Engineering Standard

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Corrosion Protection Requirements
for Pipelines, Piping and Process Equipment

Document Responsibility: Materials and Corrosion Control Standards Committee

Saudi Aramco DeskTop Standards

Table of Contents

1 Scope.. 2

2 Conflicts and Deviations................................ 2

3 References... 2

4 Definitions.. 8

5 Minimum Mandatory Requirements............. 10

6 Determining Corrosive and
Crack-Inducing Environments.............. 11

7 Corrosion and Cracking Control Measures.. 15

8 Corrosion Management Program-
Requirements for New Projects
and Major Facilities Upgrades.............. 28

9 Corrosion Monitoring Facilities..................... 37

Appendices – Technical Modules
for Refinery Services............................ 42

1 Scope

This standard specifies minimum mandatory measures to control internal and external corrosion, and environmental cracking for onshore and offshore pipelines, structures, plant and platform piping, wellhead piping, well casings, and other pressure-retaining process and ancillary equipment.

The corrosion control measures specified herein are to be applied during design, construction, operation, maintenance, and repair of such facilities.

2 Conflicts and Deviations

2.1 Any conflicts between this standard and other applicable Saudi Aramco Engineering Standards (SAESs), Materials System Specifications (SAMSSs), Standard Drawings (SASDs) or industry standards, codes and forms shall be resolved in writing by the Company or Buyer Representative through the Manager, Consulting Services Department, Saudi Aramco, Dhahran.

2.2 Direct all requests to deviate from this standard in writing to the Company or Buyer Representative, who shall follow internal company procedure SAEP-302 and forward such requests to the Manager, Consulting Services Department, Saudi Aramco, Dhahran.

3 References

The selection of material and equipment, and the design, construction, maintenance, and repair of equipment and facilities covered by this standard shall comply with all Saudi Aramco Mandatory Engineering Requirements, with particular emphasis on the documents listed below. Unless otherwise stated, the most recent edition of each document shall be used.

3.1 Saudi Aramco References

Saudi Aramco Engineering Procedures

SAEP-20	*Equipment Inspection Schedule*
SAEP-122	*Project Records*
SAEP-302	*Instructions for Obtaining a Waiver of a Mandatory Saudi Aramco Engineering Requirement*
SAEP-316	*Performance Qualification of Coating Personnel*
SAEP-332	*Cathodic Protection Commissioning*

SAEP-333	*Cathodic Protection Monitoring*
SAEP-343	*Risk Based Inspection (RBI) for In-Plant Static Equipment and Piping*
SAEP-345	*Composite Non-metallic Repair Systems for Pipelines and Pipework*
SAEP-1026	*Boiler Lay-Up Procedure*
SAEP-1135	*On-Stream Inspection Administration*

Saudi Aramco Engineering Standards

SAES-A-007	*Hydrostatic Testing Fluids and Lay-Up Procedures*
SAES-A-205	*Oilfield Chemicals*
SAES-A-206	*Positive Materials Identification*
SAES-A-208	*Water Treatment Chemicals*
SAES-B-006	*Fireproofing for Plants*
SAES-D-001	*Design Criteria for Pressure Vessels*
SAES-H-001	*Coating Selection and Application Requirements for Industrial Plants and Equipment*
SAES-H-002	*Internal and External Coatings for Steel Pipelines and Piping*
SAES-H-004	*Protective Coating Selection and Application Requirements for Offshore Structures and Facilities*
SAES-J-801	*Control Buildings*
SAES-L-100	*Applicable Codes and Standards for Pressure Piping System*
SAES-L-105	*Piping Material Specifications*
SAES-L-109	*Selection of Flanges, Stud Bolts and Gaskets*
SAES-L-132	*Material Selection for Piping Systems*
SAES-L-136	*Restrictions on the Use of Line Pipe*
SAES-L-310	*Design of Plant Piping*
SAES-L-410	*Design of Pipelines*
SAES-L-420	*Scraper Trap Station and Appurtenances*
SAES-L-610	*Nonmetallic Piping in Oily Water Services*

SAES-M-005	*Design and Construction of Fixed Offshore Platforms*
SAES-W-010	*Welding Requirements for Pressure Vessels*
SAES-W-011	*Welding Requirements for On-Plot Piping*
SAES-W-012	*Welding Requirements for Pipelines*
SAES-X-300	*Cathodic Protection of Marine Structures*
SAES-X-400	*Cathodic Protection of Buried Pipelines*
SAES-X-500	*Cathodic Protection of Vessel and Tank Internals*
SAES-X-600	*Cathodic Protection of Plant Facilities*
SAES-X-700	*Cathodic Protection of Onshore Well Casings*

Saudi Aramco Materials System Specifications

01-SAMSS-016	*Qualification of Storage Tanks and Pressured Equipment for Resistance to Hydrogen-Induced Cracking*
01-SAMSS-023	*Intrusive Online Corrosion Monitoring*
01-SAMSS-025	*Specification for Heavy Duty Polytetrafluorethylene (PTFE) and Perfluoroalkoxy (PFA) Lined Carbon Steel Pipe and Fittings*
01-SAMSS-029	*RTR (Fiberglass) Sewer Pipe and Fittings for Gravity Flow*
01-SAMSS-034	*RTR (Fiberglass) Pressure Pipe and Fittings*
01-SAMSS-035	*API Line Pipe*
01-SAMSS-038	*Small Quantity Purchase of Pipe from Stockist*
01-SAMSS-042	*Reinforced Thermoset Resin (RTR) Pipe and Fittings in Water and Hydrocarbon Services*
01-SAMSS-043	*Carbon Steel Pipes for On-Plot Piping*
01-SAMSS-045	*Qualification Requirements for Composite Materials used in Lined Carbon Steel Downhole Tubing and Casing*
01-SAMSS-046	*Stainless Steel Pipe*
01-SAMSS-333	*High Frequency Welded Line Pipe*
02-SAMSS-005	*Butt Welding Pipe Fittings*

02-SAMSS-011	*Forged Steel and Alloy Flanges*
23-SAMSS-073	*3D Asset Virtualization Tool*
32-SAMSS-004	*Manufacture of Pressure Vessels*
32-SAMSS-007	*Manufacture of Shell and Tube Heat Exchangers*
32-SAMSS-011	*Manufacture of Air-Cooled Heat Exchangers*

Saudi Aramco Best Practices

SABP-A-001	*Polythionic Acid SCC Mitigation - Materials Selection and Effective Protection of Austenitic Stainless Steels and Other Austenitic Alloys*
SABP-A-013	*Corrosion Control in Amine Units*
SABP-A-014	*Atmospheric Oil Degassing, Spheroids and Stabilizers Corrosion Control*
SABP-A-015	*Chemical Injection Systems*
SABP-A-016	*Crude Unit Corrosion Control*
SABP-A-018	*GOSP Corrosion Control*
SABP-A-019	*Pipelines Corrosion Control*
SABP-A-020	*Corrosion Control in Sulfur Recovery*
SABP-A-021	*Corrosion Control in Desalination Plants*
SABP-A-025	*Corrosion Control in Vacuum Distillation Units*
SABP-A-026	*Cooling Systems Corrosion Control*
SABP-A-029	*Corrosion Control in Boilers*
SABP-A-033	*Corrosion Management Program (CMP) Manual - Basic Requirements and Deployment Activities (to be published in 2012)*

Saudi Aramco Drawings

Standard Drawing AA-036242

Library Drawing DA-950035, 2005

Saudi Aramco Inspection Procedures

00-SAIP-74	*Inspection of Corrosion under Insulation and Fireproofing*
01-SAIP-04	*Injection Point Inspection Program*

3.2 Industry Codes and Standards

American Petroleum Institute

API RP 571	*Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*
API RP 578	*Material Verification Program for New and Existing Alloy Piping Systems*
API RP 579-1/ASME FFS-1	*Fitness-for-Service*
API RP 580	*Risk Based Inspection*
API RP 581	*Risk-Based Inspection Technology*
API RP 584	*Integrity Operating Window*
API PUBL 932-A	*A Study of Corrosion in Hydroprocess Reactor Effluent Air Cooler Systems*
API RP 932-B	*Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems*
API RP 934-A	*Materials and Fabrication of 2¼Cr-1Mo, 2¼Cr-1Mo-¼V, 3Cr-1Mo, and 3Cr-1Mo-¼V Steel Heavy Wall Pressure Vessels for High-temperature, High-pressure Hydrogen Service*
API RP 934-C	*Materials and Fabrication of 1 1/4Cr-1/2Mo Steel Heavy Wall Pressure Vessels for High-pressure Hydrogen Service Operating at or Below 825°F (441°C)*
API RP 939-C	*Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*
API RP 941	*Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*
API RP 945	*Avoiding Environmental Cracking in Amine Units*

American Society for Testing and Materials

ASTM C795	*Standard Specification for Thermal Insulation for Use in Contact with Austenitic Stainless Steel*

Energy Institute

Guidance for Corrosion Management in Oil and Gas Production and

Processing, May 2008

European Federation of Corrosion

EFC 55	*Corrosion under Insulation Guidelines*

The International Society of Automation (ISA)

ISA 71.04	*Environmental Conditions for Process Measurements and Control Systems: Airborne Contaminants*

International Organization for Standardization

ISO 15156/NACE MR0175	*Petroleum and Natural Gas Industries-Materials for Use in H_2S-Containing Environments in Oil and Gas Production*
ISO 14224	*Petroleum, Petrochemical, and Natural Gas Industries—Collection and Exchange of Reliability and Maintenance Data for Equipment*

Manufacturers Standardization Society

MSS SP54	*Quality Standard for Steel Castings for Valves, Flanges, and Fittings and Other Piping Components - Radiographic Examination Method*

National Association of Corrosion Engineers

Commentary Note:

NACE is in the process of changing the designations RP to SP. Use the equivalent SP document when it is issued.

