Inspection Manual

Edition-1

May-2010

Inspection Engineering Unit

Operations Inspection Division

Inspection Department

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SAUDI ARAMCO IN-SERVICE STATIC PROCESS EQUIPMENT INSPECTION MANUAL

INSPECTION ENGINEERING UNIT/OPERATION INSPECTION DIVISION/INSPECTION DEPARTMENT

Dhahran, Saudi Arabia

May, 2010

PREFACE

Inspection Department realizes its role to ensure the integrity, un-interrupted and safe operation of all operating facilities under direct or shared custody of Saudi Aramco. In light of achieving this mission, Inspection Department has developed Engineering Standards and Procedures which provide necessary regulations to cover inspection of process static equipment. However, the available setup highly depends on the training excellence and experience of the plant inspectors. Because of the wide-spread geographical area of operations, and increased demand for inspection of aging facilities, currently it is not feasible to achieve the uniform highest level of expertise throughout the company. Hence, it is required to establish a system which helps reducing the dependence on inspection experience, and achieve a uniform level of inspection quality amongst all process facilities. This Inspection Manual is the first step towards achieving this Goal. Inspection Engineering Unit/Operation Inspection Division, with the help of operation inspection units, has compiled this inspection manual with the intent to provide step by step guidelines for the Plant Inspectors, to perform comprehensive inspection of the in-service Static Equipment. All procedures provided in this manual are based on the established Saudi Aramco and Industry Standards/Inspection procedures. The detailed guidelines will help the inspectors in locating and evaluating the damages eminent to the Static Equipment due to process, design, manufacturing and maintenance related activities. This Manual is a non-mandatory document which supplements the mandatory Saudi Aramco Engineering Procedure SAEP-325, Inspection Requirements for Pressurized Equipment.

Significant Features of the Inspection Manual:

In order to ensure the incident free execution of the Inspection jobs, the Section-4 of this manual provides the minimum safety requirements and guideline for the Safe Work Planning. Appendix-A of this manual provides the details of most commonly encountered Oil & Gas fields related hazards, means of controlling, and safe exposure limits for each hazard. The Safe Work planning of the Job can be done as per instruction provided in Section-4, in conjunction with Appendix-A. All of the Hazards could not be covered in Appendix-A. It is the responsibility of the plant inspection unit to develop and implement similar kind of guidelines for any hazards associated to the unique process being carried out in their facility. If the governing safety standards of the process facility provide the stringent requirements, then the safety standards of the process facility will supersede the requirements provided in this Manual.

The inspection procedures provided in Section-5, are divided into "General Inspection Requirements" (Para-1), and "Specific Inspection Requirements" (Para 2 through 10). The General Requirements provided in Section-5 Para-1 are the requirements common to all kind of process equipment, while the Specific Inspection Requirements provided in Para 2 through 10 are explicit to particular type of the Equipment. All clauses of the General Requirements are not applicable to each type of process equipment. The inspectors, while performing the inspection on any static equipment, are required to follow specific requirements which guide the inspector to relevant clauses of General Requirements.

Based on the reported failure incidents, the Consulting Services Department (CSD) in its 2009 Annual Corrosion report has highlighted most active damage mechanisms, in all upstream and downstream operation sectors in Saudi Aramco. Section-6 of this manual highlights these damage mechanisms relative to the process conditions, indentifies the most vulnerable locations/parts of the static equipment where these damages can occur, and provides guidelines for selecting the most relevant inspection technique for detection and evaluation of the potential damage.

This edition of the inspection manual covers most of the process equipment being used in upstream and downstream operation facilities in Saudi Aramco. However, the inspection procedures of some equipment types are not available in this edition. The manual is designed with the open structure for continuous expansion and maintenance. Inspection Department is committed to provide the inspection procedures of all types of static equipment in the later editions. The Inspection Units of all process facilities are welcomed to participate in the enhancement of this manual with their in-house inspection procedures for the static equipment particular to unique process being carried out in their facility. These procedures will be added in the later editions of the manual.

Since the mode of operation of the process equipment is not covered in the scope of this manual, it is therefore, the responsibility of the inspector to understand the basic operation of the equipment to be inspected. This manual is not primarily designed as a training document; therefore, it is expected that user of this manual have fulfilled the minimum Saudi Aramco Plant Inspection Training requirements. Inspection Department also expects that the junior inspectors using this manual would still be provided with necessary mentorship by their respective Operation Inspection Units.

We acknowledge the efforts of members of IEU/OID/ID in compiling this manual, and inspection units of all operation facilities, especially Harrad Gas Plant, Jeddah Refinery, Khurais Producing, and Juaymah NGL, for their valuable contribution in reviewing and providing comments to incorporate in this edition of Inspection Manual.

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This manual is primarily compiled for the inspection of Process equipment that has been placed in service. Any part of this manual can be used for the inspection of newly constructed equipment; however none of paragraphs of this manual can be used to supersede the quality control requirement established (by original contract) for the new construction of the equipment.

This manual is compiled in accordance with established Process Industry and Saudi Aramco Engineering/Inspection Standards and Best Practices. The draft of Edition-1was initially reviewed by the members of IEU/OID and later was sent to all operation inspection units for review and comments. IEU/OID greatly appreciates the contributions and valuable comments given by some operation Inspection units. All review comments from IEU and operation inspection units have been incorporated at the appropriate location. However, If any part of this Edition is found in contradiction with the established Industry practices, or editorial corrections/clarifications are required, please forward your request, in writing, to principal author of Edition-1, Iffat Ali Taimoor (taimooia) or Supervisor IEU/OID/ID.

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Section one

Scope & Introduction

1. Scope:

1.1. This document provides the guidelines for external and internal visual inspection of the static equipment at the operation facilities in direct or shared administrative control of Saudi Aramco. These facilities include but are not limited to all of the Onshore/Offshore extraction, transportation, processing, storage, and distribution plants for oil and gas products.

1.2. Guidelines in this document can also be used for inspection of static equipment being used for the community services at the facilities under direct or shared administrative control of Saudi Aramco.

1.3. This manual supplements the Saudi Aramco inspection procedure 00-SAIP-80 “Guide lines for process Equipment Inspection” and Inspection Requirement for Pressurized Equipment SAEP-325.

1.4. The manual provides the guidelines and procedures for external and internal visual inspection only. All other inspection techniques including Destructive or Nondestructive testing, and specialized inspection tasks should be performed according to the established Saudi Aramco and the manufacturer’s procedures.

1.5. If any part of this manual comes in conflict with any of established industry standards, procedures or recommended practice published by API, ASME, or NACE, the requirements of these documents will take precedence. Other conflicting established industry standards and procedures like DIN, CSA, British or Japanese standards should be forwarded to Supervisor Inspection Engineering Unit for Evaluation.

1.6. If any part of this manual comes in conflict with the established Saudi Aramco Standard or procedure, the subject should be forwarded to Supervisor Inspection Engineering Unit for Evaluation.

2. Introduction:

2.1. Structure of the manual:

2.1.1. The current Revision of this inspection manual is designed as follows:

a. Section-1: Scope and Introduction.

b. Section-2: Reference documents used in compiling the inspection and safety guidelines mentioned in this manual.

c. Section-3: The definitions of the terms used in this manual.

d. Section-4: Mandatory Safety requirements for performing the Inspection Job by Saudi Aramco Operation facilities.

e. Section-5: Inspection Procedures of various Static Equipments.

f. Section-6: Common damage Mechanisms associated with the Static equipments in the process industry.

g. Appendix-A: Introduction to Hazards and Safe work planning guidelines.

h. Appendix-B: Commonly used data.

i. Appendix-C: Guidelines of generating an effective inspection report.

j. Appendix-D: Common Inspection tools.

2.2. Safety:

2.2.1. Safety of the Saudi Aramco and Contract employees takes precedence over everything. Section-4 of this manual provides the minimum safety requirements that an inspector and the inspection team should look for while performing the inspection activities. Each operation facility should have its own established safety program. It is the responsibility of the inspection unit supervisor to use his best judgment to decide which document amongst "facility administered safety program" or "this manual" provides the stringent safety requirements. The document providing stringent safety requirements will take precedence.

2.2.2. All of the requirements provided in section-4 are mandatory if the operation facility has not implemented a better safety program.

2.2.3. Appendix A provides the fact sheets and the safe work planning guideline for the common hazards associated with the process industry. These guidelines should be used in safe work planning to perform all of the inspection jobs. It is the responsibility of the inspection unit supervisor to arrange for the safe work planning guidelines for all other hazards which are specific to the operation facility, and are not included in Appendix-A.

2.3. Usage of this manual:

2.3.1. All Inspection requirements are provided in section-5 of this manual.

2.3.2. In order to accommodate the common inspection requirements between all Static Equipment, the section-5 of this manual is divided into general requirements and the specific requirements.

2.3.3. The inspector should use both general and specific inspection requirement guidelines while planning and executing the inspection tasks.

2.3.4. All of the general requirements are not applicable to some equipment. The inspector must select the applicable clauses (segments) of the general requirements.

2.3.5. None of the inspection requirements provided in section-5 of this revision are mandatory. The inspector can modify the inspection procedure according to specific conditions, provided following conditions are satisfied.

a. The modified practice is according to tested and approved inspection procedures.

b. None of the essential components associated with the pressure envelop of the equipment are missed from inspection.

c. The procedure offers better results in providing essential information about the integrity of the equipment being tested.

3. Enhancement of the manual:

3.1. It is the intent of Inspection Engineering Unit/OID/ID to keep this manual up to date, and under continuous maintenance and improvement. Therefore all inspection units are invited to

3.1.1. Provide their in-house inspection procedures to Supervisor IEU/OID/ID for specific static equipments not included in the current edition of this manual. These procedures after necessary modification (to suit format of manual) will be included in the next revision of the manual.

3.1.2. Report the anomalies found during the inspection of the static equipments at their facilities, which are not mentioned in this manual. These “special case” inputs from the inspection units will be added to the next revision of the manual.

3.2. Any questions or concerns regarding the contents of this manual or requirement of editorial corrections should be forwarded, in writing (letter or email), to the Supervisor Inspection Engineering Unit.

3.3. The requirement of interpretation of any part of this manual should be forwarded, in writing (letter or email), to the Supervisor Inspection Engineering Unit.

Section-2

References

The latest editions of the following documents are used in preparation of this Manual. The user of this manual should consult the relevant sections of these reference documents for further information.

1: **Saudi Aramco Documents**

1.1 Saudi Aramco Engineering Standards:

SAES-D-008	Repairs, Alteration, and Re-rating of Process Equipment
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-W-014	Weld Overlays and Welding of Clad Materials
SAES-W-017	Welding Requirement for API Tanks
SAES-H-001	Coating Selection & Application Requirements for Industrial Plants & Equipment
SAES-L-132	Material Selection for Piping Systems
SAES-L-310	Design of Plant Piping
SAES-L-133	Corrosion Protection Requirements for Pipelines, Piping and Process Equipment
SAES-L-125	Safety Instruction Sheet for Piping and Pipelines

1.2 Saudi Aramco Engineering Procedures:

SAEP-20	Equipment Inspection Schedule
SAEP-310	Piping and Pipeline Repair
SAEP-333	Cathodic Protection Monitoring
SAEP-325	Inspection Requirements for Pressurized Equipment
SAEP-317	Testing and Inspection (T&I) of Shell and Tube Heat Exchangers.
SAEP-306	Assessment of the Remaining Strength of Corroded Pipes
SAEP-1141	Industrial Radiation Safety
SAEP-1135	On-Stream Inspection Administration

1.3 Saudi Aramco Inspection Procedures:

00-SAIP-74	Inspection of Corrosion under Insulation & Fireproofing
00-SAIP-75	External Visual Inspection Procedure
01-SAIP-01	Small Nipple Inspection Program
01-SAIP-02	Retirement Thickness of In-Plant Piping
01-SAIP-04	Injection Point Inspection Program
32-SAIP-11	Inspection of Air-Cooled Exchangers

1.4 Saudi Aramco Best Practices

SABP-A-001	Polythionic Acid SCC Mitigation
SABP-A-013	Corrosion Control in Amine Units
SABP-A-014	Spheroids & Stabilizers Corr. Control
SABP-A-015	Chemical Injection Systems
SABP-A-016	Crude Unit Corrosion Control
SABP-A-018	GOSP Corrosion Control
SABP-A-019	Pipeline Corrosion Control
SABP-A-020	Sulfur Recovery Units Corr. Control
SABP-A-021	Desalination Plants Corr. Control
SABP-A-025	Vacuum Distillation Units Corr. Control
SABP-A-026	Cooling Systems Corrosion Control
SABP-A-029	Corrosion Control in Boilers
Doc # COE-110.06	Saudi Aramco Engineering Encyclopedia “Corrosion Failures”.

2: Industry Codes and Standards:

2.1 American Society of Mechanical Engineers:

ASME SEC VIII	Boiler and Pressure Vessel Code
ASME B 31.3	Chemical Plants and Petroleum Refinery Piping

2.2 American Petroleum Institute

API RP 535	Burners for Fired Heaters in General Refinery Services.
API RP 571	Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
API RP 572	Inspection of Pressure Vessels
API RP 573	Inspection of Fired Boilers and Heaters
API RP 574	Inspection of Piping System Components
API RP 575	Inspection of Atmospheric and Low-Pressure Storage Tanks
API RP 577	Welding Inspection and Metallurgy
API RP 579	Fitness-For-Service
API RP 580	Risk Based Inspection
API STD 510	Pressure Vessel Inspection Code
API STD 570	Piping Inspection Code
API STD 620	Design and construction of Large, Welded, Low Pressure Storage Tanks
API STD 650	Welded Steel Tanks for Storage
API STD 653	Tank Inspection, Repair, Alteration, and Reconstruction
API STD 660	Shell and Tube Heat Exchangers
API STD 661	Air Fin-Coolers
API-RP-2016	Guidelines and Procedures for Entering and Cleaning Petroleum Storage Tanks

3: Safety Related Documents:

Extreme Hot or Cold Temperature Conditions: http://www.ccohs.ca/oshanswers/

Benzene Hazard: http://www.ccohs.ca/oshanswers/

H_2S Alive: HSE Manuals

Working In confined space HSE Manuals

Overview of NORM in Petroleum Industry: ANL/EAIS-7 US department of energy

Environmental Assessment and Information science division

API PUBL 7103: Management and Disposal Alternatives for Naturally Occurring Radioactive Material (NORM) Wastes in Oil Production and Gas Plant Equipment

Note: A range of other safety related publications used are not mentioned here.

Definitions

1.1. Wherever used in this manual the terms should be interpreted as per the definitions given in section-3 Para 1.3.

1.2. If any definition is in contradiction with the definition given in industry or Aramco standards, for the purpose of this manual these definitions will be applicable. However while using other documents none of these definitions will supersede the conflicting definition of the subject document.

1.3. Definitions

Active Metals: Upper end elements in the galvanic series which undergo more corrosion, often used as sacrificial anodes.

Alteration: Any work on a static equipment that changes its physical dimensions or configuration that has design implications beyond the scope described in existing data reports. The following should not be considered alterations: any comparable or duplicate replacement, the addition of any reinforced nozzle less than or equal to the size of existing reinforced nozzles, and the addition of nozzles not requiring reinforcement.

Anode: See Sacrificial Anode.

ASME: American Society of Mechanical Engineers. The Group that oversees boiler and pressure vessel construction and safety rules in the USA.

Aromatic: An aromatic hydrocarbon has six carbon atoms in the shape of a ring with double bonds. Benzene is the simplest aromatic. Aromatics have very high octane numbers typically around 110 to 120.

Atmospheric pressure: One atmosphere is approximately 14.7 psi at sea level.

Backing bar or Ring : A strip of steel at the head to shell (girth) weld that remains in the tank after welding.

Cathodic Protection: The electric protection provided to the buried (underground) or internal metallic surfaces. The electric current is established between the metical surface and sacrificial anode in which the sacrificial anode corrodes preferentially, saving the metallic surface.

Benzene: The simplest aromatic, it is present in both reformer feed and product. Please refer to the MSDS for more information.

Boiler Feed Water (BFW): Boiler feed water is chemically treated water circulated through the convection section steam generator. It is abbreviated BFW.

Boot, Water Leg: A boot is a vertical extension below a horizontal vessel to accumulate water.

Boot: See Water boot and Gas Boot.

Boroscopy: The inspection of the tubes using the remote visual inspection equipment.

Bottom-side (of tank): The exterior surface of the tank bottom in contact with the soild of any other tank foundation.

Breakover point: The area on a tank bottom where the settlement begins.

Catalyst: A catalyst is a substance that promotes a chemical reaction to proceed at much faster pace or at milder conditions. It is not consumed during the reaction. Two catalysts are used in the reformer. A platinum, rhenium, and chloride on aluminum oxide catalyst is used for the reforming reactions. A nickel and molybdenum on aluminum oxide catalyst is used to desulfurize (clean) the reformer feed. Please refer to the MSDS for more information.

Cement Lining: A Blend of Portland Cement specially formulated as a tank lining. It is usually applied over a galvanized steel mesh to a thickness of .75". Rated at 210ºF

Corrosion Allowance: An optional increase in a metal thickness over ASME minimum design value, which is added to allow for the corrosion metal loss.

Chloride: Some acid activity is needed for the reforming catalyst to promote the desired chemical reactions. This acid activity is provided by chloride on the reforming catalyst. The chloride concentration (acid activity) is controlled at about 1.1 weight % by adding TCE to the reformer feed.

Circuit: See Piping Circuit

Coke: This is another term for carbon on catalyst.

Compressor Surge: When a centrifugal compressor is operated at very low throughputs, its operation can become unstable. It is said to be "surging" or "in surge." If the flow of recycle gas cannot be increased, the compressor spillback control should be used if surging is encountered.

Compulsory Safety Gear: See Safety Gear

Contactor: The contactor is the type of tower which (due to its specific design) helps absorption of one element in a gas mixture flowing from bottom to up, in another liquid medium flowing from top to bottom.

Contractor Inspector: The inspector employed to a contractor inspection company which is hired by the inspection unit to perform the inspection activity.

Convection Section: The convection section of a heater is a coil just below the stack where waste heat from the fire box is recovered before the flue gas is discharged to the atmosphere.

Corrosion - General: Corrosion that is distributed more or less uniformly over the surface of the metal.

Corrosion – localized (pitting): Corrosion that is distributed locally in form of sporadic or clustered pitting.

Corrosion Class: The grouping done on the static equipment depending on their corrosion rate and the service class.

Corrosion under insulation (CUI): The corrosion of the insulated static equipment due to the accumulation of the moisture or other corrosive fluid inside the insulation material. CUI Refers to all forms of corrosion including stress corrosion cracking, general and localized wall loss due to pitting etc.

Corrosion: Corrosion is the loss of metal from pipes or vessels caused by chemical attack usually by acids in the presence of water. Because reformers usually run fairly dry, corrosion is minimal even though an acid catalyst is used. Corrosion can be more prevalent in the desulfurization section of the unit as the feed can be wet and hydrogen sulfide H_2S and hydrogen chloride HCl (acid compounds) are present.

Corrosive Service: If the tank contents include any material that can corrode carbon steel, the tank must be designed accordingly. The most common example is compressed air, which contains water vapor. Inspection openings or a manway is required in pressure vessels designed for corrosive service.

Critical zone: The portion of the tank bottom or annular plate within 3 in. of the inside edge of the shell, measured

Dearator: A vertical vessel in a water line that allows air bubbles to rise to the top. This protects pumps and other vulnerable equipment from damage trapped air causes.

Deadlegs: Components of a piping system that normally have no significant flow.

Dehydrogenation: This is an important reforming reaction where naphthenes are converted into very high octane aromatics. Substantial hydrogen is produced as well. The reaction is catalyzed by the platinum on the catalyst. Low pressure and high temperature promote this reaction.

De-rating: A decrease design temperature or the maximum allowable working pressure (or both) of a static equipment in order to accommodate the deterioration in the condition due to process related damage.

Desulfurization: The most important reformer feed contaminant is sulfur. The sulfur is removed from the naphtha in the desulfurization section of the unit. Other contaminants are removed along with the sulfur: oxygen, nitrogen, chloride, and metals. The collective process is also called "naphtha hydrotreating." Desulfurization is abbreviated HDS and naphtha hydrotreating is abbreviated NHT.

Dike (or Dyke): The containment around the tank(s) designed to hold the stored material in the tank, in case of the leakage from the tank.

Distillation: Distillation is the separation of a mixture of components by boiling and condensation.

Dynamic Piping Support: A mechanical or hydraulic piping support designed to prevent excessive piping motion, but allowing normal thermal expansion.

Galvalization: Coating done by immersion in molten Zinc. Known as Hot Dip Galvanizing, it is rated at 400ºF in service.

Glass lining: A glass material coating done in which Material is sprayed on a sandblasted surface and fired at 1500 degrees F.

Equipment inspection Schedule EIS: The set schedule of the static equipment inspection as governed by SAEP-20.

ET: Eddy Current testing.

External inspection: A formal visual inspection, to assess the condition of static equipment from outside with or with out taking the equipment out of service.

Fitness-for-service assessment (FFSA): A methodology used to assess the seriousness of flaw towards the integrity of static equipment for continued service without imminent failure. Different levels of fitness for service methodology is provided by API standard API-579

Fixed/Static Piping Support: A piping support without hydraulic or mechanical control.

Fuel Gas: The gas used for burning in the furnaces (see fuel System for details)

Fuel System: The system including the piping compressors and the control gagets which provide the fuel to the furnaces, the fuel is usually the off gas streams from the various refinery units comprising mostly hydrogen, methane, ethane, and ethylene are routed to the refinery fuel system.

Fusion bond lining: The metallic lining achieved by joining the metals together with and explosive (dynamite) in between and creating a controlled explosion. The explosion momentarily melts the mating surfaces and fuses then together.

Galvanic Series: Galvanic series is the table of the metals arranged according to the relative electro-potential. When the metals from different location of the galvanic series are joined together in presence of electrolyte the galvanic corrosion takes place on more electropositive (anodic) metal. The upper metals in the galvanic series, called as active elements are more anodic (undergo more corrosion), as compared to the lower metals called as passive elements.

Gas Boot: A gas boot is a vertical extension above the horizontal vessel to accumulate gas produced in a phase separation.

Hardness Testing: Testing of the hardness of the material.

Heat Affected Zone (HAZ): The portion of the base metal adjacent to a weld which has not been melted, but whose metallurgical microstructure and mechanical properties have been changed by the heat of welding, sometimes with undesirable effects.

Heat Exchanger: A coil or tube bundle installed in a water tank that heats up the water by passing steam or boiler water through the tubes.

Heat Treatment: See Post-Weld heat Treatment.

HIC: Hydrogen induced Cracking.

Holiday Test: A test to confirm that a tank or vessel lining or paint system has achieved complete coverage. This requires that all sharp edges are ground smooth after welding.

Hydrocracking: In the hydrocracking reaction, larges molecules are cracked, or broken, into smaller molecules. Olefins are the intermediate product. Hydrogen then saturates the olefins to produce a paraffin. Hydrocracking is an exothermic reaction favored by high temperature and acid catalyst. Since low value LPG is produced from gasoline, hydrocracking is an undesirable reaction in the reformer.

Hydrogen Induces Cracking (HIC): The stepwise cracking joining the laminar tearing produced as a result of damage done by sour service.

Hydrogen Sulfide (H_2S): Hydrogen sulfide is a very poisonous compound formed primarily in the desulfurization section of the unit. Special note is made to the safety precautions for exposure to hydrogen sulfide throughout this manual wherever it is expected. Keep in mind that it can be anywhere in the unit during an upset. Please refer to the MSDS for more information.

Hydrotest: A pressure test performed with water or any non reactive and non toxic liquid medium, in which the integrity of the static equipment is checked by pressurizing it to 1.5 (or 1.3) times maximum allowable working pressure.

Indications: A response or evidence resulting from the application of a nondestructive examination.

Injection point: Locations where relatively small quantities of materials are injected into process streams to

In-service inspection: All inspection activities associated with a static equipment once it has been placed in service.

