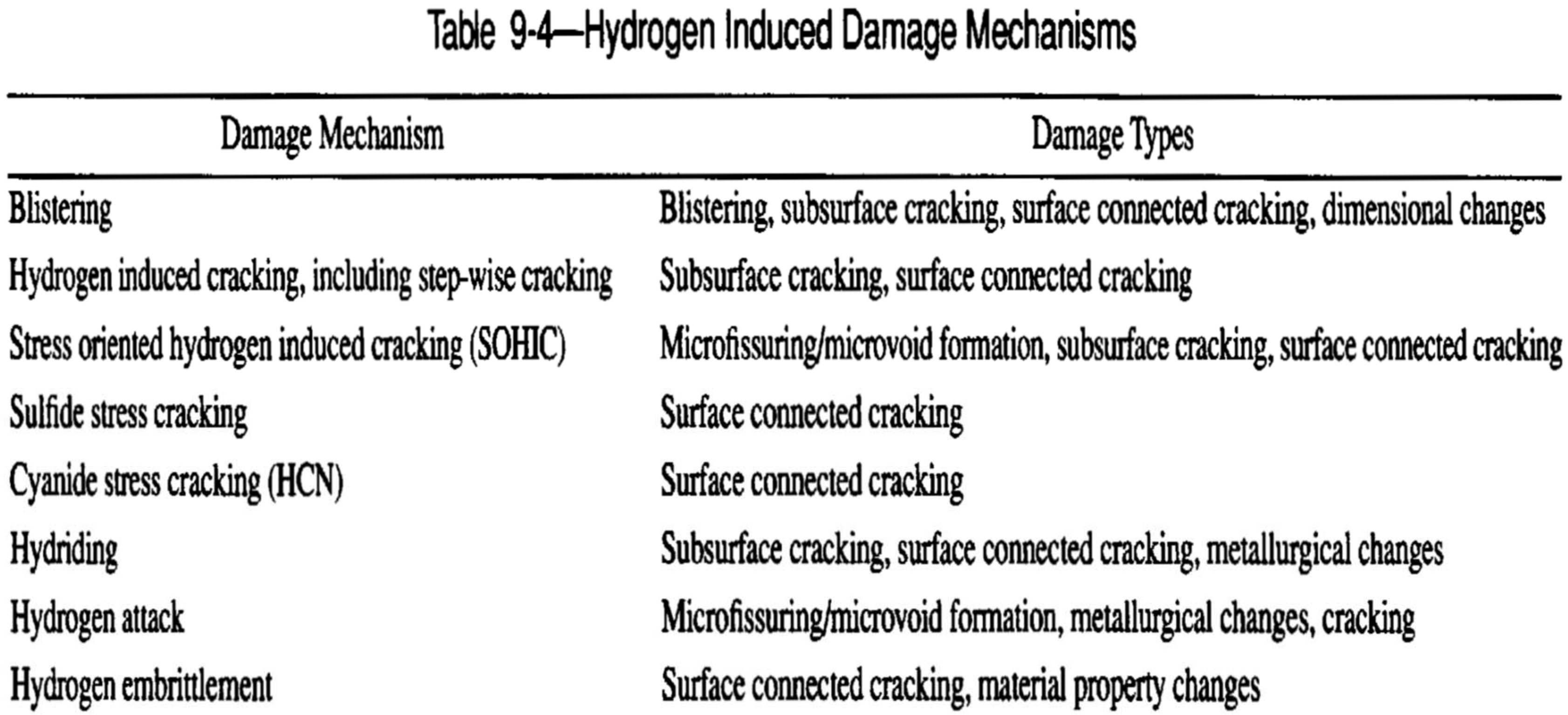


Table 9-4—Hydrogen Induced Damage Mechanisms

Damage Mechanism	Damage Types
Blistering	Blistering, subsurface cracking, surface connected cracking, dimensional changes
Hydrogen induced cracking, including step-wise cracking	Subsurface cracking, surface connected cracking
Stress oriented hydrogen induced cracking (SOHIC)	Microfissuring/microvoid formation, subsurface cracking, surface connected cracking
Sulfide stress cracking	Surface connected cracking
Cyanide stress cracking (HCN)	Surface connected cracking
Hydriding	Subsurface cracking, surface connected cracking, metallurgical changes
Hydrogen attack	Microfissuring/microvoid formation, metallurgical changes, cracking
Hydrogen embrittlement	Surface connected cracking, material property changes

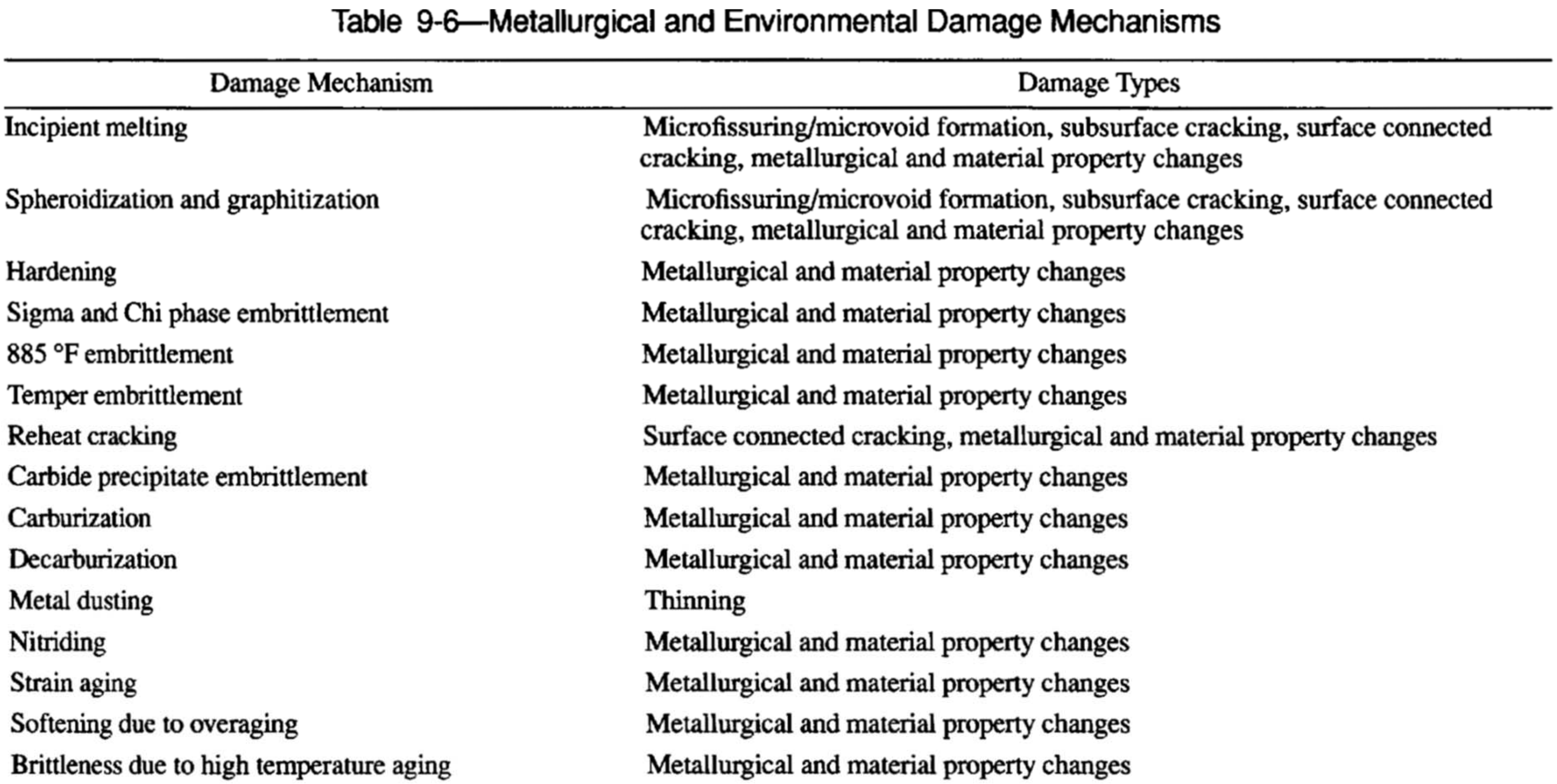


Table 9-6—Metallurgical and Environmental Damage Mechanisms

Damage Mechanism	Damage Types
Incipient melting	Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical and material property changes
Spheroidization and graphitization	Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical and material property changes
Hardening	Metallurgical and material property changes
Sigma and Chi phase embrittlement	Metallurgical and material property changes
885 °F embrittlement	Metallurgical and material property changes
Temper embrittlement	Metallurgical and material property changes
Reheat cracking	Surface connected cracking, metallurgical and material property changes
Carbide precipitate embrittlement	Metallurgical and material property changes
Carburization	Metallurgical and material property changes
Decarburization	Metallurgical and material property changes
Metal dusting	Thinning
Nitriding	Metallurgical and material property changes
Strain aging	Metallurgical and material property changes
Softening due to overaging	Metallurgical and material property changes
Brittleness due to high temperature aging	Metallurgical and material property changes

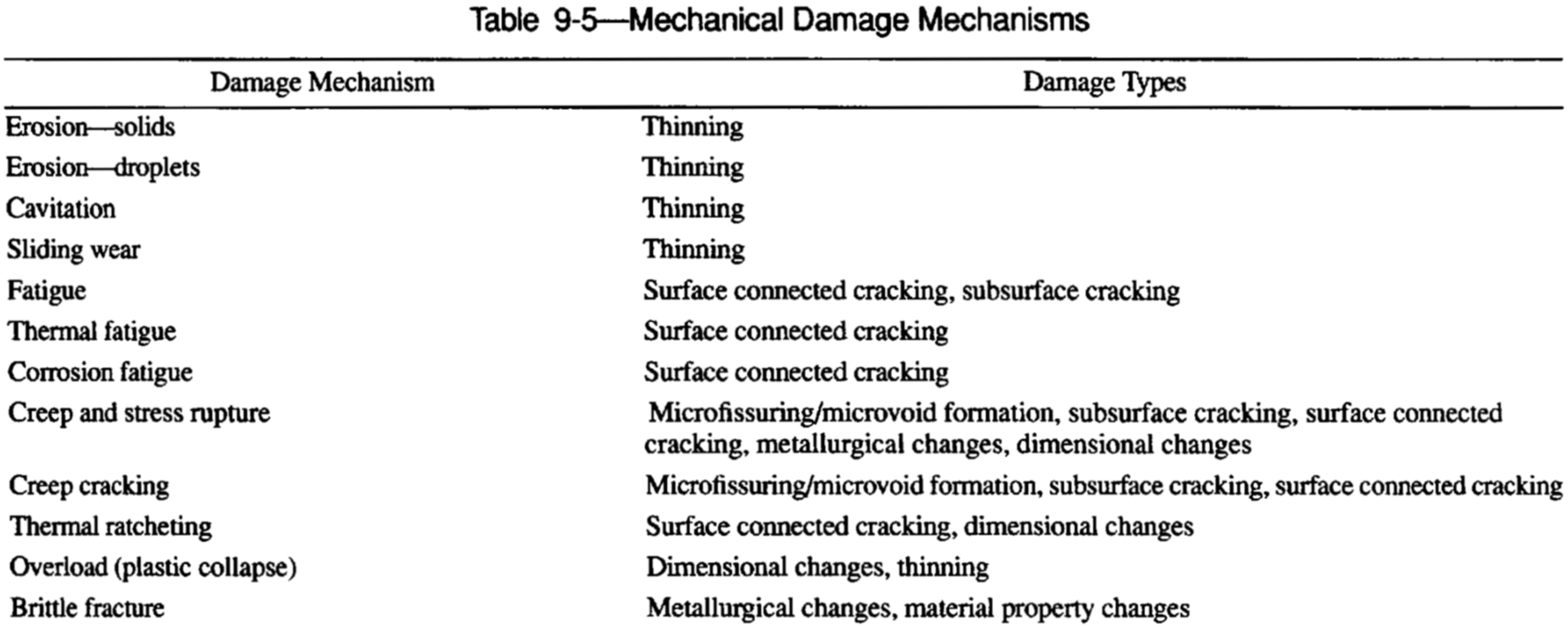


Table 9-5—Mechanical Damage Mechanisms

Damage Mechanism	Damage Types
Erosion—solids	Thinning
Erosion—droplets	Thinning
Cavitation	Thinning
Sliding wear	Thinning
Fatigue	Surface connected cracking, subsurface cracking
Thermal fatigue	Surface connected cracking
Corrosion fatigue	Surface connected cracking
Creep and stress rupture	Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical changes, dimensional changes
Creep cracking	Microfissuring/microvoid formation, subsurface cracking, surface connected cracking
Thermal ratcheting	Surface connected cracking, dimensional changes
Overload (plastic collapse)	Dimensional changes, thinning
Brittle fracture	Metallurgical changes, material property changes

تقسیم بندی مکانیزم های تخریب جهت محاسبه DF براساس API581

1. Thinning (General & local)— Dthin .

2. STRESS CORROSION CRACKING (SCC) DF— *Dscc*

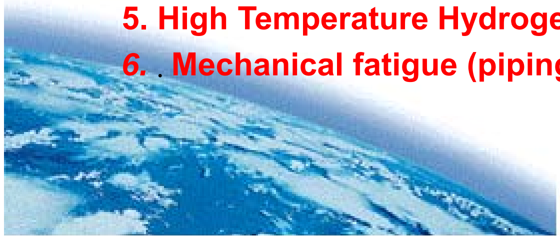
- Amine Stress Corrosion Cracking SCC
- Caustic Stress Corrosion Cracking SCC
- Sulfide Stress Cracking (SSC)
- Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced (HIC/SOHIC-H2S)
- Alkaline Carbonate Stress Corrosion Cracking (ACSCC)
- Polythionic Acid Stress Corrosion Cracking (PASCC)
- Chloride Stress Corrosion Cracking (ClSCC)
- Hydrogen Stress Cracking in Hydrofluoric Acid (HSC-HF)
- Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking in Hydrofluoric Acid Services (HIC/SOHIC-HF)

3. External damage — *Dextd*

- External Corrosion DF—Ferritic Component
- Corrosion Under Insulation (CUI) DF—Ferritic Component
- External Chloride Stress Corrosion Cracking (ExtClSCC) DF—Austenitic Component
- External CUI ClSCC DF—Austenitic Component

4. Brittle fracture— *Dbrit*

- Brittle Fracture
- Sigma Phase Embrittlement DF
- Low Alloy Steel Embrittlement Damage Factor
- 885 °F Embrittlement DF



5. High Temperature Hydrogen Attack HTHA— Dhtha .

6. . Mechanical fatigue (piping only)— Dmfat .