NACE MR0103	*Materials Resistant to Sulfide Stress Cracking in Corrosive Refinery Environments*
NACE SP0198	*Control of Corrosion under Thermal Insulation and Fireproofing Materials*
NACE SP0102	*In-Line Inspection of Pipelines*
NACE RP0170	*Protection of Austenitic Stainless Steels and other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking during Shutdown of Refinery Equipment*

NACE SP0403	*Avoiding Caustic Stress Corrosion Cracking of Carbon Steel Refinery Equipment and Piping*
NACE SP0407	*Format, Content, and Guidelines for Developing a Material Selection Diagram*
NACE Report 34101	*Refinery Injection and Process Mixing Points*
NACE Report 34103	*Overview of Sulfidic Corrosion in Petroleum Refining*

4 Definitions

Baseline ILI survey: performed on scrapable pipelines prior to commissioning for the purpose of establishing the original condition of the line and to provide a "filter" enabling subsequent surveys to discriminate damage that has occurred in service.

Caustic Cracking: a form of stress corrosion cracking characterized by surface-initiated cracks that occur in piping and equipment exposed to caustic, primarily adjacent to non-post weld heat treated welds.

Corrosion: deterioration of a material, usually a metal, that results from a reaction with its environment. For the purposes of this document, corrosion includes general and localized corrosion mechanisms, as well as environmental cracking mechanisms including, but not limited to, stress corrosion cracking (SCC), sulfide stress cracking (SSC), hydrogen induced cracking (HIC) and stress-oriented hydrogen induced cracking (SOHIC).

Corrosion-critical: piping systems whose failure could present a hazard to humans or to the environment, or where such failure cannot be repaired without disrupting operation. Piping systems in hydrocarbon, hydrocarbon processing, flare, and firewater service are considered corrosion-critical. Piping systems in other services may be defined as corrosion-critical by the operating organization with the concurrence of CSD/ME&CCD.

Corrosion Loop: A term to define equipment and piping grouped together that are similar in their process environment, made of like material and are susceptible to the same damage mechanisms.

Environmental Cracking: brittle fracture of a normally ductile material in which the corrosive effect of the environment is a causative factor.

EPC: Engineering, Procurement and Construction contractor.

Erosion-corrosion: conjoint action of erosion and corrosion in a flowing single or multiphase corrosive fluid leading to the accelerated loss of material. This phenomenon encompasses a wide range of processes including solid particle or liquid droplet impingement, cavitation, and single-phase erosion of protective films.

Hydrogen **I**nduced **C**racking (**HIC**)**:** the mechanism, related to hydrogen blistering, that produces subsurface cracks parallel to the surface and, sometimes, stepwise cracks in the through-thickness direction.

In-**L**ine **I**nspection (**ILI**)**:** internal inspection of a pipeline using an in-line inspection tool. Also called *Intelligent or Instrument Scraping.*

In-Line Inspection Tool: device or vehicle that is designed to travel through a pipeline and survey the condition of the pipeline wall using nondestructive examination (NDE) techniques. Also known as *Intelligent* or *Instrument Scraper.*

Microbiologically **I**nfluenced **C**orrosion (**MIC**)**:** refers to corrosion mechanisms attributed to microorganisms and their by-products.

Pipelines: include cross-country and offshore transportation lines, flowlines, trunklines, tie-lines, water supply and injection lines and pipeline branches such as jump-overs. SAES-L-100 defines some of these types of pipelines.

Piping: includes pipelines, plant piping, and wellhead piping.

Plant piping: includes above and below-ground piping inside a plant area, as defined in SAES-L-100.

Plant: includes, but is not limited to, gas oil separation plants (GOSPs), water injection plants (WIPs), water treatment plants, gas processing plants, fractionation plants, refinery, marine or aviation terminals, bulk plants, power plants, tank farms, and pipeline pump stations.

Polythionic **A**cid **S**tress **C**orrosion **C**racking (**PASCC**)**:** a form of stress corrosion cracking normally occurring due to sulfur acids forming from sulfide scale, air and moisture acting on sensitized austenitic stainless steels.

RSA: Responsible Standardization Agent.

Sensitization: refers to the composition-time-temperature dependent formation of chromium carbide in the grain boundaries of austenitic stainless steels and some Ni alloys; occurs in the 750°F to 1500°F (400°C to 815°C) temperature range.

Stress **C**orrosion **C**racking (**SCC**)**:** cracking of a metal produced by the combined action of corrosion and tensile stress (residual or applied).

Stress-**O**riented **H**ydrogen **I**nduced **C**racking (**SOHIC**)**:** is a rare through-thickness type of environmental cracking where a staggered array of small cracks forms, with the array approximately perpendicular to the principal stress. SOHIC occurs in severe wet, sour service and can occur in carbon steel pipe and plate that is resistant to HIC and SSC.

Sulfide **S**tress **C**racking (**SSC**)**:** brittle failure by cracking under the combined action of susceptible microstructure, tensile stress and corrosion in the presence of water and hydrogen sulfide.

Wellhead Piping: is the piping between the wellhead wing valve and the plot limit valve of a single or multiple well drilling site or offshore production platform. See SAES-L-410.

5 Minimum Mandatory Requirements

5.1 Use the corrosion-control measures mandated by this standard for all piping and pressure-retaining equipment exposed either internally or externally to one or more of the conditions described in Sections 6.1, 6.2, or 6.3 of this standard. In addition to this standard, consult SAES-L-132 for environment-specific materials selection and SAES-L-136 for carbon steel pipe-type selections and restrictions.

5.2 For piping systems that are not corrosion-critical, follow the requirements in the pertinent standards and codes.

Commentary Note:

Some piping systems, not defined as corrosion-critical in this standard, must still be built with corrosion-resistant materials as specified in other standards or codes. Examples are sewer lines, wastewater disposal lines, and potable water lines.

5.3 Normal, Foreseeable and Contingent Conditions

5.3.1 Select appropriate corrosion control methods and materials (see Section 7) for all of the following conditions. Always take measures, as described in Section 7.2, to prevent sulfide stress cracking (SSC), stress corrosion cracking (SCC) such as caustic cracking, SOHIC, and other rapid environmental cracking mechanisms:

- Maximum normal operating conditions, projected over the design life of the system which is specified as a minimum of 20 years,

  Commentary Note:

  The design life is specified as a minimum of 20 years. There may well be circumstances where a longer design life is appropriate, if the equipment is located in a hard-to-repair location. One example is the use of 50-year sub-sea valves on pipelines because sub-sea maintenance of valves is extremely challenging.

- Process start up,
- End of run variations and
- Foreseeable intermittent or occasional operations, such as hydrostatic test, steam cleaning or carryover of contaminants from an upstream process (e.g., caustic from a stripper).

5.3.2 Select corrosion control and materials for contingent conditions, such as those that may be encountered during construction, start-up, shutdown, process upset operations, or the failure of a single component. Always take measures, as described in Section 7.2, to prevent sulfide stress cracking (SSC), stress corrosion cracking (SCC) such as caustic cracking, SOHIC, and other rapid environmental cracking mechanisms. Contingency failure requirements may not require provision for general corrosion, localized corrosion, or hydrogen induced cracking, if the time exposure is very limited. However, additional corrosion control measures shall be required if the contingent conditions exist for an extended period. Consult the Corrosion Technology Unit, ME&CCD, CSD.

Commentary Note:

> *Consideration must be given to potential corrosion of valve trim/seats during hydrotest. The type of hydrotest medium must be considered together with likely exposure time and ambient temperature. Company experience has shown that certain materials (such as 304 SS) used in valve internals suffer from pitting (and in some cases severe pitting) prior to pipelines entering service. Consequently, consideration of hydrotest medium, exposure time and temperature may require an upgrade in valve trim and seat materials. See SAES-A-007 for specific recommendations for hydrotest fluids and treatment of hydrotest fluids.*

5.4 For situations not adequately addressed by codes and standards, use the optimum corrosion and materials engineering practices commonly accepted in the oil and gas and refining industry, with the concurrence of the Supervisor, Corrosion Technology Unit, CSD/ME&CCD.

6 Determining Corrosive and Crack-Inducing Environments

6.1 Corrosive Environments

For design purposes, an environment that meets any one of the conditions listed below is corrosive enough to require specific corrosion control measures (see Section 7). A piping system or process equipment predicted to be exposed to such an environment during its design life requires measures to control metal-loss corrosion:

6.1.1 Acidic or near neutral pH water phase with an oxygen concentration in excess of 20 micrograms per liter (20 ppb).

Commentary Note:

Acidic or near-neutral pH water that has access to atmosphere will contain up to 8 mg/L dissolved oxygen and is corrosive. Water with a pH of 10 to 12 is considered non-corrosive to steel in many environments.

6.1.2 A water phase with a pH below 5.5 calculated from available data or measured either in situ or at atmospheric pressure immediately after the sample is collected in the field.

6.1.3 A water-containing multiphase fluid with a carbon dioxide partial pressure > 206 kPa (30 psi).

Commentary Notes:

(1) Systems with CO_2 partial pressures between 20.6 kPa to 206 kPa (3 psi and 30 psi) will require corrosion control measures if the expected corrosion rate is high (see 6.1.4). Systems with partial pressures below 20.6 kPa (3 psi) are usually non-corrosive.

(2) Mixed corrosive systems containing both carbon dioxide and hydrogen sulfide shall be considered to be dominated by the carbon dioxide corrosion mechanism when the ratio $H_2S/ CO_2 < 0.6$. Such corrosion systems are generally called "sweet" when considering general thinning, pitting, and erosion-corrosion. However, note that the systems may contain sufficient hydrogen sulfide to also meet the requirements of sour systems presented in Paragraphs 6.2.1 and 6.2.2.

6.1.4 A service condition that would cause a metal penetration rate of 76 µm/yr (3.0 mpy) or more. The penetration rate may be from uniform corrosion, localized corrosion, or pitting. Determine this service condition jointly by consulting corrosion engineers from the responsible operating organizations and CSD/ME&CCD.

6.1.5 All soils and waters in which piping systems are buried or immersed.

6.1.6 A water-containing fluid stream with flowing solids such as scale or sand, which may settle and initiate corrosion damage.

6.1.7 A water-containing fluid stream carrying bacteria that can cause MIC.

6.1.8 Insulated and fireproofed systems.

6.2 Crack-Inducing Environments

The environments listed below require control measures if the condition is predicted to occur during the design life of the system.