Inspection Activity: Any job that need the physical access to the static equipment (internal or external) for the purpose of the inspection conducted under the scope of this document.

Inspection interval: The time interval between two scheduled inspections, determined by Equipment inspection Schedule EIS. The interval can be increased or reduced depending upon the corrosion class vitiation or other condition related to the integrity of equipment.

Inspection team: The group assigned to perform an inspection activity, including the inspectors and support staff. The team could be single person or more than one, depending on the size of task.

Inspection Unit: The organization delegated the inspection and corrosion monitoring responsibilities in the facility.

Inspector: All of the certified Aramco and contract employees working under the supervision of the inspection unit. The no certified employees assigned the responsibilities of the supporting the inspection activity also are included in his category.

Internal Inspection: The inspection done to assess the internal condition of the static equipment either with or without the physical entry inside the vessel. The equipment usually has to be out of service for internal inspection.

Iron Sulfide: Iron sulfide is produced as a corrosion product primarily in the desulfurization section of the unit. Iron sulfide is pyrophoric which means it can spontaneously ignite when exposed to air. Combustion can be prevented by keeping the iron sulfide wet. Any iron sulfide spilled during turnaround should be cleaned up immediately to prevent fires and exposure to the noxious sulfur dioxide produce during burning.

Job: Inspection activity

Johnson Screen: The reformer reactor internal screens (center pipe and outer basket) are made of Johnson Screen. This is a special wire grid made by UOP to hold the catalyst in place with very low pressure drop.

Level bridle: A level gauge glass piping assembly attached to a vessel.

Liquified Petroleum Gas (LPG): Propane and butanes (normal butane and isobutane) are referred to as LPG since they would be gasses at ambient temperatures if they were not kept under pressure.

Lining: The coating auxiliary cover provided to save the metallic surface of primary equipment from erosion or corrosion. Lining could be metallic strips welded together, dynamite bond fusion lining or the coatings of different types such epoxy, glass, galvanizing, cement, and paint linings.

Low Pressure Separator (LPS): The low pressure separator is a vessel where the gas phase and liquid phase of the reformer reactor effluent are separated.

LPI: Liquid Penetrant Inspection

Magnetic flux leakage (MFL): An electromagnetic scanning test in which the flaw detection and sizing is done by sensing the variation magnetic flux from the flaw. The MFL can be used to test the exchanger tube in case of tube internal inspection and for the underside corrosion on the tank floor. Some texts also call this test as "magnetic Flux exclusion (MFE).

Maximum allowable working pressure (MAWP): The calculated value of maximum gauge pressure permitted at the top of a pressure vessel or other static equipment, in its operating position for a designated temperature.
Metallic Hard Facing: See hard facing.

Minimum design metal temperature (MDMT): The lowest temperature below which the significant load (within design pressure) can cause the brittle failure of material. The MDMT depends upon the material and the thickness of the material.

MT: Magnetic particles testing

Naphtha Hydrotreater (NHT): This is another term for desulfurization unit. The NHT catalytically decontaminates reformer feed in the presence of hydrogen.

Naphtha: Naphtha is a term used for reformer feed. It is obtained from crude oil. It boils between about 150 F and 400 F. It is lighter than kerosene. Please refer to the MSDS for more information.

Non Corrosive service: Tanks that are designed for contents that have no moisture or other corrosive material in them. For example, propane tanks can be built without a manway or inspection openings in most cases.

Pressure Vessel: Usually a welded steel cylindrical container designed and built to store its contents under internal and external pressure. Different rules apply according to the contents.

PSIA: Pounds per square inch atmospheric. A pressure measurement that includes atmospheric pressure. (approximately 14.7# psi at sea level)

PSIG: Pounds per square inch gage. A measurement that does not include the normal atmospheric pressure (approximately 14.7# psi at sea level).

Sacrificial Anode: A metallic anode used in cathodic protection where it is intended to be dissolved to protect other metallic components. The more active metal is more easily oxidized than the protected metal and corrodes first (hence the term "sacrificial"); it generally must oxidize nearly completely before the less active metal will corrode, thus acting as a barrier against corrosion for the protected metal.

Shell: The cylindrical section of a vessel, not including the heads.

Stress Cracking: A damage Mechanism in which the cracks are produced in the material under stress. The atmospheric condition contribute cracking. There are various kind of stress cracking which are detailed in API-RP-571.

Non-pressure boundary: The portion of the static equipment that in not designed to hold the process pressure.

NORM: Naturally occurring radioactive materials.

NPS: Nominal pipe size.

On-stream Inspection OSI: Inspection done while equipment is in service. Term is usually for the ultrasonic thickness measurement from outside the equipment. OSI is administered by SAEP-1135. (Also see In-service Inspection).

Overlay: The welding done build the metal lost thick due to corrosion or erosion.

Oxidation: Conversion into oxides by the chemical reactions. Corrosion is often

Passive Metals: Upper end elements in the galvanic series which seldom undergo

pH: pH refers to the relative basic or acid trait of a water solution. Acid solutions have pH's between 0 to 7, and basic solution have between 7 to 14. The lower the pH means more acid traits and higher pH means more basic traits.

Phase Separation: See two phase separation and three phase separation.

Phased Array: Advanced ultrasonic inspection technique used for determining the flaws in the material using multiple transducers in controlled synchronization. The synchronized energizing of the multiple transducers provided advantage of the ultrasonic beam maneuvering.

Piping Circuit: The series of piping from one end to other in which the fluid remains in identical chemical and physical conditions.

PJHA: (See Pre-job safety Analysis)

Pneumatic test: A pressure test performed with air or any non reactive and non toxic gas like nitrogen, in which the integrity of the static equipment is checked by pressurizing it to 1.1 times maximum allowable working pressure.

Positive Material Identification (PMI): The testing done to confirm the material composition of the metals.
Post-weld heat treatment (PWHT): The controlled heat treatment of the welds or welded structure for the purpose of relieving the accumulated stress due to welding process.

Pre Job Hazard Analysis (PJHA): A document/checklist which is filled by the inspection team before starting the job. PJHA id signed by whole inspection team members, and countersigned by the team leader and the safety coordinator.

Pressure Boundary: see Pressure Envelop.

Pressure Envelop: The portion of the static equipment that is designed to hold the process pressure.

PT: Liquid Penetrant testing.

Purge: Removal of hydrocarbons or other toxic gasses with passive gasses line nitrogen.

Radiant Section: The radiant section of a heater is the firebox section.

Reactor: A reactor holds the catalyst for the reaction to take place. The reactor is designed to allow the reaction mixture flow through the catalyst body. The catalyst helps in the intended reaction to take place.

Reboiler: A reboiler is a heat exchanger that takes heat from a source and transfers it into the distillation tower. This heat boils some of the liquid. This vapor travels up the tower to provide the fractionation.

Recycle Gas: Hydrogen is recycled back to the reformer reactors to saturate the olefins produced during hydrocracking.

Reforming: Reforming is the rearranging of molecules from low octane feed to high octane products. Aromatics production is the goal of reforming. Hydrogen is produced as a valuable byproduct for desulfurization of oils and as fuel gas.

Regeneration: Regeneration is a multistep process where inactive, coke covered catalyst is reactivated to its original activity. The carbon or coke is burned off, the platinum is oxidized to redistribute it on the catalyst, and the platinum is reduced to its metallic form needed for the reactions.

Reid Vapor Pressure (RVP): RVP is a measure of the volatility of a gasoline. Low RVP makes engine starting hard, but high RVP leads to vapor lock. RVP is usually adjusted by adding normal butane. RVP Specifications change with the season: higher in the winter and lower in the summer.

Remote Visual testing: The visual inspection of normally inaccessible areas using robotic or non robotic visual (camera) inspection equipment.

Rerating: A change (increase or decrease) in either or both the design temperature or the maximum allowable working pressure of static equipment.

RFT: Remote field testing, a kind of eddy current testing.

Risk-based inspection (RBI): A risk assessment and management process that is focused on inspection planning for loss of containment of pressurized equipment in processing facilities, due to material deterioration. These risks are managed primarily through inspection in order to influence the probability of failure.

RT: Radiographic testing

Safety Coordinator: A person acting as the safety liaison of inspection unit supervisor who is responsible to look after the safety aspects of the inspection activity. The qualification of safety coordinator is as per Para 2.1.c, and range of responsibilities of safety coordinator is as per Para 2.2. of this manual.

Safety Gear: Compulsory safety gear including, hard hat, safety foot wear, safety glasses, and fire retardant clothing.

Saturated Hydrocarbons: Saturated hydrocarbons have no double carbon to carbon bonds in their molecular structure. Paraffins and naphthenes are saturated hydrocarbons. Olefins and aromatics have double bonds and are unsaturated hydrocarbons.

Section-3

Shear wave UT: The ultrasonic inspection utilizing the shear wave mode, projected at different angles inside the material.

Small-bore piping (SBP): Piping that is less than or equal to NPS 2.

Soda Ash: Soda ash is a basic compound used to neutralize the acid compounds HCl and CO_2 (carbon dioxide) released from the reactors during regeneration. It is used to maintain the pH of the circulating solution between 6 and 8. Soda ash is much safer to use than caustic for this service. Please refer to the MSDS for more information.

Soil Side (of tank): See Bottom side.

Sour Water: Acidic water tastes sour. Therefore, water containing acid compounds (especially H_2S) is called sour water. Water drained from the desulfurizer separator boot and the stripper receiver boot are sour waters. Caution must be used when draining sour water due to the poisonous nature of H_2S.

Stabilizer, Stabilization: The stabilizer tower is used to remove the LPG from the reformate to "stabilize" it so that it is not too volatile for storage in a tank.

Static Equipment: The process equipment including the pressure vessels, process piping and the storage tanks etc, used in the process industry which in their use do not relocate or change their fixed position.

Stepwise Cracking: See Hydrogen induced cracking HIC

Stream Mix Points: The locations where to or more process streams mix together.

Stress Relieving: Heat treating a fabricated tank in a furnace. This relaxes the stresses caused by metal forming and welding during manufacture.

Stress oriented hydrogen induced cracking (SOHIC): The array of cracks, aligned nearly perpendicular to the stress, that are formed by the link-up of small HIC cracks in steel. SOHIC is commonly observed in the base metal adjacent to the Heat Affected Zone (HAZ) of a weld, oriented in the through-thickness direction

Stripper, Stripping: The stripper tower removes or strips the contaminating products of the desulfurizer reactor effluent so they are not fed to the reformer.

Sulfate: If sulfur contaminated reformer catalyst is regenerated, the sulfur is oxidized to sulfate. This interferes with the desired reactions so it is removed by carrying out a sulfate removal procedure.

Superheated Steam: Superheated steam has been heated to a temperature above its condensation or dew point. This is done to the 300 PSI steam produced in the heater convection section to prevent feeding water droplets to the recycle compressor turbine.

Supplementary Safety gear: The additional safety gear as required by the job condition and identified in PJHA. The supplementary safety gear includes but not limited to, hearing protection, full body harness, respiratory protection, safety goggles, sun shades etc.

Support Staff: All employees which assigned to help perform inspection activity. This includes the Aramco and the contract employees. The support staff includes but is not limited to labor, safety watch personnel, rescue team assigned, operation & engineering personnel if these personnel will access the job site at any during the job execution.

Thermography: The infra red imaging of the hot equipment, used to determine the temperature gradient at different locations on a static equipment.

Three Phase Separation: Separation of gas hydrocarbon and water from a mixture is called as three phase separation. The vessel used for the process is called as three phase separator.

Time of flight diffraction TOFD: Advanced ultrasonic inspection technique for determining the weld flaws, using the diffracted signals from the crack (or flaw) edges.

Two Phase Separation: Separation of gas from liquid mixture is called as two Phase separation. The vessel used for the process is called as two phase separator.

Under side (of tank): See bottom side.

Water Boot: A water boot is a vertical extension below the horizontal vessel to accumulate water in a phase separation.

Water Draw off: The system of nozzles, sump pit, piping and pumps meant to take the settled water from the tank or vessels is called as water draw off system.

WFMT: Wet fluorescent magnetic-particle testing.

Zero Degree Ultrasonic Inspection: Inspection conducted by the normal (longitudinal compression) waves, usually done in the contact mode, involving the through wall echo sensing.

Section - 4

On-job Personal Safety Requirements.

1. General:

    1.1. This section provided the minimum guidelines to inspection unit personnel for planning and performing the inspection tasks safely.

    1.2. None of the parts of this section should be taken as the guidelines for the preparation of the equipment for safe entry.

    1.3. This section of the inspection manual supplements the existing company and process facility's safety standards. If any part of this section comes in conflict with the governing company and/or process facility's safety standards, the safety measures of the document providing the stringent safety rules should be followed.

    1.4. Where ever deemed necessary, the inspector and inspection team must adopt additional safety and preparatory measures to perform the inspection activity safely.

    1.5. The inspector and the inspection team member(s) must refuse any task which according to his/her best judgment has the potential of injuring the worker(s). The inspection unit or the process facility management should develop the "safety related work refusal policy" which should highlight the denial of any disciplinary actions against employees refusing the work on safety reasons, even if the refusal is determined unjustified.

2. Responsibilities:

    Following are the minimum responsibilities of each discipline involved, towards the safe execution of the inspection task.

    2.1. Inspection Unit:

    Inspection unit supervisor or his delegate should ensure that following minimum requirements have been met for the employees to perform the inspection activity safely.

    a. Ensure that the scope of the job is clearly defined. The inspector and the inspection team are provided with the complete information about the job required.

    b. Ensure that all employees involved in the inspection activity have up-to-date safety orientation of the operation facility and are aware of all hazards & safety regulations in place.

    c. Ensure that a safety coordinator is assigned to supervise the job, who is authorized to take necessary administrative actions to ensure safety of the workers as given in Para 2.2. The safety coordinator can be one of the following individuals.

1. Senior inspector and member of the team assigned to perform the inspection activity.

2. Senior inspector from inspection unit, who is familiar with the facility safety regulations, and emergency plan. This inspector is not member of the inspection team but is supervising the inspection activity. In the situations like full plant shutdown, this individual can act as safety coordinator for more than one inspection activity.

3. Any third party person trained and qualified to act as the safety coordinator, and assigned to monitor the inspection activity. This person should be familiar with the facility safety regulations, and emergency rescue plan.

d. Ensure all logistic support for performing a job safely has been provided to the inspection team.

e. Develop and maintain the safety manual (or standard), which should detail all of the possible safety hazards specific for the operation facility. If any document like this is already available through loss prevention department or facility's own safety department, it should be adopted completely. This manual should be available to all of the members of the team, as and when required.

f. Provide all of the basic safety trainings to its employees. As of minimum each inspection unit employee and the contract employees working in the operating facilities should have following safety trainings.

1. Working and Confined Spaces.

2. H2S Alive & Rescue Techniques.

3. Fall arrest training.

4. Usage of breathing apparatus and fit testing.

Additional safety training for the hazards specific to the process of the facility must be added to the requirements. OSHA or industry standards should be used in order to implement the training programs. Inspection unit should keep the log of the trained employees and make sure that only safety qualified employees are deployed to the task.

Supplementary Note: Each Inspection unit should present the safety training certificates and wallet cards to its employees and should make incumbent to the contractors to provide these trainings to its employees working on the Aramco Operating Facilities.

g. Develop and maintain the Pre Job Safety Hazard Analysis (PJHA) form (or equivalent), as specified in Para 3.5.

h. Develop or participate in developing the emergency Rescue plan along with the operation and Safety department of the facility. Make sure that the designated rescuers are trained for this task as per established industry standards.

i. Ensure the operating facility has policy of using only qualified personnel as the confined space attendants. As given in Para-----

j. Review the safety related job refusal justification from the inspection team or the individual member of the team.

Supplementary Note:

The IU supervisor should make his best judgment to determine the validity of identified safety concern.

I. *In case the justification of worker(s) is found valid, the corrective action should be advised to eliminate the Hazard.*

II. *If IU supervisor determines that work conditions are safe to carry on, the refusing worker should be given choice to resume the job or not. No disciplinary action should be taken against the worker(s) (refusing the job) on these grounds.*

2.2. Safety Coordinator:

The safety coordinator is the individual, as described in Para 2.1.c, is assigned to ensure that the job is being performed safely. The responsibilities of the safety coordinator include but are not limited to,

a. Ensure that all members of the team are fully aware of the scope of the job.

b. Hold the pre job tool box meeting as per Para 3.4.

c. Ensure that Pre Job Hazard Analysis PJHA form is diligently filled on the jobsite, as per Para 3.5.

d. Ensure emergency response plan as describes in Para 4.2 is in place.

e. Stop the job if any unsafe conditions appear during the job, and ensure that the unsafe conditions are rectified before resuming the job.

f. Survey the job site before the tool box meeting (if possible) and provide the feed back to the team during the tool box meeting.

g. Report all of the safely related issues and infraction observed during the job to safety governing authority. If such authority is not available the report should be presented to inspection unit supervisor. The report should include all of the near miss incidents, and injuries occurred (if any) during the inspection task.

h. Coordinate and help the individual(s) who refuses to perform the job due to unsafe situations in given on Para 1.5.

i. Safety coordinator will inform all support staff, and people in the area about the about the hazards due to intended job.

j. Re-evaluate the hazards identified in PJHA in case any change occurs in the job site.

k. Stay at the job site all the time during the duration of the job. Ensure to delegate his responsibilities of safety coordinator to a competent individual if he has to leave the job site.

2.3. <u>Members of Inspection team:</u>

The responsibilities of the inspector and the members of the inspection team include but are not limited to.

a. Report to the job site only when they are physically fit. The individuals, who are sick, intoxicated or under the effect of medication to the extent that their normal abilities are impaired, should not report to work until they are out of the effect.

b. Report the physical or psychological conditions (if any) to the safety coordinator or team leader which limit his/her ability to perform the job safety. The physical and psychological conditions include any temporary or permanent disability, sickness, phobias (height phobia or claustrophobia, stress disorders etc.). The team leader or safety coordinator is responsible to assign the individual on the task which will not be affected by his/her disabilities or limitations.

c. Attend the tool box meeting as described in Para 2.2.b.

d. Senior member of team (or safety coordinator) will generate the PJHA. Every member of the team will sign the PJHA. Signing the PJHA will mean that the team member is fully aware of the hazards identified and is responsible to follow the instructions tabulated in PJHA, to avoid the injury from these hazards.

e. Ensure using all necessary personal protective equipment PPE mandatory for the job. The list of mandatory PPE will be provided in the PJHA. Additional PPE can be used during the job as deemed necessary.

f. Refuse any activity which is determined unsafe or proper safety measures are not in place. The team or the team member refusing the job will provide the justification in writing to the inspection unit supervisor.

g. Experienced members of the team must guide the inexperienced members and be cautious of their unsafe actions.

h. Report all near miss safety infractions, in writing as soon as possible.

i. Each individual is responsible for his/her safety and the safety of others, environment, and company property. No member of the team will intentionally conduct any action which can directly or indirectly endanger the safety of personnel, environment, equipment, and the company property. If such conditions are generated as a result of any unintentional act of individual, it is responsibility of the individual to report such condition for immediate rectification.

2.4. Confined space attendant:

Following are the minimum requirements for the qualification and on job conduct of the confined space attendant (also often know as safety watch or manwatch).

a. Confined space attendant must be literate (able to read and write).

b. Must be trained as per industry standards or should have a clear awareness about his duties as safety watch.

c. Must know that he should not enter the confined space under any circumstances, unless some other equally capable person takes over his responsibilities.

d. Must not engage himself in any other activity, at any time, that may affect his attendance from the assigned position.

e. Must possess the radio, or should be in the close proximity of the emergency telephone in working condition, to alert the rescue team of any emergency situation that could happen in the confined space.

f. Must have a horn or other communication means to alert the entrants of the confined space of any emergency situation outside the confined space.

g. Should be able to keep in the constant visual or verbal contact with the entrants. If the verbal contact is not possible, the contact should be maintained by radio or a life line.

Supplementary Note: Life line is a rope tied to the entrant, other end of rope is held by the safety watch. The confined space entrant and the safety watch mutually develop a tug code for the "all okay", and emergency situations.

h. More than one safety watch person should be used if multiple teams have to work in one confined space, having different sections, (such as columns). One safety watch should not be assigned to attend more than one entry points in same to two different confined spaces, no matter how close these confined spaces are.

i. Must have an equally capable replacement person in case one has to leave. The confined space, if occupied, must never be left unattended.

a. Safety watch person should never be assigned a parallel job no matter how minor it is.

3. Job Planning and Coordination:

Following section provides the minimum requirements for planning and coordinating the inspection activity.

3.1. Scope of job:

a. Inspection unit responsible personnel will generate the job sheet (or worksheet) clearly defining the scope of the Job.

3.2. Team/Team Members:

a. Size of the team will be selected depending on the scope of the job. The team must be composed of individuals qualified for the job or part of the job assigned. The size of the team will vary from one person to as many required to conduct the job safely within the specified time limit.

b. All of the team members should be physically and mentally capable for performing the assigned task. Physically handicapped or the individuals with psychological limitations should not be assigned the tasks beyond their ability. The requirements given in Para 2.3.b should be applied.

c. The lead person in the team should have ample experience or performing the task. The individuals new to the assigned job will be mentored by the experience team members.

d. All members should be completely versed with the Hazards in the job. The individuals (new to the task) who are not aware of the hazards should be provided with complete information about the Hazards involved.

3.3. Job Permit

a. According to existing permit issuance policy of the operation facility, the inspection team leader (or safety coordinator) must get the permit from the operation before starting any job. No work will be done without permit from the operations.

b. The permit receiver must ensure that information about the physical state of equipment identified in the permit is correct. If required the permit receiver must physically review the job site.

3.4. Tool box meeting (pre-job meeting):

a. The tool box meeting will be conducted before every job. If the job extends more than one shift (or days) the tool box meeting will be held before every shift.

b. Senior inspector/safety coordinator of the team is responsible of coordinating the tool box meeting.

c. The tool box meeting should preferably be conducted on the job site.

d. Each member of the team must attend the meeting. The members joining later will be clearly informed about the minutes of the meeting. Safety coordinator is responsible to provide information discussed in tool box meeting to member(s) joining after the meeting.

e. The scope of the job will be discussed in detail in this meeting.

f. All of the hazards associated with the job and the corrective actions adopted to mitigate the chances of injuries should be discussed. Feedback from all of the members of the team should be taken into account.

g. Pre-Job Hazard Analysis PJHA will be generated or validated daily in the tool box.

3.5. Pre job hazard Analysis (PJHA):

a. The facility Inspection unit is responsible to develop a Pre-job Hazard Analysis (PJHA) form. All of the possible hazards associated with different processes carried out the parent facility should be enlisted. The format of the PJHA could be descriptive or in form of checklist. This PJHA should be useable for safe work planning of most of the inspection jobs. Provisions should be given in the format for additional Hazards specific with any inspection job (if any).

b. PJHA should be filled in the tool box meeting. The tool box meeting should preferably be held on the job site. If meeting is not conducted on the job site then the team safety coordinator/senior inspector will provide the feedback from the jobsite survey conducted just before the toolbox meeting.

c. The planning for the safe execution of all inspection jobs should be carried out Pre-Job Hazard Analysis (PJHA). All of the safety hazards associated with this job should be enlisted in PJHA. The measured taken to control the hazards and special PPE required (if any) should be mentioned. Some of the common Hazards associated with process industry and the safe work planning are given in Appendix A.

d. PJHA should reference to the established Rescue plan, or briefly enlist the steps of the rescue plan, if required. Each member of the team should be aware of his/her responsibilities in case any emergency situation happens.

e. If the inspection activity requires the involvement of the support staff, the job hazards identified in PJHA will be communicated to each member of the support staff. (See definition of support staff in section-3).

f. Same PJHA can be used for same job if the job is extended for more than one day, provided the hazards identified are the same. However tool box meeting will be held at the beginning of every day at the beginning of work shift, and the PJHA should be updated/validated every day by the team leader (or safety coordinator).

g. Same PJHA can be used by more than one teams performing same kind of job at same locations. , as long as the Hazards are identical and both teams have attended the same tool box meeting.

h. If any unsafe condition (new or existing) which are not identified in the PJHA appear (or is identified), the PJHA must be updated and communicated to all members of team and the support staff. The safety coordinator will analyze the hazard. The job will be halted if necessary until the corrective action is taken.

i. Every member of the team will sign the PJHA. Signing the PJHA will mean that the team member is fully aware of the hazards identified and is responsible to follow the instructions tabulated in PJHA, to avoid the injury from these hazards.