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

DF Calculations

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

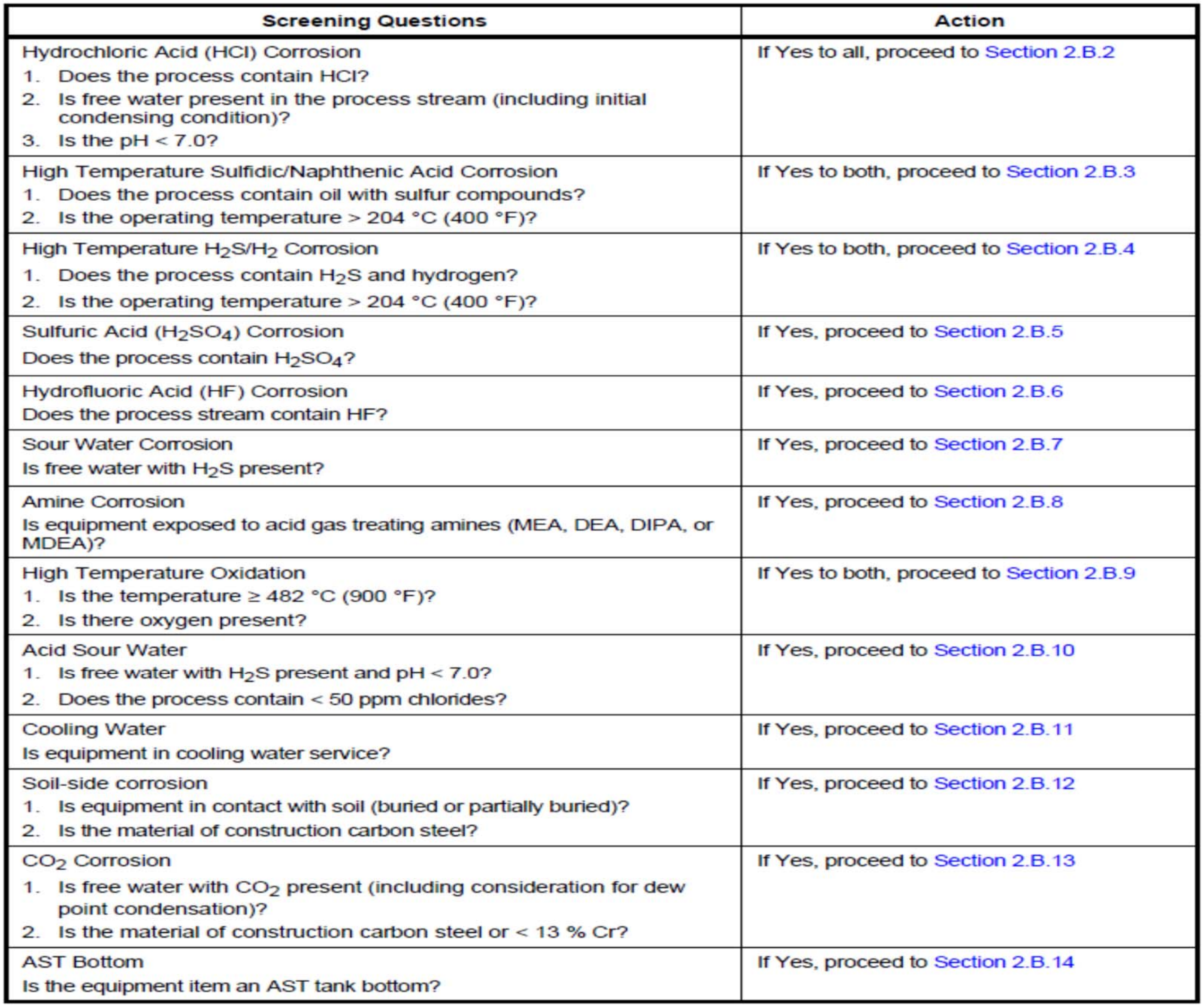
$$D_{f-total} = \max\left[D_{f-gov}^{thin},\ D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

$$D_{f-gov}^{scc} = \max\left[\begin{array}{l} D_f^{caustic},\ D_f^{amine},\ D_f^{ssc},\ D_f^{HIC/SOHIC-H_2S},\ D_f^{ACSCC}, \\ D_f^{PASCC},\ D_f^{CLSCC},\ D_f^{HSC-HF},\ D_f^{HIC/SOHIC-HF} \end{array}\right]$$

$$D_{f-gov}^{brit} = \max\left[\left(D_f^{brit} + D_f^{tempe}\right),\ D_f^{885F},\ D_f^{sigma}\right]$$

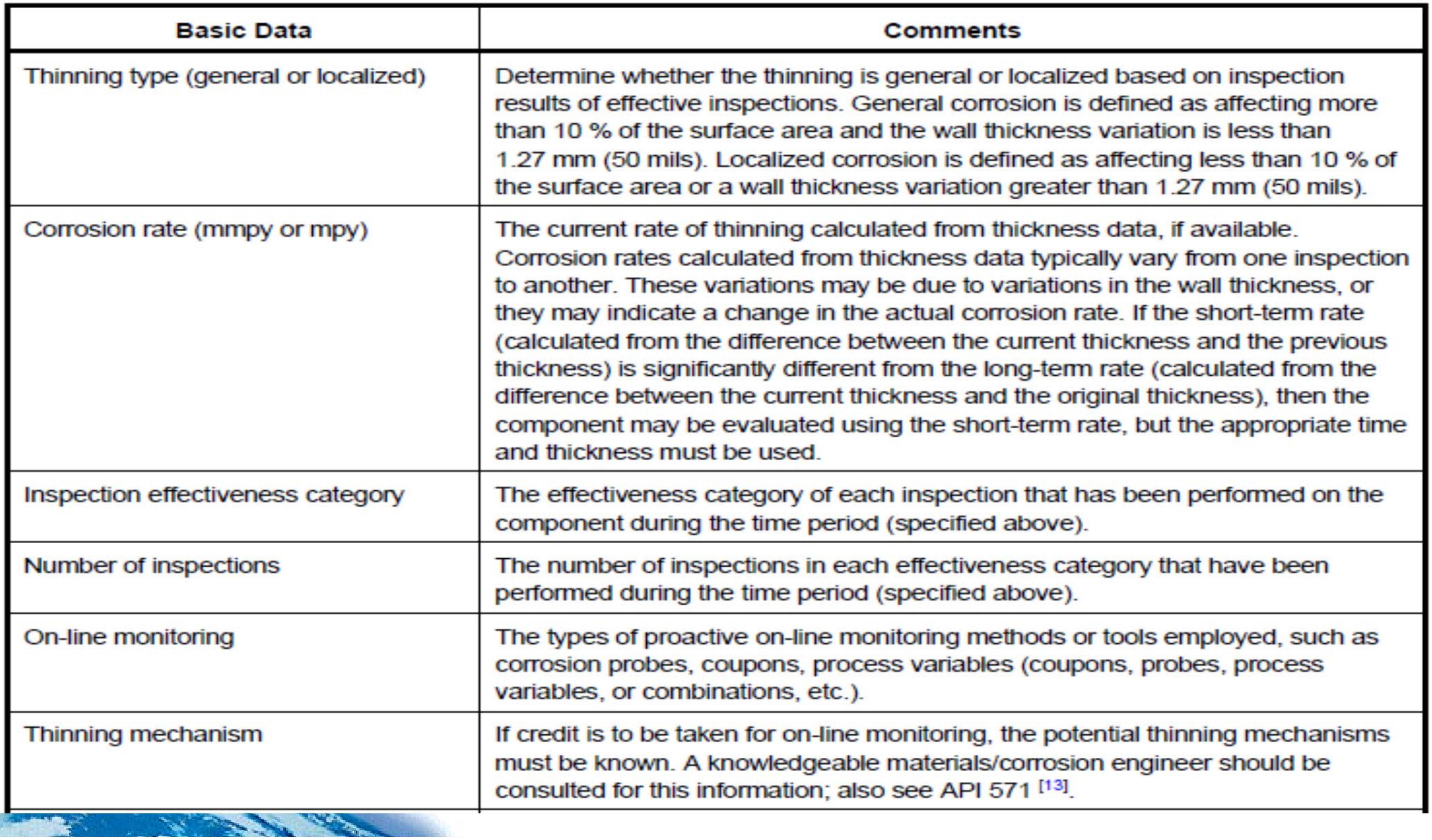
$$D_{f-gov}^{extd} = \max\left[D_f^{extf},\ D_f^{CUIF},\ D_f^{ext-CLSCC},\ D_f^{CUI-CLSCC}\right]$$

Thininng

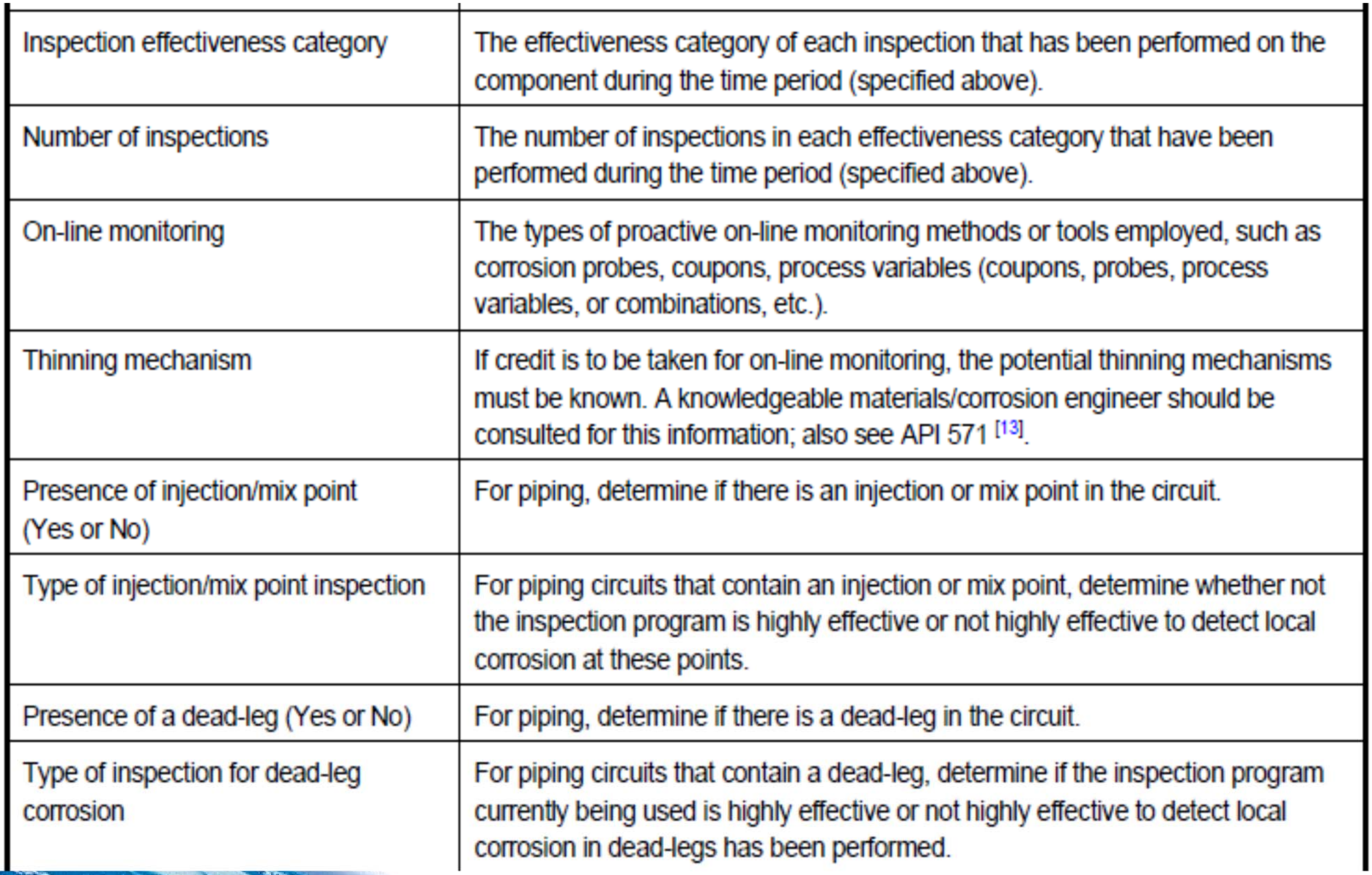


Screening Questions	Action
Hydrochloric Acid (HCl) Corrosion 1. Does the process contain HCl? 2. Is free water present in the process stream (including initial condensing condition)? 3. Is the pH < 7.0?	If Yes to all, proceed to Section 2.B.2
High Temperature Sulfidic/Naphthenic Acid Corrosion 1. Does the process contain oil with sulfur compounds? 2. Is the operating temperature > 204 °C (400 °F)?	If Yes to both, proceed to Section 2.B.3
High Temperature H_2S/H_2 Corrosion 1. Does the process contain H_2S and hydrogen? 2. Is the operating temperature > 204 °C (400 °F)?	If Yes to both, proceed to Section 2.B.4
Sulfuric Acid (H_2SO_4) Corrosion Does the process contain H_2SO_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_2S 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 ≥ 482 °C (900 °F)? 2. Is there oxygen present?	If Yes to both, proceed to Section 2.B.9
Acid Sour Water 1. Is free water with H_2S 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 4.4—Data Required for Determination of the Thinning DF