6.2.1 A piping system or process equipment exposed to an environment meeting any one of the following conditions requires sulfide stress cracking (SSC) control measures:

6.2.1.1 Service meeting the definition of sour environments in ISO 15156, Part II, Paragraph 7.1.2.

6.2.1.2 Service meeting the definition of sour environments in ISO 15156, Part II, Paragraph 7.2.1.4, SSC Regions 1, 2, and 3.

6.2.1.3 Service meeting the definition of sour service in NACE MR0103 - latest revision where the requirements of this document are more restrictive than ISO 15156 or cover environmental conditions not addressed by ISO 15156 including:

(a) >50 ppmw total sulfide content in the aqueous phase;

(b) ≥1 ppmw total sulfide content in the aqueous phase and pH <4; or

(c) ≥1 ppmw total sulfide content and 20 ppmw free cyanide in the aqueous phase, and pH >7.6.

Commentary Notes:

Total sulfide content means the total concentration of dissolved hydrogen sulfide (H_2S_{aq}), plus bisulfide ion (HS^-), plus sulfide ion (S^{2-}). For a detailed explanation of this subject, see NACE MR0103 paragraph 1.3.5.

In the case of uncertainty in requirements between ISO 15156 and NACE MR0103, CSD/ME&CCD shall be the final arbiter.

6.2.2 Piping systems and process equipment exposed to an environment with >50 ppmw total sulfide content in the aqueous phase require the use of HIC resistant steel that meets 01-SAMSS-035 and 01-SAMSS-043 for pipes and 01-SAMSS-016 for tanks, heat exchangers, and pressure vessels.

6.2.2.1 Rich diglycolamine (DGA) systems are not required to meet this requirement. However, the amine stripper, its overhead (exit) gas piping, cooler, and overhead receiver shall be fabricated from HIC-resistant materials.

6.2.2.2 All other rich amine systems shall meet this requirement.

6.2.2.3 Lean amine systems are not required to meet this requirement.

Commentary Note:

> *In new plant build the use of HIC resistant material for some of the piping and non-HIC resistant material for the remainder will require segregation, control, and tracking of the two material types and an effective method to differentiate between the two types of material at the construction site. The use of HIC resistant pipe throughout a system may reduce costs due to simplified inventory and tracking.*

6.2.2.4 Caustic systems are not required to meet this requirement.

6.2.3 Aluminum heat exchangers must not be used in gas stream cryogenic service where the mercury content is greater than 10 ng/Nm^3 (nanograms per normal cubic meter) in order to avoid liquid Metal Embrittlement (LME). For control measures see Section 7.2.6.

6.2.4 Environments recognized by other standards or by good engineering practice as potential environments for stress corrosion cracking (SCC) require control measures. CSD/ME&CCD shall be the final arbiter in the resolution of such design questions.

Commentary Note:

> *Some SCC environments are listed in SAES-W-010 Paragraph 13.3 and SAES-W-011 Paragraph 13.3. Other amine SCC environments are listed in API RP 945. The conditions cited in the above standards include, but are not limited to, those listed below:*
>
> 1. *All caustic soda (NaOH) solutions, including conditions where caustic carryover may occur (e.g., downstream of caustic injection points).*
> 2. *All monoethanolamine (MEA) solutions (all temperatures).*
> 3. *All diglycol amine (DGA) solutions above 138°C design temperature.*
> 4. *All rich amino diisopropanol (ADIP) solutions above 90°C design temperature.*
> 5. *All lean ADIP solutions above 60°C design temperature.*
> 6. *Boiler deaerator service (i.e., ambient temperature vacuum deaerators are exempt).*
> 7. *Hydrogen service for P-No. 3, 4, and 5A/B/C base materials.*
> 8. *All diethanolamine (DEA) solutions.*
> 9. *All MDEA / aMDEA solutions.*

10. *Shut down conditions that may lead to the development of polythionic stress corrosion cracking (see SABP-A-001).*

11. *FCC Fractionator overhead systems.*

6.3 High Temperature and Refining Environments

High Temperature refinery environments identified by Saudi Aramco Best Practices, API RP 571, and compatible documents including, but not limited to API PUBL 932-A, API RP 932-B, API RP 939-C, API RP 941,and API RP 945.

7 Corrosion and Cracking Control Measures

7.1 Corrosion Control Requirements

To mitigate internal corrosion design corrosion-critical piping systems or equipment with at least one acceptable measure of internal corrosion control. A combination of two or more acceptable corrosion control measures for any given environment is preferred whenever economically and technically feasible.

7.1.1 Select the measure(s) to achieve an average metal penetration rate of less than 76 µm/yr (3.0 mpy) and/or select adequate corrosion allowance (e.g., 1.6 mm up to 6.35 mm) to allow the system to function as designed until planned replacement.

Use corrosion allowance as mandated by industry codes or other Saudi Aramco Standards. For carbon steel and alloy steel systems, always use a minimum corrosion allowance of at least 1.6 mm. The standard corrosion allowance is 3.2 mm. If a higher corrosion allowance is required, the part needs to be highlighted for additional on-stream, inspection coverage. The maximum corrosion allowance is 6.4 mm which may only be applied with specific approval of Saudi Aramco. If the calculated required corrosion allowance exceeds 6.4 mm, evaluate alternative measures.

Commentary Note:

Corrosion allowance will not reduce the corrosion rate of the piping material. However, the extra wall thickness of the pipe may provide a longer service life if the mode of attack is uniform general corrosion. Corrosion allowances are often not effective against localized corrosion, such as pitting. However, if pitting rates are well defined from historical data, adequate corrosion allowance can be viable.

7.1.2 Acceptable corrosion control measures include, but are not limited to, the following:

- Corrosion-resistant alloys. Procure austentic and duplex stainless steel pipes for on-plot piping in accordance with 01-SAMSS-046.

- Nonmetallic materials and linings where permitted by Saudi Aramco standards. See 12-SAMSS-025 and 01-SAMSS-045 for lined-pipe applications. See SAEP-345 for composite non-metallic repair systems for Pipelines and Pipework. See 01-SAMSS-029, 01-SAMSS-034, and 01-SAMSS-042 for various reinforced thermoset resin (RTR) applications. Coordinate with CSD/ME&CCD for applications not adequately addressed by Saudi Aramco standards such as SAES-L-132 and SAES-L-610.

- Coatings (internal/external) and linings (internal) meeting SAES-H-001 or SAES-H-002.

- Galvanic or impressed current cathodic protection in accordance with SAES-X-300, SAES-X-400, SAES-X-500, SAES-X-600, SAES-X-700, SAEP-332, and SAEP-333.

- Chemical treatment. Upstream operations must select inhibitors and chemicals using the methodology of SAES-A-205. For upstream pipeline treatment, the recommended corrosion control practice is to use pipeline internal scraping in conjunction with the corrosion inhibitor program to aid effective distribution of the inhibitor to the pipe wall. Refining operations must select inhibitors and chemicals using the agreed terms of the Saudi Aramco Chemical Optimization Program contracts. Refining processes do not use internal scraping for inhibitor distribution.

  Commentary Notes:

  > *Corrosion inhibitor added to the service fluid stream continuously, or introduced in a concentrated slug intermittently is acceptable provided, that the corrosion rate is consistent with the corrosion allowance. Perform periodic pipeline scraping in conjunction with chemical treatment to provide effective corrosion control. Some pipelines should be cleaned using surfactants and/or gels to remove solids.*
  >
  > *Note that when more than one chemical is added to a system for corrosion control or process improvement, these chemicals may interact and their effectiveness may be reduced or even reversed. Perform chemical compatibility testing of all process stream additives.*
  >
  > *Products such as kinetic hydrate inhibitors (KHIs) and drag reducers may be adversely affected by corrosion inhibitors and other treatments. P&CSD shall be consulted for the selection of kinetic hydrate inhibitors for new projects.*

7.1.3 Specification and Purchase of “first fill” chemicals

7.1.3.1 The LSTK (Lump Sum Turnkey) contractor shall fund the purchase of the "first fill" of all such chemicals, and shall be responsible for ensuring the cleanliness and mechanical operation of the chemical injection systems as designed.

7.1.3.2 Follow the requirements for oilfield chemicals in Materials Service Group (MSG) 147000 as defined in SAES-A-205 for first-fill where oilfield chemicals such as corrosion inhibitors, scale inhibitors, anti-foams, demulsifiers, biocides, or neutralizers, are to be used. If a chemical alliance exists or is being developed for the facility, follow Paragraph 7.1.3.4.

7.1.3.3 Follow the requirements of SAES-A-208 for water treatment chemicals in Materials Service Group (MSG) 147000 provided at first-fill. If a chemical alliance exists or is being developed for the facility, follow Paragraph 7.1.3.4.

7.1.3.4 For plants or other facilities that have an existing "chemical alliance" program such as SARCOP (Saudi Aramco Refinery Chemical Optimization Program) in place, the alliance chemical vendor shall be requested to supply chemicals for the new plant. Chemicals shall be selected and approved following the written contract procedures for the alliance that shall include input from the plant, CSD, and Purchasing.

7.1.3.5 For all other capital projects where corrosion inhibitor or other oil field or refinery chemicals, such as scale inhibitors, anti-foams, de-emulsifiers, biocides, or neutralizers are to be used:

- The LSTK (Lump Sum Turnkey) contractor shall be responsible for purchase of the "first fill" of all such chemicals, and for QA/QC requirements.
- The LSTK contractor shall be responsible for ensuring the cleanliness and mechanical operation of the chemical injection systems as designed.
- The specification and selection of the chemical(s) shall be the responsibility of the operating organization, with concurrence of CSD/ME&CCD, and Purchasing. Process additives such as kinetic hydrate inhibitors and drag reducers are the responsibility of P&CSD.
- PMT shall provide the operating organization, CSD/ME&CCD, and Purchasing with adequate time and information needed to make the chemical selection. In no

case shall this be less than six (6) months prior to the date the project is scheduled to start operation.

7.1.4 Protect all buried steel piping against soil-side corrosion by both external coating and cathodic protection. Use coating systems specified in SAES-H-002. Install cathodic protection systems in accordance with SAES-X-400 or SAES-X-600. Evaluate and mitigate the risks of stray current corrosion.