4. Preparation of the equipment for inspection:

It is responsibility of the operation department to prepare the equipment for the inspection. Following text gives the minimum requirements for preparation of the equipment, that an inspector and his team must be looking for before starting any inspection job. This text cannot be taken as the guide lines to prepare the equipment for inspection. The operation department should develop its own detailed procedures for the preparation of the equipment for inspection and maintenance activity. Inspector and his team must make sure that following minimum requirements have been fulfilled before accepting the equipment for inspection.

4.1. Confined space Preparation:

a. Ensure that the confined space (including vessels and tanks) is completely Isolated form the process at all attached piping. The isolation should be achieved either by blinding or disconnecting the process lines.. The blinds installed on each line should be physically checked. The closure valves should never be relied for isolation.

b. Ensure the confined space is completely drained, clean, purged and ventilated.

c. The atmosphere inside the confined space should be free of all toxic gasses and provide oxygen contents between 19.5 to 22 %.

d. Ensure if continuous ventilation with fresh breathing air is available.

e. Ensure that continuous breathing air supply is available in case where the ventilation is not possible, and the people using the breathing apparatus are trained and fit tested.

f. All electrical, mechanical, and pneumatic energy sources are locked and tagged out.

g. Enough lighting is available to illuminate all the internal structure of the confined space.

h. Proper scaffolding or decking is available to perform the job on normally inaccessible areas.

i. Ensure a qualified manwatch is available to monitor the physical condition of the people inside the confined space, and intimate the occupants of the confined space in case the evacuation is necessary due to the hazardous conditions outside the confined space.

j. Ensure proper means of communication are available between the manwatch and the entrant in the confined space.

k. Ensure proper emergency rescue plan is available for prompt and effective rescue of the people injured (if any) inside the confined space.

l. Ensure that the manwatch person has enough means of communication to intimate the emergency response team to initiate the rescue immediately.

m. The equipment shall be sufficiently clean to offer good visual access to all surfaces. This usually will entail cleaning the vessel with hot water, steaming or by using solvents. Internally coated vessels shall not be cleaned with steam or other suitable methods which do not contribute in deterioration of the coating.

n. Magnetic particle testing shall require a “white metal” surface. This can be accomplished using either power brushing or abrasive blasting.

4.2. <u>Emergency response Plan:</u>

Inspector and his team must not entre in the confined space unless a proper emergency rescue plan is not implemented. Following should be minimum elements to ensure the effectiveness of emergency rescue plan.

a. A documented emergency rescue plan should be available showing step by step procedure to follow in case a rescue from the confined space is required.

b. The plan is effective enough to execute prompt rescue.

c. The rescuers should be designated for the rescue job and should be available on site during the time of job. The designated rescuers should not be involved in any other activity which can hamper their timely availability.

d. The designated rescuers should be trained and certified for the rescue from the confined space, and must he familiar with the internal configuration of the confined space.

e. The designated rescuers should be trained and certified for the providing first aid to the injured and monitor the condition until paramedic staff arrives and take over.

Inspection - General Requirements

The general inspection requirements provided below are applicable to all kind of vessels, towers, furnaces, boilers, exchangers, above ground storage tanks and the piping. The Inspector using this text should select the applicable requirements to conduct inspections. For inspection of the process equipment, the general requirements should be used in conjunction with the specific inspection requirements for particular type of equipment.

1.1. General Instructions:

1.1.1. It is the responsibility of the inspector to make sure that all of the applicable safety requirements as mandated in Section 4 are fulfilled.

1.1.2. Before commencing any inspection activity the inspector should go through the design details of the equipment, previous inspection history, the operational procedures and parameters of the equipment. The history of operational upsets occurred in the equipment should also be reviewed thoroughly.

1.1.3. In order to identify the damage mechanism in the equipment, inspector needs to know the normal operation parameters, stream conditions, material of construction and design code of the equipment. Guidelines provided in API-RP-571 should be followed for identifying the potential damage mechanisms. The inspector should consult the periodic chemical analysis of the process streams going in and coming out of the equipment.

1.1.4. General process of the equipment and the potential damage mechanism should be considered while planning the inspection. The inspector should decide which supplemental NDT techniques should be used to identify the damage particular with the process environment.

1.1.5. The inspection should be conducted or mentored by the qualified senior inspector with ample inspection experience. If the inspection is conducted by the junior inspectors or by the individual with lesser inspection experience, all of the findings should be re-evaluated by the senior inspector.

1.1.6. All of the general inspection requirements provided in the Para 1.2 through 1.10, along with the applicable specific requirement provided in Para-2 through Para-10 should be applied while performing the thorough inspection of process equipment.

1.1.7. All Inspection and evaluation of the inspection results should be done as per the requirements of API-510 Section 7 for pressure vessels, API-653 Section-4 for Atmospheric storage tanks and API-570 Section 7 for process piping.

1.1.8. The inspection results should be diligently recorded on the inspection report. Any suitable format of the inspection report can be used as long as it provided complete and accurate information and inspection findings. All NDT results should also be provided with the visual inspection report providing the reference number of the NDT report for detailed results.

1.1.9. The equipment for which internal inspection is not possible due to size and configuration, the evaluation should be done by the suitable NDT methods. The extent of coverage should be selected such that maximum information is obtained about the condition of the equipment. Wherever required more than one NDT method should be used to acquire maximum information. These NDT techniques include but are not limited to Radiography, Ultrasonic inspection, pressure testing, remote visual techniques like boroscopy, Eddy Currents, remote field testing, smart pigging, advanced ultrasonic inspection methods, or any other applicable specialized techniques. The selection, procedure and the extent of the specialized inspection techniques is beyond the scope of this procedure. Inspector after consultation with corrosion engineer should select the suitable technique and the extent of coverage.

1.1.10. Advanced NDT techniques should also be used to detect, monitor and record the progress of the process related damages in the equipment. Inspector and corrosion engineer should decide the technique and the extent of coverage.

1.1.11. For internal inspection the surface of the vessel to be inspected should be cleaned to the extent that the shell and components surface is completely exposed. The degree of surface preparation shall depend on the type of inspection being performed. If the inspection scope includes performing magnetic particle and Liquid penetrant inspection, additional surface preparation requirements should be fulfilled to facilitate the testing. The degree of surface preparation should selected according to the NDT procedure requirements. Special consideration should be given to areas which are identified having problems in the previous inspection history.

1.2. <u>Shell Inspection:</u>

These general inspection requirements are applicable to the internal and external inspection of the surface of shell, heads, floor, roof and piping.

1.2.1. <u>Inspection of insulation (for insulated Equipment)</u>

If the equipment is insulated the inspection will be performed on the insulation as follows

a. Over all condition of the insulation should be recorded. All rips, cuts, dents and missing sections should be reported for repair. The condition of the calking (weather proofing) on all of the nozzles opening and other protrusions in the insulation should be carefully inspected. All locations of potential moisture ingress should be recorded for rectification.

b. If the vessel or the piping operates at the temperature below 120 C, the inspector should look at the signs of moss build up at the bottom on the vessel (at 6 o clock on horizontal vessel, around skirt for the vertical vessels). The cladding should be removed from these areas. If the insulation is found moist then insulation from larger section should be removed to assess the damage due to Corrosion Under insulation (CUI). If significant CUI is found then the insulation should be removed from whole vessel to evaluate the extent of the corrosion. If the equipment is found significantly affected the fitness for service evaluation should be done for the affected areas. The technique for fitness for service is provided in the specific requirement for each equipment.

c. Vertical vessels with external stiffener rings tend to trap moisture in the insulation just above the stiffener rings. If suspected, remove the insulation from these locations to look for CUI.

d. Look for the vessels (and piping) with the steam tracings. The overall condition of the tracing should be evaluated. Report any leaks in the tracing joints. The leaking steam may condense and cause excessive CUI and other environmental damage to the external surface of the piping and the vessels.

e. If significant CUI is found at some areas the insulation should be removed from all other areas susceptible to CUI. If the equipment is found significantly affected the fitness for service evaluation should be done for the affected areas. The technique for fitness for service is provided in the specific requirement for each equipment.

1.2.2. <u>Shell & Heads (Un-Insulated Vessels, External/Internal Inspection)</u>

a. Look for the overall structure of the equipment. The location and dimensions of all significant dents, or deformation should be recorded. If the deformation has not been reported and investigated before, it should be marked for further investigation. As of minimum following tests should be conducted on these locations.

- Magnetic Particle Testing or Liquid Penetrant Testing for surface breaking cracks, and ultrasonic thickness measurement for the laminar tearing.

- If the bulge is suspected due to localized heat impingement, the affected area should be tested for hardness. Further the eddy current test should be done on the area and compared with the unaffected area for the phase shift.

- The localized bulging could also be due to hydrogen blistering. In this case the careful zero degree scanning should also be done in the area to find out the stepwise laminar tearing. If suspected for cracking, shear wave testing should also be done at these locations. Further evaluation can be done using Automated UT.

b. Look of any manufacturing defects on the shell. Major manufacturing defects to note are following.

- Arc strikes:

  All arc strikes if not evaluated before should be tested with MT or PT. If no cracks are found in the ark strikes, these areas should not be ground out, however the location should be carefully recorded for re-evaluation in next inspection opportunity. The interval for the next inspection will be determined by established inspection scheduling for the equipment. If the cracks or other reject able indication are found by the NDT, the affected area should be ground out until the indication is completely removed. If the remaining wall thickness in the ground out areas is above required t-min, then these areas should be blended with 3:1 ratio for width to depth. If the depth exceeds the required t-min than the fitness for service analysis should be done using guidelines of API-579. If the ground out area is found not acceptable for the safe operation of the vessel then than these areas should be built up using approved welding procedure. The buildup areas should be ground flush with the parent metal. Suitable NDT should be conducted at the final and initial stage of the buildup. If the vessel was originally coated the compatible coating should be applied on these areas using the approved coating procedure.

- Deep grinding marks:

  Any significant grinding marks if shape like a notch should be evaluated using fitness for service analysis techniques as provided in API-579. Most critical are the grinding marks parallel to the longitudinal welds of the vessel. If found not acceptable, than 3:1 (width to depth) blending should be done on these areas for depth within required t-min, otherwise weld build up should be done as given above.

c. Look for all service related defects on the shell. The detailed instructions of the service related defects are provided in the specific requirements of all equipments.

d. Shell should be checked for the minor deformation around the nozzles, due to the over loading because of inadequate piping support. If possible shake the attached piping and look of the amplitude of the natural vibration. If the shell is found deformed the nozzles to shell welds should be tested with PT or MT (whichever is applicable).

e. Check the condition of the nozzle re-pads (if any). Each repad should have weep holes as per design requirements. The weep holes should not be blocked with the materials that can hamper the free ventilation of the space between repad and shell. Look for the signs of the product leaks at the weep holes. Any leak found, should be reported immediately and the vessel should be taken out of the service immediately for further investigation.

f. Look for the corrosion pitting on the shell. Excessive and generalized pitting with depth deeper than t-min should be evaluated for fitness for service. Report the exact location of the isolated pitting for monitored the growth. In case of the significant pitting, measure the depth of the pitting and compare with the design t_{min}.

Supplementary note: While performing the shell inspection the best method to look for the shell deformations is to shine the flash light from the side and look for shadows. Direct shining of the light on the shell can mask various important defects like blistering. There is chance of missing the minor deformations contours if viewed from the front.

1.2.3. Coating Inspection:

a. Condition of coating on the vessel external should be evaluated with a skilled judgment. Rust spots, blisters, and paint dis-bonding are the types of failures usually found. If necessary, the dis-bonded paint or coating should be scraped off, to determine the extent of under coat corrosion. Any damaged areas should be marked for the re-application of compatible coating, using Aramco approved coating procedures.

b. For internally coated equipment the coating inspection should be done according to the applicable Saudi Aramco Engineering H Standards.

c. All coatings or Non-metallic linings shall be closely examined for any signs of pinholes, blistering, cracking, delamination or disbondment.

d. All precautions should be taken to avoid damaging the existing coating in good condition. This includes not using the abrasive foot wear while inside the vessel, and avoiding the scaffold erecting unless very necessary due to the scope requirements.

e. The isolated blisters in the coating if are not popped open, should not be disturbed. However heavily blistered coating should be removed and area should be recoated with the compatible coating.

f. If required, the coating integrity should be tested with a holiday testers. The voltage of the tester shall not exceed the dielectric strength of the coating.

g. If the repair is required the spot repair can be performed using a compatible patch compound while more extensive repairs may require the removal and reapplication of either a portion or all of the coating. The recoating could be done according to Aramco approved procedures.

1.3. Welds Inspection:

1.3.1. Structural Welds:

Following are most commonly found weld defects which inspector should be looking for while performing the structural welds inspection.

a. Excessive undercut:

Use Pit gauge or undercut gauge to measure the depth of significant undercuts. The design criteria of particular equipment should be consulted for the acceptable value of the undercut. The undercuts exceeding the acceptable limits should be marked for further evaluation. If the equipment had been in service successfully, no repair is required. However fitness for service evaluation should be done on the undercuts if the equipment is in cyclic service. In case of cyclic (vibration) service these areas should be checked with NDT periodically for initiation of the crack with in undercut. The frequency of the monitoring should be set by the inspector keeping in mind the severity of the vibration.

b. Cracks:

- Cracks of any size and orientation are unacceptable, If cracks are found these areas should be marked for further evaluation with appropriate NDT technique. The repair should be done as soon as possible using approved repair procedures.

- If the repair is not possible at the moment and the vessel is in successful service, the Fitness for service analysis should be done on these cracks. This practice can be used to evaluate the time allowed and the service extremes in which the equipment should operate until the repair can be done.

- The nature of the cracks should be determined by the subject matter expert. If the cracks are determined to be related to service conditions, the inspection scope should be increased. All sections of the vessel susceptible to cracking due to pertinent service conditions should be evaluated with the applicable NDT method.

- If further evaluation determines that the cracking is not localized, (other locations also show same problem), the equipment should be immediately taken out of service for repairs.

c. Corrosion :

The metallurgical makeup of the welds is not exactly identical to the parent metal. Due to this reason the deterioration rate of the welds in the corrosive environment could be different from the parent metals. The accumulated stresses in the welds which are not post weld stress relieved also pay contributing factor in the accelerated corrosion of the welds. Depending on the corrosive environment, the weld corrosion could be pitting, generalized, or preferential. All corroded welds should be evaluated with the suitable NDT method, and repaired if necessary. The corrosion aspects specific to the process equipment type are further discussed in the specific requirements. The excessive corrosion washout, which makes the weld unable to withstand the design extreme conditions, should be repaired with approved welding procedures.

d. Porosity (from manufacturing):

For the weld in the successful service the porosity is not a very big issue. However if significant porosity is found in welds within the pressure envelop of the equipment, the fitness for service evaluation should be conducted and repaired if found unacceptable.

e. Arc Strikes :

All arc strikes if not evaluated before should be marked for MT or PT. If no cracks are found in the ark strikes, these areas should not be ground out, however the location should be carefully recorded for next inspection and evaluation. If the cracks or other reject able indication are found by the NDT, these areas should be ground out until the indication is completely removed. The ground out areas should be built up using approved welding procedure and PWHT procedures (if required).

f. High Low:

If significant high-low is found in the structural welds, the effective cross-sectional thickness of these welds is lower than expected. In this case the pressure retaining ability for the weld should be re-evaluated. If the area is found un-acceptable, the welds should be removed and components should be re-welded with proper fitting, or the service parameters of the equipment should be readjusted at lower ratings until the repairs is done.

g. Incomplete fill:

The weld cavities due to incomplete fill weaken the joint. All cavities, if found not acceptable for the service, should be built up using approved welding and PWHT procedures (if applicable).

1.3.2. Re-pad Welds:

a. The reinforcing repad welds should be visually inspected for all of the manufacturing and service related defects.

b. Insitue pressure testing is one of the quick checks for the integrity of the repad welds. The integrity of shell to repad, nozzle to repad and shell to nozzle weld (under the re-pad) can be checked simultaneously with this method. Following steps should be taken for the pressure testing.

I. Using the correct size threading tap, reclaim the worn out threads in the weep hole.

II. Fix the threaded nozzle on the repad and using the hand or foot air pump, pressurize the repad areas to at least 10 to 15 PSI.

III. Conduct the soap test on the repad and the nozzle to repad welds.

IV. If the leaks are found, further evaluation should be done using appropriate NDT method.

If the leak is due to the cracking in the welds, the area should be ground out to check if the crack is propagating in to the pressure envelop of the equipment. The cracks in the shell or the nozzles should be ground out completely and rebuilt using approved welding procedure.

c. If pressure testing as described in Para 1.3.2.b is not possible, all of the accessible repad welds should be tested with MPI or LPI.

Supplementary note: The insitue pressure testing is low pressure basic testing. It should never be adopted as alternative of the critical repad integrity tests as and whenever required in special situation.

d. Where ever required the shell to nozzle welds under the repad should be inspected internally with the visual or NDT Techniques.

e. In case of the cyclic loading situations (like compressor pulsation bottles), if the internal access is not available, the integrity of these welds should be inspected with Acoustic Emission or creeping wave Ultrasonic techniques. These techniques need specialized equipment and training. The inspector performing these tests should be trained and certified for these techniques as per applicable standards.

1.3.3. Nozzle Welds:

a. All exposed shell to nozzle welds, and nozzle to flange welds should be inspected as per the General requirements Para 1.3.1, and applicable sections of Para 1.5.

b. All shell to nozzle welds covered under the repad welds should be inspected as per Para 1.3.2.b, d and e. and the applicable sections of Para 1.5.

1.4. Support Structure Inspection:

1.4.1. Ground Settlement:

The ground settlement usually takes place in the equipment handling heavy loads of the process fluid. Significant settlements are seen in the larger equipment like storage tanks, sludge catchers, LPG bullets, large capacity treaters, towers and large size Shell tube exchangers etc. The settlement is the one of the main concern for the storage tanks, and is discussed in the specific requirements for atmospheric storage tanks Para 10.5. Following text covers the settlement issues in the equipment other than Storage tanks.

a. Look for the signs of the unevenness caused due to settlement in the areas surrounding the equipment.

b. The deformation or dislodging of the anchor bolts is another sign of significant ground settlement.

c. If above normal settlement is suspected the leveling survey of the area around the equipment should be done.

d. In case of the equipment with active ground settlement the record of successive settlements should be kept to monitor the settlement trend.

e. All of the piping attached with the equipment with the settlement problem should be evaluated for over loading due to displacement of the equipment. Similarly the shell area on the nozzles should be evaluated properly for the deformation due to settlement.

f. Look for the signs of concrete cracks caused by uneven settlement of the underlying foundation base

1.4.2. <u>Saddles Inspection (for horizontal Vessels):</u>

a. Evaluate the structural integrity of the saddles. Look for the significant deformation or corrosion damage on the saddle ribs, base, side supports and the wear plate.

b. Wear Plate to shell, and saddles to re-pad welds should be thoroughly inspected for manufacturing and service related defects, as per requirements of Para 1.3.1 and 1.3.2.

c. The condition of the anchor bots should be checked thoroughly. The bolt holes for the longer vessels or for the vessels operating at high temperature should be slotted in one of the saddle. The bolts on the slotted side are kept loose to allow the vessel movement due to thermal expansion. The cracks in concrete base at the locations of the bolts, or the bent/distorted bolts are the signs of the restricted movement. If the restricted movement is suspected, than the lock nuts on slotted saddle should be loosened. If possible the slide cushion martial should also be provided under the saddle which is allowed to move due to thermal expansion of vessel.

d. The coating of the saddles should also be assessed. Some saddles may have fire proofing. Look for the significant cracks in the fire proofing and any other locations for moisture ingress. If the significant corrosion on the saddles under the fire proofing is not suspected the open cracks in the fire proofing should be filled with compatible material.

1.4.3. Skirt for Vertical Vessels and Towers:

a. The overall condition of the skirt should be assessed. Significant dents, corrosion or any other mechanical damages can jeopardize the load bearing capacity of the skirt. Such condition should be recorded and evaluated by the structural engineer experienced in vessel designing.

b. If the skirt is covered with the fire proofing, evaluate the integrity of the fire proofing. If cracks or other locations for the moisture ingress are found then evaluate the corrosion damage under the fire proofing. Fireproofing should not be removed unless deemed necessary. If possible evaluate the skirt thickness from inside by ultrasonic thickness measurement. Scan the area and especially the bottom part of the skirt and note the minimum thickness. If significant metal loss is found than fire proofing should be removed for detailed evaluation. However if the significant corrosion on the skirt under the fire proofing is not suspected the open cracks in the fire proofing should be filled with compatible material.

c. The structural and the attachment welds in the skirt should be evaluated as per Para 1.3.1.

d. Evaluate the condition of the anchor bolts. If the possibility of the dislodging of bolts inside the concrete foundation exist, the best method is to gently tap the bolts from side with light hammer and look for the movement of the bolts. If the bolts move by tapping then they are dislodged in the concrete.

Supplementary Note: If the plant is in service and there is significant fire Hazard it is preferable to use copper hammer to avoid sparking.

e. Perform the UT at the bolt head to evaluate if the bolts are broken or cracked inside the concrete.

f. All of the threads on the anchor bolts should be fully engaged. Any short bolting should be reported and corrected if possible. For proper fastening the preferred set up is, two interlocking nuts with at least ½ diameter of the bolt extended above the 2nd nut.

1.4.4. Support Legs (vertical vessels):

a. Some vessels are supported on three or four support legs welded to the shell or the bottom head. Look for the overall condition of the support legs. Report any unfavorable conditions like excessive corrosion, structural damage, paint deterioration and missing anchor bolts etc.

b. The support legs to shell welds should be evaluated as per Para 1.3.1. These vessels may vibrate due to sudden influx of the liquids or any other reason. The movement of the vessel body may crack the shell to support legs welds.

c. If the cracks are found, further evaluation should be done with suitable NDT method. The cracked welds should be repaired with approved welding procedure.

d. The condition of the concrete or metallic base on which the legs are anchored should be evaluated thoroughly.

1.4.5. <u>Straps & U-bolts:</u>

a. Smaller vessels like filter pots fuel gas scrubbers are sometimes tied with the straps and the u-bolts. The anchoring location could be with the pipe supports, other structural columns. Most of the time the attached piping on such vessels is small bore piping or threaded piping. The tightness of the straps should be carefully evaluated for these vessels. Loose straps or bolts may result in the exerting the load on the attached piping which are not designed to sustain the weight on the equipment. This situation can become cause of leaks and serious accident. The vessels in continuous vibration like fuel gas scrubbers in a Gas compressor stations are most prone to this kind of situation.

b. U-bolts and metallic straps sometimes rub against the shell causing the coating failure and hence exposing shell to the corrosion. In case of cyclic vibration, the fretting between the u-bolt and the shell is also observed. If the material of vessel and the u-bolts are slightly different in the galvanic series, the galvanic corrosion may take place in corrosive environments. The wall loss in this kind of situation should be evaluated and the location of the bold should be changed.