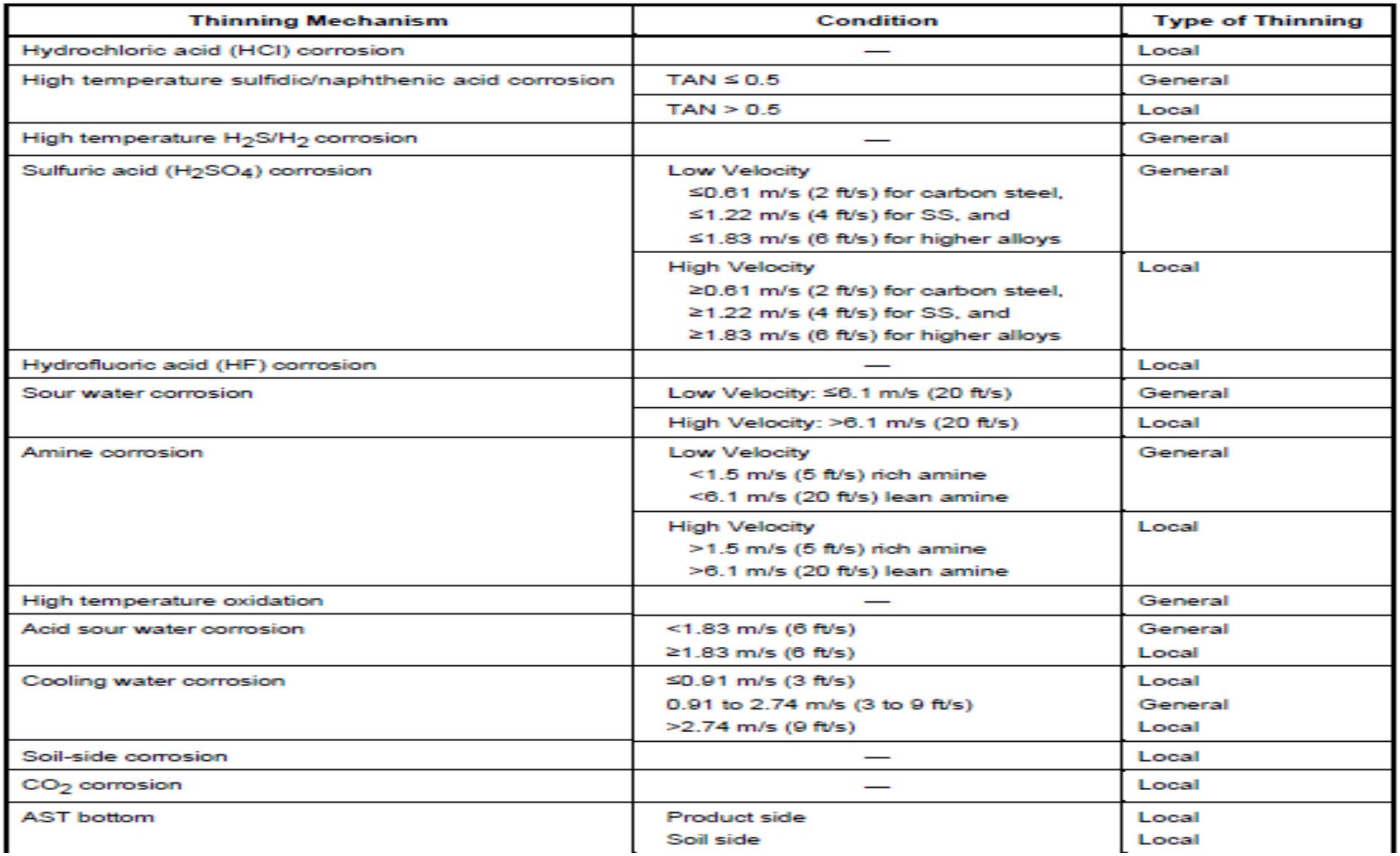


Basic Data	Comments
Thinning type (general or localized)	Determine whether the thinning is general or localized based on inspection results of effective inspections. General corrosion is defined as affecting more than 10 % of the surface area and the wall thickness variation is less than 1.27 mm (50 mils). Localized corrosion is defined as affecting less than 10 % of the surface area or a wall thickness variation greater than 1.27 mm (50 mils).
Corrosion rate (mmpy or mpy)	The current rate of thinning calculated from thickness data, if available. Corrosion rates calculated from thickness data typically vary from one inspection to another. These variations may be due to variations in the wall thickness, or they may indicate a change in the actual corrosion rate. If the short-term rate (calculated from the difference between the current thickness and the previous thickness) is significantly different from the long-term rate (calculated from the difference between the current thickness and the original thickness), then the component may be evaluated using the short-term rate, but the appropriate time and thickness must be used.
Inspection effectiveness category	The effectiveness category of each inspection that has been performed on the component during the time period (specified above).
Number of inspections	The number of inspections in each effectiveness category that have been performed during the time period (specified above).
On-line monitoring	The types of proactive on-line monitoring methods or tools employed, such as corrosion probes, coupons, process variables (coupons, probes, process variables, or combinations, etc.).
Thinning mechanism	If credit is to be taken for on-line monitoring, the potential thinning mechanisms must be known. A knowledgeable materials/corrosion engineer should be consulted for this information; also see API 571 [13].



Inspection effectiveness category	The effectiveness category of each inspection that has been performed on the component during the time period (specified above).
Number of inspections	The number of inspections in each effectiveness category that have been performed during the time period (specified above).
On-line monitoring	The types of proactive on-line monitoring methods or tools employed, such as corrosion probes, coupons, process variables (coupons, probes, process variables, or combinations, etc.).
Thinning mechanism	If credit is to be taken for on-line monitoring, the potential thinning mechanisms must be known. A knowledgeable materials/corrosion engineer should be consulted for this information; also see API 571 [13].
Presence of injection/mix point (Yes or No)	For piping, determine if there is an injection or mix point in the circuit.
Type of injection/mix point inspection	For piping circuits that contain an injection or mix point, determine whether not the inspection program is highly effective or not highly effective to detect local corrosion at these points.
Presence of a dead-leg (Yes or No)	For piping, determine if there is a dead-leg in the circuit.
Type of inspection for dead-leg corrosion	For piping circuits that contain a dead-leg, determine if the inspection program currently being used is highly effective or not highly effective to detect local corrosion in dead-legs has been performed.

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_2S/H_2 corrosion	—	General
Sulfuric acid (H_2SO_4) corrosion	Low Velocity ≤0.61 m/s (2 ft/s) for carbon steel, ≤1.22 m/s (4 ft/s) for SS, and ≤1.83 m/s (6 ft/s) for higher alloys	General
	High Velocity ≥0.61 m/s (2 ft/s) for carbon steel, ≥1.22 m/s (4 ft/s) for SS, and ≥1.83 m/s (6 ft/s) for higher alloys	Local
Hydrofluoric acid (HF) corrosion	—	Local
Sour water corrosion	Low Velocity: ≤6.1 m/s (20 ft/s)	General
	High Velocity: >6.1 m/s (20 ft/s)	Local
Amine corrosion	Low Velocity <1.5 m/s (5 ft/s) rich amine <6.1 m/s (20 ft/s) lean amine	General
	High Velocity >1.5 m/s (5 ft/s) rich amine >6.1 m/s (20 ft/s) lean amine	Local
High temperature oxidation	—	General
Acid sour water corrosion	<1.83 m/s (6 ft/s) ≥1.83 m/s (6 ft/s)	General Local
Cooling water corrosion	≤0.91 m/s (3 ft/s) 0.91 to 2.74 m/s (3 to 9 ft/s) >2.74 m/s (9 ft/s)	Local General Local
Soil-side corrosion	—	Local
CO_2 corrosion	—	Local
AST bottom	Product side Soil side	Local Local

Table G-6A—Guidelines for Assigning Inspection Effectiveness—General Thinning

Inspection Effectiveness Category	Example: Intrusive Inspection	Example: Nonintrusive Inspection
Highly Effective	50–100% examination of the surface (partial internals removed), and accompanied by thickness measurements.	50–100% ultrasonic scanning coverage (automated or manual) or profile radiography
Usually Effective	Nominally 20% examination (no internals removed), and spot external ultrasonic thickness measurements.	Nominally 20% ultrasonic scanning coverage (automated or manual), or profile radiography, or external spot thickness (statistically validated).
Fairly Effective	Visual examination without thickness measurements.	2–3% examination, spot external ultrasonic thickness measurements, and little or no internal visual examination.
Poorly Effective	External spot thickness readings only.	Several thickness measurements, and a documented inspection planning system.
Ineffective	No inspection.	Several thickness measurements taken only externally, and a poorly documented inspection planning system.

Table G-6B—Guidelines for Assigning Inspection Effectiveness—Localized Thinning

Inspection Effectiveness Category	Example: Intrusive Inspection	Example: Nonintrusive Inspection
Highly Effective	100% visual examination (with removal of internal packing, trays, etc.) and thickness measurements.	50–100% coverage using automated ultrasonic scanning, or profile radiography in areas specified by a corrosion engineer or other knowledgeable specialist.
Usually Effective	100% visual examination (with partial removal of the internals) including manways, nozzles, etc. and thickness measurements.	20% coverage using automated ultrasonic scanning, or 50% manual ultrasonic scanning, or 50% profile radiography in areas specified by a corrosion engineer or other knowledgeable specialist.
Fairly Effective	Nominally 20% visual examination and spot ultrasonic thickness measurements.	Nominally 20% coverage using automated or manual ultrasonic scanning, or profile radiography, and spot thickness measurements at areas specified by a corrosion engineer or other knowledgeable specialist.
Poorly Effective	No inspection.	Spot ultrasonic thickness measurements or profile radiography without areas being specified by a corrosion engineer or other knowledgeable specialist.

Sour Environment

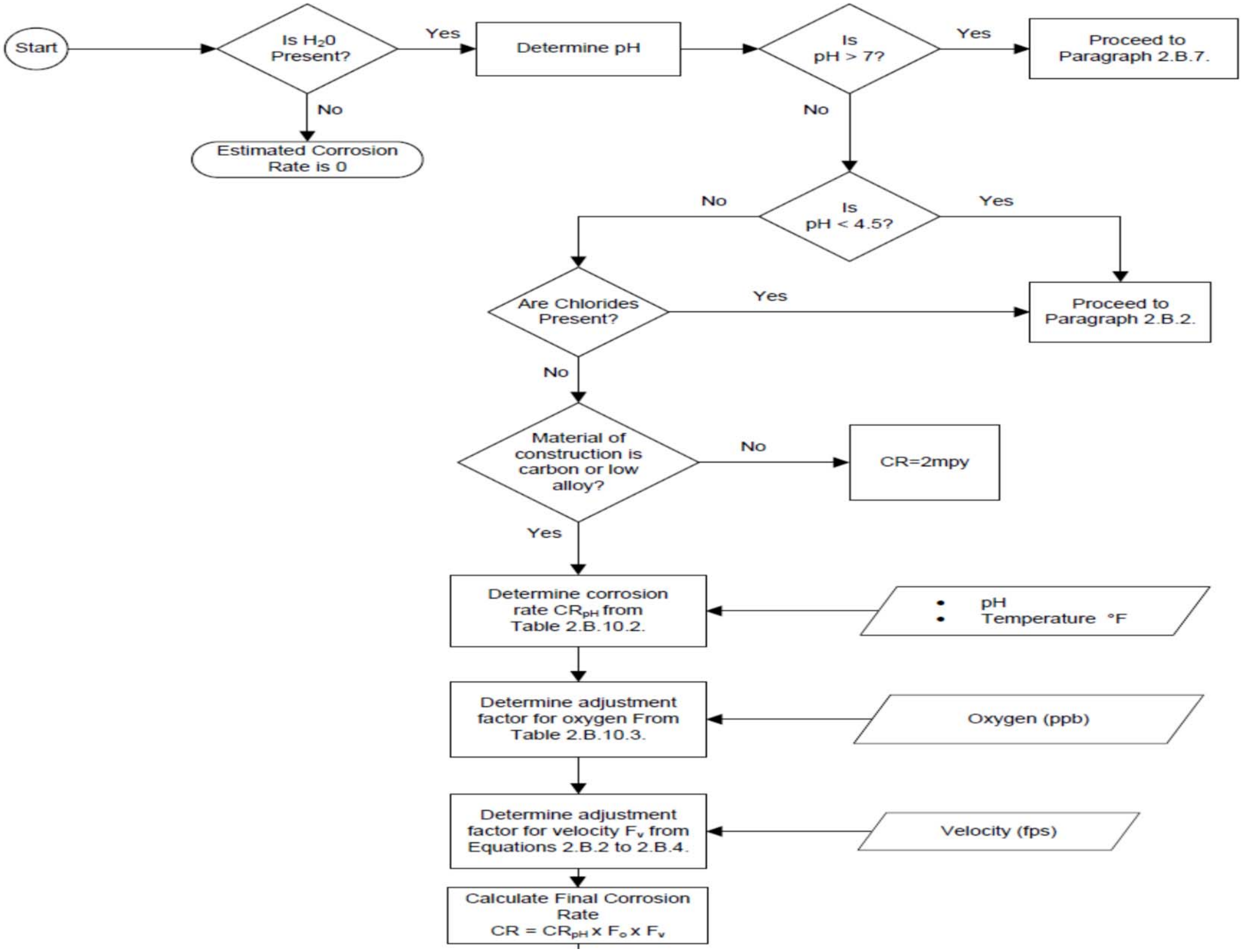
- Definition (Free H_2O with H_2S)

1. Sour Water Corrosion (Acidic and Alkaline)

2. Wet H_2S Damage (SSC&Belister,HIC/SOHIC)

All of these damage mechanisms related to the absorption and permeation of hydrogen in steels

Sour water Corrosion (API 581)



Start

Is H_20 Present?

Yes

No

Estimated Corrosion Rate is 0

Determine pH

Is pH > 7?

Yes

Proceed to Paragraph 2.B.7.

No

Is pH < 4.5?

Yes

Proceed to Paragraph 2.B.2.

No

Are Chlorides Present?

Yes

No

Material of construction is carbon or low alloy?

No

CR=2mpy

Yes

Determine corrosion rate CR_{pH} from Table 2.B.10.2.

- pH
- Temperature °F

Determine adjustment factor for oxygen From Table 2.B.10.3.

Oxygen (ppb)

Determine adjustment factor for velocity F_v from Equations 2.B.2 to 2.B.4.

Velocity (fps)

Calculate Final Corrosion Rate

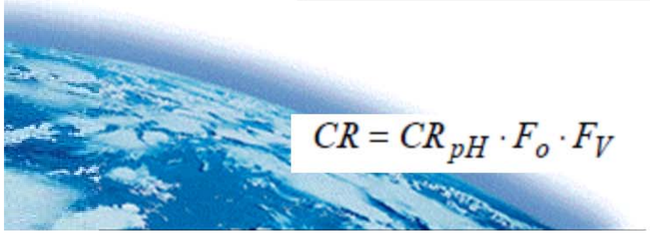
$CR = CR_{pH} \times F_o \times F_v$

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



$$CR = CR_{pH} \cdot F_o \cdot F_V$$

For SI units, use Equations (2.B.2) through (2.B.4):

$F_V = 1.0$ when velocity < 1.83 m/s

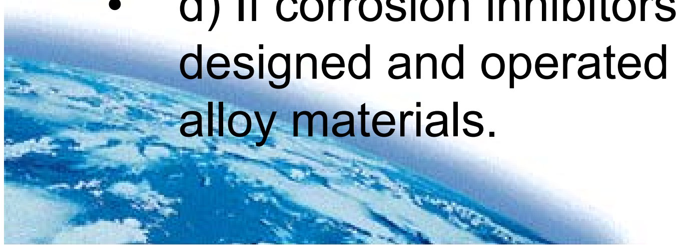
$F_V = 0.82 \cdot velocity - 0.5$ when 1.83 m/s ≤ velocity ≤ 6.10 m/s

$F_V = 5.0$ when velocity > 6.10 m/s

Cooling Water Corrosion

- **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.
- 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..
- f) SCC—SCC associated with SCC of these alloys are aqueous chloride environments for 300-series stainless steels and ammonia for specific copper alloys.