7.1.5 For offshore pipelines and platforms, protect all submerged external surfaces by coating as required by SAES-M-005. Use coating systems specified in SAES-H-001 and SAES-H-004, and cathodic protection as specified in SAES-X-300. All casings for offshore wells in non-electrified fields shall be externally coated to increase the effectiveness of the cathodic protection system.

Commentary Note:

Coating of submerged structures is governed by SAES-M-005 and SAES-H-001, however, it is mentioned here in SAES-L-133 because failure to coat the structure can adversely affect the ability of the cathodic protection system to adequately protect the submerged piping and well casings under certain circumstances.

7.1.6 Externally protect offshore structures, piping and other static equipment exposed to marine environment (defined in SAES-H-001, SAES-H-002, and SAES-H-004). Critical structural or process components, i.e., jacket members, risers, J tubes shall be protected by sheathing with Monel through the splash zones. Components exposed to the atmosphere or submerged and non-critical structural components in the splash zone, i.e., boat landings or barge bumpers shall be protected with coatings. Selection of coating systems shall comply with SAES-H-001, SAES-H-002, and SAES-H-004.

7.1.7 Erosion corrosion is mitigated primarily by adherence to SAES-L-132 for material selection and fluid velocity limitations. Similar principles can be applied to cases not specifically addressed in SAES-L-132.

7.1.8 Measures for mitigation of MIC include control of bacteria by application of a biocide chemical, selection of resistant materials, and selection of coatings.

7.1.9 Protect all piping and pipelines subject to low flow, intermittent flow or stagnant conditions by the use of one of the following: internal coating, non-metallic piping, corrosion resistance alloy (cladding, weld-overlay, thermal spray, or solid), or non-metallic liners. This specifically includes flowlines, pipeline jump-overs in crude oil and wet gas service, and production headers. Dead-legs shall be handled in accordance with SAES-L-310, Paragraph 11.4. Reference standards and documents are provided in the table below

Table (1) – Corrosion Control Methods

Corrosion Control Method	Applicable Standards and Guideline Documents
Internal coating	SAES-H-002, Internal and External Coatings for Steel Pipelines and Piping
Non-metallic Piping	01-SAMSS-042, Reinforced Thermoset Resin (RTR) Pipe and Fittings in Water and Hydrocarbon Services SAES-L-620, Design of Nibnmetallic Piping in Hydrocarbon and Water Injection Systems SAES-L-650, Construction of Nonmetallic Piping in Hydrocarbon and Water Injection Systems
Theremoplastic liners for pipelines and flowlines	NACE RP0304, Design, Installation and Operation of Thermoplastic Liners for Oilfield Pipelines NACE 35101, Plastic Liners for Oilfield Pipelines
Thermoplastic liners for piping	12-SAMSS-025, Specification for Heavy Duty Polytetrafluoroethylene and Perfluoroalkoxy Lined Carbon Steel Pipe and Fittings

7.1.10 Galvanic corrosion between electrochemically different metals and alloys shall be prevented in systems carrying highly conductive, corrosive fluids such as mostly water, when there is a good probability that a continuous liquid water phase will exist between the two dissimilar metal surfaces. Insulating gaskets and insulated bolt sets shall be used following the requirements of SAES-L-105, Paragraph 11.4. For threaded joints, insulating unions shall be used if acceptable to all other Saudi Aramco mandatory codes.

7.1.10.1 Insulating devices are not required for services that are essentially dry or non-conducting.

7.1.10.2 Insulating devices shall not be used in hydrocarbon service unless specifically approved on a case-by-case basis by the Chairman of the Piping Standards Committee.

7.1.10.3 Per SAES-L-109, insulating gaskets shall not be used at operating temperatures of 250°F and higher.

7.1.10.4 Stainless steel instrument connections to carbon steel pipework are acceptable in tempered water service.

7.1.10.5 Galvanic corrosion can be reduced by the use of corrosion inhibitors, but much higher concentrations of inhibitor are necessary to overcome the galvanic couple.

7.1.10.6 Galvanic isolation may be required to prevent damage mechanisms such as hydriding of titanium. Consult CSD/ME&CCD when using titanium alloys.

7.1.10.7 Note that insulating devices installed to provide galvanic isolation will impact the continuity of cathodic protection on buried pipelines and equipment. Evaluate this as part of the design.

7.1.11 Prevent corrosion under insulation

7.1.11.1 Protect all carbon steel and alloy steel thermally insulated systems from corrosion under insulation by applying coating systems and/or wraps (metallic or organic coating) specifically qualified for the purpose. This includes services from cryogenic temperature up to the maximum service temperature of the available coating systems.

7.1.11.2 For 300 series austenitic stainless steel see Paragraph 7.2.5.

7.1.11.3 Follow the requirements and recommendations of the latest edition of NACE RP0198 and EFC 55. If organic coatings are used follow the selection guideline in SAES-H-001.

7.1.11.4 Design insulation systems to exclude water through effective sealing of outer cladding and through the use of non-absorbent insulation media.

7.1.11.5 Use low leachable chloride insulation following the recommendations of NACE RP0198 and EFC 55.

7.1.11.6 Do not use insulation unless it is essential to do so; for example, do not use for personnel protective purposes unless no other solution is possible. Consider insulating paints or equipment cages (see EFC 55 Section 4.3).

7.1.12 Prevent corrosion under fireproofing

7.1.12.1 New carbon steel equipment shall have a compatible corrosion-resistant, coating applied underneath both cementitious and intumescent fireproofing material in accordance with SAES-H-001, NACE RP0198-2008 Table 2, System 11, and SAES-B-006. The coating shall be one that is specifically approved for this service in consultation with the fireproofing mortar manufacturer and Loss Prevention Department.

7.1.12.2 Corrosion under fireproofing in Saudi Aramco is often associated with the testing of firewater monitors and washing down areas, particularly when seawater is used as firewater. In existing plants, minimize or avoid these actions if at all possible.

7.1.12.3 Fireproofing must be designed to prevent ingress of water behind the fireproofing material. Adequate sealing especially using caps and flashing is required. Water traps must be avoided by adequate design and the use of mastic where necessary.

7.1.12.4 Some intumescent coatings degrade with time. Acidic products may cause significant damage to older systems. Inspection programs are essential.

7.1.13 Prevent corrosion during and subsequent to hydrotest

7.1.13.1 *SAES-A-007* mandates corrosion protection requirements for hydrostatic test water composition and post-hydrotest lay-up procedures.

7.1.13.2 Hydrotest records shall include documentation of water sources used for each and every test and documentation of bacteria test results, chloride test results (required for stainless steel systems) and chemical programs used. Records shall be transmitted to the Plant Inspection Unit as part of the Precommissioning Record Book. (see SAEP 122, Paragraph 1.9).

Commentary Note:

Multiple plant failures have occurred shortly after start-up due to inadequate execution of hydrotest and lay-up procedures. Stainless steel and copper alloy systems are particularly prone to hydrotest damage.

7.1.14 Prevent corrosion during lay-up and mothballing

7.1.14.1 Severe corrosion can occur during short lay-up periods under some circumstances. For example, ammonium or amine chloride deposits in equipment can be very corrosive if equipment is opened to atmosphere. Plan measures to prevent corrosion even during short shutdowns.

7.1.14.2 When equipment is idle, the facility manager shall ensure that a mothball plan is developed and implemented in a timely fashion. The plan shall clearly state the length of intended mothball and the required snap-back period. Adequate funding and manpower shall be provided throughout the life of the mothball to maintain the mothball effectiveness and equipment readiness. The Mothball Manual describes techniques for preservation of equipment. SAEP-1026 mandates lay-up procedures for boilers.

7.1.14.3 Severe corrosion can occur during construction operations if partially build facilities are not adequately protected. One example is construction of a pipeline segment offshore that awaits tie-in at a later time to other pipelines or onshore facilities. Severe corrosion will result unless adequate measures are implemented. Consult the Corrosion Technology Unit, ME&CCD, CSD.

7.2 Cracking Control Measures

7.2.1 In the environments defined in Paragraph 6.2.1 or single contingency failure circumstances described in Paragraph 5.3.2 that might allow the environments defined in Paragraph 6.2.1 to be present, use materials that comply with the requirements of ISO 15156 or meet Saudi Aramco standards and specifications that ensure equivalent performance. For refinery applications, materials that meet the requirements of NACE MR0103 are also acceptable.

ASME SA515 or 516 steel, Grade 70 or higher strength, shall not be used unless post weld heat treatment is applied after fabrication.

Metallic plating, metallic coatings, and plastic coatings or linings are not acceptable for preventing SSC of base metals. Internal coatings may be used to mitigate corrosion, however, this does not eliminate the requirement that the base metal be resistant to SSC.

Refer to SAES-W-010, SAES-W-011 and SAES-W-012 welding standards for welding procedure qualification hardness testing, production weld hardness testing, and restrictions on dissimilar metal welds, for sour service applications.

Commentary Note:

The material requirements in 01-SAMSS-035, 01-SAMSS-038, 01-SAMSS-333, 02-SAMSS-005, 02-SAMSS-011 (except for low temperature flanges), 32-SAMSS-004, 32-SAMSS-007, and 32-SAMSS-011 for pipe, fittings, flanges, and process equipment comply with ISO 15156/NACE MR0175 or provide equivalent performance, even though the NACE standard is not, and should not be, explicitly referenced in the catalog description or purchase order.

7.2.2 HIC resistant steel is required for pipes, scraper traps, vessels and other pressure retaining equipment exposed to environments defined in Paragraph 6.2.2.