1.4.6. <u>Supported by attached piping:</u>

In some cases the smaller vessels are supported by the inlet and outlet piping. At normal operating condition the piping is designed to carry the weight of these vessels. However the extreme vibration modes cannot be predicted accurately at the design stage. If such vessels are subject to extreme cyclic loading, an independent vibration mode is introduced into the system. If the neural frequency of the vessel is widely different than the normal frequency of the external vibration source, extreme stress is not developed on the vessel nozzles. However, if natural frequency of the vessel is close to the applied frequency (or its fundamental mode), the vessel may start resonating with the applied loading. This induces high cyclic stress on the nozzles on which the vessel is mounted. This may induce micro fatigue cracks in the nozzles to shell welds (under repad). The typical situation like this is found in the suction bottles mounted on the cylinders of reciprocating gas compressors. No visual inspection method is available to detect these cracks. One of the most successful methods for detecting these micro fatigue cracks is creeping wave ultrasonic inspection. However it needs skilled judgment to detect and correctly interpret these indications. The pneumatic testing during the T&I can be used to detect these cracks. Historically most of the fatigue related leaks have been found at the gusset welds which hold the PSV at the discharge line. Due to this reason all of these welds must be tested with MPI or LPI periodically. The testing period should be adjusted according to the magnitude of vibration problem and the experience with the equipment.

1.4.7. Guy Wires:

Slim towers like Glycol or amine contactors for Gas sweetening and dehydration are sometimes provided additional support with the Guy wires. The flare stacks and furnace exhausts are also tied with the Guy wires. Visual inspection of these wires has not proved to be of any value. However specialized NDT methods are available to evaluate the tension of the wires and the overall condition of wires. These methods should be applies on the critical systems at T&I and whenever a problem is suspected. In case the tension in any of the wires is found loosed, the wire must be inspected for broken strands at any one of the (top or ground) anchor points. Other cause of the loosed tension is the dislodging of the deadman anchor at the ground. The concrete foundations of deadman anchors should be carefully inspected. The structural engineer should be consulted if the tension problem is suspected in the Guy wires.

1.5. Nozzles:

1.5.1. Piping Nozzles:

a. All nozzles should be carefully inspected for deformation or stress due to over loading from unsupported piping. Usually the nozzles are made of forged piping spools which are (in most cases) over scheduled in thickness. Hence most of the time the load is shifted to the shell as discussed in Para 1.2.2.d; however in some cases the nozzles itself can be deformed. If any deformation is found in the nozzles, both of the welds on the nozzles (with shell and flange) should be inspected with MT or PT.

b. The adjacent piping up to the first piping support should be carefully inspected. Shake the piping with ample force and look for the violent vibrations. Inadequately supported piping will show above normal vibration. Note the condition of the first support. If the support is lifted or displaced from its designed location the shims should be added at the bottom of the support to fill up the gap and dampen the vibration in the piping. Otherwise auxiliary supports should be provided with the piping. The specific inspection requirements for the piping is discussed in Para 9.

c. Look for the coating damage on the nozzles. Damaged coating should be recoated with the compatible coating.

d. Look for the environmental damage on the nozzle. Any significant corrosion should be reported and evaluated for fitness for service.

e. Check for the misalignment between the mating flanges (of nozzles and attached piping). Leakage may take place from the significantly misaligned flanges. The misalignment should be corrected at the earliest available opportunity.

f. Look for the signs of leaks at the gasket area. Check the correct rating of the gasket from the color coding.

g. Look for the short bolting on the nozzle and attached piping flanges. Minimum of three to four threads should be exposed on either sides of the bolt.

h. Occasionally check the rating from the marking on the flange.

i. The forging sometimes is not concentric, giving rise to over thickness on one half and reduced thickness on other half. Since the forged nozzles are often over scheduled in thickness so the thinner parts stay within the minimum design requirements. However if the vessel is in highly corrosive service the thickness reduction may take place. Due to this reason the OSI points should be added on all for quadrants of the nozzles.

j. The re-pad welds on the reinforced nozzles should be checked as per Para 1.3.2.

k. Carefully examine the bolts and the bolt holes in the flanges. The galvanic corrosion may take place between the bolts and the flanges if two materials are not compatible. Depending on the relative galvanic potential, the corrosion may take place either on bolts or the flange. In both cases significant corrosion may loosen the gasket seal and leaks may occur.

l. In highly corrosive services the stainless steel piping is joined with carbon steel vessels. The mating areas of the flanges are isolated by insulating gaskets. The galvanic corrosion may take place between two flanges in case the isolation fails.

1.5.2. <u>Manway Nozzle:</u>

a. Check over all condition of the manway nozzle, and cover.

b. Look for the short bolting on the manway cover or nozzle flanges. Minimum of three to four threads should be exposed on either sides of the bolt.

c. Look at the structure of the davit arm or the hinges on the manway cover. Report any damage to the davit arm.

d. For safety reasons the manway cover hanger should extend long enough (out of davit arm slot) to put two interlocking nuts on top.

e. Look for the general condition of the gasket between the manway flange and the cover. Try to figure out the correct rating of the gasket from the color coding. Look for the signs of leakage at the bottom of the flange.

f. The re-pad welds if any should be checked as per Section 5 Para 1.3.2

1.6. Ladders and platforms:

1.6.1. Ladders and platforms should be adequately supported on the equipment. The weight should be evenly distributed without exerting unbalanced load on single area of the vessel.

1.6.2. While inspecting try to shake the structure and watch for the abnormal movement. The structure should not have excessive vibration independent of the vessel. Excessive vibration can add fatigue to the mounting brackets.

1.6.3. Look for the lose bolts on the support braces. Slight snug with the small wrench can tell if the bolts are loose. Sometimes the crevice corrosion between the bolt holes and bolts can loosen the bolts. Such situation should be corrected as soon as possible.

1.6.4. The repad welds holding the mounting brackets should either have weep holes or should not be completely welded.

1.6.5. All of the safety provisions like toe board, hand rails, knee rails and the safety latch should be in good condition.

1.6.6. All sections of the gratings or checker plates should be tight and be placed in interlocking position or welded/tied to the structure. Look for the overall condition of the grating. Assess the paint deterioration and rusting on the grating. The worn out grating could be the life threatening Hazard at heights. Similarly old worn out checker plates could be slippery and can have thickness reduction below the required strength. Such plates should be reported for replacement.

1.6.7. Check the structural integrity of the galvanized leader. The rungs and the side strips should be free of significant corrosion or mechanical damage. Check the condition of the guard cage of the leader.

1.7. Gauges:

1.7.1. Sight Glasses (level gauges) and level bridles:

a. The overall condition of the bridal should be assessed. Look for the excessive corrosion or mechanical damage.

b. The integrity of the sight glass and the bridles should be looked after carefully. The cracked or blurry glasses should be reported for replacement. The pressure rating of the new glass should be looked after carefully.

c. Look for the leaks or weeping closure valves on top and bottom of the level gauges. If the inspection is being performed while the vessel is in operation the LEL counts should be taken at these valves, using the suitable gas tester.

d. Special attention should be paid on the isolated level gauges and bridles on the vessels in service. These sections act as the process dead legs especially for the vessels in high temperature corrosive service. The isolated legs should be periodically checked with ultrasonic to monitor the wall loss due to convective currents generated inside the isolated sections.

1.7.2. Pressure & Temperature gauges:

a. Check if all of the gauges are operational or not, record any malfunctioning and/or broken glass.

b. The range of the gauge should be such that the normal operating pressure and temperature are between 25% to 75 % of the scale.

1.8. Attachments:

Following text covers general inspection requirements both kind of external and internal attachments on the process equipments. The inspection requirements of the attachments specific to the particular equipments are covered in the specific inspection requirements of each equipment.

1.8.1. External Attachments:

The vessels external attachments cover a broad range of equipment which varies from one service vessel to other. These equipment include but are not limited to the electrical resistance corrosion monitoring devices, corrosion coupons, sacrificial anodes, level controls, bridle still columns, sample collection ports, Radar level controls, thermo wells, thermo couples, gas detection leak detection systems, truck out (dump out) port. and Inlet (fill in) or loading ports.

The assessment for proper functioning of the specialized equipment is the responsibility of the qualified instrumentation technical. Mechanical inspector is responsible of assessing the general condition of these attachments.

a. Look at the general condition of these equipment, try to assess if they are operational or not.

b. Look for the electrical connections. The loose connections can create sparks. Report any loose or broken connection for rectification as soon as possible.

c. Inspect the mounting on the attachments, detect the gas leaks from the threaded connections using the gas detector.

d. Sacrificial anodes should be properly short circuited with the shell.

e. For the fill in or dump out ports the provision for static charge grounding must always be available. Temporary grounding connector and line could be provided by the supply/dumping truck however it should not be relied on. Report if the grounding connector and line are not available.

1.8.2. Internal Attachments:

The internal attachments cover a broad range of equipment which varies from one instrument service to other. These equipment include but are not limited the demister pads and assembly, filter screens, baffle plates, inlet deflectors, vortex breakers, structural assemblies like fire tube holders, internal cathodic protection etc. The process specific internal equipment like tube bundles, treys and fire tube etc are discussed in the specific requirements sections of the particular equipments. Close attention should be paid to the integrity of these internal. The internals should be removed if the inspection of the shell and the internal attachment itself is not possible while assembled. These internals do not contribute to the integrity of the vessels, however if deteriorated may alter the process parameters of the vessel. This in turn, can add to the excessive and accelerated corrosion or erosion damage to the vessel. If the internal attachments are found broken or heavily corroded, these attachments should be replaced as required. The inspection of the internal attachments is more elaborated in the section of specific inspection requirements for the equipments.

1.9. Electrical Grounding:

Vessel must be electrically grounded, either directly or indirectly through the skid structure. The grounding of the piping separated by the gaskets cannot be taken as adequate grounding. Check for the integrity of the grounding connection, and the grounding wire. The flowing fluids have tendency of accumulating the static charge in the vessels. It is preferable that a static electric potential be measured between the vessels and the surrounding structure.

1.10. Gaskets Inspection:

1.10.1. External Inspection:

Because of being soft the gaskets are vulnerable to damage during the installation and service. Biggest concern is the yielding of the gaskets due to over torque, and the cyclic fatigue in the vibration services (like gas compressors). These conditions may result in the leaks during the service. Similarly the correct rating, material and thickness of the gaskets is also very important. Substandard and relatively thicker gaskets may cause the torque loss with the time due to which leaks may occur. Complete inspection for the gaskets installation is not possible while vessel is in service however close observation of the areas between the flanges will give some idea about the condition of the gaskets.

a. Look for the misalignment of the flanges. Flanges could not be completely in line (concentric) or might be over torque on one side showing the different gap width on two sides. Both of these condition could induce the over stressing on the gasket, and cause leaks. Such condition should be reported for rectification.

b. Installation of two gaskets to fill up the wider gaps is not preferred in pressure service. If such situation is found and no leak are detected, this set up should not be disturbed however should be reported for correction in next T&I.

c. Look for the errosion or any other service related damage in the gaskets.

d. For the new gasket, look for the physical damages like cracks, yielding due to mishandling or any other condition that cause leakage.

e. The rating or the kind of the gasket can be confirmed from the color coding at the edge of the gasket. ASME B16.20 gasket color coding is given below.

Metal	O.D. Ring Color
304 Stainless Steel	Yellow
316L Stainless Steel	Green
317L Stainless Steel	Maroon
321 Stainless Steel	Turquoise
347 Stainless Steel	Blue
MONEL®	Orange
Nickel	Red
Titanium	Purple
Alloy 20	Black
INCONEL® 600	Gold
HASTELLOY® B	Brown
HASTELLOY® C	Beige
INCOLOY® 800	White
Material	**Stripe Color**
Flexible Graphite	Gray
PTFE	White
Ceramic	Lt. Green
Verdicarb (Mica Graphite)	Pink

1.10.2. Internal Inspection:

The requirements of the internal inspection of the gasket areas have been provided in the internal inspection specific requirements of each static equipment.

Section -5

Vessels & Drums Specific requirements

2. Specific Inspection Requirements for Vessels

This section covers the specific inspection requirements of the pressure vessels without the special purpose internal structures like treys, down comers, or catalyst beds. The text in this section can be used for the internal and external inspection of the types of vessels including but not limited to Drums, Flash tanks, LPG Bullets, Two phase and Three phase Separators, sludge catchers, deaerators, and steam drums etc.

The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flanged connection the inspection of piping should be performed according to the requirements of Section 5 Para 9 of this manual. The inspector should consult the design details, operation parameters, history of operational upsets, and the previous inspection reports before commencing the inspection.

It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and any additional requirements specific for the vessel being inspected are in place. Additional safety requirements as deemed necessary must be adopted.

2.1. External Inspection

2.1.1. Support Structure:

The support structure should be inspected as per the General requirements Para 1.4.

2.1.2. Ladders and Platforms:

If applicable the leaders and platforms should be inspected as per General Requirements Para 1.6.

2.1.3. Insulation Inspection:

If vessel is insulated, the inspection of the insulation should be performed as per General requirements Para 1.2.1. In case CUI is suspected than remove the insulation from the affected area and inspect the shell as per General Requirements 1.2.2.

2.1.4. Shell and Heads:

If vessel is not insulated than inspection of heads and shell should be performed as per General Requirements 1.2.2.

2.1.5. Welds:

The structural, nozzle and attachment welds should be performed as per General Requirements Para 1.3.

2.1.6. Nozzles:

All of the nozzles should be inspected as per General Requirements Para 1.5.

2.1.7. Attachments:

Inspection of all of the attachments should be performed as per General Requirements Para 1.8

2.1.8. Gauges:

Inspect condition of all of the gauges as per General Requirements Para 1.7

2.1.9. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

2.1.10. Gaskets:

Check for the leaks and gasket integrity as per General Requirements Para 1.10

2.1.11. Attached Piping:

a. Inspect the general condition of the attached piping. To determine if the attached piping is not exerting undue stress on the vessel, attention should be paid to the pipe supports on the piping directly attached to the vessel. The unsupported piping exerts the stress on the localized areas of the vessel which could be above the designed limits of the vessel. The pipe support inspection should be extended to at least to the 1st support away from the vessel.

b. Look for the vibrating sections of piping directly attached to the vessel. Vibration trend of the piping can be determined by shaking the piping with light force. The vibrating section of attached piping can induce the mechanical fatigue at the nozzle weld areas.

2.2. Internal Inspection:

Vessel should be prepared for internal inspection as mandated in section 4.

2.2.1. Shell & Heads:

a. The shell, heads, drain & gas boots (if applicable) should be inspected as per General Requirements Para 1.2.2.

b. The area of the shell or head below and above the normal product level is typically susceptible to pitting and general corrosion. Sometimes the generalized wall loss takes place which is not easy to detect visually. The Zero degree Ultrasonic thickness measurement should be done in this case.

c. The area of the shell adjacent to the baffle plate (on the downstream side for separators) is susceptible to erosion, pitting and general corrosion. This area should also be examined with ultrasonic to determine the actual wall thickness of the shell.

d. Depending upon the contents of the vessel, the bottom of the vessels especially areas around the drain nozzles and the drain boot are susceptible to under deposit and various kind of the corrosion mechanisms including sour (wet H2S damage) and biological corrosion pitting.

e. If the wall loss falls below the design t_{min}, the fitness for service analysis should be conducted using the guide lines of API-510 Para, 7.4. If the analysis determines that the corroded area is not fit for continuous service at the design parameters, the damaged area should be restored using approved welding procedures.

f. If restoration of excessively corroded areas is not possible at time being the vessel should be derated and operated at reduced pressure limits until the repair is done. New working pressure should be calculated as follows.

- New working pressure due to corrosion wall loss on shell:

$$P = \frac{SEt}{R + 0.6t}$$

- New working pressure due to corrosion wall loss on dished head:

$$P = \frac{SEt}{R + 0.1t}$$

Whereas t = Measured minimum thickness in corroded areas (in inches)
P = De-rated working pressure (measured in psi)
E = Joint efficiency (E=1 if the corroded areas is away from weld)
R = Radius in vessel (in inches)
S = The allowable stress, (1/4 times tensile strength for vessels Manufactured before 1999, and 1/3.5 times tensile strength for vessels manufactured after 1999).

g. The PSV setting on the derated vessel should be adjusted accordingly.

h. Since the corrosion process is active in the derated vessels, further deterioration is eminent during the derated service, (unless some operational procedures are not altered relative to the active demerge mechanisms). Hence an ultimate safe thickness value (ultimate required t_{min}) of the corroded shell should be fixed. The vessel must come out of service if the minimum thickness of the subject corroded area falls below this ultimate required t_{min}. Due to this reason the subject corroded areas must be periodically monitored with ultrasonic scanning (from outside). The time period of monitoring should be determined based on the corrosion rate, and the severity of the service.

i. Once the ultimate required t_{min} is determined the remaining life of the vessel (in derated service) should be determined as given below. The remaining life will determine the time interval allowed for the continued service.

$$Corr.Rate = \frac{t_{Prev} - t_{latest}}{Duration\ of\ previous\ service}$$

$$Remaining\ life = \frac{t_{latest} - t_{\min req}}{Corrosion\ rate}$$

t_{prev} = The min thickness at time of previous inspection. (if no thickness is available the design thickness should be used.

t_{latest} = The measured minimum thickness at present.

$t_{min\ req}$ = The ultimate minimum thickness decided.

Supplementary note:

i. This approach should also be used to determine the remaining life for vessels which are not in the derated service.

ii. If enough OSI data for the corroded area is available so that the long term and short term corrosion rates can be calculated (as given is API-510 Para 7.1.1.1). The highest of two should be used to determine the remaining life. However it must be noted that the general corrosion rate of the vessel might not be applicable at the localized area which shows excessive corrosion. Therefore it is safe to develop separate corrosion rate of these areas with stringent approach.

2.2.2. Coated Vessels:

If vessel is internally coated the inspection should be done according to General requirements Para 1.2.3.

2.2.3. Lined Vessels:

The vessels in erosive services are internally lined with the metallic liners or weld overlaid. Following are the minimum requirements for the proper inspection of the weld lining inspection.

a. No corrosion is occurring either on the surface of the lining or below.

b. The lining is properly installed, and no imperfections like disbanded or cracking exist. All weld overlaying should be inspected with Liquid Penetrant inspection.

c. Bulges or buckling of internal liners usually indicates that the process fluid or gas has been trapped beneath the liner. This may present a potentially dangerous situation if the pressure has not been relieved prior to inspection. Such situation should be carefully reviewed prior to initiating any inspection work inside of the pressure vessel. The trapped fluid could be an explosive mixture of hydrocarbons. All means should be adopted to relieve the trapped pressure behind the bulges.

d. In case of the bonded lining (done by the explosion lining process), where ever suspected the integrity of the lining should be checked with ultrasonic.

e. Check shell and nozzle thicknesses just above and below cladding. Sometimes the shell besides the lining shows excessive generalized corrosion which could not be judged by visual inspection.

2.2.4. Weld Inspection:

Inspect all internal structural, nozzle and attachment welds as per General Requirements Para 1.3. The attachment welds are of significant importance. Most of the vessel failures are associated with the defects originating from the attachment welds. If the service related defects are suspected at some welds, the Magnetic particle inspection (if not already part of scope) should be added to the scope of inspection.

2.2.5. Nozzles Inspection:

a. All nozzles (including manways) should be checked thoroughly, for corrosion or any other service related defects.

b. Check nozzles for plugging with deposits, especially small draw-off and instrument nozzles.

c. Look at the gasket face for corrosion and erosion. The gasket faces are prone to have crevice corrosion if the debris is trapped in between.

d. Report any condition that could affect the sealing and cause the leaks. Over torque can sometimes damage the mating faces of the flanges.

e. Look for the appropriate depth of machined serrations, both on the nozzle flanges nozzle and the cover (or mating flange) gasket faces. Best visual judgment is adequate to find out if the serration depth is appropriate or not, however the micrometer measurements can also be taken if required.

2.2.6. Internal Attachments:

a. Check the structural integrity of the internal attachments like vortex breaks, Baffle plates, inlet deflectors, impingement plates, stiffener rings, demister pad holding assemblies etc. The damage to these attachments significantly affects the operation parameters of the vessel and alters the damage mechanism. Repairs should be recommended if the attachments are found excessively corroded, dismantled or damaged to the extent that intended function is not achievable.

b. If applicable the demister pads and/or filters should be removed and cleaned for inspection. Replace these components if found corroded or damaged to the extent that the mesh or assembly would not survive the next service cycle.

c. Check inlet distributors and surrounding area for abnormal wear or corrosion

2.2.7. Magnetic particle inspection should be added to the scope of inspection, if the cracking is suspected. The scope and extent of MT is decided based upon the vessel history, potential damage mechanism and the severity of the service conditions. However Wet Fluorescent MPI or LPI (whichever applicable) must be done at the welds in following vessels.

a. Vessels in sour service.

b. Vessels in refrigerated service.

c. Vessels in hydrogen service.

d. Vessels subjected to thermal and mechanical fatigue.

e. Where ever stress corrosion cracking of any kind is suspected.

2.2.8. Internal instruments like floaters, thermo wells, Corrosion coupons, internal cathodic protection anodes etc (if not disassembled) should be inspected for the integrity and the intended functions. These instruments could be subjected to the resonant vibration because of the flow dynamics inside the vessel. Check for the fatigue signs on these instruments.

2.3. Additional Inspection with the specialized None destructive methods like AUT, acoustic emission, remote visual, magnetic flux leakage and Eddy currents etc. should be carried out as the special requirements. The detailed procedure and precautions for using these techniques is beyond the scope of this manual.

Section-5

Towers/Columns Specific Requirements

3. Specific Inspection Requirements For Towers/Columns:

This section covers the specific inspection requirements of columns/towers with internal structure carrying trays and down comers. The text below covers different types of columns including, but not limited to, Contactors, Absorbers, Regenerators, Fractionators (distillation Columns), strippers, hydro-treaters, hydro crackers, mole sieves (for gas stream purifications) and pressure swing absorbers etc.

The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flange the inspection should be performed according to the requirements of Section 5 Para 9 of this manual. The conjoining flange will be covered in inspection scope of both, vessel and piping. The inspector should consult the design details, operation parameters, history of operational upsets, and the previous inspection reports before commencing the inspection.

It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and any additional requirements specific for the vessel being inspected are in place. Additional safety requirements as deemed necessary must be adopted.

3.1. External Inspection:

3.1.1. Support Structure:

a. Inspect the support structure including the foundation, skirt, anchor bolts and auxiliary support structure (if any) as per the General requirements Para 1.4.3.

b. Check for grout cracks underneath the columns base plate & if classified as grout category 7 & 8 as per SAIP- 076, Attachment 3, this needs immediate repairs as per applicable approved repair procedure.

c. Check for foundation cracks & if classified as concrete category 1 & 2 (fine & shrinkage cracks) as per SAIP- 076, Attachment 3, this should be patch up & sealed to avoid ingress of moisture. But if classified as concrete category 3&4(severe surface damaged & severe cracking), this needs immediate repairs as per applicable approved repair procedure.

3.1.2. Ladders and Platforms:

The integrity of leaders and platforms should be checked as per General Requirements Para 1.6

3.1.3. Insulation Inspection:

If tower is insulated, the insulation inspection should be done as per General requirements Para 1.2.1. In case CUI is suspected the insulation from the affected area should be removed and inspected as per General Requirements 1.2.2.

3.1.4. <u>Shell and Heads:</u>

If tower is not insulated then heads and shell should be inspected as per General Requirements 1.2.2.

3.1.5. <u>Welds:</u>

All structural, nozzle and attachment welds should be inspected as per General Requirements Para 1.3

3.1.6. <u>Nozzles:</u>

All of the nozzles should be inspected as per General Requirements Para 1.5.

3.1.7. <u>Attachments:</u>

All of the attachments should be inspected as per General Requirements Para 1.8.

3.1.8. <u>Gauges:</u>

Inspect condition of all of the gauges as per General Requirements Para 1.7.

3.1.9. <u>Grounding Connection:</u>

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

3.1.10. <u>Gasket:</u>

Check for the leaks and gasket integrity as per General Requirements Para 1.10.

3.1.11. <u>Attached Piping:</u>

a. Inspect the general condition of the attached piping. To determine if the attached piping is not exerting undue stress on the tower, attention should be paid to the pipe supports on the piping directly attached to the tower. The unsupported piping exerts the stress on the localized areas of the tower which could be above the designed limits of the tower. The pipe support inspection should be extended at least to the 1st support away from the tower.

b. Look for the vibrating sections of piping directly attached to the tower. Vibration trend of the piping can be determined by slight shaking. The vibrating section of attached piping can induce the mechanical fatigue at the nozzle areas.