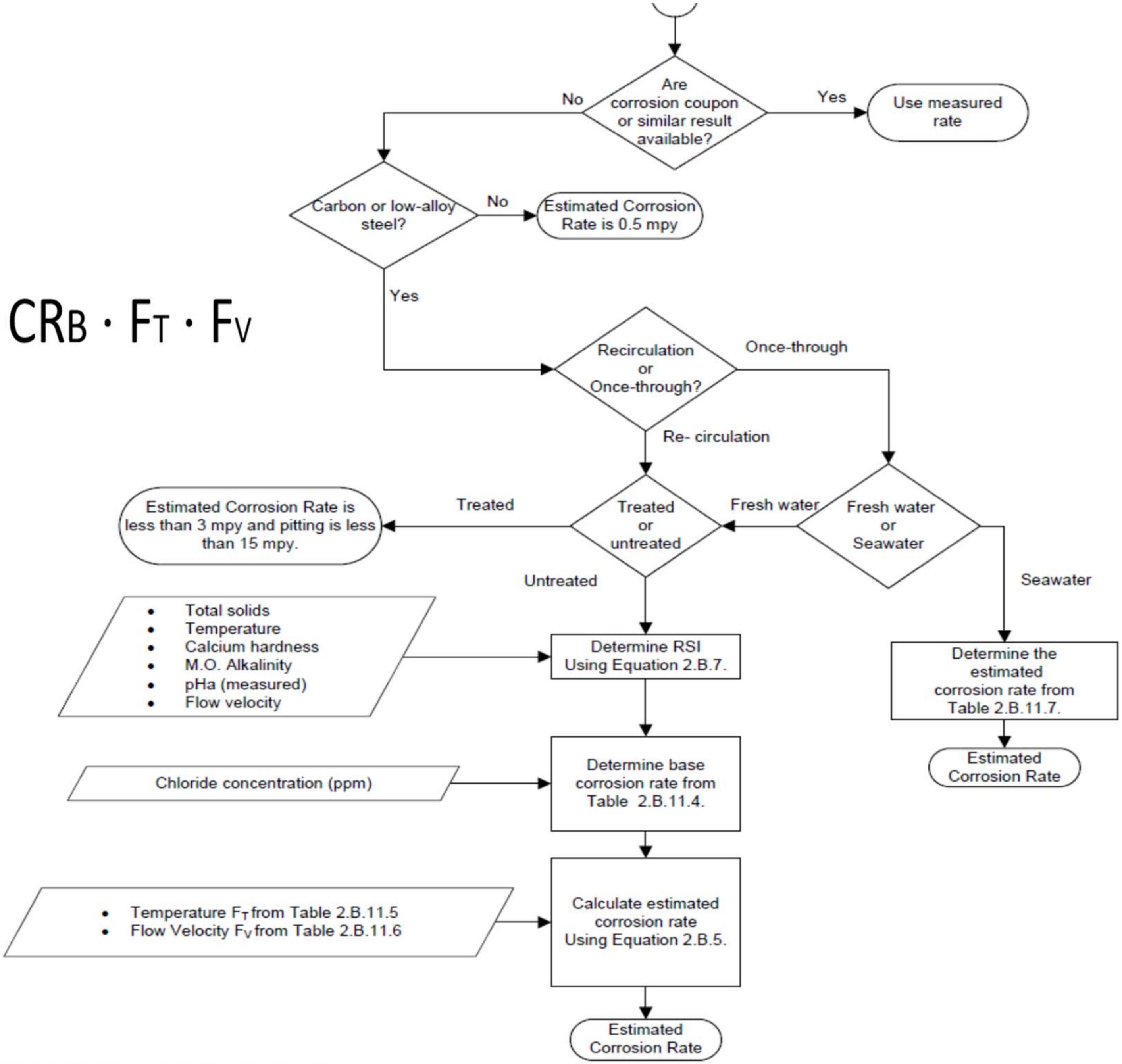
- **Assumptions**
- Cooling water systems can be very complex, and this risk-based inspection model does not attempt to address every issue that must be considered. For the purposes of this model, the following assumptions have been made.
- a) Low alloy steels are rarely used in cooling water systems 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.



- **Assumption**

- 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.

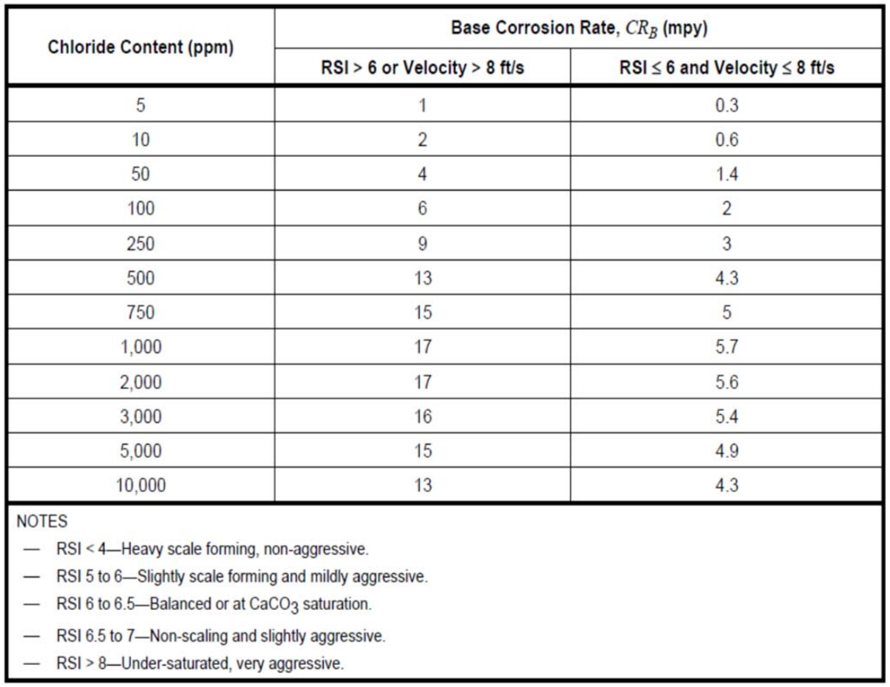
- $CR = CR_B \cdot F_T \cdot F_V$


Are corrosion coupon or similar result available?
Yes
Use measured rate
No
Carbon or low-alloy steel?
No
Estimated Corrosion Rate is 0.5 mpy
Yes
Recirculation or Once-through?
Once-through
Re- circulation
Treated or untreated
Treated
Estimated Corrosion Rate is less than 3 mpy and pitting is less than 15 mpy.
Fresh water or Seawater
Fresh water
Seawater
Untreated
- Total solids
- Temperature
- Calcium hardness
- M.O. Alkalinity
- pHa (measured)
- Flow velocity

Determine RSI Using Equation 2.B.7.
Determine the estimated corrosion rate from Table 2.B.11.7.
Estimated Corrosion Rate
Chloride concentration (ppm)
Determine base corrosion rate from Table 2.B.11.4.
- Temperature F_T from Table 2.B.11.5
- Flow Velocity F_V from Table 2.B.11.6

Calculate estimated corrosion rate Using Equation 2.B.5.
Estimated Corrosion Rate

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

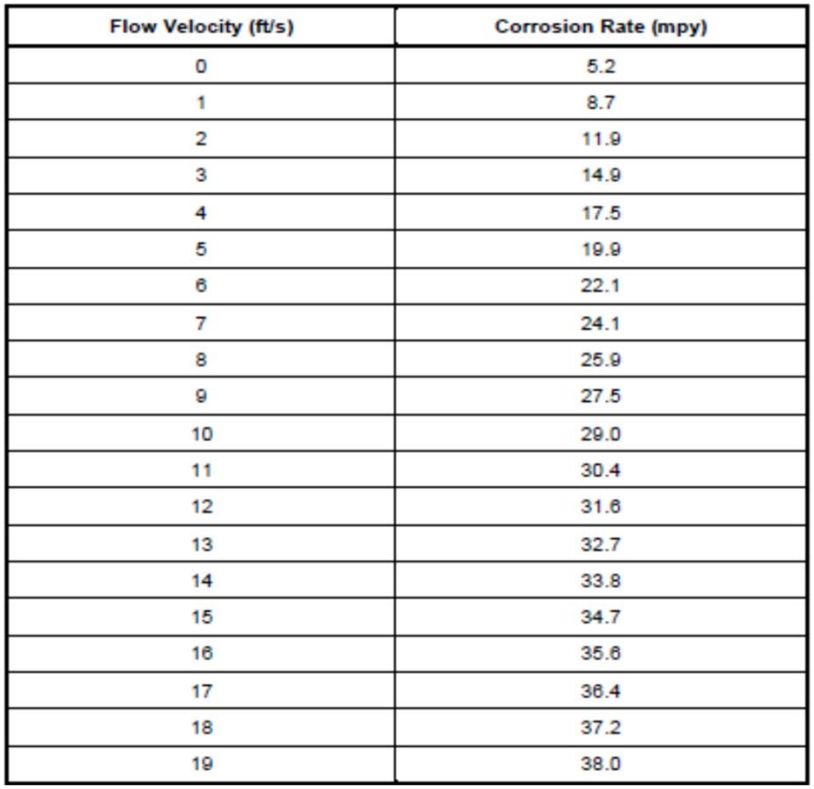


Chloride Content (ppm)	Base Corrosion Rate, CR_B (mpy)	
	RSI > 6 or Velocity > 8 ft/s	RSI ≤ 6 and Velocity ≤ 8 ft/s
5	1	0.3
10	2	0.6
50	4	1.4
100	6	2
250	9	3
500	13	4.3
750	15	5
1,000	17	5.7
2,000	17	5.6
3,000	16	5.4
5,000	15	4.9
10,000	13	4.3

NOTES

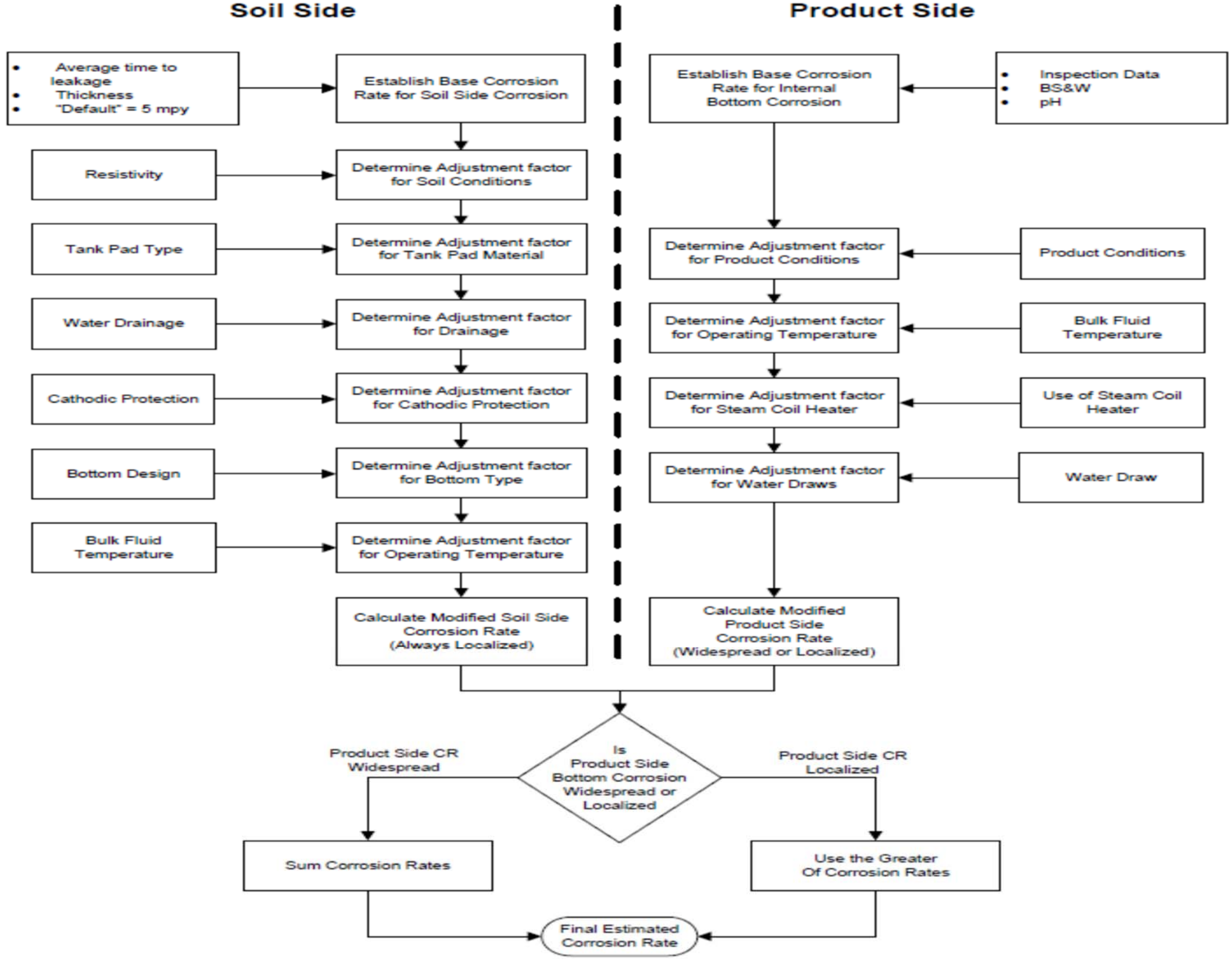
- RSI < 4—Heavy scale forming, non-aggressive.
- RSI 5 to 6—Slightly scale forming and mildly aggressive.
- RSI 6 to 6.5—Balanced or at $CaCO_3$ saturation.
- RSI 6.5 to 7—Non-scaling and slightly aggressive.
- RSI > 8—Under-saturated, very aggressive.