7.2.2.1 Seamless pipe, forgings, and castings are considered to be resistant to HIC.

7.2.2.2 Process equipment carbon steel plates shall meet the requirements of 01-SAMSS-016.

7.2.2.3 Welded carbon steel pipe must meet the requirements of 01-SAMSS-035.

7.2.2.4 *Exception:* For induction pipe bends and quantities of pipe not to exceed 36 meters (120 feet) in length at any location, when HIC-resistant pipe is not available, use of other pipe with the grade and wall thickness such that the hoop stress does not exceed 25% of the specified minimum yield strength (SMYS) at the maximum allowable operating pressure is permissible with prior written concurrence of CSD/ME&CCD and the operating department. This provision does not preclude or modify the requirement in Paragraph 9.8 to build new pipelines to allow the passage of ILI tools. Where the internal diameter of a bend or pipe section would be reduced enough to prevent passage of ILI tools, Paragraph 9.8 shall take precedence.

7.2.2.5 The temporary conversion of existing, non-HIC-resistant pipe systems, except spiral pipe, to sour service, is allowed if the hoop stress does not exceed 25% of the specified minimum yield strength at the maximum allowable operating pressure (MAOP) and if the pipe meets the requirements of 7.2.1.

Commentary Note:

Operating non-HIC-resistant pipe at 25% SMYS does not result in immunity from hydrogen damage, including blisters, but reduces the probability of a service leak or rupture. The pipe, *welds, fittings, etcetera, must not be susceptible to sulfide stress cracking.*

7.2.2.6 For new equipment, corrosion resistant alloy internal cladding is acceptable to prevent HIC. Therefore, the backing carbon steel material need not be HIC resistant.

7.2.2.7 For new equipment, organic coatings are not considered to be acceptable for preventing HIC. Therefore, the base carbon steel material shall be resistant to HIC.

7.2.2.8 For existing equipment fabricated from non-HIC resistant steel, internal organic coatings may be used to mitigate HIC and extend the service life until replacement.

7.2.3 Design sour gas in-plant piping systems and pipelines for resistance to SOHIC by observing the restrictions in SAES-L-136. Note that steels and weldments that are resistant to HIC may be susceptible to SOHIC. Per SAES-L-136, to prevent the probability of SOHIC, welded pipe, e.g., straight or spiral seam, shall not be used in sour gas unless it is stress relieved (e.g., by heat treatment).

7.2.4 Design all corrosion-critical piping systems and equipment for resistance to stress-corrosion cracking (SCC). Possible control measures include material selection, coatings, modification of the environment, post-weld heat treatment, or significantly reduced design stress.

7.2.4.1 Prevent cracking and corrosion in new or repaired amine systems as detailed in Paragraph 6.2.4 by following the recommended practices of API RP 945 and applying the post-weld heat treatment requirements of SAES-W-010, SAES-W-011 and SAES-W-012.

7.2.4.2 Prevent polythionic acid stress corrosion cracking (PASCC) in potential cracking environments by following NACE RP0170 and Saudi Aramco Best Practice SABP-A-001. However, seek input from CSD/ME&CCD on the treatment of poorly draining equipment such as vertical heater coils.

- Select stabilized materials that resist sensitization and operate below the sensitizing temperature:
  - Type 304/304H/316/316H, operate at temperatures less than 370°C.
  - Type 304L/316L, operate at temperatures less than 400°C.

- Type 321 and 347, operate at temperatures less than 455°C
- Alloy 625 and 825, operate at temperatures less than 650°C
- Use welding procedures that minimize sensitization.

- In systems that have a high potential for PASCC, control environment during T&Is and maintenance. Prevent access of moist air to surface of equipment by not opening equipment unless absolutely necessary. Use nitrogen blanket to pressurize as needed.
- Remove sulfide scales before opening by washing equipment with sulfide scale converter before opening equipment or alternatively, neutralize surface by washing equipment with 1% Na_2CO_3 before opening equipment and during extended openings; limit solution chloride concentration to 250 ppm.
- Systems that use steam air decoking - add 5,000 ppm ammonia to steam for neutralization.
- If hydrotest of existing used austenitic stainless steel equipment and other susceptible alloys that have been exposed to sour environments and sensitizing conditions is necessary, use 1% Na_2CO_3 solution for the hydrotest.

7.2.4.3 Chloride impurities in the Na_2CO_3 solution (soda ash wash) can represent a major hazard of chloride cracking austenitic materials.

7.2.4.4 Prevent carbonate cracking in FCC systems and other susceptible equipment. As a minimum, post-weld heat treat the main fractionator overhead system through to the first vessel in the gas recovery unit. Avoid using ammonium polysulfide (APS) upstream of the FCC as this has been suggested to enhance carbonate cracking.

7.2.4.5 Prevent caustic cracking by following the NACE SP0403 and the requirements of Saudi Aramco welding and pressure vessel standards.

Commentary note

Caustic cracking has occurred most commonly in Saudi

Aramco facilities due to the carry-over of caustic from Merox Units or the miss-feeding of high concentration caustic in crude units to locations that were not intended to receive caustic. Such failures represent single contingent failure. Be sure to consider these and other operational variations.

7.2.4.6 Follow the requirements of SAES-D-001, Paragraph 11.3.

7.2.5 Completely coat the outer metal surface of all 300-series stainless steels that may cycle into the temperature range from 104°F (40°C) up to the maximum service temperature of the available coating systems in order to protect them from pitting and stress corrosion cracking. Use thermal spray aluminum, organic coatings with zero leachable chlorides that are approved for immersion service, or foil wraps as detailed in the NACE RP0198 - 2004, Section 4, Table 1 and EFC 55. Contact the coatings RSA in CSD/ME&CCD for a list of approved coating products. Use low leachable chloride insulation in accordance with ASTM C795. Use insulation materials and weatherproofing to prevent water ingress and that do not allow the absorption of water.

7.2.6 Install Mercury Removal Unit (MRU) upstream of the aluminum heat exchangers in cryogenic services to remove mercury from the gas stream. Mercury content in the gas outlet of the MRU should not exceed 10 ng/Nm³ to protect the exchangers against liquid metal embrittlement (LME). Corrosion engineers from CSD/ME&CCD can be consulted for specific cases.

7.3 Minimize the risk of high temperature and refinery damage mechanisms

7.3.1 Apply all Saudi Aramco Corrosion Best Practices designated SABP-A-XXX such as SABP-A-013. Apply industry standards and common practices including API RP 941 (Nelson Curves), Modified McConomy curves (see SABP-A-016, Section, 7.4) and Couper Gorman Curves for H_2S/H_2 corrosion in the selection of appropriate materials and appropriate service conditions. Follow API RP 939-C for sulfidation control (publication expected 2009). See NACE Report 34103 for sulfidation guidance. Prevent corrosion damage predicted by API RP 571, Refinery Damage Mechanisms.

7.3.2 For refineries and process plants, follow the Appendices of this standard.

7.3.3 Design and Install Effective Water Wash Systems

Process water wash systems shall be designed to deliver sufficient water such that at least 25% of the injected water remains in the liquid phase. Demonstrate the adequacy of design by providing calculations for the phase distribution of injected water and for the ability of the water injection pipework and nozzle to deliver the required volume of water. Use a Whirljet injection nozzle following the designs presented in SABP-A-015. Continuous water wash is the norm. Intermittent water wash may not be used without the prior written approval specifically addressing this topic from the Supervisor, Corrosion Technology Unit/Materials Engineering and Corrosion Control Division/CSD and the plant corrosion engineer.

7.3.4 For process streams operating above 450°F (232°C) without hydrogen, modified McConomy Curves shall be used to estimate corrosion rate. Extrapolation of the curve below 500°F (260°C) is allowed.

7.3.5 For reactor effluent of hydro processing units operating above 400°F (204°C) containing hydrogen and hydrogen sulfide, Couper-Gorman Curves shall be used. For reactor feed streams containing hydrocarbons and hydrogen or separator liquid containing some hydrogen (before or after pressure let down), corrosion rate shall be determined by the higher value of the Couper-Gorman Curves and modified McConomy Curves.

7.3.6 For reactor effluent systems of a hydro processing unit, Kp for ammonium bisulfide and ammonium chloride shall be calculated and reported. Water wash shall be installed before reaching the salt formation temperature.

7.3.7 For sour water, the Honeywell Intercorr program Predict SW provides more accurate estimation for general corrosion rates, and this package can be purchased from Honeywell. API RP 581 (2.B.7) may be used if Predict SW cannot be obtained.

7.3.8 For outlet tees of REAC of hydro processing unit, wall shear stress at REAC outlet shall be individually calculated if Predict SW results are used to estimate corrosion rate.

7.3.9 For corrosion rate in the amine systems, API RP 581 (2.B.8) shall be used. Since this is a very rough estimation, all circuits with corrosion rate higher than 10 mpy shall be reported.

7.3.10 Corrosion control for each sour overhead reflux system (for each major tower) shall be evaluated separately to determine its corrosiveness. The system shall be referred to Consulting Services Department if there is no chemical treatment or water wash proposed for a main fractionator over head system.

7.3.11 For high temperature hydrogen services, the latest edition of API RP 941 shall be used to check the risk of having high temperature hydrogen attack. The maximum operating temperature shall not exceed the Nelson curve safe operating limit for the material class minus 122°F (50°C)--that is, apply a safety margin of 122°F (50°C).

8 Corrosion Management Program--Requirements for New Projects and Major Facilities Upgrades

8.1 Each new project or major facility revision shall include a Corrosion Management Program (CMP) to reduce the total cost of ownership and to reduce the operational, safety, and environmental impact of corrosion and materials failure. The CMP shall

8.1.1 Follow the intent and structure of the United Kingdom Health and Safety Executive requirements published by the Energy Institute in Guidance for Corrosion Management in Oil and Gas Production and Processing, May 2008, ISBN 978 0 85293 497 5.

8.1.2 Be documented in a Refinery Instruction Manual (RIM) or equivalent document for other facilities.

8.1.3 Provide a proactive, integrated, and structured approach to all aspects of corrosion management from design through operation and maintenance to decommissioning.

8.1.4 Clearly define roles, responsibilities, and competencies at all levels of that structured approach.

8.1.5 Establish benchmarks and key performance indicators at all levels of that structured approach.

8.1.6 Use realistic service life of the facilities as a means to calculate cost effective corrosion and materials failure control options.

8.1.7 Use a risk-based evaluation to optimize the design and planned inspection program following the intent of SAEP-343, API RP 580, and API RP 581.