3.2. Internal Inspection:

Towers should be prepared for internal inspection as mandated in section number 4. Inspection should be preferably conducted by descending from top to bottom. For the safety purpose only one person should be descending thorough the tray manways at a time. Wider columns with two side tray manways and down comers should be inspected by two inspectors at the same time by descending through both sides of the tower. While inspecting, trays should be numbered from top to bottom. All observations should be reported with respect to the tray number.

3.2.1. Heads and Shell:

a. Both top and bottom heads and shell should be inspected as per General Requirements Para 1.2.2.

b. Determine the thickness of the corroded areas and pitting either using the pit gauge or ultrasonic thickness measurement. If the corroded area is found below the minimum required thickness t_{min}. The fitness for service analysis should be done as per API-510, Para 7.4.

c. If the analysis determines that the corroded area is not fit for continuous service at the design parameters, the damaged area should be restored using approved repair and welding procedures.

d. In case the repair is not possible at the time being, the derating of the tower should be considered, and the remaining life for the derated operation should be determined using steps provided in Section-5 Para 2.2.1.f , g, h and i, of this manual.

e. The portions of the shell behind the down comers shall be thoroughly examined for any evidence of blistering, corrosion, erosion, cracks or any other service related defects.

f. The shell in contact with the edges of down comer often shows the erosion. Use pit gauge to measure the erosion groves.

g. Check inlet distributors and surrounding area for abnormal wear or corrosion.

3.2.2. Coating inspection:

If any section of the tower is coated the inspection of the coating should be performed as per General requirements 1.2.3.

3.2.3. Lining Inspection:

If the tower is internally lined or weld overlaid. Internal metallic linings shall be examined for following potential lining related flaws.

a. No corrosion is occurring either on the surface of the lining or under.

b. Check for the proper installation and layout of the liner plates.

c. Bulges or buckling of internal liners usually indicates that the process fluid or gas has been trapped beneath the liner. This may present a potentially dangerous situation if the pressure has not been relieved prior to inspection. It is suggested this situation be carefully reviewed prior to initiating any inspection work inside of the tower/column.

d. If it is bonded lining (done by the explosion lining process), where ever suspected the integrity of the lining should be checked with ultrasonic.

e. The weld overlaying should be inspected with Liquid Penetrant inspection. Preferred inspection locations are the edges of the welds with the parent metal. If the cracking is suspected than the scope of inspection can be increased accordingly.

f. Check shell and nozzle thicknesses just above and below cladding. Sometimes the shell besides the lining shows excessive generalized corrosion which could not be judged by visual inspection. Ultrasonic thickness measurement should be done on these areas.

3.2.4. Weld Inspection:

All internal structural, nozzle and attachment welds should be inspected as per General Requirements Para 1.3. The attachment welds are of significant importance. Most of the vessel failures are associated with the defects originating from the attachment welds.

a. The attachment welds at the tray support rings should be carefully inspected for the service related and manufacturing defects. Corrosion is one of the biggest concerns on these welds.

b. Close attention shall be given to the down comer to shell welds. Due to access difficulties the welds often have lesser penetration or reduced weld layup from original manufacturing. These defects often emerge as the cracks in the shell to down comer welds. In some cases the cracking could progress into the shell. If this situation is observed, the surface shall be cleaned to a white metal finish and examined with wet magnetic particles. Document each finding with respect to the tray number. The cracked welds should be repaired using the approved weld procedures.

3.2.5. Demister pads and filters:

If applicable the demister pads and/or filters should be removed and cleaned for inspection. Replace these components if found corded or damaged to the extent that the mesh or assembly would not survive the next service cycle.

3.2.6. Nozzles Inspection:

a. All of the nozzles (including manways) should be checked thoroughly, for corrosion or any other service related defects.

b. The plugged nozzles should be cleaned and thoroughly inspected.

c. Look at the gasket face for corrosion and erosion. Report any condition that could affect the proper seal and cause the leaks.

d. The tower may have some auxiliary nozzles which are normally blinded at the flange. Such nozzles in the hot service act as dead legs and, depending on the diameter and configuration, can house strong convectional currents of the gas or fluids. These nozzles should be carefully inspected as severe erosion can take place in these nozzles, and the blinding cap.

3.2.7. Trays, down comers and related Hardware:

Trays, wear plates and the down comers are the most important part of the tower. The condition of the tray and associate equipment do not affect the integrity of the vessel but will affect the efficiency of the process. This change in efficiency may, in turn, alter the corrosion mechanism. For this reason, the general condition of the trays and tray supports is very important.

a. Look for all of the missing bubble caps, loose clips, missing hardware and deformation in the trays and the down comers.

b. Note the corrosion on the trays down comer and the support structure. Check for the bubble cap holes on the trays. If the holes are significantly oval in shape, then corrosion has initiated on the trays. If the support structure of the trays is severely corroded it should be changed or stiffened accordingly.

c. Assess if the trays will survive the next service cycle. The process upsets like gas surge and the liquid over loading deform the tray. Check for the significant deformation of the trays and down comers. The deformation alters the flow pattern which reduces efficiency of the tower.

d. Check if the bubble caps are not stuck at any level. If all or most of the bubble caps are stuck at any level, the trapped gas below the tray will exert upward force on the tray which can result into deformation or collapsing of the trays.

e. In case of the Stainless steel trays attached with the carbon steel towers/tray support, the galvanic corrosion may initiate between the trays and the support rings. This situation should be assessed properly and if required the metallurgy of the trays should be recommended to be change.

3.2.8. Internal Attachments:

a. Other than trays and down comers, the internal attachments of the tower include but are not limited to distributers, spargers, vortex breaks, inlet deflectors, impingement plates, stiffener rings, demister pads, and demister pad holding assemblies etc. The damage to these attachments significantly affect the operation parameters of the vessel and alter the damage mechanism. Repairs should be recommended if the attachments are found excessively corroded, dismantled or damaged to the extent that intended function is not achievable.

b. If applicable the demister pads and/or filters should be removed and cleaned for inspection. Replace these components if found corroded or damaged to the extent that the mesh or assembly would not survive the next service cycle

3.2.9. Scope of NDT:

Depending on the stream conditions and the damage mechanism, appropriate Nondestructive testing should be added to the scope of inspection. If service related cracking is suspected the potentially affected areas should be inspected with Magnetic particles inspection. The scope and extent of MT is decided based upon the Towers history and the severity of the service conditions. Wet Fluorescent MPI must be done on the welds in following services.

a. Towers in sour service.

b. Towers in refrigerated service.

c. Towers in hydrogen service.

d. Towers subjected to thermal and mechanical fatigue.

e. Where ever stress corrosion cracking of any kind is suspected.

3.2.10. Internal Instruments:

Internal instruments like floaters, thermo wells, Corrosion coupons, internal cathodic protection anodes etc (if not disassembled) should be inspected for the integrity and the intended functions. These instruments are sometimes subjected to the mechanical and thermal fatigue due to severe process conditions. The overall condition of these instruments should be evaluated for fitness for service.

3.3. Additional Inspection with the specialized None destructive methods like AUT, acoustic emission remote visual, magnetic flux leakage and Eddy currents etc. should be carried out as the special requirements. The scope and procedure of inspection with these techniques is beyond the scope of this manual.

Section-5

Shell Tube Heat Exchangers Specific requirements

This section covers the specific inspection requirements of Shell-Tube type heat exchangers. The exchanger performance is an important indicator of its condition. The inspector should consult the design details, operation parameters, history of operational upsets, and the previous inspection reports before commencing the inspection. The operation and sample reports should also be closely reviewed to identify if the heat duties and temperatures/pressures values have changed from the designed values. The significant deviation from the expected design values is the indication of possible tube leaks or fouling.

Following procedure can be used to inspect all shell-tube type heat exchangers including fixed tubes sheet type, Removable U-bundle type, internal floating head type, and external floating head type. Inspector using this procedure should select the applicable sections. The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flange the inspection should be performed according to the requirements of Section 5 Para 9 of this manual. The conjoining flange will be covered in inspection scope of both, exchanger and piping.

It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and any additional requirements specific for the vessel being inspected are in place. Additional safety requirements as deemed necessary must be adopted.

4.1. External Inspection

4.1.1. Support Structure:

Inspect the support structure as per the General requirements Para 1.4. For the horizontal type heat exchanger, there is possibility of the support damage due to lateral loading on the supports due to bundle pulling and pushing activities. The anchor bolts locations on the saddle supports should therefore be closely monitored.

4.1.2. Ladders and Platforms:

If applicable inspect the leaders and platforms as per General Requirements Para 1.6.

4.1.3. Insulation Inspection:

If exchanger is insulated then inspect the insulation integrity as per General requirements Para 1.2.1. In case CUI is suspected than remove the insulation from the affected area and inspect the shell as per General Requirements 1.2.2.

4.1.4. Shell, heads and Channel:

If exchanger is not insulated than inspect the shell, heads, channels and channel covers as per General Requirements 1.2.2.

4.1.5. Welds:

Inspection of the structural, nozzle and attachment welds should be done as per General Requirements Para 1.3.

4.1.6. Nozzles:

All nozzles should be inspected as per General Requirements Para 1.5.

4.1.7. Attachments:

All external attachment should be inspected as per General Requirements Para 1.8.

4.1.8. Gauges:

Inspect condition of all of the gauges as per General Requirements Para 1.7

4.1.9. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

4.1.10. Gaskets:

Check for the leaks and gasket integrity as per General Requirements Para 1.10. The gaskets at the channel, and the channel covers often show leaks due to damage caused during installation.

4.1.11. Attached Piping:

a. Inspect the general condition of the attached piping. To determine if the attached piping is not exerting undue stress on the vessel, attention should be paid to the pipe sports on the piping directly attached to the heat exchanger. The unsupported piping exerts the stress on the localized areas of the heat exchanger which could be above the designed limits. The pipe support inspection should be extended at least to the 1st support away from the exchanger.

b. Look for the vibrating sections of piping directly attached to the heat exchanger. Vibration trend of the piping can be determined by slight shaking. The vibrating section of attached piping can induce the mechanical fatigue at the nozzle areas.

4.2. Internal Inspection:

All of the removable internal including tube bundle, floating head, channel head, and bonnet should be completely removed for the internal inspection. Heat Exchanger should be prepared for internal inspection as mandated in section 4.

4.2.1. Shell heads and Channel:

a. The internal surface of shell, heads, bonnets, channel, and floating head should be inspected as per General Requirements Para 1.2.2. The bottom of the shell should be inspected for the corrosion and erosion based upon the damage mechanism in the vessel.

b. Determine the thickness of the corroded areas and pitting either using the pit gauge or ultrasonic thickness measurement. If the corroded area is found below the minimum required thickness t_{min}. The fitness for service analysis should be done as per API-510, Para 7.4.

c. If the analysis determines that the corroded area is not fit for continuous service at the design parameters, the damaged area should be restored using approved welding procedures.

d. In case the repair is not possible at the time being the derating of the exchanger should be done, and the remaining life for the derated operation should be determined using steps provided in Section-5 Para 2.2.1.f , g, h and i, of this manual.

e. If the tubes are fixed then inspect the shell besides the tube sheet. This section of the shell sometimes undergoes the erosion corrosion due to high velocity flow of the sediments and corrosive fluids. The generalized corrosion can be felt by rubbing the fingers carefully on shell near the fixed tube sheet.

f. In case of the fixed tubes exchangers the internal inspection of the inaccessible section of the shell between the tube sheets should be inspected as per Para 4.2.2.

g. If the tubes bundle is removable the inspection should be performed on complete shell. Find out the approximate location where bundle baffle plates sit while in operation. Pay close attention on the generalized wall thinning on these locations. Due to slight gap between the baffle and shell, turbulent flow can take place behind the baffles. The pit gauge or Zero degree Ultrasonic thickness measurement should be done if significant erosion is found.

h. Also look for the mechanical gouging due to bundle removal and loading. Any significant damage found should be evaluated for fitness for service using the guidelines of API-579.

4.2.2. Inspection of Fixed Tube sheet Exchanger:

a. In case of the fixed tube sheet, the visual inspection of the shell between the both end tubes sheets is not possible, unless special remote visual techniques are applied. Various specialized remote visual techniques are available. One of the techniques is by inserting the robotic camera through the inlet and outlet nozzles. The condition of fixed tube bundle can also be assessed with this method. However the inspection with these techniques is limited.

b. The integrity of this section of shell should be thoroughly checked with extensive ultrasonic inspection. This inspection should include the Zero degree and the shear wave inspection. The scope and extent of the inspection should be determined based upon the service and the history of the exchanger. In case of the sour or hydrogen service, particular attention should be given to the potential of blistering and hydrogen induced cracking. If preliminary ultrasonic inspection shows the signs of such damage, the UT scope should be increased and this section should be inspected with advanced ultrasonic techniques like P-scan and phased array. TOFD inspection should be done on the welds for SOHIC. In-service monitoring with Acoustic Emission method is also another option of monitoring such equipments.

4.2.3. <u>Tube Side Internal Inspection:</u>

a. The tube side internals (channel, channel covers, floating heads, and bonnets should also be closely observed for any corrosion or erosion.

b. In case of the U-tube and the floating head type exchangers, pay close attention to the machined surfaces of the gasket areas, especially at the pass partition (divider plate between the tube side inlet and outlet) gasket at the plate and the channel cover. Any damage to the gasket caused while installation will create a leaking spot between the tubes inlet and outlet side. The leak can be widened during the service and cause flow erosion damage at the gasket surfaces of channel cover and pass partition plate. Such damages should be weld build up and re-machined before putting exchanger back into service.

c. The partition plate (pass plate) sometimes gets the beat from the turbulent flow and the differential pressure on the tube inlet and outlet side. This can cause the weir of the partition. The welds on the edges are often found cracked. MPI should be done on these welds. The broken or cracked welds should be repaired wing the approved welding procedure.

4.2.4. <u>Weld Inspection:</u>

Inspect all internal structural, nozzle and attachment welds as per General Requirements Para 1.3. If the service related defects are suspected at some welds, the Magnetic Particle inspection (if not already part of scope) should be added to the scope of inspection as per requirements of Para 4.2.7.

4.2.5. Nozzle Inspections:

All of the shell side, tube side and the drain nozzles should be thoroughly checked, for corrosion, erosion or any other service related defects. Some Heat exchanges like Kettle type Reservoirs Rebuilders have the attachments like weir plates, vortex breakers, and in some cases have the demister pads for the gas out. Check the integrity of these internal attachments. Repairs should be recommended if the attachments are found corroded or damaged to the extent that the intended service is not achievable.

4.2.6. Floating head and the expansion joints:

The floating head and the expansion joints (if available), undergo the mechanical movement more than any other component. There is higher potential of fatigue cracking and erosion on these components. These components should be preferably inspected by MT or PT.

4.2.7. Nondestructive testing:

Magnetic particle inspection should be added to the scope of inspection, if the cracking is suspected. The scope and extent of MT is decided based upon the heat exchanger history and the severity of the service conditions. The Wet Fluorescent MPI must be done on the welds in following services.

a. Heat Exchangers in sour service.

b. Heat Exchangers in chilling & Cryogenic service.

c. Heat Exchangers in hydrogen service.

d. Heat Exchangers subjected to thermal and mechanical fatigue.

e. Where ever stress corrosion cracking of any kind is suspected.

Initial inspection should be performed at the nozzles and 12" on each side of Tee intersection of long and circ seams. If cracks or other service related indications are found, the scope of inspection should be increased accordingly.

4.2.8. Internal Cathodic Protection:

If the internal cathodic protection is applied, the condition of the anodes should be monitored to evaluate the effectiveness of the protection. New anodes should always be installed at every Shut down unless the old once are in good condition.

4.2.9. Gasket Inspection:

Look at the gasket face for corrosion and erosion. Report any condition that could affect the sealing and cause the leaks. The Shell to Channel and Channel to channel cover gaskets are sometimes damaged due to mishandling and over torque while installation.

All abnormalities which can cause the leak of contents during service should be carefully addressed.

Commentary Note: It is very common to find marks and scratches due to the use of crowbars to disassembly the flanges.

4.3. Tube sheet and bundle integrity inspection.

4.3.1. Tube sheet Inspection:

a. Thoroughly inspect the tube sheet for any corrosion. If significant corrosion is found the fitness for service evaluation should be done for this tube sheet.

b. If tube sheet is fixed, check the integrity of the tube sheet to shell seal weld. Look for preferential corrosion on the weld. Perform the WFMPI or PT on this weld. Any cracks found in this weld should be repaired using Aramco approved welding and PWHT procedures (if applicable).

c. Look at the tube sheet to tubes seal formation. If tubes are seal welded, look for the weld corrosion of missing welds. If tubes are rolled check for the rolled edges. Any leak or gaps between tube sheet and tubes should be fixed before putting the Exchanger back into service.

d. The integrity of the tubes should be inspected by one or combination of the methods like Eddy currents, internal rotary inspection system IRIS (Ultrasonic Technique), magnetic flux leakage MFL techniques and pressure testing.

e. The leaked tubes or the tubes not able to survive the next service interval should be plugged at both ends. Care should be given to use compatible material of the plugs. Inspector is responsible to perform (or recommend for) the Positive Material Identification (PMI) on the plugs and tubes and accept or reject the plug material. Wrong plugs material will cause the galvanic corrosion at the tube and/or plug. It is also recommended to vent the plugged (Not leaking) tubes in order to avoid any pressure build up that can blow the plug. (See SAEP 317 7.5.5. Commentary Note)

f. Look for the integrity of existing plugs (if any). Corroded plugs should be replaced with the plugs of compatible material. Check if both sides of the tubes are plugged (by counting the location of the plugs on both sides). Also check the tightness of the existing plugs.

g. Check the gasket face of the tube sheet. Look for the signs of any flow erosion or the crevice corrosion. The damaged gasket faces should be weld build up and re-machined.

4.3.2. Removable Tubes Bundle Inspection:

a. The bundle should preferably be inspected before and after cleaning. The pre-cleaning inspection reveals the important information about the service conditions and leaks in the tube. Assess all of the fouling and take the samples if required.

b. Check the overall structure of the bundle. Look for the mechanical damage on all of the components caused by mishandling while pulling. Biggest signs of the structural damage due to mishandling are the bent tubes and tie rods at the baffle plates which touch the bottom side of the shell. The misalignment of the baffle plates is also another sign of the beating due to erroneous pulling or pushing practices. Report and evaluate the deformation for fitness for service.

c. Evaluate the integrity of the baffle plates. Check for the alignment and parallel formation of these plates. Carefully look at the outer (circumferential edge of the plates. Any extensive damage like corrosion or erosion will cause excessive flow of the shell side fluid behind the baffles. Bottom side edge of the baffles can have excessive wear due to pulling and pushing of the bundle. Significant localized damage should be addressed by weld build up and grinding flush with the original profile.

d. Another problem usually encountered is the galvanic corrosion of the baffle plates and the tube sheet (in case of the brass tubes). This is caused by the wrong choice of the materials at time of designing, or the change in the operation parameters which the exchanger is not designed for. If such problem is found the bundle should be replaced with tube sheet and baffle plates materials compatible with the service conditions.

e. Tie rods are most important role players in the overall structural integrity of the bundle. Check for the tightness of the tie rods and spacers by shaking all of the rods. Because of lower grade materials being used the tie rods are often found excessively corded as compared to other components of the bundle. Evaluate the condition of the tie rods for next service cycle. If these rods and spacers are found excessively damaged, they must be replaced.

f. Look for the integrity of the tubes. Record any mechanical damage caused by the bundle removal and loading. Look for corrosion pitting or any other service related damage on the tubes. The sections of the tubes near the shell side inlet (around the impingement plate) often show the erosion damage. Similarly the tubes near the shell outlet also have potential of erosion metal loss.

g. In case of reboiler, the tubes in the vapor zone are prone to metal loss due to generalized and pitting corrosion. If these tubes are found damaged to the extent that leak may occur during next service cycles. These tubes should be replaced or plugged.

h. Look for signs of mechanical damage due to vibration in the tubes. Tubes are often found pinched or gouged at the baffle plate hole. Sometimes the signs of the galvanic corrosion are also found at the matting surface of the tubes and the baffle plates. This is caused due to wrong material selection while designing. If significant damage is found on the tubes, record the damage and assess for fitness for service.

i. I significant amount of sludge is found in the exchange at the time of opening, special attention should be paid the bottom side tubes of the bundle for corrosion and damage caused by the movement in the sludge while bundle pulling.

j. All of the tubes should be checked with the NDT methods like Eddy currents, internal rotary inspection system IRIS (Ultrasonic Technique), magnetic flux leakage MFL techniques and pressure testing. The leaked tubes or the tubes not able to survive the next service interval should be plugged at both ends. Care should be given to use compatible material of the plugs. Inspector is responsible to perform (or recommend for) the Positive Material Identification (PMI) on the plugs and tubes and accept or reject the plug material. Wrong plugs material will induce the galvanic corrosion at the tube and/or plug. It is also recommended to vent the plugged (Not leaking) tubes in order to avoid any pressure build up that can blow the plug. (See SAEP 317 7.5.5. Commentary Note)

k. Look at the condition of the (shell side fluid) impingement plate on the bundle. If this plate is found excessively thin, it should be replaced with new.

4.3.3. Non-Removable Tubes Bundle Inspection

a. The visual inspection of the tubes in fixed tube sheet exchange is not possible unless remote visual techniques are applied. These tubes should be checked with the NDT methods like Eddy currents, internal rotary inspection system IRIS (Ultrasonic Technique), magnetic flux leakage MFL techniques and pressure testing. The leaked tubes or the tubes not able to survive the next service interval should be plugged at both ends. Care should be given to use compatible material of the plugs. Inspector is responsible to perform (or recommend for) the Positive Material Identification (PMI) on the plugs and tubes and accept or reject the plug material. Wrong plugs material will induce the galvanic corrosion at the tube and/or plug. It is also recommended to vent the plugged (Not leaking) tubes in order to avoid any pressure build up that can blow the plug. (See SAEP 317 7.5.5. Commentary Note)

4.4. Additional Inspection with the specialized None destructive methods like AUT, acoustic emission remote visual, magnetic flux leakage and Eddy currents etc. should be carried out as the special requirements. The inspection procedure for these techniques is beyond the scope of this manual.

Section 5

Fin Fan Cooler Specific Requirements

5. Fin Fan Cooler (Air Cooled heat exchangers-ACHE) Inspection-General:

Fin Fan Coolers are also known as Air cooled heat exchanger, or aerial coolers. This section covers the specific inspection requirements of process related components of the Fin Fan Coolers, the inspection of the mechanical parts for the air movement including the motor, drive shaft, drive belt (or gear box), fan and associated control system is beyond the scope on this manual. This section is applicable to the inspection of induced draft type cooler (fan above the tubes), forced draft type (fan below the tubes) and horizontal coolers on the gas compressor packages. Before any inspection, the inspector should look at the operation history and previous inspection findings for the cooler.

At the time of inspection if the cooler is in operation, it is responsibility of the inspector to ensure that all of the safeguards from the moving parts are in place. The hazard of the high draft and the dust movement exits below the fan particularly in the forced draft type coolers. There for it is recommended that the inspector should wear the safety goggles while being in the vicinity of the cooler in operation. If the inspection is being performed on the cooler in operation, any hydrocarbon or hazardous gases leaks in the area should be accounted for by the continuous gas monitoring. Inspector should also ensure that all of the protective measures for working on heights are in place while inspection the top section of the coolers.

The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flange the inspection should be performed according to the requirements of Section 5 Para 9 of this manual. The conjoining flange will be covered in inspection scope of both, cooler and piping.

5.1. External Inspection

For fin fan coolers it is preferable that the inspection should be done while the equipment is in operation. All of the necessary precautions should be adopted to avoid injury from noise, electrical hazards and high wind draft (such as debris or sand getting into the eyes by using goggles, and wearing thicker full body coveralls).