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

Tank Bottom Corrosion



Soil Side

- Average time to leakage
- Thickness
- "Default" = 5 mpy

Establish Base Corrosion Rate for Soil Side Corrosion

Resistivity → Determine Adjustment factor for Soil Conditions

Tank Pad Type → Determine Adjustment factor for Tank Pad Material

Water Drainage → Determine Adjustment factor for Drainage

Cathodic Protection → Determine Adjustment factor for Cathodic Protection

Bottom Design → Determine Adjustment factor for Bottom Type

Bulk Fluid Temperature → Determine Adjustment factor for Operating Temperature

Calculate Modified Soil Side Corrosion Rate (Always Localized)

Product Side

- Inspection Data
- BS&W
- pH

Establish Base Corrosion Rate for Internal Bottom Corrosion

Product Conditions → Determine Adjustment factor for Product Conditions

Bulk Fluid Temperature → Determine Adjustment factor for Operating Temperature

Use of Steam Coil Heater → Determine Adjustment factor for Steam Coil Heater

Water Draw → Determine Adjustment factor for Water Draws

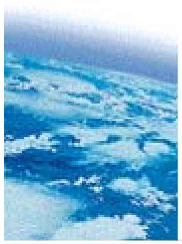
Calculate Modified Product Side Corrosion Rate (Widespread or Localized)

Is Product Side Bottom Corrosion Widespread or Localized

Product Side CR Widespread → Sum Corrosion Rates

Product Side CR Localized → Use the Greater Of Corrosion Rates

Final Estimated Corrosion Rate



خوردگی کف مخازن

❖ ۱. خوردگی کف مخازن و تست MFL:

SCC Damage Mechanism

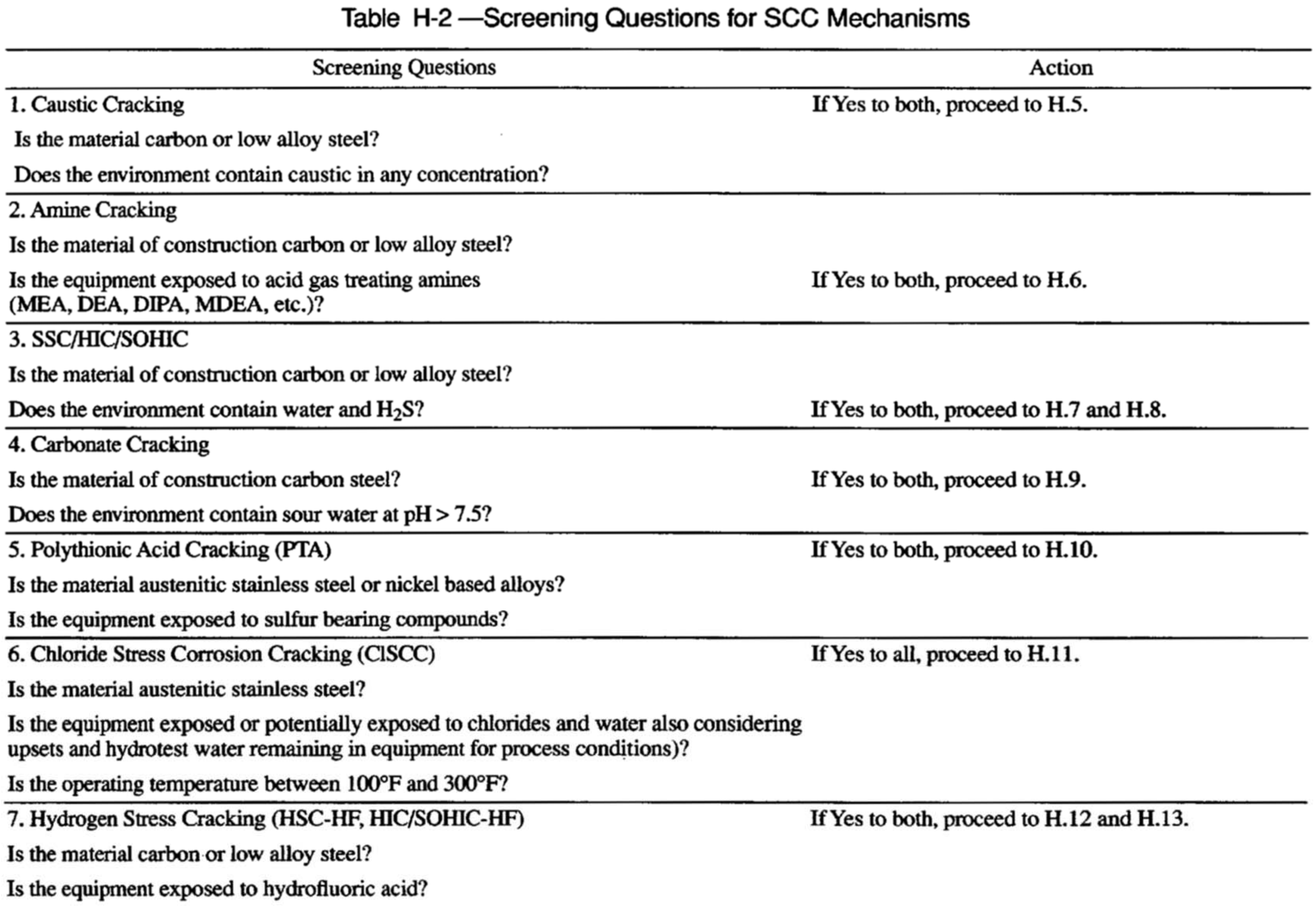
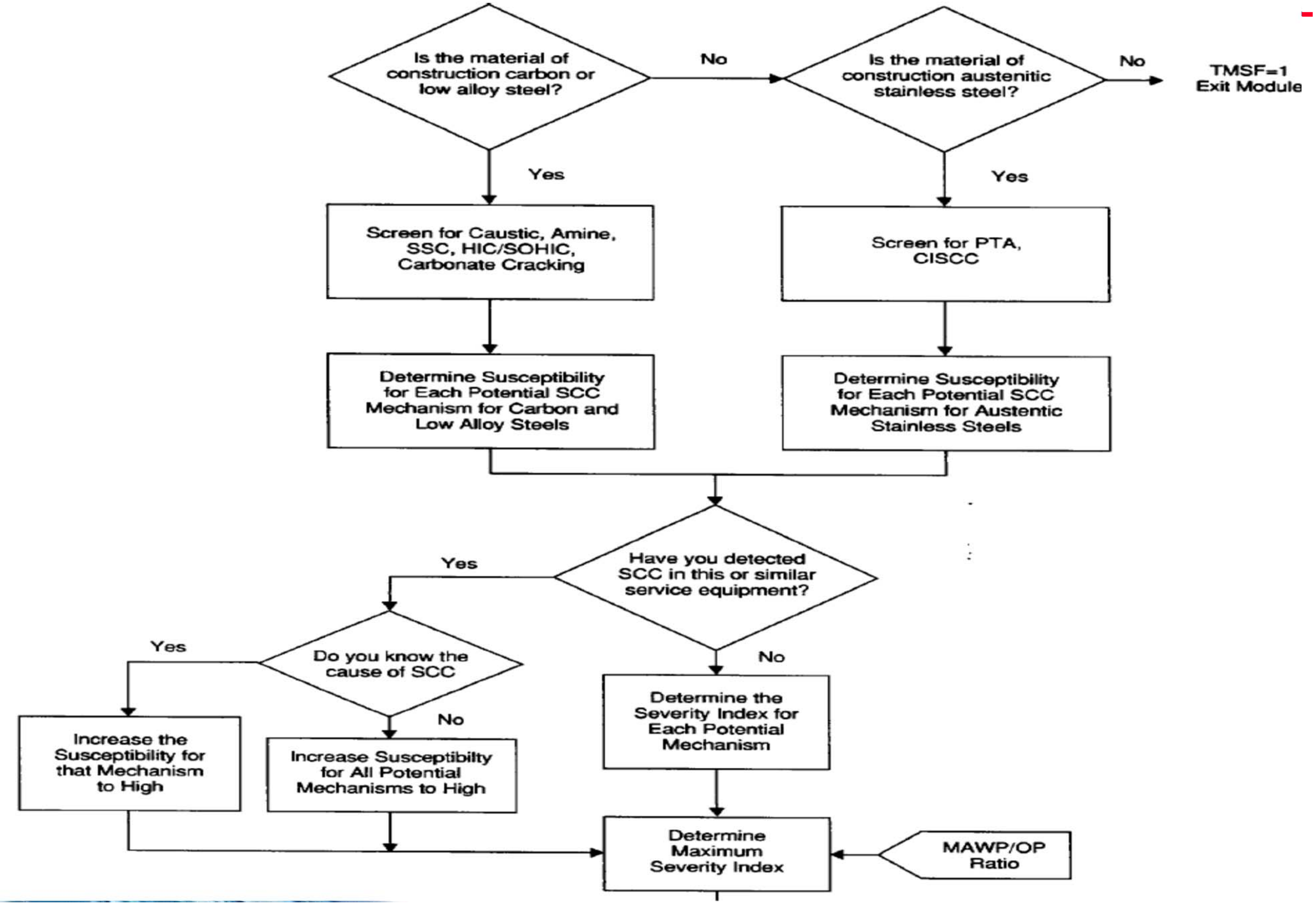


Table H-2 —Screening Questions for SCC Mechanisms

Screening Questions	Action
1. Caustic Cracking	If Yes to both, proceed to H.5.
Is the material carbon or low alloy steel?	
Does the environment contain caustic in any concentration?	
2. Amine Cracking	
Is the material of construction carbon or low alloy steel?	
Is the equipment exposed to acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.)?	If Yes to both, proceed to H.6.
3. SSC/HIC/SOHIC	
Is the material of construction carbon or low alloy steel?	
Does the environment contain water and H_2S?	If Yes to both, proceed to H.7 and H.8.
4. Carbonate Cracking	
Is the material of construction carbon steel?	If Yes to both, proceed to H.9.
Does the environment contain sour water at $pH > 7.5$?	
5. Polythionic Acid Cracking (PTA)	If Yes to both, proceed to H.10.
Is the material austenitic stainless steel or nickel based alloys?	
Is the equipment exposed to sulfur bearing compounds?	
6. Chloride Stress Corrosion Cracking (ClSCC)	If Yes to all, proceed to H.11.
Is the material austenitic stainless steel?	
Is the equipment exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in equipment for process conditions)?	
Is the operating temperature between 100°F and 300°F?	
7. Hydrogen Stress Cracking (HSC-HF, HIC/SOHIC-HF)	If Yes to both, proceed to H.12 and H.13.
Is the material carbon or low alloy steel?	
Is the equipment exposed to hydrofluoric acid?	

DF_{SCC} Flow Chart



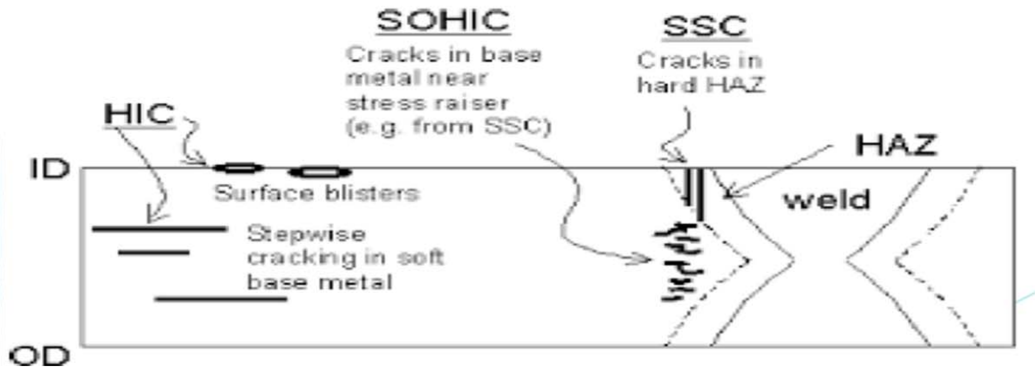
Sour Environment

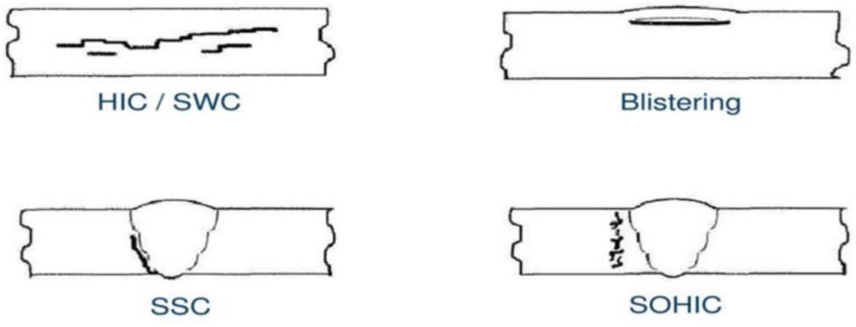
- Definition (Free H_2O with H_2S)

1. Sour Water Corrosion (Acidic and basic)

2. Wet H_2S Damage (SSC, Blister/ HIC/SOHIC)

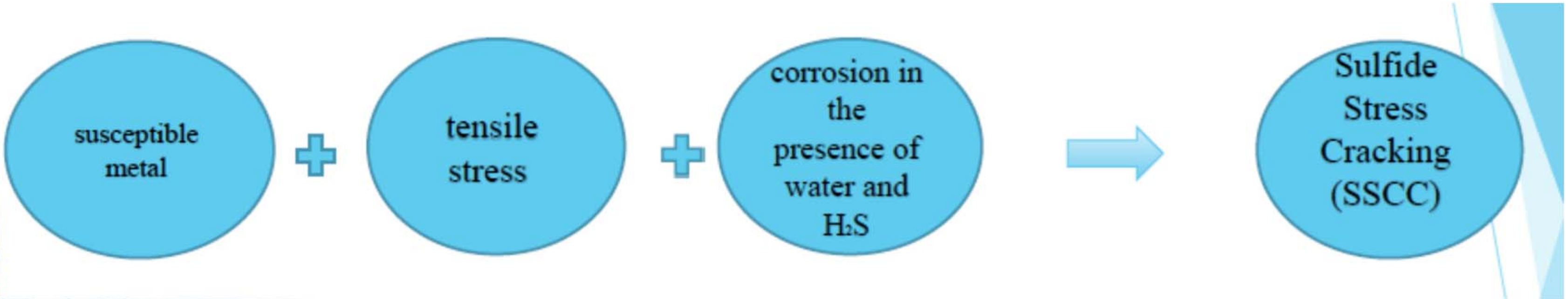
All of these damage mechanisms related to the absorption and permeation of hydrogen in steels





Sulfide Stress Cracked (SSC)

- Description of Damage
- SSC is a form of HSC resulting from absorption of atomic hydrogen that is produced by sulfide corrosion on metal surface. $H_2S + Fe \longrightarrow FeS + H_2$
- hydrogen permeation flux in the steel related to PH and H2S of water
- Susceptibility to SSC is related to two parameters, hardness and stress level
- High-strength steels (generally those with hardness greater than 22 HRC) and for Carbon steel, weld deposits and HAZs may contain zones of high hardness and high residual stresses from welding
- Control of hardness and reduction and residual stresses or applying PWHT to reduce the hardness of the welds are recognized methods for preventing SSC as outlined in NACE RP0472



Sulfide Stress Cracked (SSC)

- Screening Criteria(معیار غربالگری)

If the component's material of construction is carbon or low alloy steel and the process environment contains water and H2S in any concentration