8.1.8 Apply international and Saudi Aramco standards, best practices, and metrics referenced in this standard.

8.2 The CMP shall be submitted for review and approval of the Coordinator, Materials Engineering and Corrosion Control Division, Consulting Services Department, at each stage of the project review process. At the Project Proposal and Detailed Design stages, the submission shall be a separate document that specifically addresses the CMP program in a level of detail appropriate to that stage of the design process. At the project completion stage, the Corrosion Management Plan must be submitted including corrected, as-built drawings, corrosion/inspection isometrics, baseline on-stream inspection data, etcetera, as required by standards, in accordance with SAEP-122.

8.3 All aspects of the design, construction, and operation cycle shall be addressed in the corrosion management program including:

8.3.1 Scoping and design phases, procurement, construction, commissioning, operation, inspection, major maintenance, and mothballing and decommissioning.

8.3.2 The CMP will include corrosion of structures and utility systems in addition to the process systems.

8.3.3 The CMP shall document all design features and operating requirements regarding materials selection, coatings, cathodic protection, inhibitors and chemical treatment, calculation of corrosion allowances, corrosion monitoring and inspection, post-weld heat treatment if required, scraping, control of microbially induced corrosion, and other relevant corrosion control techniques necessary to comply with this standard.

8.4 CMP--Design Basis Scoping Paper

The CMP at the Design Basis Scoping Paper stage shall include major corrosion and materials challenges, design choices, and any need for additional field data or corrosion test data. It shall include basic requirements to build pipelines suitable for in-line inspection in accordance with Paragraph 9.8 of this standard. The DBSP shall define the end presentation format of the operational Corrosion Management Program.

Commentary Notes:

- *Design choices could include the selection of a larger diameter pipeline between two platforms to facilitate through-platform in-line inspection, thus reducing future inspection costs, the choices between different types of process units that achieve the same end, the purchase of steam or treated water from a third party, and the choice to complete wells with tubing that must be replaced frequently versus alloy tubing with an indefinite life span.*
- *Specific design choices might include the provision of a sub-sea valve with a design life of 50 years to avoid the necessity to do maintenance on a sub-sea valve. It might also include the selection of wireless data transmission for process control which could be expanded to include wireless corrosion monitoring. It could also*

include the decision to provide internal coating in a long pipeline to avoid the cost and impact of black powder generation.

- *The need for additional data could be the need for additional drill stem tests for a producing formation or it could be the need to test corrosion inhibitor packages, and so forth.*

8.5 CMP—Design

8.5.1 The CMP at the project proposal stage will clearly define all roles and responsibilities in the selection of materials and development of corrosion control strategies for the project. This will include responsibility for design choices, procurement and quality assurance, as well as all aspects of field implementation through to commissioning, and shall maintain documented records to verify the same.

The CMP at the Project Proposal stage shall also clearly specify for inclusion in engineering contracts all records and actions that must be completed per SAEP-122, Project Records.

The CMP at the Project Proposal stage shall include the scope of corrosion monitoring fittings and equipment such as the need to provide in-line inspection (pipeline scraping) facilities or intrusive corrosion monitoring probes and data processing such that adequate funding can be assigned at the Project Proposal stage.

8.5.2 Develop and obtain SAO approval of Materials Selection Tables (MST) and Materials Selection Diagrams (MSD). Preliminary development and approval of these must be completed at the Project Proposal stage. Final completion and approval of these tables must be done in a timely manner to allow necessary review and approval time before it is necessary to commit to major long lead-time purchases such as vessels. Generally, this will be before the 30% Detailed Design Review.

8.5.2.1 MST shall be used to host all process design and maximum operating conditions (temperature and pressure), fluid description, fluid phase, water dew point, minimum design metal temperature (MDMT), corrosive component concentration, licensor's materials recommendation, Engineering, Procurement, and Construction (EPC) materials recommendation, final materials selection decision, valve trim, expected corrosion mechanism(s), corrosion allowance, estimated corrosion rate, design life, heat treatment requirement, and piping component specification number. Special fabrication and corrosion control requirements shall also be documented on MST in the form of notes. Corrosion control and materials selection shall meet all requirements stated in this standard noting in particular Paragraph 5.3.

8.5.2.2 Plant Integrity Windows detailing critical operating parameters and benchmarks shall be developed based upon the limitations necessary to optimize the process itself AND the limitations required to safely operate the equipment with the selected metallurgies and corrosion control strategies. Plant Integrity Windows shall be reviewed approved by the Proponent organization, Process and Control Systems Department, and Consulting Services Department/Materials Engineering and Corrosion Control Division.

8.5.2.3 Risk based analysis shall be used to validate the materials and corrosion control strategies developed and plant integrity windows, and to develop future inspection requirements.

8.5.2.4 Materials Selection Diagrams (MSD) shall be developed that are color coded diagrams to summarize materials selection results for easy review. MSD shall include key process data and follow the requirements of NACE SP0407, Format, Content, and Guidelines for Developing a Materials Selection Diagram.

8.5.2.5 Deviations in materials and corrosion control techniques in the detailed engineering drawings from those approved in the MST and MSD may only be made with the approval of the Project Management Team Manager, the proponent organization superintendent and the Supervisor, Materials Engineering Unit, CSD.

8.5.3 Contractor Lead Process Engineer (CLPE). The CLPE shall be the keeper of materials selection information and results and shall be responsible for ensuring compliance.

8.5.3.1 Keeper of the Materials Selection Tables (MST) and Materials Selection Diagrams (MSD)

i) Create MST and populate process information to MST

ii) Populate licensor's materials recommendations to MST

iii) Identify and list corrosive components defined in SAO Mandatory Engineering Requirements and Best Practices

iv) Populate concentration for each corrosive component on MST

v) Issue MST to Contractor's Materials Engineering Department for materials selection

vi) Create MSD based on MST

vii) Contractor internal review of MST and MSD

viii) Issue MST and MSD to SAO for approval

ix) Update process information on MST when process design is changed and repeat Steps v to viii and create change logs.

8.5.3.2 Identify all chemical treatment and water washing locations and obtain SAO approval.

i) Mark all chemical treatment and water washing locations on PFD and P&ID

ii) Prepare a list of chemical treating and water washing locations

iii) Provide brief description of the purposes and control limits of each chemical treatment or water washing program

iv) Define job scope of these treating or water washing programs in the detail design stage

v) Provide detailed injection point design drawings and specify materials in a specific MST per 8.5.2.

vi) Follow requirements of SABP-A-015 and the guidance of NACE Publication 34101, Refinery Injection and Process Mixing Points.

8.5.4 Contractor Materials Engineer (CME). The CME shall have the following responsibilities:

8.5.4.1 Perform materials selection in accordance with information provided by CLPE and this standard.

8.5.4.2 Identify conflicts between licensor's recommendations and SAO requirements and provide inputs for conflict resolutions.

8.5.4.3 Provide technical inputs to improve materials selection results, corrosion control measures, and fabrication requirements.

8.5.5 Contractor Piping Engineer (CPE)

8.5.5.1 CPE is responsible for converting materials selection results into line class specifications.

8.5.5.2 CPE is responsible to consolidate various line class specifications from different vendors into a single set of project line class specifications.

8.5.5.3 CPE is responsible for creating piping fabrication packages in accordance with SAO materials and fabrication requirements.

8.5.6 Corrosion Monitoring and Inspection Systems. The design shall include a corrosion monitoring and inspection plan and facilities to assure that essential corrosion control parameters are maintained within KPI's. Corrosion monitoring requirements are detailed in Paragraph 9 of this standard.

8.6 CMP--Procurement and Construction

8.6.1 The CMP shall include a program to ensure quality assurance of materials installed and construction processes used, such as welding, in the fabrication of plant. This shall include qualification of vendors and sub-contractors of key equipment and material, physical inspection at key vendor sites during manufacturing of equipment. It shall include Positive Material Identification programs meeting or exceeding the requirements of SAES-A-206 and API RP 578. This shall include a secure materials management program to identify, segregate, and track different grades and specifications of process piping and equipment, and welding consumables.

8.6.2 The CMP shall include a program to preserve materials and minimize corrosion during the delivery, storage, construction, and commissioning activities. This preservation program shall also include the preservation of Class 19 essential spares and similar items supplied with the project which shall be preserved in a suitable manner to provide ten years preservation outdoors in Saudi Arabia without intervention except for the addition of electrical power for heating coils where necessary.

8.7 CMP—Commissioning

The CMP shall ensure that corrosion is prevented before, during, and subsequent to commissioning. Particular emphasis is placed upon approving and following hydrotest procedures.

8.8 CMP—Documentation

8.8.1 PMT shall ensure that all drawings (including MSDs) within the scope of the project must be updated to reflect the "as built" condition of the plant and these drawings must be installed into the I-Plant integrated plant information system a minimum of one month before the "On-Stream date."

8.8.2 PMT shall ensure that 3-D CAD drawing programs are updated to reflect the as-built condition a minimum of one month before the "On-Stream date."

8.9 CMP—Inspection Programs

8.9.1 The EPC shall develop corrosion loops, on-stream inspection points, and the EIS (Equipment Inspection Schedule) data sheets for all process systems, and all other systems with a predicted corrosion rate in excess of 1 mpy, in accordance with SAEP-20, Paragraph 4.1, SAEP-122, and SAEP-1135, based on the risk based analysis that was completed under paragraph 8.5.2.3.

The Corrosion Loops shall define all applicable damage mechanisms following the intent of API RP 571. The Corrosion Loops shall define the Plant Integrity Window for equipment such as temperature, pressure, velocity, maximum allowable corrosion rate, etc. Measurable KPIs shall be listed.

3-D CAD models, if developed for the project, shall segment complex items that involve more than one corrosion loop into different drawing elements. For example, a column that has three significantly different corrosive conditions or materials at different heights in the column must be segmented into three drawing elements to represent the three different corrosion zones.