5.1.1. Excessive Vibration:

First thing to note is the is excessive vibration in the structure or andy unusual noise. The vibration and unusual noise are the indications of the unbalanced rotation of the fans. This is the origin of various other potential problems that could be encountered, including the structural problems, tubes damage due to striking and fatigue in the tubes at the junction with the header box. Various tube leaks occurred in the fin fan coolers have been reported due to mechanical fatigue induced by cyclic vibration induced from unbalanced fan assembly. If excessive vibration exists, the care full gas testing should be done on the tubes at the junction with the header box. If any leaks are found the situation should be immediately notified to operation and the cooler should be isolated for rectification of the leak.

5.1.2. Support Structure Inspection:

a. The support structure of the fin fan cooler generally is composed of the columns, braces, and cross beams. This structure supports the exchanger at a sufficient elevation above grade to allow the necessary volume of air to enter below at desired velocity. At the base the structure is either bolted to various anchor bolts protruding out from the concrete, or welded to the metallic pilings. The support structure inspection should be done according to established structural steel inspection procedures.

b. Carefully look for the minor structural deformation if there is excessive vibration in the system.

c. Check all of the attachment welds on the frame and note the corrosion and the cracks in the frame welds for repair. The welds in the lowest section of the frame get the most beat.

d. Also look for the deformed anchor bolts and the cracks in the concrete base if the fan has excessive vibration.

5.1.3. Ladders and Platforms:

Inspect the leaders and platforms as per General Requirements Para 1.6

5.1.4. Header box inspection:

The header box on both sides of the cooler should be inspected as per General Requirements Para 1.2.2. Usually the header box does not get any physical damage because of being very thick. However any significant service related or manufacturing defects should be noted for further investigation.

5.1.5. Inspection of welds:

Inspect the structural, nozzle and attachment welds on the header boxes as per General Requirements Para 1.3.

5.1.6. Nozzles Inspection:

Inspect inlet, outlet, drain and vent nozzles as per General Requirements Para 1.1.

5.1.7. Gauges Inspection:

Inspect condition of all of the pressure and temperature gauges as per General Requirements Para 1.7.

5.1.8. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9

5.1.9. Plugs Inspection:

Check for the leaks and gasket integrity as per General Requirements Para 1.10. Carefully observe the leaks at the plugs. If required the careful gas testing should also be done at the plugs while cooler is in operation, to detect minor leaks.

5.1.10. Tube Inspection:

a. Inspect the condition of the tubes and fins on the visually accessible areas. Excessive damage to the fins affects the heat dissipation of the tubes. Along with other reasons the fin damage could also be caused by the vibration of the tubes. Note the debris on the fins. The sand or dust clogged in the fins significantly affects the heat dissipation of the tubes giving rise to the local hot spots.

b. Note the tube vibration if the fan is running. The vibrating tubes can develop the mechanical fatigue at both ends (at header junction). Report the vibration in the tubes and excessive fins damage for further evaluation at next shutdown.

c. Look at the signs of tubes leak from the bottom side. If the medium is gas than use the gas detector for the leak detection. Complete visual access to the tubes could not be available; however the inspection scope could be extended if the signs of leak are found at any location. Binoculars should be used to have a closer view if the adequate access is not available to the bottom side of the cooler.

d. Thermography should be done on the tubes to locate the localized hot spots. The localized hot spots develop due to damaged fins from external wear or fouling/restricted flow inside the tubes. The localize hot spots can cause the thermal fatigue on the tubes and be the origin of the containment leaks.

5.1.11. Piping Inspection:

a. Inspect the general condition of the attached piping. Most of the time the inlet and outlet are taken from a header which could supply to more than one coolers in parallel arrangement. Attention should be focused on the piping supports, to determine if the attached piping is adequately supported. The unsupported piping exerts the stress on the header and the inlet and outlet nozzles.

b. The un-even distribution of the product from the header is also a common problem which is caused by poor designing. This problem exerts extra thermal and mechanical load on the central coolers in the bank. The acoustic flow measurement should be done if such situation is suspected.

c. When the overheads from the sour service equipments are required to be cooled, the corrosion inhibitors or the wash water injections are often done in the inlet piping upstream of the coolers. These piping should be monitored as per injection circuits for high anticipated corrosion rates.

d. The vibrating section of attached piping can induce the mechanical fatigue at the attachment with header or the inlet and outlet nozzles. The small bore drain lines are often not adequately supported and vibrate at the natural frequency. The connections with the header on these lines are prone to get the fatigue cracking. Is excessive vibration is found on these lines, MPI or LPI should be done on the weld joint with the header, and additional support should be provided to dampen the vibration.

5.1.12. Louvers inspection:

a. The louvers are often added to the forced draft coolers to control the cooling rate. The overall condition of the louvers should be checked. The broken and dented louvers should be reported for replacement of rectification.

b. The mechanical movement of the air inlet louvers (if available) for controlling the air intake should be checked.

c. Check for the mechanical movement of the top closure louvers (in case of forced draft type cooler). These lovers should be slightly angled to protect the tubes from the falling debris.

Supplementary Note: The Inlet louvers are added to control the amount of air intake to reduce the excessive cooling in the colder parts of world. These louvers should not be common in Saudi Aramco Facilities.

5.1.13. The fan Assembly:

Look at the overall condition of the mechanical system, including fan, plenum, shroud drive shaft, belts (for less than 50 hp motor) or gear box (for bigger fans and more than 50 hp motors). The detailed inspection of these components is not in the scope of this manual, and should be conducted by individuals trained for this task.

5.2. Internal Inspection:

The internal visual inspection of Fin Fan cooer is different for the plugs type header and the cover plate type header. The complete internal inspection of the cover plate type header is possible after removing the cover plate. However for the plugged header the complete inspection is not possible due to reduced visual access. Hi tech remote visual methods can be adopted but still 100% coverage cannot be guaranteed. However the header boxes are usually designed with very thick materials which give excessive corrosion allowance. The Ultrasonic inspection of the suspected areas is the best available alternative to the internal inspection. Depending upon the accessibility for the internal components following inspection procedure should be adopted.

5.2.1. Header Box Inspection:

a. For the cover plate type headers, remove the header plates from both sides. Do the preliminary inspection before cleaning, and detailed inspection after cleaning. Similarly for the plugged headers remove all of the plugs (if specified in the work scope) or 10 % of the plugs on the same tubes from both sides.

b. Thoroughly inspect the tube sheet's visually accessible area. Look for any corrosion and the tube to tube sheet joint. In case of the plugged headers, if the problems are found the scope of the work should be increased and more plugs should be removed.

c. Look carefully on the header partition plate (if exposed).

d. Look at the gasket area of the plugs, and on the cover plate in case of the plate type header. Report any condition that could affect the sealing and cause the leaks.

5.2.2. Tubes Internal Inspection:

The integrity of the tubes is inspected by one or combination of the methods like Eddy currents, remote visual (borocopy), internal rotary inspection system IRIS (Ultrasonic Technique), magnetic flux leakage MFL techniques and pressure testing. The damage tubes should be either replaced or plugged with the compatible material plugs. PMI should be done on the plugs in order to check the compatibility of materials.

5.2.3. Nozzles Inspection:

If the attached piping is removed, internal surface of the inlet and outlet nozzles should be visually inspected. Otherwise the detailed thickness measurement with ultrasonic should be done on the complete surface of the nozzles.

Section-5

Plate Exchanger Specific Requirements

6. Plate Exchanger-General:

A plate heat exchanger consists of packed corrugated metal plates (also called as elements) between a frame plate and a pressure plate and compressed by tightening bolts. In case of welded or brazed plates exchangers the elements are joined by brazing or welding. The specially engineered corrugated structure of the plates provides the turbulent flow pattern for the fluids. The gaskets between the plates are so arranged that hot and cold fluids are directed onto the alternate plates. The hot and cold fluids flow in the opposite directions in odd and even plates providing the broad contact areas for the heat transfer. Due to this arrangement the plate exchangers provide the heat recovery efficiency of 85% to 95%. The most common problem with the plate exchanger is the gasket damage between the plates which could happen while assembly or with any kind of process upset, like sudden temperature of pressure shock. The damaged gaskets can cause the intermixing of the fluids or the external leaks.

Improper startup and failure to vent the space between the plates can cause the air locks and differential pressure build up, which can damage the plates. Other possible damage mechanics include the thermal or mechanical shocking due the turbulent flow and channels blockage due to fouling. The Plates material can yield and produce cracks because of the thermal and mechanical shocks. In order to avoid the fouling the strainers (filters) are often used on the upstream side of both inlets to help purify the inflowing fluids.

Depending on the metallurgy of the plates used, the plate exchangers can also be affected by various types of environmental damages like stress corrosion cracking. Due to the structure and the complexity of the assembly the internal inspection of the plate exchangers is done only if the problem is anticipated from the operation data. Unless required, there is no regular T&I for plate exchangers. Due to these reasons a detailed external inspection is very important.

The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flange the inspection should be performed according to the requirements of Section 5 Para 9 of this manual. The conjoining flange will be covered in inspection scope of both, exchanger and piping.

6.1. External Inspection:

6.1.1. Support Structure:

Thorough visual inspection is required to the support structure of the plate exchanger looking for proper balance and alignment with the attached piping. Plate exchanges are often bolted to the ground or the steel structural beams. Over all inspection of the support structure should be as per requirements of Para 1.4 of this manual.

6.1.2. Assembly Inspection:

Look at the overall condition of the components including the frame plate (fixed) and pressure plates (movable), tie bars, top and bottom guide bar and the end support bar. Only limited visual access is available for the element plates, look for the mechanical damage or external corrosion on the visible ends of element plates.

6.1.3. Nozzle Inspection:

Inspect the inlet and outlet nozzles as per General Requirements Para 1.3. Perform Ultrasonic Scanning on the nozzles for internal corrosion. Wall Thickness readings should be evaluated as per the applicable inspection code requirements.

6.1.4. Gauges:

Inspect condition of pressure and temperature gauges on inlet and outlet nozzles as per General Requirements Para 1.7.

6.1.5. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

6.1.6. Leaks:

Look for signs of leaks on the plates and report to operations for any active leaks found during inspection.

6.1.7. Piping Inspection:

Inspect the general condition of the attached piping. The unsupported piping exerts the stress on the inlet and outlet nozzles. Similarly the vibrating section of attached piping can induce the mechanical fatigue at the attachment with header or the inlet and outlet nozzles.

6.2. Internal Inspection:

The internal inspection of the Plate exchangers is only possible on the inlet and outlet nozzles. If the remote visual techniques are applied than the sections of the pipes downstream of the nozzles and the associated headers, (if any) can be inspected. The internal inspection of the plates is not possible unless the exchanger is opened due to operational problems like excessive fouling or the internal leaks (determined by the operation from the product sampling). The brazed and welded plate exchangers cannot be opened, however the press fitted exchanger can be opened, which needs the high level of expertise and shop properly equipped for this purpose. The construction and the assembly difficulties leave the pressure testing as the only accomplishable option to check the integrity of the Plate exchanger in the field.

6.2.1. Pressure Testing:

The pressure testing should be done according to the established Aramco Procedures and manufactures specifications. The pneumatic testing with nitrogen gas should preferably be done, however the hydrostatic testing can also be performed using the fluids which are inert for the metallurgy of the plates. Alternative testing should be done on the cold and the hot sides. While pressure testing the one side (hot or cold) the other side of exchanger should be kept at atmospheric pressure.

The hydrostatic test pressure for each test should be held for a sufficient time to permit a thorough inspection and detection of small seepage leaks, but not less than 30 min. After completion of the test, the Plates Heat Exchanger should be drained.

Failed pressure test is the indication of the worn out plates or the leaking gasket areas. In this case the exchanger has to be replaced if the repair is not possible due to design. If the exchanger can be opened than the repair procedure devised by the Manufacturer should be used. The press fitted exchangers (with tie rods) can be unassembled easily, however cutting of the joints is required for the Brazed or welded plate exchangers. The cutting of the brazed or welded joints should be done according the manufactures qualified procedures.

Once the exchanger is opened the inspection of the plates can be done as per following.

6.2.2. Plate Inspection after opening:

a. Visually inspect the plates with in the flow channels, any corrosion or the wall loss or pitting should be reported.

b. Close attention should be given on the Gasket areas for erosion, crevice corrosion or the stress corrosion cracking. Any scratches or damage in these areas can cause leak, and should be addressed accordingly.

c. Most often the plates are made of stainless steel or aluminum alloys. Liquid Penetrant inspection should be performed on the plates to look for environmental damage such as Stress Corrosion Cracking, or liquid metal attack.

d. Damaged plates should be evaluated by the authorized inspector. Replacement should be done if the plates are found not fit for service.

e. Upon assembling the exchanger the inspection should be done for gasket installation and the proper alignment of the plates. The assembly should be pressure tested as per Para 6.2.1

6.2.3. Ultrasonic Inspection of the Nozzles:

The ultrasonic inspection of the nozzles and the associated piping can be use to best predict the problems with the heat exchanger. If the exchanger is in an aggressively corrosive service, the detailed scanning of the nozzles should be done. Frequently inspections are recommended to determine the actual corrosion rate of the system. However this method is not appropriated to predict any kind of environmentally assisted damage inside the exchanger.

6.2.4. Indirect evaluation methods.

Due to the complexity of the Plate Exchanges the indirect methods of evaluation of the status should be adopted. These methods include but are not limited to

a. The frequent sample analysis on the downstream end of both hot and cold sides of the exchanges. The internal leak can be detected if the hot and cold side fluids are being mixed.

b. Evaluation of the thermal efficiency of the exchanger. The excessive deviation from the designed heat duties of the exchanger will also be the indication of the problems like internal leak or excessive fouling of the exchanger.

c. Monitoring the conditions of the strainers (filters), and regular measurement of the filter efficiency. For this reason the frequent sampling of the plate exchanger inlet (downstream of the filters) should also be done regularly.

Fixed Bed Reactors Specific Requirements

7: Fixed Bed Reactors General:

a. The reactors are used for variety of functions in the refining process like hydro-treating, catalytic reforming, fluid Catalytic Cracking, and de-sulfurization etc. The primary process involves passing the hot gaseous phase mixture of fluids from the bed of the catalyst at high temperature, which aids desired reaction process. Depending on the process, some specialized reactor designs provide the continuous mechanical movement of the catalyst, the inspection of these kinds of reactors is not covered in this manual. This section provides the specific inspection requirements of the fixed bed type reactors in which the Catalyst is stationery.

b. The reactors due to their intended functions are internally designed to provide the uniform distribution of the flowing gases and allow maximum contact with the catalyst. Other than the new design of continuous regeneration reactors CCR (where the catalyst is replenished continuously), the catalyst in most of the reactors is consumable and has to be replaced after certain period of time. This provided the best chance of the internal inspection and maintenance of the reactor. The inspection procedure for the mechanical part of the CCR type reactors is not in the scope of this manual. The inspection of these parts should be done according to the manufactures instructions. The following text covers the specific inspection requirements of the fixed bed type reactors.

c. The fixed bed reactors are mainly of two types, axial flow and the radial flow reactors. Following text provided the inspection procedure of both types. The inspector using this procedure should select the relevant sections. The coverage of the inspection in this procedure is limited to the first flange, either blinded or connected with the attached piping. Past the first flange the inspection should be performed according to the requirements of Section 5 Para 9 of this manual. The conjoining flange will be covered in inspection scope of both, reactor and piping. The inspector should consult the design details, operation parameters, history of operational upsets, the theromography reports and the previous inspection reports before commencing the inspection. The reactors have tendency of the temperature runaways (sudden hikes) and unanticipated excessive pressure drops, which can effect the integrity of the reactors. Similarly local hot spots developed due to reasons given in the following text can cause the irreversible metallurgical damage to the shell. Hence the operational upsets must be thoroughly reviewed before planning the inspection.

d. It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and any additional requirements specific for the vessel being inspected are in place. Additional safety requirements as deemed necessary must be adopted.

7.1. External Inspection

Following external inspection requirements are applicable to both axial flow and the radial flow reactors.

7.1.1. Support Structure:

The reactors generally have the raised support structure. This structure could be built with concrete or with structural steel. The Inspection of the support structure should be done as per the General requirements Para 1.4.

7.1.2. Ladders and Platforms:

Inspect the leaders and platforms of the reactor as per General Requirements Para 1.6

7.1.3. Insulation Inspection:

Other than cold process reactors, almost all of the new generation of the reactors operates at higher temperature. Due to higher operation temperatures, most of the reactors are insulated. The insulation inspection should be done as per General requirements Para 1.2.1. If CUI is suspected than remove the insulation from the affected area and inspect the shell as per General Requirements 1.2.2.

7.1.4. Shell and Heads:

Since Reactors operate at the temperatures above the CUI susceptibility range, so CUI is not major issue, unless the reactor is in intermittent service or stayed idle for longer period of time. If the reactors have not been in idle state for prolonged time and the general condition of insulation is in good, the external deterioration of the shell and heads is not very likely. However selected external areas of shell and heads should be exposed for visual inspection as per general requirements Para 1.2.2.

7.1.5. Welds:

All of the visually accessible structural, nozzle and attachment welds should be inspected as per General Requirements Para 1.3.

7.1.6. Nozzles:

All of the nozzles should be inspected as per General Requirements Para 1.5.

7.1.7. Attachments:

All external attachments should be inspected as per General Requirements Para 1.8.

7.1.8. Gauges:

The condition of all pressure and temperature gauges should be assessed as per General Requirements Para 1.7.

7.1.9. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

7.1.10. Gaskets:

Check for the leaks and gasket integrity as per General Requirements Para 1.10.

7.1.11. Attached Piping:

Inspect the general condition of the attached piping. Determine if the attached piping is adequately supported. The unsupported piping exerts the stress on the localized areas of the vessel which could be above the designed limits of the vessel. Similarly the vibrating section of attached piping can induce the mechanical fatigue at the nozzle areas.

7.1.12. Thermocouples:

Thermocouples are attached to the reactor skin to find out the external skin temperature. Check the condition of the thermocouples and the thermocouple attachments welds. Broken or damaged thermocouples should be restored.

7.2. Internal Inspection-General:

a. There are mainly two designs of the fixed bed reactors, the axial flow and radial flow reactors. In the axial flow (or down flow) reactors the hot gas mixture gas usually flows from top towards the bottom passing from the catalyst. The product (effluent) is collected from the bottom of the reactor. The Catalyst beds are either one or two (or more), depending on the volume of the required process fluid. The mixture of reactants is collected from the bottom (called as effluent). The reactor beds are in from of the porous treys which hold piles of the uniformly distributed catalyst. The integrity of the treys holding the catalyst is of primary importance. The internal structure of this kind of reactor is quite similar to treyed tower, so the internal inspection procedure of the columns can be applied while inspection the beds and the support structure of the axial flow reactors. The following text is specifically for the internal inspection of radial flow type reactors.

b. The radial flow reactor internal constitute scallops, center pipe, inlet distributors, deflecting baffles, center pipe supports, cover plates, shrouds and catalyst transfer pipes. The shell and heads are often lined with hard metal overlay or lined with bond lining process. The typical schematic configuration of a Radial Flow reactor consists of the Scallops or outer baskets, a catalytic bed and a centre pipe. The hot gas enters usually from the top and gets distributed into the scallops, which are arranged parallel to the ID surface of the reactor. Through the scallops the hot gas enters into the Catalyst bed where the desired reaction takes place, and the product gas is collected into the centre pipe. The gas flow could be reverse (from the inside outwards) depending on the design. The performance of the reactor depends upon the quality and even distribution on the catalyst. The internal structural integrity of the components helps maintain the even distribution of the catalyst.

c. Reactor should be prepared for internal inspection as mandated in section 4. It is responsibility of the inspector entering the reactor to check if all of the safety measures mandatory for the reactor inspection have been adopted

7.2.1. Shell and Heads:

a. The shell and heads should be inspected as per General Requirements Para 1.2.2. If required the scallops should be removed for the careful inspection of the shell.

b. Look for the bulging or disbanding in the lining. The visual inspection must be supplemented with PT or MT (whichever is applicable) for the defects in the lining. The localized dis-bonding of the lining can give rise to the hot areas. The suspected areas of dis-bonding should be checked with Zero degree Ultrasonic inspection method. In case of significant bulging in the lining there are chances of trapped gas behind the lining. I this case a hole should be drilled in the dis-bonded liner to relieve the trapped gas, before any other repair procedures.

c. Inspector should review thermocouple output report generated by the control room to identify the localized hot spots. The thorough inspection should be done on these locations for heat damage.

d. Depending on the process the dominating damage mechanism on the internal surface of the reactors is high temperature hydrogen attack. The insitu-metalography (replicas) should be done of the selected location of the shell. If the damage is found, the scope of inspection should be increased.

e. Look for the discoloration in the shell. If some areas are suspected for the heat damage it is recommended that the hardness testing and the Eddy current testing of these areas should be done on the outer and the inner surface. If significant variation in the metallurgical properties is found, these areas should be checked with in-situ metallography (replicas) as given above in Para 7.2.1.d.

7.2.2. Scallops and Centre Pipe:

a. The integrity of the scallops should be checked thoroughly. Look for the dents, rips or tears in the scallop screen. Catalyst should not entre inside the scallops. Evaluate the cause if significant amount of catalyst is found inside the scallops.

b. The slits openings are very important. Use the appropriate filler gauge to check the slits gap at the suspected areas. If the openings are plugged due to damaged in scallops this can alter the gas flow, which may give rise to localized hot spot.

c. Look for the heat damage and the general thickness of the scallop screens. Damaged screens should be replaced. The operational parameters should be evaluated if the screens show the heat damage or any other service related damage at the localized areas.

d. Check for the integrity of the scallop keeper bar and the overall assembly of the scallops. The position of the scallops is also significant for the operation of the reactor. Check the seal between the scallops. Often the seal is provided by the ceramic fiber rope. Report for replacement if the ceramic insulation rope is damaged.

e. Check the integrity of the centre pipe and the support. Look for the rips, dents or heat damage on the pipe. The perforations gap should be checked. If the gaps are found wider at any location, this situation should be recorded for further evaluation

7.2.3. Welds:

a. Inspect all internal structural, nozzle and attachment welds as per General Requirements Para 1.3.

b. All of the attachment welds should be inspected with MPI or LPI if the service related damage is suspected.

7.2.4. Nozzles:

a. All of the nozzles (including manways) should be checked thoroughly, for corrosion or any other service related defects.

b. Look at the gasket face for corrosion and erosion. Report any condition that could affect the sealing and cause the leaks.

7.3. Additional Inspection with the specialized Non destructive methods like thermography, AUT, acoustic emission remote visual, magnetic flux leakage and Eddy currents etc. should be carried out as the special requirements. The procedure for specialized inspection is beyond scope of this manual and should be performed as per requirements of manufacturer.

Section-5

Fired Heaters. Specific Requirements

This section covers the specific inspection requirements of fired heaters. The inspector should review the operation history of the furnace and the Infra red (IR) inspection reports carefully before planning the inspection.

It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and any additional requirements specific for the heater being inspected are in place. Additional safety requirements as deemed necessary must be adopted.

8.1 External Inspection

8.1.1. Support Structure:

The fired heaters are often supported on the frame structures. Inspection of the support structure should be done as per general requirements Para 1.4.3.

8.1.2. Ladders and Platforms:

The integrity of ladders and platforms should be checked as per General Requirements Para 1.6.

8.1.3. Insulation Inspection:

Most of the furnaces in Saudi Aramco facilities are not insulated, however if the furnace is insulated the inspection for the integrity of insulation should be done as per General requirements Para 1.2.1. CUI of the furnace skin could become a concern, especially for the furnaces in the intermittent service or if the furnace is left idle for a longer time. If CUI is suspected than remove the insulation from the affected area and inspect the Skin as per General Requirements 1.2.2.