- Required Data

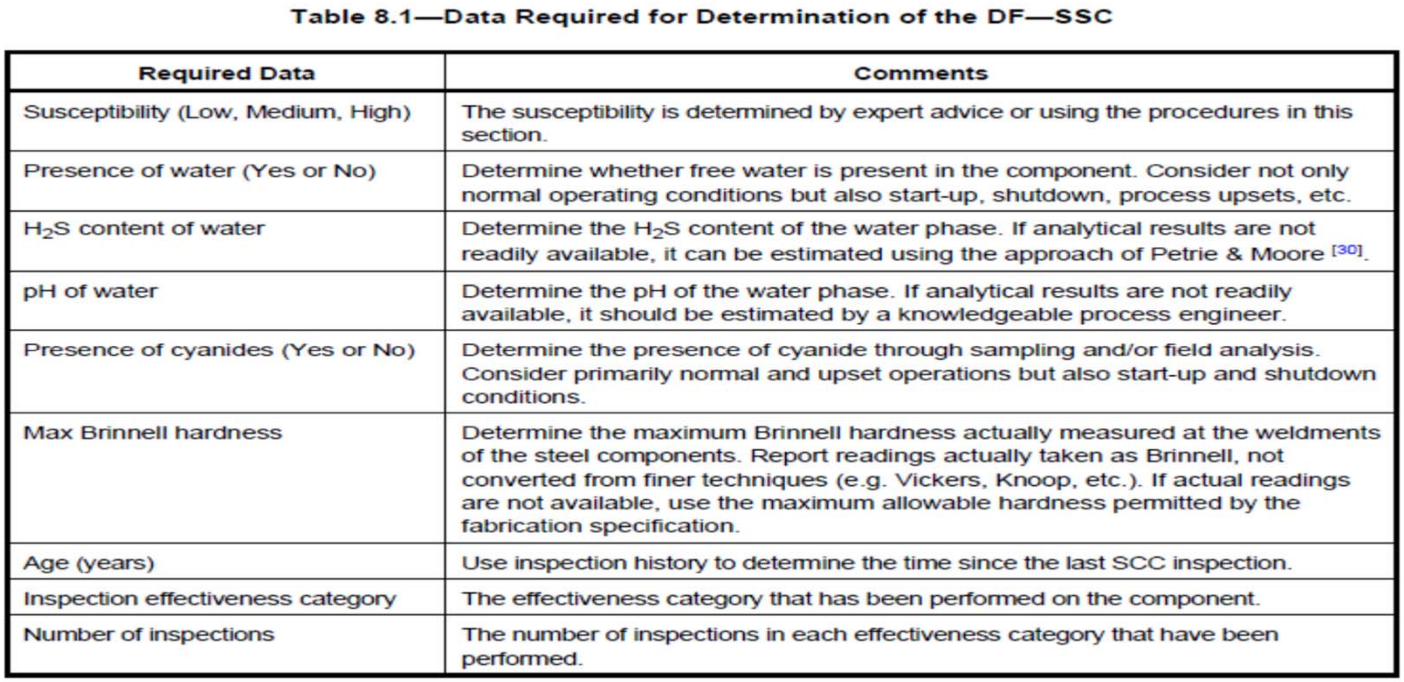
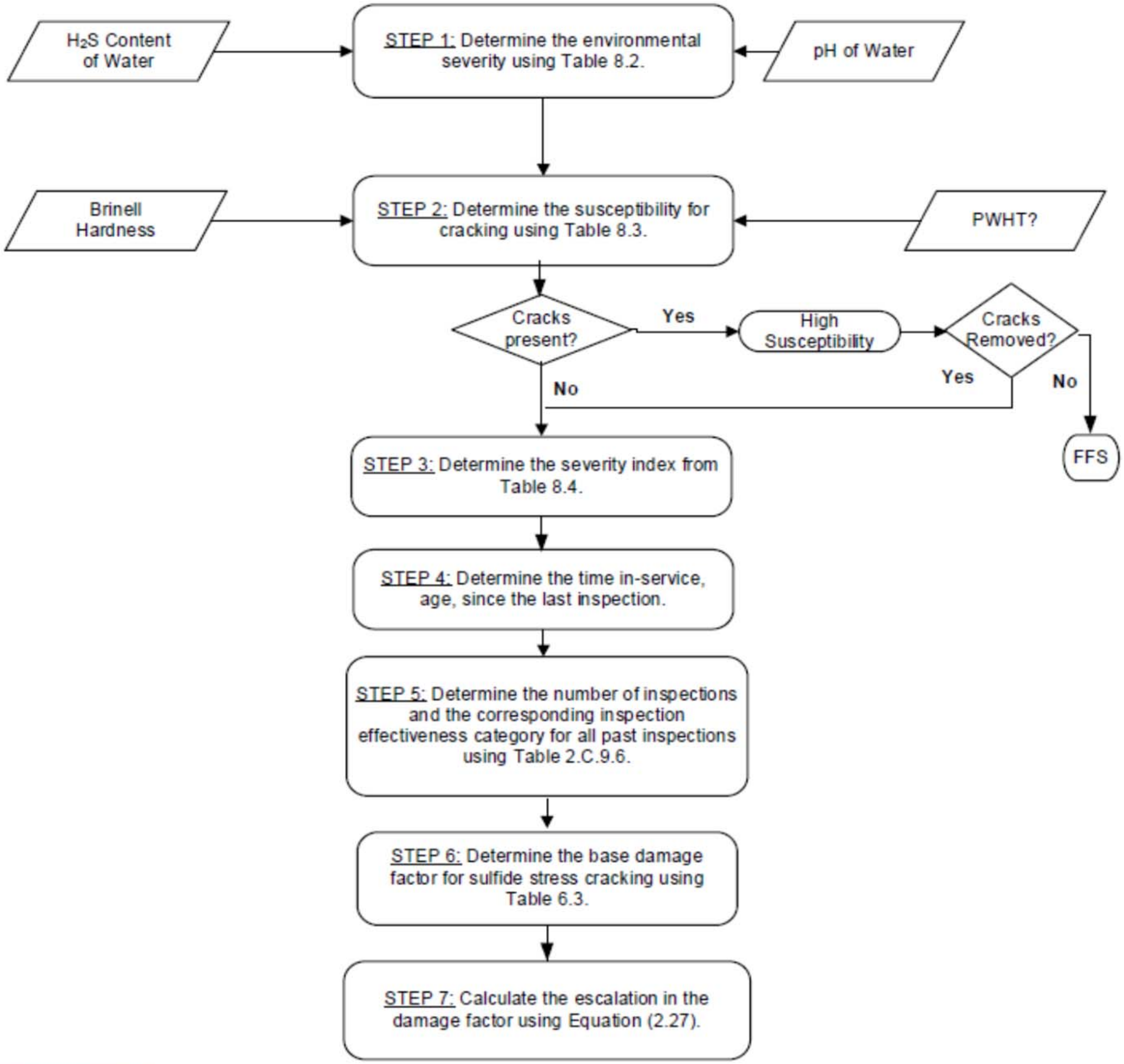


Table 8.1—Data Required for Determination of the DF—SSC

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Presence of water (Yes or No)	Determine whether free water is present in the component. Consider not only normal operating conditions but also start-up, shutdown, process upsets, etc.
H_2S content of water	Determine the H_2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore [30].
pH of water	Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of cyanides (Yes or No)	Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also start-up and shutdown conditions.
Max Brinnell hardness	Determine the maximum Brinnell hardness actually measured at the weldments of the steel components. Report readings actually taken as Brinnell, not converted from finer techniques (e.g. Vickers, Knoop, etc.). If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Determination of Susceptibility



STEP 1: Determine the environmental severity using Table 8.2.

STEP 2: Determine the susceptibility for cracking using Table 8.3.

STEP 3: Determine the severity index from Table 8.4.

STEP 4: Determine the time in-service, age, since the last inspection.

STEP 5: Determine the number of inspections and the corresponding inspection effectiveness category for all past inspections using Table 2.C.9.6.

STEP 6: Determine the base damage factor for sulfide stress cracking using Table 6.3.

STEP 7: Calculate the escalation in the damage factor using Equation (2.27).

Table 8.2—Environmental Severity—SSC

pH of Water	Environmental Severity as a Function of H_2S Content of Water			
	<50 ppm	50 to 1,000 ppm	1,000 to 10,000 ppm	>10,000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate [a]	High [a]
>9.0	Low	Moderate	High [a]	High [a]

[a] If cyanides are present, increase the susceptibility to SSC one category for pH > 8.3 and H_2S concentrations greater than 1,000 ppm.

Table 8.3—Susceptibility to SSC—SSC

Environmental Severity	Susceptibility to SSC as a Function of Heat Treatment					
	As-welded Max Brinnell Hardness [a]			PWHT Max Brinnell Hardness [a]		
	<200	200 to 237	>237	<200	200 to 237	>237
High	Low	Medium	High	Not	Low	Medium
Moderate	Low	Medium	High	Not	Not	Low
Low	Low	Low	Medium	Not	Not	Not

[a] Actually tested as Brinnell, not converted from finer techniques, e.g. Vickers, Knoop, etc.

Table 2.C.9.8—LoIE Example for HSC-HF Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [a, b]	Non-intrusive Inspection Example [a, b]
A	Highly Effective	For the total weld area: 100 % WFMT/ACFM with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: >75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: >75 % automated or manual ultrasonic scanning **OR** AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: >35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: >35 % automated or manual ultrasonic scanning **OR** >65 % radiographic testing
D	Poorly Effective	For selected welds/weld area: >10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: >10 % automated or manual ultrasonic scanning **OR** >35 % radiographic testing
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

[a] Inspection quality is high.

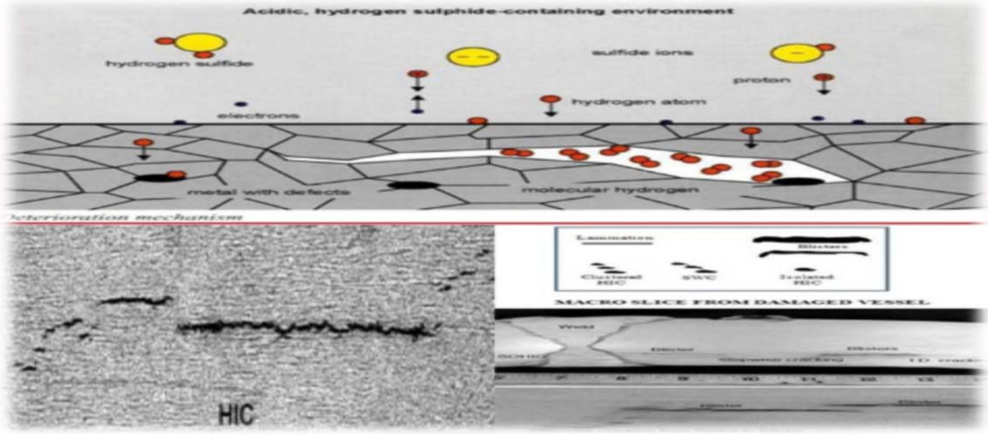
[b] Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).

SCC DF—Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking in Hydrogen Sulfide Services (HIC/SOHIC-H2S)

Description of Damage

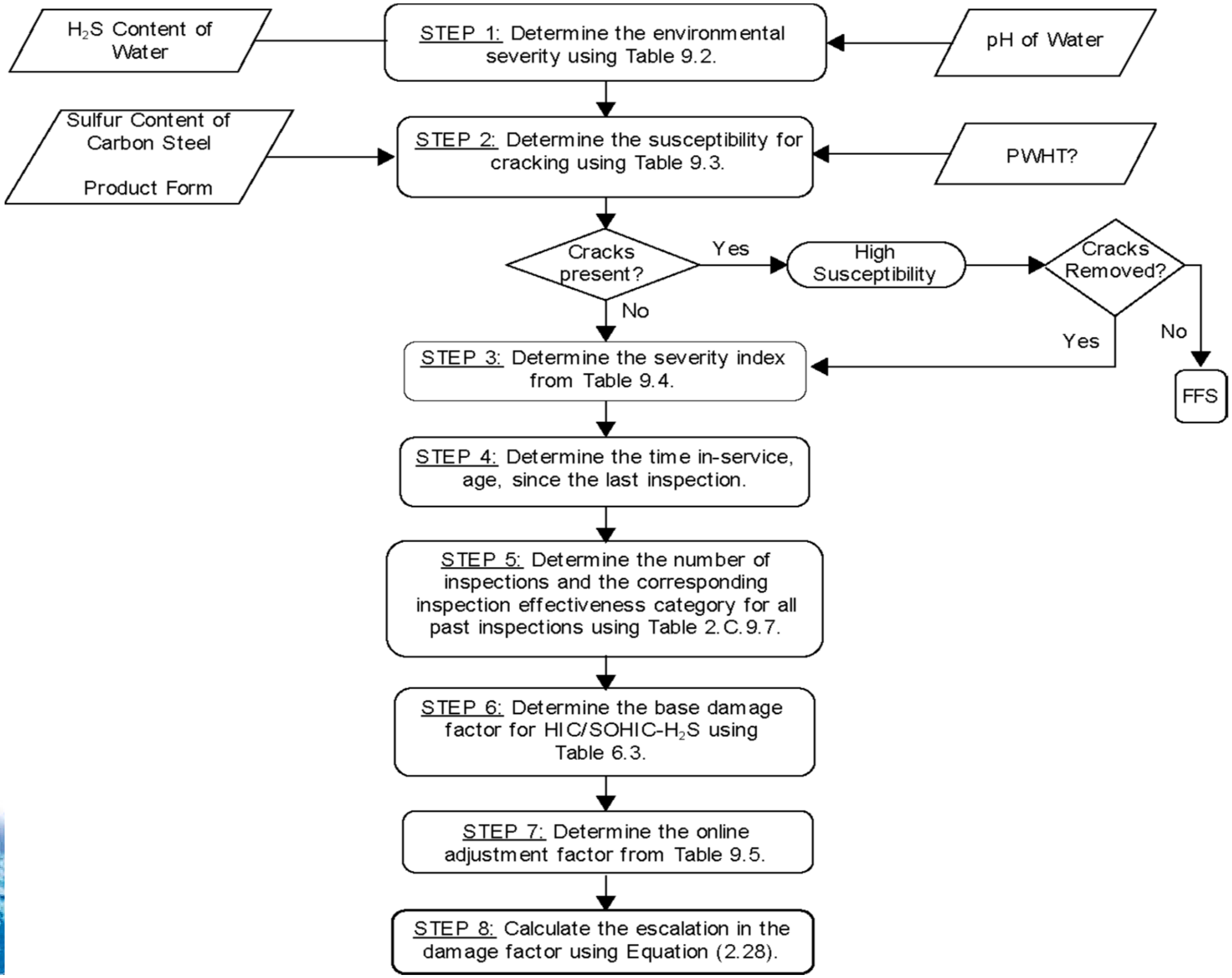
- HIC is defined as stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal or to the metal surface. An externally applied stress is not required for the formation of HIC. The driving force for the cracking is high stresses at the circumference of the hydrogen blisters caused by buildup of internal pressure in the blisters. Interactions between these high stress fields tend to cause cracks to develop that link blisters on different planes in the steel

- Blistering and HIC are strongly affected by the presence of inclusions and laminations,which provides ites for diffusing hydrogen to accumulate



- SOHIC results from an array of HIC (separations or cracks) stacked on top of each other. When acted upon by a high stress level (residual or applied), the stacked HIC will connect and create a thru-thickness crack that is perpendicular to the surface. SOHIC most often occurs in the base metal adjacent to weld HAZs, the residual stress from welding being the most common driver of SOHIC. SOHIC can initiate from the stacked HIC alone, from sulfide stress cracks, or from other crack-like defects or stress concentrations. SOHIC is a potentially more damaging form of cracking than HIC because of its relatively higher rate of developing a thru-wall crack. In addition, an absence of visual blistering may leave a false sense of security that H2S damage is not active, yet subsurface SOHIC may be present.