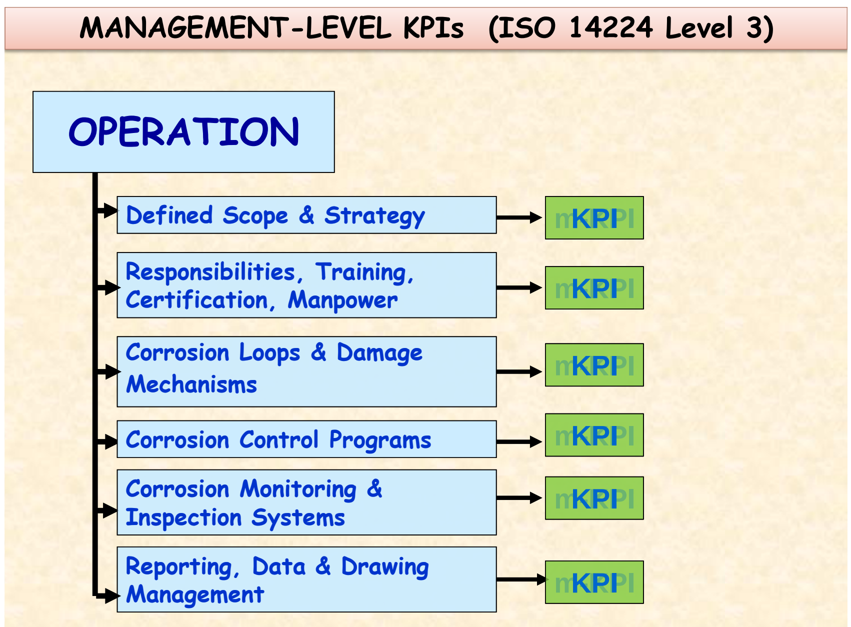
8.9.2 Simplified isometrics specifically designed to assist the inspection program shall be developed by the EPC and approved by the Plant Inspection Unit.

8.9.3 The EPC shall complete the baseline OSI survey, in accordance with SAEP-122. The data shall be input to the SAIF inspection program one month before the "on-stream" date.

8.9.4 The EPC shall develop inspection and monitoring programs for special items including but not limited to: Inspection of injection points, per 01-SAIP-04, Inspection for corrosion under insulation per 00-SAIP-74 and EFC-55, inspection of nipples, nozzles, and vents, and a deadleg inspection program.

8.10 CMP—Operation

8.10.1 The Corrosion Management Program for operating plants, process facilities, offshore platforms, and similar well defined facilities, shall provide a hierarchy of KPIs and exception items that can be applied at three levels: senior management (ISO 14224, Paragraph 8.2, Level 3), intermediate management (Level 4-5), and operators and engineers (Level 6-9), and will provide alerts to appropriate levels for correction items as needed. KPIs will address six key areas and will be developed in close cooperation with the proponent organization and Engineering Services Corrosion Management Team.



These KPIs will directly reference the Plant Integrity Window (see Paragraph 8.5.2.2). For projects where a 3-D CAD drawing package is developed, these data shall presented in a user friendly 3-D interactive plant display operating on Microstation design files that interfaces with an oracle or SQL database management system and all plant information systems including PI, SAIF, and SAP, and defined in 23-SAMSS-073, 3D Asset Virtualization Tool, The data shall also be available in a "dashboard" format providing informative summary information. 3-D CAD files shall also be provided by major equipment vendors for heaters, vessels, and other major equipment. If a 3-D CAD package is not required by the project, then the final presentation form can be provided by the database system.

8.10.2 The CMP shall include procedures for preventing damage where corrosion or metallurgical failures may occur during start-up or operation. Examples include: the need to preheat water in waste heat boilers in sulfur plants in order to avoid shock condensation of sulfurous/sulfuric acid on start-up, and the need to control the heating or cooling and pressurization of 2¼ Cr reaction vessels, and so forth.

8.10.3 The CMP shall include a defined Management of Change procedure that includes the requirement for review and approval by the plant corrosion engineer of all process, operation, or maintenance changes.

8.11 CMP—Maintenance, Lay-up, and Mothballing

8.11.1 Assessment of Damaged Equipment. Localized corrosion assessments shall be performed in accordance with methodologies of API RP 579.

8.11.2 The CMP shall include procedures for preserving equipment where special procedures are needed during downtime. Examples include: the need to keep sulfur systems at temperature to prevent acid gas condensation; the need to exclude oxygen from process vessels that contain potentially corrosive deposits, and so forth.

Commentary Note:

> *Severe damage has occurred in distillation columns and other equipment during downtime. Corrosive chloride salts such as ammonium or amine chloride salts can cause corrosion at the rate of over 1,000 mpy if exposed to moisture and air. Sulfide scales can cause polythionic acid SCC of austenitic stainless steel (see paragraph 7.2.4.2).*

8.11.3 The CMP provided by the EPC shall include preservation procedures for all major pieces of equipment such as generators, turbines, large pumps, and similar items should it be necessary to mothball this equipment sometime in the future. Generally, these shall be written by the original equipment manufacturer (OEM). These procedures shall include instructions for cleaning the equipment after use in the planned service environment. The procedures shall include detailed instructions and the measures required to preserve shafts and bearings.

Commentary Note:

> *Under some circumstances, shafts in rotating equipment may deform if left in place without rotation. Also, bearing surfaces may degrade. Removal of shafts and vertical storage is one option. OEM shall specify if this is necessary.*

8.12 Integration of CMP Plans between Different Projects

8.12.1 If major projects are arranged as two or more indepent budget items (BI's) such as offshore pipelines, production facilities, and onshore processing plants, the CMP shall be integrated as necessary to facilitate the design, building, and operation of each separate BI and/or BI and existing facility.

Commentary Note:

For example, where a recirculating inhibitor, methyl ethyl glycol (MEG) or other chemical system is used offshore and reprocessed in the onshore plant, the two CMP's shall be integrated. Where onshore facilities, such as a slug catcher or separator receive fluids from offshore, sample locations shall be provided as required by the upstream offshore project and corrosion monitoring data shall be made available to both upstream and downstream projects through software programming supported by hard copy, as required.

8.12.2 The integrated CMP plans shall be included in the submission for review and approval as per 8.2. CSD/ME&CCD shall be the final authority concerning the need to integrate part or all of the Corrosion Management Programs as described in 8.12.1.

9 Corrosion Monitoring Facilities

9.1 Design and provide corrosion-monitoring capabilities for all new corrosion-critical piping systems. Provide details of the corrosion monitoring philosophy and design as part of the Corrosion Management Program. The scope shall be submitted as part of the Project Proposal to ensure adequate funding. A detailed submission is required during the detailed design review. SAEP-1135 requires on stream inspection programs to be developed for any system with a corrosion rate greater than 1 mpy.

Commentary Note:

For low-corrosive systems, the corrosion monitoring capabilities may be as simple as providing access for ultrasonic surveys. The objective here is to develop a philosophy early in a project so that the philosophy is reviewed and approved and corrosion monitoring equipment may be installed along with any required access platforms.

9.2 The corrosion monitoring plan shall include the number and approximate location of corrosion monitoring fittings, the provision of safe permanent adequately sized access to each test location, the measurement technique to be employed, the provision of data management software, data transmission, networking, racks, and marshalling cabinets. In cases where multiple engineering contractors are working on various units in integrated major projects, where possible, the engineering contractors should interface to develop one integrated system that maximizes use of existing facilities (computer, etcetera) and avoids unnecessary duplication.

9.3 01-SAMSS-023, Intrusive Online Corrosion Monitoring, specifies requirements for these systems. CSD/ME&CCD is the Responsible Standardization Agent (RSA) for corrosion monitoring tools. See the approval requirements in 01-SAMSS-023, Paragraphs 5.1, 5.2, and 5.3.

9.4 Corrosion monitoring end devices shall not be installed more than two weeks in advance of facility start up to prevent excessive attack in a non-process environment. Corrosion monitoring end devices, shall not be exposed to any hydrotest.

9.5 Corrosion monitoring systems may be commissioned subsequently to the signature of the Mechanical Completion Certificate. However, if this occurs, the Project Management Team shall provide sufficient funding for completion and start-up of the corrosion monitoring system and this must include the provision of funds for specialist manpower from the equipment manufacturer required to commission the system.

9.6 Corrosion monitoring access fittings used must be approved by the Supervisor, Corrosion Technology Unit, CSD, and the facility corrosion engineer. Generally, fittings used in refinery operations will be retractable fittings. In selecting fittings, consideration must be given to compatibility with the design of any pre-existing fittings in the plant. Use of on-line retrievable fittings introduces a personnel safety risk, however that risk is controllable and shall be accounted for in the selection and positioning of these fittings during the design phase. On-line retrievable fittings shall not be used in any hydrogen service.

9.7 Corrosion monitoring fittings shall be positioned in consultation with the facility corrosion engineer and CSD/ME&CCD/Corrosion Technology Unit. Generally, fittings used in upstream operations will employ Cosasco 2-inch high pressure fittings following the general requirements of Library Drawing DA-950035, 2005 revision. The fittings shall be oriented as follows:

9.7.1 For non-hydrocarbon contaminated water systems where a line will be filled completely with water, i.e., power water injection, utility water, etcetera, corrosion monitoring locations can be mounted at 3, 9 or 12 o'clock. Ease of access and serviceability are major components in the position selection. 6 o'clock fittings are not normally employed.

9.7.2 For hydrocarbon contaminated water systems where a line can be partially filled with water and with a hydrocarbon layer in the upper portion of the pipe, i.e., produced water injection, oily water processes, etcetera, corrosion monitoring locations shall be mounted at 3 or 9 o'clock. 12 o'clock mounting shall not be used except with the specific prior written approval of the facility corrosion engineer, as hydrocarbon films can interfere with monitoring elements. 6 o'clock fittings are not normally employed.

9.7.3 For liquid hydrocarbon systems, the design and positioning of the corrosion monitoring fitting requires the specific prior written approval of the facility corrosion engineer, in consultation with CSD.

Commentary Notes:

In some operations, monitoring is achieved through the use of 6 o'clock position bottom of the line tee traps. The tee trap design reduces the requirement for line elevation or the excavation of permanent servicing pits. It also provides a collection area for water in low water cut lines. The tee trap design provides double block and bleed isolation, for fitting replacement or monitoring device servicing without the valve and retriever or if the service valve and retriever are used, additionally, the clearance axis is shifted to the horizontal from the vertical. Tee trap designs allow the use of finger-type probes in scraped systems. Some field organizations arrange for flushing of these monitoring locations in combination with the scraping program.