8.1.4. Skin inspection:

a. The integrity of the furnace skin should be inspected as per general inspection requirements Para 1.2.2. Look for all of the cracks, corrosion or dents in the skin. Excessive dents might have broken the insulation inside the furnace.

b. In case the furnace is left idle for the longer time, there are chances of the moisture ingress between the internal refractory and the casing skin (inner side). If such an issue is suspected than use ultrasonic thickness measurement to determine the internal corrosion between the Refractory and the skin. The damaged areas should be reported for the patch repair or replacement as applicable.

c. Inspector should look for hot spots or heat damage of the skin. The hot spots are the sign of the damaged insulation inside the furnace. Periodic thermography of the furnace also can be used to find out the hot spots. If these reports are not available then the potential hot spots should be determined from the internal refractory inspection. If there is refractory damage inside the furnace (fallen or cracked), the furnace skin can get heat damage at these location. If such hot spots are determined the visual inspection should be supplemented by following tests.

- UT thickness measurement to determine the remaining thickness.
- MT or PT the areas for cracks.
- Hardness testing.
- Eddy current testing (not mandatory).
- The damaged areas should be reported for replacement.

8.1.5. Explosion Doors:

The integrity of the explosion doors should be inspected thoroughly. Check for corrosion of the hinges. Note any conditions which can hamper the intended operation (opening in case of emergency).

8.1.6. Exhaust Stack:

Check the structural integrity of the Exhaust stack. Look for the cracks, dents or bulging that may weaken the structure. Look for the visible heat damage and discoloration externally. The heat damage will be the sign of the refractory damage inside. The IR inspection report should also be consulted to find out the hot spots in the exhaust stack.

8.1.7. Dampers:

Check the integrity of the dampers, and the associated moving gear. The dampers should be free to move without significant resistance.

8.1.8. Welds:

Inspect the structural, and attachment welds as per General Requirements Para 1.3

8.1.9. Attachments:

Inspect all of the attachments as per General Requirements Para 1.8

8.1.10. Thermo wells:

Inspect condition of all of the thermo wells per General Requirements Para 1.7

8.1.11. Grounding Connection:

Integrity of the grounding connection should be checked as per General Requirements Para 1.9.

8.1.12. Attached Piping:

Check the integrity of the attached piping thoroughly. The piping includes the inlet and outlet product piping and the fuel gas lines. Attention should be focused on the piping supports, to determine if the attached piping is adequately supported. The unsupported hot piping may undergo the premature failure due to creep at the over stressed areas. Check for the leaks on the product lines and the fuel gas line. Use gas tester for the leaks detection.

8.1.13. Instrumentation:

A qualified instrumentation technician shall test the following items.

a. Flame failure shutdown.
b. Burner and pilot condition.
c. High temperature shutdown.
d. Fuel gas regulators and shut off valves.

8.2. Internal Inspection

The furnace should be prepared for the inspection as mandated in the Section 4. The inspector should review the operation and previous inspection history of the furnace to help identify the areas of concern.

8.2.1. Refectory Inspection:

a. Refractory is the important part of every furnace, as it helps accumulate the required heat with in the desired area. The assessment of quality and the effectiveness of the installed refractory are beyond the scope of the manual. However the inspection for the integrity of the installed refractory is the responsibility of the inspector. The refractory inspection should be preferably performed by the qualified refractory inspector. Inspector to use a 1/2lb hammer to tap at different levels to note any disbanding, disintegration, cracks etc.

b. If available the IR inspection report for the hot spots should be reviewed in details to identify the problem areas.

c. The overall condition of the refractory in the furnace can be best assessed in the initial inspection (before cleaning) at the time of opening the furnace. Following are the minimum requirements for proper refractory inspection.

d. Look at the condition of the fire bricks at the floor of the furnace. Report all of the broken bricks. Look for the wide gaps between the bricks. The wider gaps will cause the heat leak and affect the bottom of the furnace, and around the burners.

e. The seams between the bricks should be filled with either by the ceramic fiber rope of by the compatible refractory cement.

f. Assess the general condition of the refractory on the walls of furnace. Report the major damages, like wide cracks, chipped and dislodged areas. The reduced thickness due to spalled refractory will cause heat damage to the skin. If the refractory is completely fallen off from some location. These areas of casing should be checked for the heat damage as per Para 8.1.4.c.

g. If furnace has the ceramic fiber lining such as K-O-Wool insulation, then look for the blown off areas, most susceptible areas are at the top of the furnace in the convection zone.

h. Look for the integrity of the refractory anchorage if they are exposed. The anchorage (mesh or the pins) at the exposed areas get excessive heat damage. If such condition is found it should be reported for repair.

8.2.2. <u>Burners System Inspection:</u>

a. The alignment of the burners should be checked before dismantling for maintenance. The alignment will give good indication of the potential hot spots on the tubes. The localized flame impingement may change the metallurgical properties of the tubes, and can cause the premature creep failure.

b. Look for the erosion or thermally induced cracks on the burner tip and the pilot burners.

c. If the fuel of the furnace is not clean it can cause the accumulation in the burners. The plugged and broken burners tend to deflect the flame in one direction. This can be the cause of the excessive heat damage on the tubes due to flame impingement.

d. Check the overall condition of the igniters and assess the flame damage if any.

e. Look at the air intake passages including the air registers and the air filter. The damaged or plugged air filters may cause the efficiency loss and mistuning of the burners. Usually the particulates in the emission of the furnace rise if the air intake lowers down. The ashy or the oily deposits on the tubes near the bottom sections show the signs of inefficient burning either due to poor air intake of the dirty fuel with heavier products.

f. Some high efficiency heaters are equipped with the forced draft burners in which the air is induces with the help of fans or blowers. The mechanical assembly of the blowers, in these furnaces, should be inspected by the manufacturer qualifies inspector.

g. The burner inspection window should also be checked

8.2.3. Check the integrity of the tube hangers, report if any of the hangers is broken or deformed.

8.2.4. Check the snuffing steam nozzles (soot blowers). Look if the blowers are properly directed to the tubes. Look for the corrosion or erosion damage into the nozzles.

8.2.5. <u>Tubes Inspection:</u>

Thorough inspection of the coil Tubes is the most important part of the fired heater inspection procedures. The damage mechanism for the furnaces tubes depends upon various factors like the temperature, pressure, metallurgy of the tubes, tubes contents, fuel gas used for the burners, and other operational upsets. It is must for the inspector to consult the operation and the previous inspection history of the furnace before thorough assessment.

8.2.5.1 <u>Common Damage Mechanisms:</u>

Complete coverage of the damage mechanism of the furnace tubes is beyond the scope of this manual; however some of the commonly found problems associated with the tubes are listed below.

a. Corrosion Pitting:

It is worth noting that most of combustion deposits (soot) are acidic in nature. The extended idle periods for the furnaces cause the moisture to be absorbed into the acidic deposits and turn into diluted acids species. Most commonly found acidic produces are sulfurous acid, sulfuric acid, hydrochloric acid and various naphthenic acids, which can cause the corrosion pitting. In some furnaces which operate on the temperatures below 100^{o} C, the water vapors produced from the combustions, condense on the top tubes in the convection sections and cause the acidic corrosion on the tubes.

b. Creep Damage:

Creep is the main damage mechanism for heater tubes caused by the combination of thermal stresses and internal hoop stresses due to the product pressure inside the tube. The creep develops at the inner diameter or just below the ID surface. The damage process results in diameter increase and creep damage at the inner diameter. Significant creep can be detected from the diameter change at the bulges, if this damage is not attended or detected at the right time the rupture can occur in the longitudinal direction.

c. Restricted Thermal Expansion:

Restricted thermal expansion causes the tubes bowing and partial yielding in the material. Most commonly found bowed tubes are the inlet and outlet legs of the radiant coils. These tubes often have restriction from thermal expansion due to design. The bowing or sagging can also be caused in the tubes with plugged expansion guide orifices at the bottom, and if the bottom bends is displaced out of expansion guide orifices.

d. Internal fouling and Thermal Fatigue:

The internal fouling of the fluid contents and the coke build up is one of the major causes of the tube failure. The heat transfer is reduced in the fouled tubes so these tubes are over heated and cause premature thermal fatigue and creep failure.

e. Thermal Shock:

Thermal shock is mostly found at the shock tubes, and the product outlet tubes (if exposed to the atmospheric temperature due to damaged insulation). The heat damage also occurs at the locations where excessive coke is builtup in the inside of the tubes and proper thermal dissipation does not take place.

f. Other Environmental/Metallurgical Damages:

Depending on the material of the tubes, temperature, burning fuel and the carrier fluid properties various other metallurgical damages are often seen in the heater tubes. The damages include but are not limited to polythionic stress corrosion cracking, liquid metal embrittlement, graphitization, Spheroidization, sulfidation, nitriding, carburization, metal dusting, vanadium and high temperature hydrogen attack etc. All of these damages are best identified by the insitu-metalography (replicas), however later stages of some can be identified by Hardness testing and other conventional NDT techniques.

8.2.5.2 Tube inspection Procedure:

a. The overall condition of the tubes should be assessed by shining light along the full length of the tube (tubes from bottom to top). Look for the straightness of the tubes. Note the bent tubes and assess the gap between the tubes, tube to the heater wall. If the bowing had already been reported then assess for the progress in bending.

b. Look for the signs of flame impingement on the tubes around the burners. The flame impingement can be caused due burner alignment and plugging.

c. The surface of the tube should be exposed by light sand blasting, scraping or chipping the scale and the combustion deposits. Thoroughly inspect the surface of the tubes for the significant damage like corrosion pitting and other metallurgical damage like carburization and Vanadium attack. Thorough knowledge of the damage mechanism and the material is required for the evaluation of the damage in the tubes. Different tube materials behave differently with the given temperature and working conditions in the furnaces. The fuel gas used at the burners also has significant effect on the metallurgy of the tubes. Look for the deposits on the tubes and collect some samples for the lab analysis. Normally the furnaces in continuous operation do not show the pitting damage. However if the furnaces are left idle for longer period of time the corrosion damage can take place.

d. The accessible tubes in the convection section from bottom and from the top (from header box) should be checked visually and with Ultrasonic thickness measurement. Extra attention should be paid on the bottom shock tubes. Perform the UT survey on these tubes and evaluate the thickness especially of the bottom tubes.

e. In some furnaces the convection section is designed with finned tubes. Look at the integrity of the fins. Not excessive soot or dust in the fins. The debris in the fins can reduce the heat transfer to the tubes.

f. Look for the localized bulging and the creep damage on the tubes. Use go/no-go gauge on the tubes to find out the localized deformation and heat damage. This method is good for the significant creep measurement with 3% or over bulging, however the initial stages of the creep cannot be detected with this method. The metallographic test is the best to evaluate the condition of the tubes at the initial stage of the creep.

g. The inaccessible areas like area between the wall and tubes should be inspected using inspection mirror.

h. Thoroughly look at top and bottom U-bends in the radiant section. Use the inspection mirrors to look behind the tubes. Report any corrosion, erosion and dents on the bends. Report any other significant finding for further evaluation.

i. Look at the bottom u-bends and the pins weld. The guide tubes on the floor should be free of debris. The plugged guide tubes may cause the restricted thermal expansion of radiant tubes during the operation, which may result in tube bowing. Other possible damages due to restricted expansion include the pin deformation, indentation at the bottom U-bends, and cracking of the pin to U-bend weld. This crack may propagate into the U-bend and cause the leak inside the furnace. MPI must be performed on these locations at every turnaround.

j. Perform thorough inspection at the top U-bends, especially at the hanger locations. Care should be given at the mating areas of the tubes with the hangers. These areas are prone to have fretting damage due to inter-rubbing between the tubes and the hangers. Some of these fretting develop notch like gouge which can develop cracks in the tubes. Thoroughly evaluate these fretting for fitness for service and report for repair wherever required.

k. Look for the signs of the fretting damage on the hanger clamps at the mid way of the tubes. Due to the thermal expansion and contraction, the midway clamps cause the mechanical and fretting damage on the tubes. If such damage is found try to find out the remaining wall thickness using UT and/or pit gauge. The fitness for service analysis should be done on each area.

l. The thermocouple joints should be carefully inspected. These joints should be thoroughly cleaned and PT should be performed on these joints.

m. The inspector can use light hammering to evaluate the coke build up in the tubes, especially bottom section, however the findings must be confirmed by the radiography.

n. The tube welds should be evaluated thoroughly by visual inspection. MT or PT should be done at selected top and bottom tube to u-bend welds. If the environment related damage is found the scope of inspection should be increased.

o. Perform UT on the extrados of both top and bottom bends of the radiant tubes. The bends should be scanned and minimum thickness should be recorder. If thinning is found the fitness for service evaluation should be done.

p. Perform UT on the flame side of the radiant tubes at the flame impingement level. The UT should also be performed at the middle and top levels of the tubes in the radiant section of the furnace.

q. Similarly UT should also be performed on the convection section tubes and the return U-bends on both ends of the convection section.

r. Radiographic shadow shots should be taken at the selected locations at the bottom U-bends and sections within 3 feet downstream of the U-bends to evaluate for the coke buildup. The history of the coke buildup and the infra red imaging, should be consulted for selecting the tubes for shadow shot Radiography.

s. In-situ metallographic test (replica) should be done at selected locations on the tubes, to determine heat metallurgical damage in the tubes. Most affected areas are the front (flame) side of the radiant tubes within 4 to 10 feet above the bottom U-bends, where the heat from the burners flame is the maximum.

t. Similarly the bottom section (fire side) of the shock tubes should also be monitored with in-situ metalography and hardness testing, as these tubes experience most thermal shock.

u. Some of the specialized nondestructive inspection techniques can also be utilized for evaluation of the tubes integrity. These include the internal pigging, and external remote magnetic flux leakage testing. All of these techniques should be performed as per manufactures instructions.

Section-5

Plant Piping Specific Requirements

9: Plant Piping-General

a. This section covers the specific inspection requirements of above surface plant piping and the support structure. The intent of the following text is to evaluate the condition of the existing Plant piping as compared to the designed conditions. The design requirements and the stress distribution analysis of the existing plant piping are not covered in the scope of this Manual. Any relevant section of this Manual may be applied to the off plot and the above surface sections of the pipelines. This manual does not address the inspection requirements of buried pipelines.

b. Before conduction the inspection the inspector should thoroughly review the design and operation parameters, carried process fluid properties, history of the operation upsets like pressure and temperature run away, and any leaks occurred. The previous inspection records including OSI, mechanical inspection and any other NDT tests conducted should also be reviewed.

c. A comprehensive inspection of the piping should be done preferably at the pre-commissioning stage. Later on separate inspections should be done at the ambient temperature and at the operation condition to check for the physical movement limits of the piping at the operating condition.

d. The dominating damage mechanisms in the plant piping include the CUI, internal erosion and corrosion, environmental cracking (including HIC, SOHIC and all kinds of SCC), bio-corrosion in the stagnant sections, and various forms of Aging & Creep damage at the lines operating at high temperature. These damages can only be successfully detected if the suitable non destructive technique is used along with the visual inspection. The latest addition of API-RP-571 and Para 6.3 of API-RP-574, should be consulted before performing a detailed inspection on any piping.

e. The additional inspection requirements should be determined based on the potential damage mechanism of the piping. The frequency of the inspection should be dependent on the corrosion class assigned to the piping.

f. While inspecting the piping, inspector should use the inspection/OSI drawings as given in Para 9.1.1. It is preferable that (unless not practical due to the configuration of piping) the individual lines should be followed from beginning to end, covering all of the static and dynamic supports (including dummy support legs), and the components like control valves gauges and flow meters etc.

g. Multiple lines can be inspected, at same time, at the locations where special provisions are required for access.

h. The piping should be inspected from the beginning to the end, including the branched connections (unless covered in a different circuit).

i. The extents of inspection should include the flange connection with the static equipments at the beginning and the end of the circuit, the conjoining flange connection will be covered in both piping inspection and the vessel inspection. In case of the branched connection covered in the different circuit, the inspection will extent up to first flanged connection with the branch, the conjoining flange connection will be covered in both circuits.

j. The Preparation of the piping for the inspection and the safe access to the areas of interest should be provided as per the requirements of section 4 of this Manual. It is responsibility of the inspector to ensure all of the safety measures have been adopted, before commencing any inspection activity.

9.1. External Inspection:

Following should be the minimum specific requirements of the piping external inspection.

9.1.1. Inspection Drawings:

a. For proper piping inspection, the OSI isometric inspection drawings for the piping should be developed as described in API-RP-574 Para 12.2, and SAEP-1135 Para 3.1.3 (b).

b. Each isometric drawing should contain only one line from start to the end point.

c. If possible the sketch of the vessels or any other static equipment at either end of the line should be included in the drawing for the reference.

d. Each Isometric drawing should be assigned a unique number and should refer to the related P&ID and PFD.

e. In case of branching of the line, or streams mixing, the joining lines should be drafted on the separate drawings.

f. Each drawing of the branched or joining line should provide the reference to the other drawing at the location of junction. The reference notes should contain the joining line number and the ISO drawing number. A part of the branched line should be drafted in the broken lines for easy referencing.

g. The flow direction should be clearly marked in the lines. The marking of the flow direction help OSI technician and the inspector to determine the impingement points and potential areas of higher erosion/corrosion.

h. TMLs should be clearly marked on the Isometric drawings. The details for any special safety requirements like scaffold access, or higher than normal temperatures should be provided wherever required.

i. The line class segregation should be marked on the isometric drawings. Location of the critical hangers, spectacle blinds, and insulating gaskets (in case of junction of different metallurgies) should be provided in the Isometric drawings.

9.1.2. <u>Pipe Supports and Structures.</u>

The support structures of the piping include the steel & concrete members, racks columns, cross bracings, saddles and dummy legs etc. Following are the minimum requirements for performing a thorough inspection of the support structures.

a. The overall structural integrity of the support structure should be thoroughly evaluated. Note any damaged, bent, broken or excessively corroded section of the steel structure. If deterioration is found any where the visual inspection should be supplemented with the appropriate Nondestructive testing.

b. The joints could be either bolted of welded. The weld joints should be evaluated as per the general inspection requirements of Para 1.3. For the bolted joints, check for the integrity of the bolts, including the corrosion and torque of the bolts.

c. Look for the coating (paint) damage and report if excessive corrosion is noted.

d. In case of the concrete supports, look for the eroded or cracked members. The excessive erosion or major cracks should be evaluated by the structural engineer. All of the cracks found detrimental to the integrity of the supports should be reported for rectification.

e. Check for the integrity of grounding connection. A qualified Electrical inspector should assess the adequacy of the grounding provided to the support structure.

f. The ground settlement is not usually an issue in the case of the pipe supports however look for the signs of the significant settlements in the ground at the columns. The deformation in the anchor bolts will show the signs of the movement in the support. If suspected the Ultrasonic inspection should be done of the anchor bolts.

g. Attention should be paid to the Dummy legs and pedestal supports of the piping. Any deformation, damage and the displacement is the sign of the excessive (beyond design limits) movement in the piping. The movement could be due to excessive liquid hammering or any other operational upsets. If such conditions are found, further investigation should be done on the rest of the piping structure. All of the dummy legs should have the weep holes to avoid any pressure buildup inside the leg during the hot and humid weathers. The dummy legs on the large side elbows should be provided with the hand hole to perform ultrasonic inspection.

9.1.3. Pipe Restraints:

The piping restrains include a range of the equipment like the static and dynamic hangers, brackets, clamps, braces, lugs, cradles, saddles, straps, turnbuckles, clevis and base supports. The inspection of specialized hangers for the heavy loads or directional movements should be done by the qualified individual using the manufacturer's instructions. Following are the minimum requirements for the inspection of the pipe restrains.

a. Assessment for the significant deterioration in the hanger structure should be done. See if the hanger brackets, spring, piston or the support bolt are bent, cracked or excessively corded. The bent hanger is the sign of the piping being displaced from its original position due to excessive loading.

b. The condition of the hanger spindle should be noted. See of the spindle is locked with locknut, cotter pin, or by any other means.

c. For the spring hangers see if the movement of springs is not obstructed by foreign material. The position of the indicator should be within the specified range. Out of range indicator should be reported for investigation and corrective action. Inspector should maintain the log of the indicator position at all of the critical hangers at successive inspections. This helps in determining the movement trend of the line during the operation, as compared to the ambient (shut down condition). Excessive movement or change in the position of the hanger should be evaluated.

d. In case of the hydraulic shock absorbers and snubbers, look for the signs of the oil leaks at the cylinder seals. The leaked shock absorber should be replaced or repaired at the earliest turnaround.

e. Look for the signs of over stressing on the static supports. Typical evidence of overstressing would be indications of bending of pipe supports or associated equipment. In addition, cracks in material or welds are further indication of overstressing.

f. Carefully inspect the mounting structure of the hangers. If the visual inspection warrants the problems in the support welds, MT should be done at the hanger to support weld.

g. Note the distorted or displaced static pipe sports. In case of distorted or displaced supports the piping may be subject to above design loads on the piping. In such cases the movement of the support from the actual design location should be measured to calculate the structural loading on the piping.

h. In case of sliding or rolling supports see if contact area is provided with cushion or lubricants suitable for the environment. Further the cushions material should not cause the galvanic corrosion at the matting surface.

9.1.4. Piping:

a. The piping external surface whether insulated or un-insulated should be inspected as per the applicable segment of general requirement Para 1.2 of this manual.

b. All of the structural welds and the attachment welds should be inspected as per the applicable segment of General requirements Para 1.3.

c. Examination of piping and the support systems should be done at various temperatures from ambient to normal operating temperature to detect interference caused by thermal expansion. In order to evaluate the expansion trend of the piping. The location marks should be made in the cold (ambient) conditions and then evaluated at the operating condition.

d. One of the major causes of Pipe sagging is the restriction from expansion. Look for the conditions where the excessive restraint in the piping is blocking the required thermal expansion.

e. Wherever possible shake the piping and look for the excessive vibration. These conditions will be the sign of inadequate support. The inadequate supports exert excessive structural load on the piping. Such conditions should be reported for further evaluation, and rectified if found unacceptable.

f. In case the vibrating piping being adjacent to another piping or equipment, the mating surface on both equipment should be monitored for fretting damage. If possible the arrangements should be provided to avoid the surface contact with other equipments.

g. Look for the significant sagging or bend in the piping. The sagging may occur due to improper weight distribution caused by the improper support design or the distortion in the supports. In such cases the displacement of the piping from original design location should be measured, and the change in the structural load distribution due to displaced supports should be re-evaluated (by the design engineer).

h. Evaluate the positioning of the hot piping on both sides of the hangers, as displaced piping (due to abnormal hanger position) may be under excessive static stress loading. The premature failure due to creep cracking can occur at such locations on the hot piping. If the excessive stress loading is expected at some locations on the hot piping, these locations should be inspected by magnetic particle testing and metallurgical replicas to determine the initiation of the creep.

i. In-service inspection of the piping is necessary to look for the displacement of the piping due to the thermal expansion and to look for the liquid hammering. Excessive hammering may cause the fatigue failure at the joints on either end of the effected section of pipe. If this condition is suspected, the weld joints with in this section of pipe should be inspected by Magnetic Particles inspection.

j. Look for the condition for the steam tracing if applicable. Most of the steamed traced lines are usually insulated. In case of the leaked tracing, excessive moisture condensation takes place which increases the potential of corrosion under insulation CUI. If such conditions are found, the insulation should be removed from the neighboring area to evaluate the CUI condition.

k. The potential of corrosion under insulation CUI should also be evaluated in the insulated piping as per the general requirements Para 1.2. All piping operating in the temperature range of -4^{o}C to 120^{o}C should be added in the CUI monitoring program. The condition of the insulation at pipe support locations should be carefully checked. Some time a window is cut in the insulation at pipe support. This provides the moisture ingress location inside the insulation which increases the potential of the corrosion. Similarly special attention should be paid at the locations of steam tracing protrusion, flanges, bends, off shoots from the piping like tees, small bore piping, nipples, vents and drains etc. The insulation at these locations cannot provide effective sealing from moisture ingress. This increases the potential of the corrosion under insulation CUI, especially in the marine environment.

l. Corrosion of the un-insulated piping at the interface with the support, like saddles, is one of the biggest cause of the failure in the piping. The major damage mechanisms at the pipe to support interface include but are not limited to

1. ***Crevice Corrosion:*** The trapped particulates between the support and the pipe surface cause/facilitate the crevice corrosion.