Susceptibly to (HIC/SOHIC-H2S)



H_2S Content of Water

pH of Water

STEP 1: Determine the environmental severity using Table 9.2.

Sulfur Content of Carbon Steel

Product Form

PWHT?

STEP 2: Determine the susceptibility for cracking using Table 9.3.

Cracks present?

Yes

High Susceptibility

Cracks Removed?

No

Yes

No

FFS

STEP 3: Determine the severity index from Table 9.4.

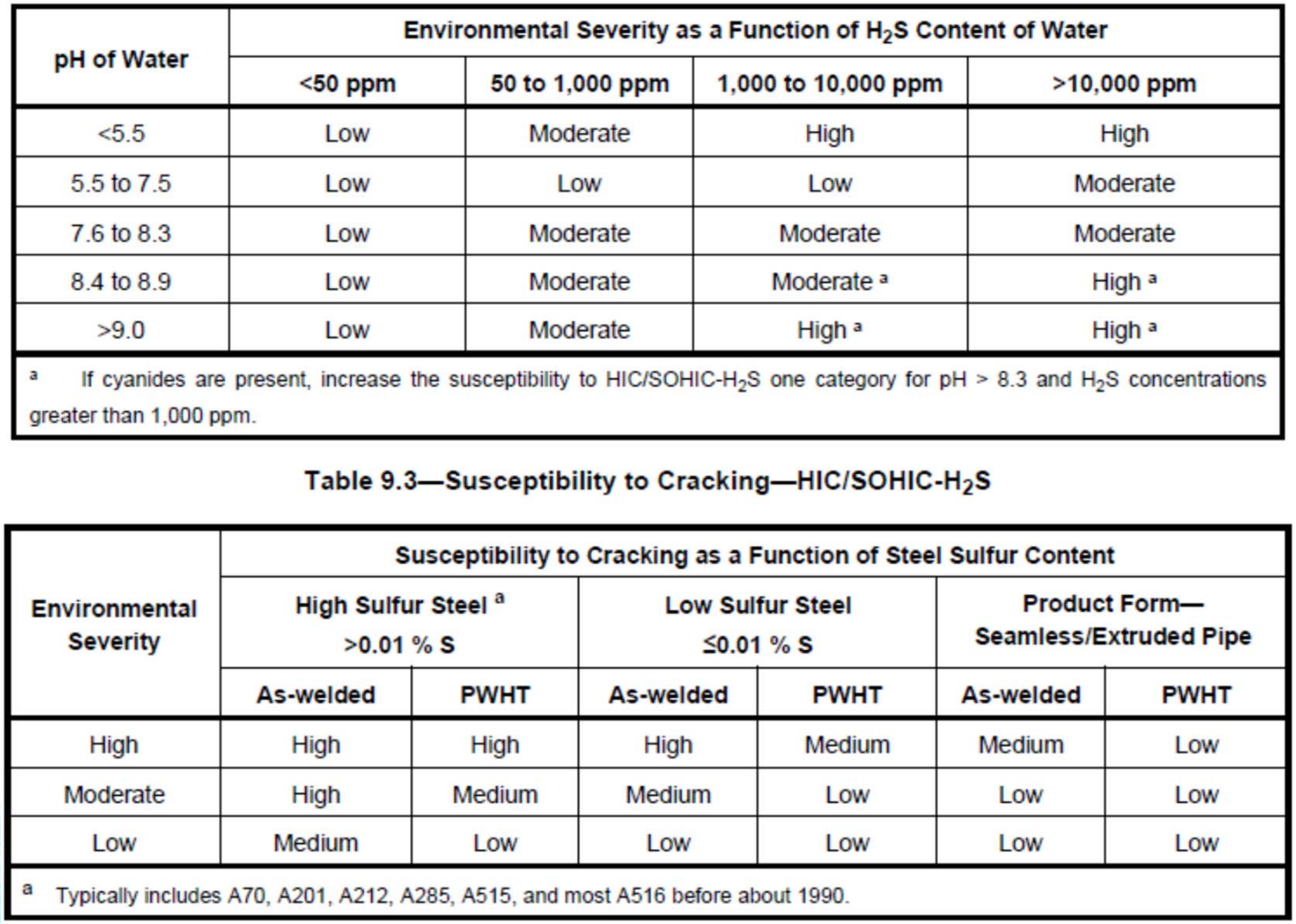
STEP 4: Determine the time in-service, age, since the last inspection.

STEP 5: Determine the number of inspections and the corresponding inspection effectiveness category for all past inspections using Table 2.C.9.7.

STEP 6: Determine the base damage factor for HIC/SOHIC-H_2S using Table 6.3.

STEP 7: Determine the online adjustment factor from Table 9.5.

STEP 8: Calculate the escalation in the damage factor using Equation (2.28).



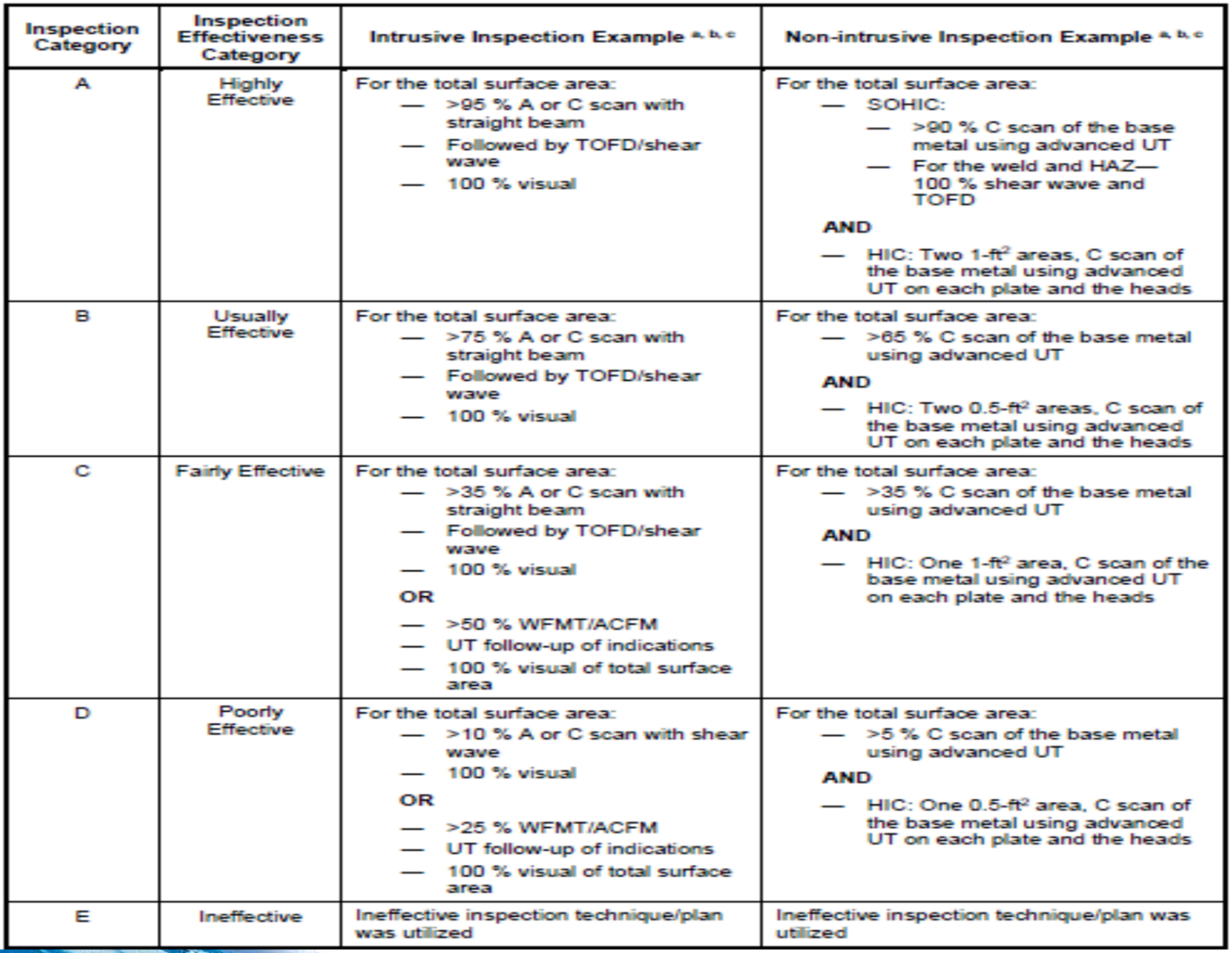
pH of Water	Environmental Severity as a Function of H_2S Content of Water			
	<50 ppm	50 to 1,000 ppm	1,000 to 10,000 ppm	>10,000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate [a]	High [a]
>9.0	Low	Moderate	High [a]	High [a]

[a] If cyanides are present, increase the susceptibility to HIC/SOHIC-H_2S one category for pH > 8.3 and H_2S concentrations greater than 1,000 ppm.

Table 9.3—Susceptibility to Cracking—HIC/SOHIC-H_2S

Environmental Severity	Susceptibility to Cracking as a Function of Steel Sulfur Content					
	High Sulfur Steel [a] >0.01 % S		Low Sulfur Steel ≤0.01 % S		Product Form—Seamless/Extruded Pipe	
	As-welded	PWHT	As-welded	PWHT	As-welded	PWHT
High	High	High	High	Medium	Medium	Low
Moderate	High	Medium	Medium	Low	Low	Low
Low	Medium	Low	Low	Low	Low	Low

[a] Typically includes A70, A201, A212, A285, A515, and most A516 before about 1990.



Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [a, b, c]	Non-intrusive Inspection Example [a, b, c]
A	Highly Effective	For the total surface area: — >95 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual	For the total surface area: — SOHIC: — >90 % C scan of the base metal using advanced UT — For the weld and HAZ—100 % shear wave and TOFD **AND** — HIC: Two 1-ft^2 areas, C scan of the base metal using advanced UT on each plate and the heads
B	Usually Effective	For the total surface area: — >75 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual	For the total surface area: — >65 % C scan of the base metal using advanced UT **AND** — HIC: Two 0.5-ft^2 areas, C scan of the base metal using advanced UT on each plate and the heads
C	Fairly Effective	For the total surface area: — >35 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual **OR** — >50 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — >35 % C scan of the base metal using advanced UT **AND** — HIC: One 1-ft^2 area, C scan of the base metal using advanced UT on each plate and the heads
D	Poorly Effective	For the total surface area: — >10 % A or C scan with shear wave — 100 % visual **OR** — >25 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — >5 % C scan of the base metal using advanced UT **AND** — HIC: One 0.5-ft^2 area, C scan of the base metal using advanced UT on each plate and the heads
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

Low Alloy Steel Embrittlement (Temper Embrittlement)

- Description of Damage
- Temper embrittlement is the reduction in fracture toughness due to a metallurgical change that can occur in some low-alloy steels as a result of long-term exposure in the temperature range of about 650 °F to 1070 °F (345 °C to 575 °C). This change causes an upward shift in the ductile-to-brittle transition temperature as measured by Charpy impact testing.
- The embrittlement is caused by segregation of tramp elements and alloying elements along grain boundaries in the steel. Susceptibility to temper embrittlement is largely determined by the presence of the alloying elements
- manganese and silicon and the tramp elements phosphorus, tin, antimony, and arsenic
- **Screening Criteria**

If all of the following are true, then the component should be evaluated for susceptibility to low alloy steel embrittlement.

a) The material is 1Cr-0.5Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, or 3Cr-1 Mo low alloy steel.

b) The operating temperature is between 343 °C and 577 °C (650 °F and 1070 °F).

885 °F Embrittlement

- 885 °F (474 °C) embrittlement is a reduction in toughness of ferritic stainless steels with a chromium content of greater than 13 %, after exposure to temperatures between 371 °C and 538 °C (700 °F and 1000 °F). The reduction in toughness is due to precipitation of a chromium-phosphorous intermetallic phase at elevated temperatures. the effect on toughness is most pronounced not at the operating temperature, but at lower temperatures experienced during plant shutdowns or upsets. Martensitic stainless steels such as Type 410 are normally considered to be immune to this problem.
- **Screening Criteria**

If both of the following are true, then the component should be evaluated for susceptibility to 885 °F embrittlement.

a) The material is a high chromium (>12 % Cr) ferritic steel.

b) The operating temperature is between 371 °C and 566 °C

Sigma Phase Embrittlement

- **Description of Damage**

Sigma phase is a hard, brittle intermetallic compound of iron and chromium. It occurs in ferritic (Fe-Cr), martensitic (Fe-Cr), and austenitic (Fe-Cr-Ni) stainless steels when exposed to temperatures in the range of 593 °C to 927 °C. Ferrite stabilizers (Cr, Si, Mo, Al, W, V, Ti, Nb) tend to promote sigma formation, while austenite stabilizers (C, Ni, N, Mn) tend to retard sigma formation. Sigma is unstable at temperatures above 899 °C

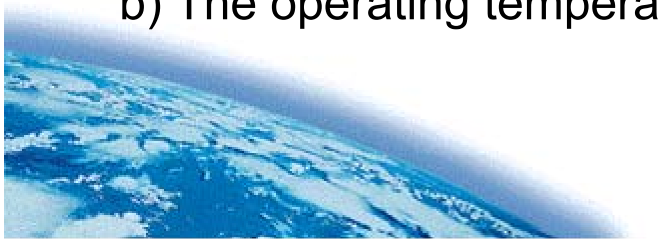
- **Screening Criteria**

If both of the following are true, then the component should be evaluated for susceptibility to sigma phase

embrittlement.

a) The material an austenitic stainless steel.