However, there are also disadvantages to the tee trap design. Probes located in these tees may not experience velocity effects, may not experience the filming effects of some inhibitors, and may promote the growth of SRBs.

9.7.4 Fittings mounted directly at 6 o'clock close to grade without the tee trap design require the provision of service cellars. These constitute a confined space and necessitate safety precautions for such; they can also accumulate sand requiring constant maintenance of the cellar. 6 o'clock fittings can also accumulate debris in the internal fitting threads as the probe is removed, possibly requiring a line shut down to clean and reinstate a probe or plug in the access fitting. Therefore, 6 o'clock fittings should not be used unless specifically approved by the Saudi Aramco corrosion engineer for that facility/system and by Supervisor, Corrosion Technology Unit, CSD.

9.7.5 Gas systems: If the gas line is prone to top of the line attack through condensation, then a 12 o'clock direct mount location would be selected. If a significant water phase is anticipated then a bottom of the line tee trap might be used. Alternately, if clearance and access are not an issue, 6 o'clock mounting with an intervening isolation valve, might be considered.

9.8 Permanent safe access is required for any location where corrosion probes or coupons need to be monitored, serviced, or replaced on-line following the general requirements in Standard Drawing AA-036242.

The platform size provided for access to 2-inch high pressure fittings shall allow the use of the high pressure access tool and valve within the confines of the platform area. Provision shall be made on elevated platforms to assist in moving the retriever equipment in place.

9.9 In-Line Inspection (ILI) – requirement for pipelines only

9.9.1 New pipelines shall be designed to accept and allow the passage of in-line inspection tools as defined in the requirements of SAES-L-410 and SAES-L-420,.

9.9.2 PMT shall provide a baseline ILI survey in accordance with the requirements of SAES-L-410, and the results shall be documented as required by SAEP-122.

9.9.3 Follow the guidance of NACE RP0102, In-Line Inspection of Pipelines.

9.9.4 Pipelines diameters may be sized to allow in-line inspection programs or cleaning programs that are launched from one platform or facility, transfer through another facility and into a second line, even when the minimum velocity requirements of SAES-L-132 will not be met for one or part of the lines. The ability to perform an internal inspection program and an internal cleaning program is more important for effective corrosion control than the velocity limitation.

9.10 Corrosion monitoring of computer control rooms and DCS will be performed following the requirements of SAES-J-801 and ISA 71.04.

	Revision Summary
18 July 2009	Major Revision. Clarifies the requirement for a Corrosion Management Program (previously called Corrosion Control Plan) and strengthens requirement to provide basic engineering documents such as corrosion loops and updated drawings. Adds requirements for the control of mercury and the prevention of liquid metal embrittlement following recent measurements on the mercury content of stream. Adds references to higher temperature corrosion/damage mechanisms reflecting the company's increasing interest in refining. Adds reference to MR0103 for refining. Adds requirements for the protection of carbon steel under insulation. Adds new published documents to the reference list. Reinstates wording from the 1997 version of the standard concerning purchase of first fill chemicals and adds clarifications for plants that already have a chemical alliance in place.
10 August 2009	Editorial revision to paragraphs 7.3.7 and 7.3.9.
26 January 2011	Minor revision.
27 September 2011	To change the primary contact for the standard as requested.
23 January 2012	Minor revision for adding paragraph 8.12 in order to clarify the Corrosion Management Program (CMP) requirements for two or more separate projects.

Appendices – Technical Modules for Refinery Services

Module A – General Requirements

1. Piping

Unless approved by SAO or specified otherwise in this document, the following guidelines shall be used:

a. All piping components shall have a design life no less than 20 years.

b. A minimum corrosion allowance of 1/8” shall be used for process piping except in CLEAN hydrocarbon streams below 450°F.

c. A minimum corrosion allowance of 1/16” may be used for clean hydrocarbon streams below 450°F. Clean hydrocarbon streams include:

   i. Hydrocarbon streams operate above water dew point or contain no free water

   ii. Hydrocarbon streams contains less than 0.05 psia hydrogen sulfide in vapor phase

   iii. Hydrocarbon streams does not contain acidic components such as chloride, sulfolane, carbon dioxide, or other corrosive or erosive components such as amines, salts, or solids

   iv. For hard-to-decide hydrocarbon streams, it should not be considered clean

   v. Most of hydrocarbon products or semi-finished products are considered clean

d. Materials selection shall be based on an estimated corrosion rate not higher than 6 mils per year for process piping. Corrosion rates shall be estimated in accordance with technical Modules provided in this standard or sources proposed by the contractors and approved by SAO.

e. A minimum corrosion allowance of 1/16” shall be used for utility applications.

f. A53 low silicon pipe shall not be used in process applications over 400°F. A business decision shall be made at the beginning of the project to determine if A53 pipe should be allowed in process applications below 400°F. The use of A53 in process applications may require A106 carbon steel pipe to be PMI'd.

g. ERW pipe shall not be used in process applications.

h. All piping components, except castings, shall have a joint efficiency equal to 1.

i. Carbon steel shall not be used over 800°F.

j. Ferritic or martensitic stainless steels containing 12% chrome shall not be used for pressure boundary materials except for pump casings and/or valve stems.

k. Type 316 spiral wound gasket with flexible graphite filler shall be the standard gaskets for all process streams.

l. API Trim 8 shall be the standard valve trim for API 600 or similar valves. API Trim 12 should be used in 300 series stainless steel piping, sour water with ammonium bisulfide concentration higher than 2%, rich amine, sulfolane, or other corrosive applications. Trim 5 shall be used in low alloy steels high temperature hydrogen applications, high temperature streams over 600°F (or higher?), or high pressure streams over 1500 psig (or higher?). For special valves with metallurgy better than Type 316 stainless steel, valve trim shall match the valve body material and half hard faced as a minimum.

m. Corrosion allowance, estimated corrosion rates, design life, and materials selection technical module shall be documented on materials selection table.

Module B – Hydrogen Free Sulfidation Corrosion with 1.0 TAN Maximum

1. Piping

   a. Materials selection for hydrogen free sulfidation environments shall follow modified McConomy Curves for process applications with the maximum operating temperature above 450°F.

      i. Sulfur content in weight percent shall be reported in all hydrogen free hydrocarbon streams over 450°F.

      ii. Both weight percent of sulfur in the liquid phase and H_2S mole percent in the vapor phase shall be reported in piping downstream of the pressure letdown valves in hydroprocessing units. Both modified McConomy Curves and Couper Gorman Curves shall be used to estimate corrosion rate by assuming 100% liquid or 100% vapor flow. The higher corrosion rate shall be used to select materials for downstream of the pressure letdown valves. Materials upgrade or extra corrosion allowance shall be considered for piping located at the immediate downstream (10X pipe diameter) of the pressure letdown valves. Materials consistency shall be maintained for piping between the separator liquid outlet and downstream of the pressure letdown valve.

      iii. For Product Stripper and/or Main Fractionator bottom reboiler systems in hydroprocessing units, the potential high corrosion rates of ferritic steels need to be addressed. For fired heater tube metal temperature higher than 700°F, Type 347 stainless steel shall be used. For reboiler/fired heater inlet and outlet piping, the minimum metallurgy shall be 9Cr-1Mo steel.

      iv. Materials for hydrogen free overhead vapor stream containing sulfur (coke drum overhead vapor line and/or FCCU reactor overhead vapor line) shall be proposed by the licensor/designer and approved by SAO.

   b. 1 1/4Cr-1/2Mo and 2 1/4Cr-1Mo shall not be used to control corrosion in hydrogen free sulfidation environments.

   c. 5Cr-1/2Mo shall be avoided in all refinery applications if possible. A business decision shall be made at the beginning of the project Feed stage to determine if 9Cr-1Mo should be used to replace 5Cr-1/2Mo. 5Cr-1/2Cr provides limited corrosion resistance in the hydrogen free sulfidation environments. Construction cost difference between 5Cr-1/2Mo and 9Cr-

1Mo is not significant, but mixing 5Cr-1/2Mo materials with 9Cr-1Mo materials has caused significant problems in sulfidation environments.

2. Vessels

a. 5Cr-1/2Mo and 9Cr-1Mo shall not be used to build pressure vessels, instead carbon steel clad with Type 405 or 410S stainless steel vessels shall be used.

Module C – High Temperature Hydrogen Services

1. General

   a. Materials selection in high temperature hydrogen services shall follow the latest revision of API RP 941

      i. Hydrogen partial pressure in psia shall be reported in each hydrogen containing stream

   b. A safety margin of 50°F and 50 psia shall be added to the maximum operating conditions to perform materials selection

2. Piping

   a. All valve s shall have API Trim Number 5

   b. All valve bodies shall be RT inspected to meet Level 2 RT requirements specified in MSS SP54

   c. All 1 1/4Cr-1/2Mo and 2 1/4Cr-1Mo piping shall be post weld heat treated regardless of process or steam applications

   d. Temper resistant 2 1/4Cr-1Mo filler metal shall not be used for piping construction

3. Vessels

   a. 2 1/4Cr-1Mo vessel fabrication shall follow *API RP 934-A*

   b. 2 1/4Cr-1Mo materials shall not be used to fabricate vessels in cyclic services such as coke drums

   c. Fabrication of 1 1/4Cr-1/2Mo vessels with shell thickness between 1" to 4" and the maximum operation temperature below 825°F shall follow API 934-C

   d. For low alloy steel vessels over 4" think in high temperature hydrogen services, 2 1/4Cr-1Mo steels or better shall be used.

4. Thermal fatigue. Mixing of high temperature streams with low temperature streams can result in thermal fatigue. 300 series stainless steels are particularly prone to this failure mechanism. ΔT shall be limited to a maximum of 50°C for stainless steels. Upgrade or downgrade materials to reduce the risk of this damage mechanism. Redesign thermal injection point to have effective mixing center stream. Coinject streams. Do not inject counter-current as this has increased the risk of failure in plant operations.