b) The operating temperature between 593 °C and 927 °C



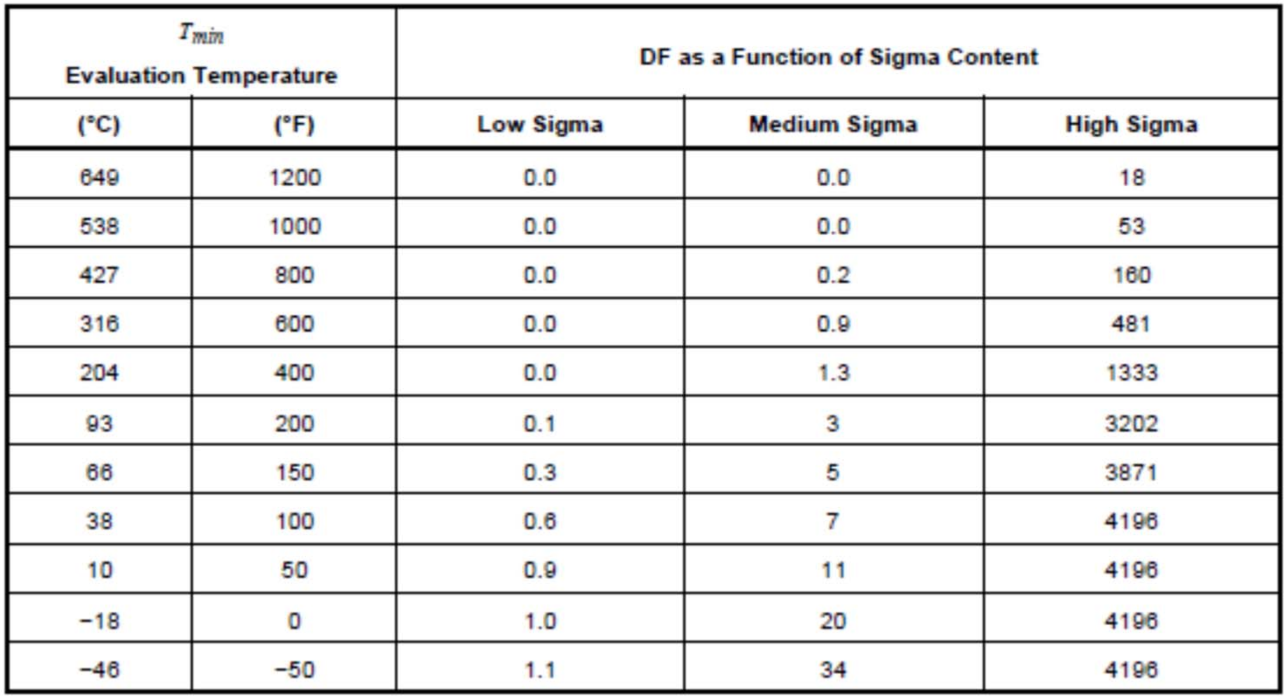


Table 23.3—DF—Sigma Phase

T_{min} Evaluation Temperature		DF as a Function of Sigma Content		
(°C)	(°F)	**Low Sigma**	**Medium Sigma**	**High Sigma**
649	1200	0.0	0.0	18
538	1000	0.0	0.0	53
427	800	0.0	0.2	160
316	600	0.0	0.9	481
204	400	0.0	1.3	1333
93	200	0.1	3	3202
66	150	0.3	5	3871
38	100	0.6	7	4196
10	50	0.9	11	4196
−18	0	1.0	20	4196
−46	−50	1.1	34	4196

Estimate of the amount of sigma phase present.

- Low (>1 %, <5 %)
- Medium (≥5 %, <10 %)
- High (≥10 %)

High Temperature Hydrogen Attack (HTHA)

- ***Description of Damage***
- High temperature hydrogen attack results from exposure to hydrogen at elevated temperatures and pressures. The hydrogen reacts with carbides in steel to form methane (CH4) which cannot diffuse through the steel. The loss of carbide causes an overall loss in strength.
- Methane pressure builds up, forming bubbles or cavities, microfissures and fissures that may combine to form cracks.
- Damage due to the HTHA can possess two forms:
- 1) internal decarburization and fissuring from the accumulation of methane gas at the carbide matrix interface;
- 2) surface decarburization from the reaction of the atomic hydrogen with carbides at or near the surface where the methane gas can escape without causing fissures.
- 300 Series SS, as well as 5Cr, 9Cr and 12 Cr alloys, are not susceptible to HTHA at conditions normally seen in refinery units.

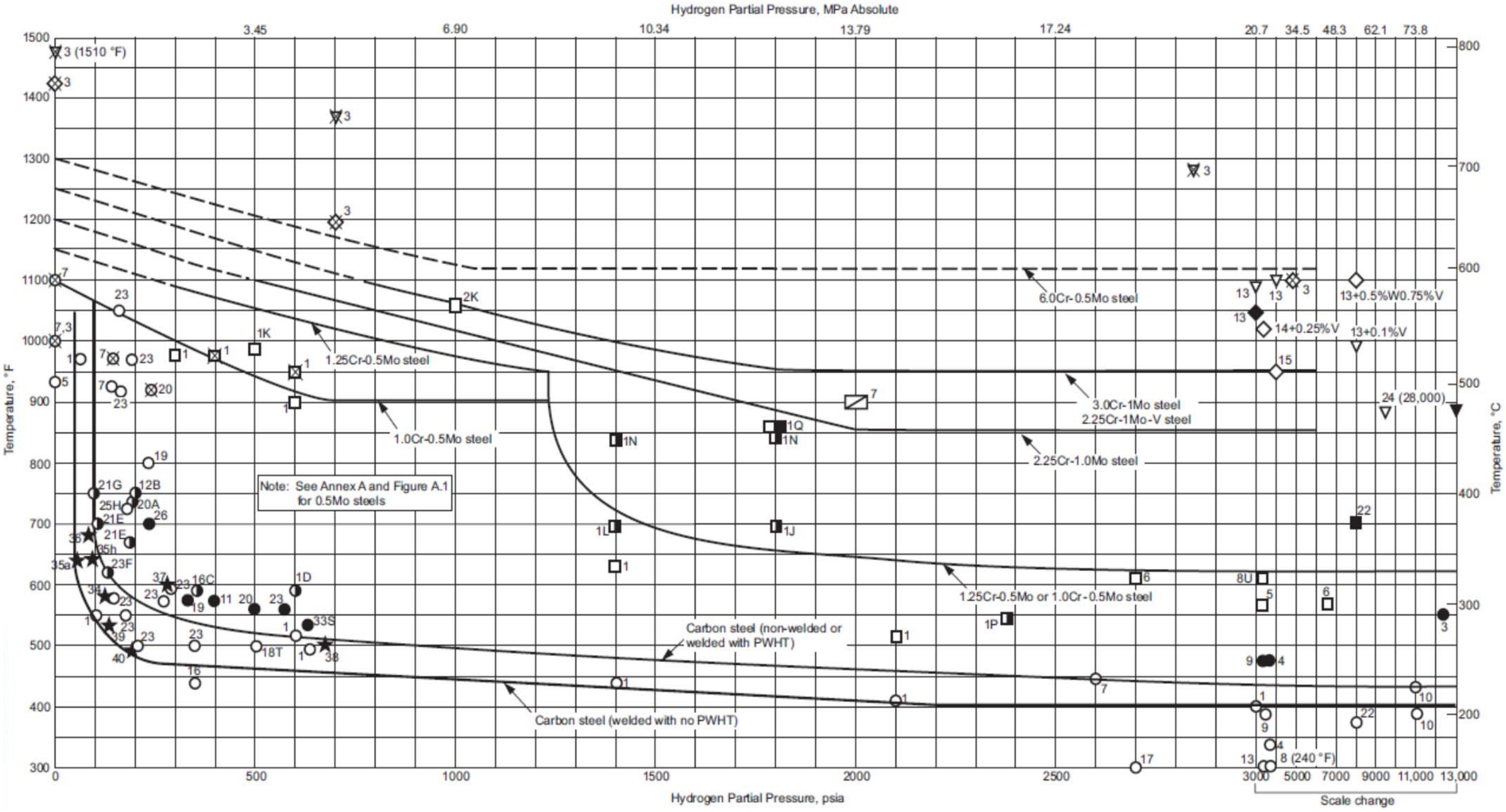
$$4H + MC \Leftrightarrow CH_4 + M$$

- **Screening Criteria**
- If all of the following are true, then the component should be evaluated for susceptibility to HTHA.
- a) The material is carbon steel, C-½ Mo, or a Cr-Mo low alloy steel (such as ½ Cr-½ Mo, 1 Cr-½ Mo, 1¼ Cr-½ Mo, 2¼ Cr-1 Mo, 3 Cr-1 Mo, 5 Cr-½ Mo, 7 Cr-1 Mo, and 9 Cr-1 Mo).
- b) The operating temperature is greater than 177 °C (350 °F).
- c) The operating hydrogen partial pressure is greater than 0.345 MPa (50 psia).

- **Susceptibility to HTHA**
- **1) For Carbon and C-½ Mo Alloy Steels.**
- a) If the exposure temperature is >177 °C (350 °F) and the exposure hydrogen partial pressure is >0.345 MPa (50 psia), assign a high susceptibility to HTHA.
- b) If exposure temperature is ≤177 °C (350 °F) and the exposure hydrogen partial pressure is ≤0.345 MPa (50 psia), assign HTHA susceptibility to None.
- **2) For All Other Cr-Mo Low Alloy Steels.**
- a) If the exposure temperature is >177 °C (>350 °F) and exposure hydrogen partial pressure is >0.345 MPa (>50 psia), calculate ΔT proximity to the API 941 curve using T and P_{H_2} from
- Assign HTHA susceptibility using Figure 19.1.

Nelson Curve (API 941)

- Operating Limits for Steels in Hydrogen Service to Avoid High Temperature Hydrogen Attack



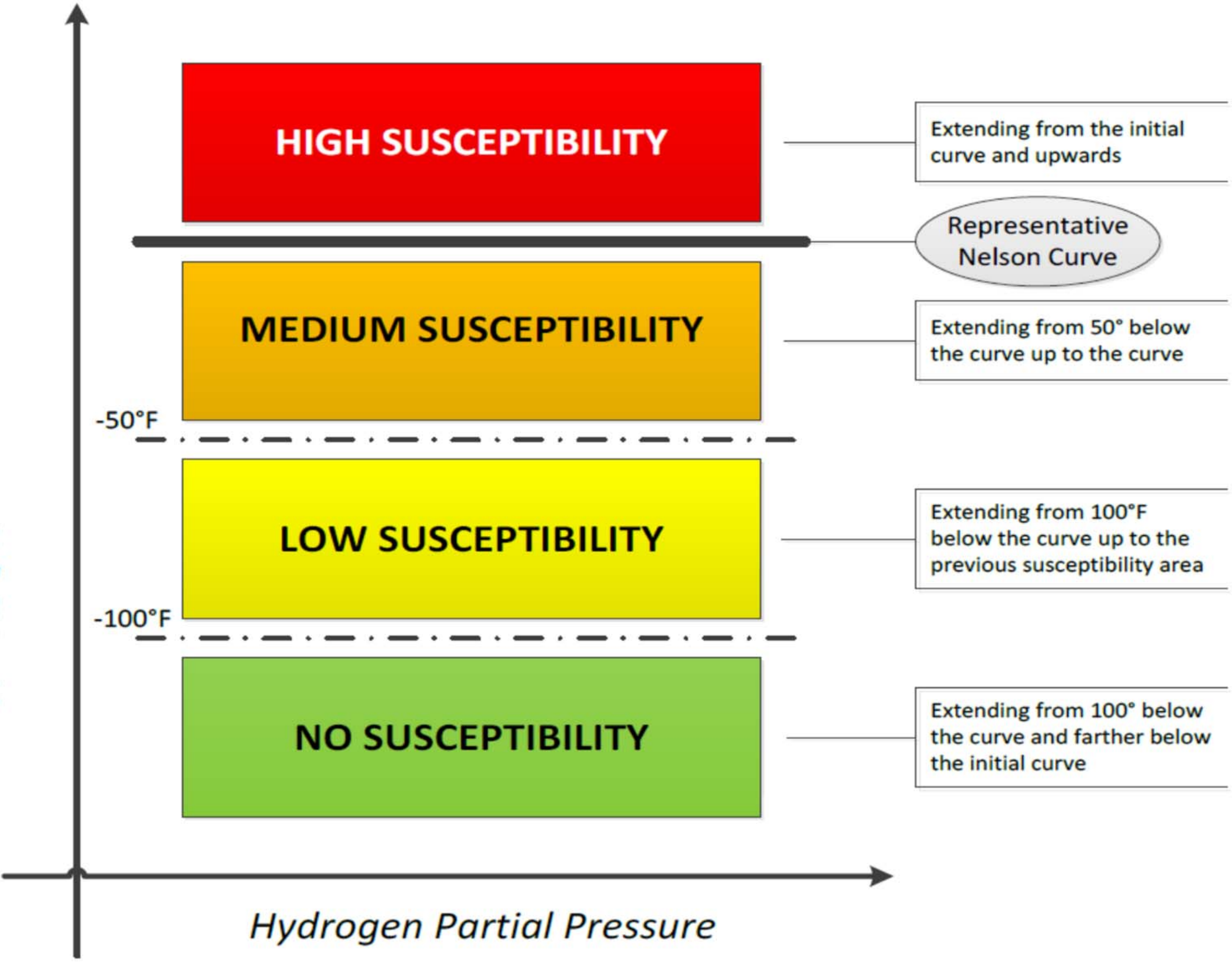


Figure 19.1—Example of HTHA Susceptibility Rankings for Cr-Mo Low Alloy Steels

Case Study

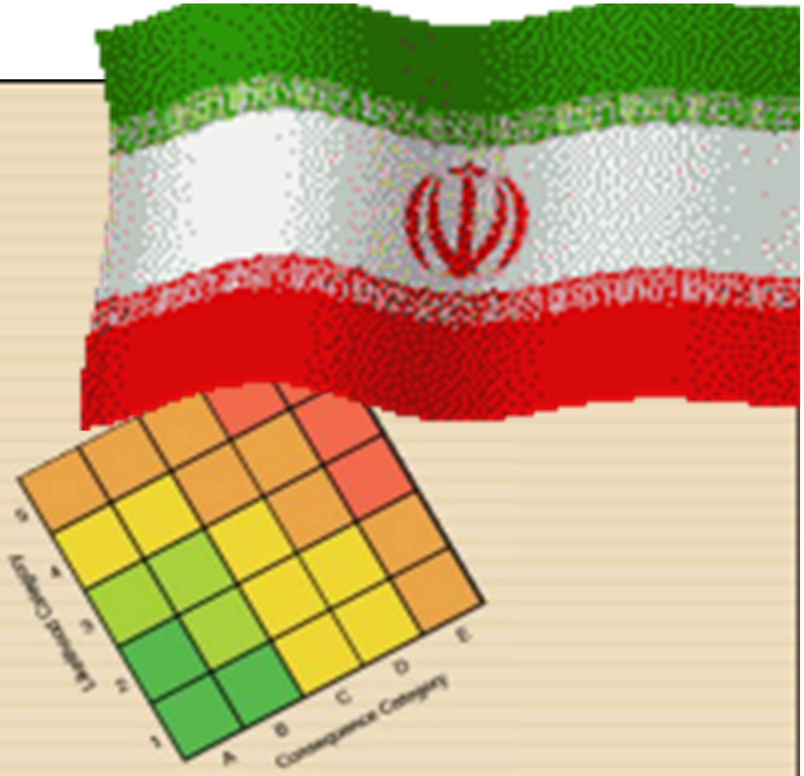
- ۱. وضعیت خوردگی در تاور الفین:

Case Study

- ۱. وضعیت خوردگی در مبدل الفین:

Case Study

- ۱. وضعیت خوردگی در تاور الفین:



Thank for your attention