2. ***Bimetallic Corrosion:*** In the extremely corrosive environments and due to difference in the metallurgy of the saddle and pipe, the mating location may act as the bimetallic corrosion cell. This causes the galvanic corrosion between pipe and the saddle in which one of the couple is preferentially corroded.

3. ***Stagnant trapped water:*** Water may be trapped between the pipe and the saddles which can cause accelerated corrosion pitting on the pipe at the interface area.

4. ***Fretting:*** Some piping are also restrained with the U-Clamps (or bolt clamps) bolted with the pipe support at the bottom. The piping with minor successive movement due to thermal (expansion and contraction) or mechanical loading may suffer the fretting due to rubbing between fixed clamp and the moving pipe.

All of these problems occur due to difficulty to maintain the paint/coating at the interface area. Further the inspection is very difficult in these areas to warn of the metal loss prior to failure. If possible the piping should be slightly lifted at these locations to inspect the contact areas. The effective nondestructive testing tools for such locations are the short range guided waves or the creeping waves ultrasonic inspection techniques. These techniques provide good inspection tool however need higher degree of skill and equipment.

9.1.5. Flanges and Flanged Connections:

While inspecting the flanged connection following are the minimum requirement that should be looked after.

a. Look at the overall condition of the flanges. Occasionally check for the rating of the flanges and compare with the design parameters of the piping.

b. Look for the condition and the rating of the gasket as per General inspection requirements Para 1.10.

c. Look for the misalignment between the joining flanges of two section of the line. The containment of the piping may leak at the excessively misaligned flanges. All such situations should be recorded and corrected at the earliest possible opportunity.

d. Note all of the short bolting situations. The minimum of two threads on the bolt should be exposed on either side. All short bolting situations should be corrected at the earliest available opportunity.

e. While inspection the flanged connections look at the condition of the fastening bolts. The incompatible bolt materials may cause the galvanic corrosion with the flange material. The corrosion may preferentially damage flange or the bolt (depending on the location in the galvanic series). The corrosion has been found aggressive in marine environments. If such situation is found inspector should warrant the PMI testing of the bolts and the flanges to confirm the in-compatibility of the materials. The corrective action should be taken at the first available opportunity.

f. Carefully look at the junction of the dissimilar material piping. These flanges should be separated by the insulating gaskets. The electrical resistance measurement should be done between the two flanges, (for proper insulation resistance should be infinite). Note the gasket type and rating from the color coding, and evaluate if correct gasket is installed at these junctions. Non insulating gasket may preferentially corrode or provide the bridge for the reducing currents, providing the active galvanic coupling between the dissimilar flanges. If such situation is left unattended for prolonged time the leak may occur due to galvanic corrosion of gasket or carbon steel flange.

g. The gaskets between the flanges should be looked for excessive compression or damage. Note the color coding of the gaskets and evaluate if the rating of the installed gasket is as per the requirements of the process condition. The gasket evaluation should be done as per the requirements of Para 1.10 of this manual.

9.1.6. Valves Inspection:

a. Assess the general condition of the valves. Excessively corded valves should be reported for replacement.

b. Ensure that heavier valves are properly supported.

c. All of the leaks on the flanges connection or bonnet packing should be reported for corrective actions. Use the gas tester to ensure leaks for the valves on the line carrying highly volatile containments.

d. Note the condition of the control handle and remote actuating system. If suspected, the instrumentation technician should be consulted to ensure the proper operation of the remote actuating system.

e. The gate valves and the check valves in the slurry service or the service where the fluid is corrosive and erosive, can be subject to the internal wall loss. Occasional thickness measurement can be used to warn off the condition of the valves.

9.1.7. PSV Piping Inspection:

a. The condition of the PSV and the lines upstream and downstream should be carefully assessed.

b. PSV should always be installed in the upright position. Report if PSV is found installed in the horizontal orientation. The situation should be rectified as the earliest available opportunity.

c. In cases where the PSV releases in the atmosphere, inspector should assess if the PSV, the inlet line and the outlet lines are adequately supported and not exerting undue stress on the vessels.

d. In case where the PSV discharges into the confines headers or the flare circuits, the condition of the flare line downstream should be checked.

e. The diameter of the downstream piping should never be smaller than the outlet size of the PSV.

f. Check, if the block valves upstream and downstream of the PSV are carsealed in open position. Report the conditions where the carseal is broken. If the block valves are found in closed position in the operating equipment, this situation should be immediately reported for rectification.

9.1.8. Each line should be assigned with the corrosion class, based on the corrosion rate, according to API-570 Para 6.2 or Appendix-A of SAEP-1135.

Supplementary note: SAEP-1135 uses the corrosion rate for the classification which is not applicable for new projects without known corrosion rate. In this case the corrosion engineer should use the approximate corrosion rate obtained from the plants in similar service and conditions until true CR is determined after successive thickness measurements.

9.1.9. The ultrasonic thickness measurement (OSI) should be done according to SAEP-1135, API-570 Para 5.6. and Para 9.3 of this section.

9.1.10. Threaded connections should be inspected for leaks and the crevice corrosion where ever applicable.

9.1.11. Check for the condition of the Swivel joints, expansion joints, flexible pipe, and expansion bellow. Look for the deformations, misalignment, displacement or expansion exceeding the design limits.

9.1.12. All of the dead legs, injection points and small nipple inspection programs should be implemented according to the established procedures.

9.1.13. The detailed inspection of specialized instrumentation in the piping is not in the scope of this Manual. Manufacturer's instructions should be used by the qualified technician to assess the functional condition of these instruments. However the general external inspection of these equipments can be added in the scope of the piping inspection.

9.1.14. In case of the piping emerging out from the ground, special attention should be paid on the Soil to air interface area. The soil should be removed at 6 to 12 inches depth around this location to assess the soil corrosion damage.

9.1.15. Buried pipelines are not covered in this manual, however the inspector should review the Cathodic protection reports periodically. Commonly accepted CP value is -0.87 volts. If any area of the buried piping shows significant deviation from the acceptable range, these areas should be exposed and the condition of piping should be evaluated.

9.1.16. A variety of other inspections methods that may be used for any special requirements. These techniques should be used according to the manufacturer's recommendations. Following are some of these techniques.

a. AUT, including Time of flight diffraction (TOFD), Phased array or C-Scans for environmental cracking.

b. Thermography of the refractory lined piping to determine the broken refractory, identifying hot spots and locations of fouling inside the hot lines.

c. Profile radiography for fouling and wall loss measurements.

d. Eddy current and RFT inspection for determining the metallurgical degradations.

e. Acoustic emission to determine the micro leaks etc.

9.2. Internal Inspection:

9.2.1. The internal inspection of the piping is very limited. Only the large diameter piping can be effective inspected by the visual inspection method. These piping if opened for inspection should be prepared as per the requirements of section 4. The inspector should be aware of the potential damage mechanism for these piping.

9.2.2. The physical internal inspection of the large bore (over 12 Inches) piping should be done as per the general requirements Para 1.2 and 1.3. of this manual. The gasket areas at the flanges should be thoroughly inspected as per requirements of Para 1.10 of this manual.

9.2.3. For the internal inspection of the piping less than 12 inched diameter the remote visual inspection techniques or pigging (Instrumentation scraping), can be used. However External OSI techniques, as given in Para 9.4, have always proved to be good alternative to the limited internal inspection of the piping.

9.3. On-Stream Inspection:

9.3.1. Thickness measurement location TMLs should be assigned on each process line as per requirements of SAEP-1135 Para3.1.5. The number and location of the TMLs selected on each line should be based on Risk Based Evaluation. The factors to consider while evaluation of the TML selection include but are not limited to

a. The criticality of the service.
b. Exiting service conditions.

c. The stream condition of line (in terms of pressure, temperature, constituents, and pH value etc,)

d. Active damage mechanisms.

e. Configuration of location with respect to the stream flow.

f. Available or anticipated corrosion rate.

g. Assess problems.

9.3.2. Appropriate inspection technique should be selected for each TML as per SAEP-1135 Para 3.2.

9.3.3. The short term corrosion rate, long term corrosion rates and remaining life should calculated for each TML as per requirements of API-570 Para 7.1.

9.3.4. Minimum required thickness t_{min} (or retirement thickness) for each line in the OSI program should be assigned using Barlow's equation

$$t_{min} = \frac{P(D - 2t_{nom})}{2S}$$

D = External diameter,

t_{nom} = Nominal thickness of pipe (including mill tolerance)

P = Max operating pressure of the line. (max surge pressures should be used in case of sudden or abrupt flows service)

S = Max allowable stress for pipe material, at the maximum possible operating temperature. The stress values can be obtained from ASME-B-31.3 Table A-1

9.3.5. The class readjustment should be done as per requirements of SAEP-1135 for TMLs showing higher than normal corrosion rate. These TMLs should be identified for monitoring at the reduced frequency according to adjusted corrosion class requirements.

9.3.6. The inspection on TMLs showing higher than normal corrosion rate should be increased by scanning the surrounding areas or by addition of more TMLs. Escalation of inspection should be planned individually for each TML depending on the Corrosion Rate, as per guidelines of SAEP-1135 Para B-3.3

9.3.7. The locations showing thickness below t_{min} determined in Para 9.1.11 should be reported for replacement. If the immediate replacement is not possible than line fitness for service FFS evaluation should be conducted on the corroded areas as per requirements of API-579. The Nature of the defect should be considered with respect to the stresses orientation on pipe while conducted FFS evaluation. Ultimate bursting pressure of pipe should be calculated for the locations of reduces thickness as per Para 9.1.11. Temporary repairs should be recommended on these locations if possible.

9.4. Inspection of Small bore Piping (SBP):

Any piping of nominal diameter of NPS-2 or lesser is considered as small bore piping. All of the high point vents and the drains should be included in the small bore piping inspection program. The small bore piping usually include the utility lines (air, water, nitrogen services), sample collection lines, drain lines, and injection lines. The small bore piping, connected to the main piping are mechanically weaker areas, which can suffer higher degrees of plastic deformation with small upsetting loads. Most of the leaks in the plant piping occur at these joint, either due to the mechanical fatigue, or due to manufacturing weld defects which deteriorates under the harsh process conditions. Following critical items should be considered while evaluating the integrity of the small bore piping.

9.4.1. Look for the mechanical deterioration of the SBP attached with the main lines. Bent or deformed lines should be identified for further evaluation with the suitable NDT methods.

9.4.2. The junction weld at the main line should be carefully inspected. The visual inspection should be supplemented with MPI or LPI for the critical piping, or the areas where the excessive damage is suspected due to process or mechanical loading. The original weld defects often deteriorate rapidly due to harsh process conditions in the parent line.

9.4.3. Note the excessive vibration on the SBP attached with the piping close to pumps and compressors. Unsupported SBP can easily be fatigued if are subjected to cyclic loading due to vibration. Perform MPI or LPI at the junction weld (with main line) to locate the fatigue cracking. Additional support like gussets or bracing should be provided with the piping in excessive vibration.

9.4.4. Special attention should be paid to the inspection of the high vent points on the hot piping. These areas are prone to erode due to the convectional currents generated in the closed section of the vent line.

9.4.5. Due to smaller diameter the ultrasonic inspection on the SBP cannot be effectively performed. Profile radiography of the selected locations should e performed on the small bore piping. The locations to be selected for inspection should be based on the expected corrosion or erosion problems in the piping.

9.4.6. Unless higher corrosion rate is anticipated, the OSI and visual inspection extent and interval of the small bore piping should be selected as per the corrosion class of the parent line.

9.5. Dead Legs Inspection:

Inspector should identify all of the process dead legs in the plant, as per criteria provided in API-570. Once all of the dead legs are identified, proper OSI monitoring program should be implemented for the inspection. The OSI program is not included in scope of this manual however it is responsibility of the inspector to fully evaluate the extent of the OSI on the dead legs, and identify the potential locations of deterioration due to the stagnant flow and the convectional currents.

9.6. Injection points and the Stream mix points Inspection:

The injection points undergo the accelerated deterioration in the point and have special inspection requirements. Inspector should identify all of the injection points in the plant and make sure that the OSI monitoring of the injection circuits is as per the requirements of API-570 Para 5.3.1. If proper OSI data is not available, the inspector should call for the ultrasonic inspection of the piping upstream and downstream of the injection point. The limits of the inspected area should be should as prescribed in API-570 Para 5.3.1.

The stream mix points should also be monitored at the reduced frequency as compared to the normal circuits. The reason for the reduced frequency is the turbulent flow that may take place downstream of the mixing point. The turbulent flow is caused due to the difference in the velocities of the mixing streams and most commonly when the mixing streams are at different phase (such as gas and liquid phases). If one of the streams carries abrasive solid particles than the chances of localized erosion at the lines down streams of the mixture point increase. Thermal shock is another problem encountered in the stream mix points, if the temperature of the mixing streams is significantly different. Depending on the thermal gradient the piping at the mix point is subjected to the mechanical and thermal stresses. The fatigue cracking can be developed due to differential expansion/contraction. This demands additional inspection requirements such as frequent MT, PT of acoustic emission monitoring. During evaluation the inspector should review the condition of the mixing streams and assess the possibility of the fatigue cracking due to thermal and mechanical shocking. Based on these conditions it should be determined, if these points need additional inspection at reduced frequency.

Above Ground Storage Tanks Specific Requirements

10. Storage Tank

This text provided the minimum specific requirements for the inspection of the welded metallic tanks used for storage of the crude and refined Petroleum products, and built as per requirements of API-650. The text cannot be used for the inspection of non-metallic or riveted tanks. The limits of the tank inspection under these specific requirements extend up to the first flange of the attached piping. Piping inspection with in the tank farm should be done as per Para 9 of section 5.
The inspector should consult the design details, operation parameters and history and the previous inspection reports before commencing the inspection.

It is the responsibility of the inspector to make sure all of the minimum safety requirements as per section-4 of this manual and additional requirements specific for the tank inspection are in place. The inspector should make sure that the preparation, entry, cleaning and the inspection activity are being supervised by the tank entry supervisor trained as per API-RP-2016. Additional safety requirements as deemed necessary must be adopted.

10.1. Dike area and Tank foundation Inspection:

10.1.1. The overall condition of the dike should be assessed thoroughly. The excessively eroded walls should be reported for repair. The proper access and egress through the ladders should be provided into the dike area. If dike walls are made of the concrete, proper assessment should be done for the cracks and other defects in the concrete.

10.1.2. The dike area should be properly sloped to allow drainage away from the tank. If the slop of the dike is significantly damaged, it should be reported for rectification.

10.1.3. The growth of vegetation in the tank farms is not biggest problem in Saudi Arabia, however if the tank farm is in the geographical areas where, the rainfall or moisture is above normal, there are chances of the moss buildup and vegetation growth in the dike area. The lower section of the tank in these locations should be carefully assessed for the corrosion due to vegetation growth and moss buildup in case of insulated tanks. The survey for the vegetation growth around the tanks should be done periodically in these areas and grown vegetation should be removed regularly.

10.1.4. Dike should not be used for permanent storage or dumping purposes. Any refuse large enough which could reduce the effective capacity of the dike as given in Para 10.1.5 should be reported for removal.

10.1.5. Capacity of dike:

The dikes provide the secondary containment in case of high volume spill from the tank due to any kind of damage or upset of the system. Due to this reason it is very important to determine the approximate the capacity of the dike. Normally the capacity of the dike reduces over the time due to erosion of the walls and filling up of the area due to sand storms and rains. In order to determine the average capacity of the dike we need to determine total area of the dike and the effective height of the dike wall (from the area inside the dike). In case of significantly sloped dike the effective height is measured form the middle of the slop. Following method should be used for determining the effective capacity of dike.

a. For Single Tank in dike:

$$Volume\ of\ dike = abc$$

b. For more than one tanks in dike:

$$Volume\ of\ dike = abc - \pi(R_1^2 + R_2^2 + R_3^2 \dots)c$$

Where a = length of dike,
b = Width of dike walls
c = Effective height of dike walls
R_1, R_2, and R_3 etc = Radii of tanks other than largest in the dike.

Multiply the total capacity of tanks (barrels) in dyke by 5.6 for cubic feet and 0.117 for cubic meter.

The acceptable capacity of dike should satisfy following criteria.

- Dike containing single tank should have capacity of 110% the total capacity of the tank.
- Dike containing more than one tank should have capacity equal to 110 % capacity of the largest tank plus 10 percent of the aggregate capacity of the remaining tanks.

10.1.6. Tank Foundation:

The assessment of the foundation varies with the type of the foundation of the tank

a. In case of the concrete foundation the overall condition of the concrete should be recorded. Significant cracks in the foundation should be assessed by the civil inspector/engineer. The foundation is normally cracked at the anchor bolts. In some cases the foundation suffers the uneven settlement, which exerts above design hydrostatic stress on the tank. If the initial visual inspection shows the signs of the settlement in the concrete foundation, careful level survey should be done in order to assess the settlement. In case of the concrete ring wall foundation, the tanks are also provided with the drip ring. Check all radial welds and the circumferential weld with the shell on the drip ring. Ensure it is not corroded, dented or damages to the extent that it does not serve the purpose of diverting the rain water away from foundation. Make sure the drip ring is over extended from the ring wall of foundation by at least 3 inches.

b. In case of the sand cushion type foundation, careful assessment should be done on the compaction of the sand near the edges. Sometimes the sand is eroded out near the edges on the tank. Significant erosion can cause the localized settling in larger tanks. The eroded edges should be reported for sand filling.

c. Some tanks foundations are provided with the secondary confinement with the ring wall made of concrete or the corrugated steel plates (in case of smaller tanks). Assessment should be done on the cracks, or sapling of the ring walls. The damaged ring walls should be reported for repair.

d. Smaller tanks can be manufactured with the raised foundations constructed by the metallic beams either directly welded to the tank or bolted through attachments on the floor. The bottom of these tanks is kept away from the ground to avoid the underside corrosion. The metallic beams rest on the concrete pilings. The inspection of these pilings should be done as per applicable section of the general requirements Para 1.4 of this manual.

10.1.7. In case of the concrete bottom or concrete peripheral foundation wall, the tank is often anchored with the anchor bolts. The condition of the anchor bolts should be thoroughly assessed. The inspection could be performed by slight hammering the bolts on side for dislodging and zero degree ultrasonic inspection to check for cracks or broken bolts. Report any missing or loose nuts for re-torquing.

10.1.8. In case the tanks are used to store the refined fuels in large quantities the tanks farm may be provided with the leak detection system. The leak detection systems include the perforated piping running under the tank foundation. The gas testing is done periodically for LELs (lower explosive limits) to detect the leaks in the floor. Make sure the leak detection piping is not collapsed, corroded or plugged with debris.

10.2. External Inspection.

10.2.1. Ladders and Platforms:

The integrity of leaders and platforms should be checked as per General Requirements Para 1.6.

10.2.2. Shell

a. The condition of the shell plates should be evaluated as per the general requirements Para 1.2.2 of this manual. If the tank is insulate, the integrity of the insulation should be assessed as per general requirements Para 1.2.1. The corroded areas of the shell should be evaluated according to the guidelines provided in Para 10.3.1 of this manual.

b. The coating/paint of the un-insulated tank should be evaluated as per General requirements Para 1.2.3 of this manual.

c. All attachments should be evaluated as per applicable section of general requirements Para 1.8.

d. Tank should be electrically grounded. The grounding connection should be evaluated as per general requirements Para 1.9.

e. The shell could be distorted due to excessive uneven settlement or rigid body tilt settlement of the tank. The settlement evaluation for the tank is given in Para 10.5. If the significant rigid body tilt or out or plane (differential) settlement is determined from the settlement analysis, the tank should be evaluated for out of plumpness or structural distortion. For rough measurements, at least 1 meter long level can be used, by placing it vertically with the bottom shell. It the tank is found slightly of the level than the plumb line measurement can be done from the top of the tank. The acceptable out of plumbness is 1:100 with the maximum of 5" (12.5 cm). Same criteria should be used for the evaluation of the out of plumbness of the external structural columns.

f. Ultrasonic thickness measurement should be done at the selected locations, if the tank is in service at the time of external inspection. Wall climber robots can be used for this purpose. The selection of the thickness measurement locations should be done by the inspector or engineers experienced with the usual process parameters of the tank and the damage mechanism for the stored fluid.

10.2.3. Floor

a. Minor sections of the sketch plates extend out of the shell. Inspect the plate to plate weld ends for possible crater cracking form original manufacturing. These cracks should not be repaired if the tank had been in service for long time and no significant ground settlement has occurred. However if the tank is new and the settlement has been indicated by ground survey, there is potential for propagation of these cracks due to stress on the edges. Fitness for service evaluation should be done for these cracks and should be repaired if found unacceptable.

b. In case of marine environment or excessive vegetation within the berm, the corrosion takes place on the ends of the sketch welds. Excessively corroded areas should be marked for evaluation from inside (at the tank outage). If the tank is not being taken out of service at this time, further evaluation can be done by removing the dirt/sand from these locations. If the corrosion is found extended under the tank, and is evaluated not suitable for continued service the tank should taken of service for repair.

c. Look for significant dents or other mechanical damage at the sketch plate ends. If significant deformation is found the adjacent section of shell to bottom (external) welds should be inspected thoroughly. Evaluate the adjacent shell areas within the vicinity of damage.

10.2.4. Fixed Roof (cone or dome)

While working on the fixed roof inspector should use full body harness with 100% tie off, and check areas with ultrasonic or light hammering for corrosion and plate thinning, before proceeding on to roof. Any significant dishing or sink in the roof could be sign of the rafter failure underneath. Unless safety is ensured the access to such roofs should be avoided under all circumstances.

a. Evaluation of the insulation should be done as per Section-5 general requirements Para 1.2.1 for insulated tank.

b. Evaluation of the roof should be done as per Section-5 general requirements Para 1.2.2 for un-insulated tank.

c. Coating should be evaluated as per general requirements Para 1.2.3.

d. Look for indication of standing water or significant sagging of fixed roof deck. This condition may be due to potential rafter failure underneath. The plate welds and shell to roof weld adjacent to sagging should be checked with MPI for cracking.

10.2.5. Welds:

a. The shell to bottom (chine) weld is the most important weld in the structure of the tank. This weld should be completely exposed for proper inspection by removing, dirt, insulation or vegetation. Unless required unnecessary removal of the coating from this weld should be avoided. Careful evaluation of the integrity of chine weld should be done as per the requirements of Para 1.3.1. Unless the MPI of the internal part of this weld is not planned, 100% NDT of the external weld should be done. Significant corrosion in this weld should be evaluated for fitness for service. No weld repair in this area should be done until the repair procedure is approved by the engineer experienced in tank repairs.

b. All other structural welds including shell plates, roof plates, external structural beam welds, and shell to top welds should be visually inspected and evaluated as per general requirements Para 1.3.1

c. The reinforcement re-pad welds (if any) should be evaluated as per General requirements Para 1.3.2.

d. The nozzle welds should be evaluated as per General requirements Para 1.3.3.

10.2.6. Nozzles:

a. All of the manway and piping nozzles should be evaluated as per the applicable section of the General requirements Para 1.5.

b. Evaluate the nozzles joints on the shell for distortion due to over loading because of improper pipe supports. All kind of in-service tank settlements, weather uniform localized differential, or rigid body tilt result in the localized shell distortion at nozzles. The settlement survey should be done if the significant distortion is the nozzles areas are found.

c. The reinforcing re-pad and welds on the nozzles will be evaluated as per Para 1.3.2.

10.2.7. Attached piping:

a. The attached piping evaluation should be done as per Section 5 Para 9 of this manual. The attached piping may include the process fluid inlet/outlet piping, sample collector manifolds, water draw of piping, and auxiliary blinded nozzles etc.

b. The pipe supports should also be evaluated and reported for rectification, if found to be source of the shell distortion.

10.2.8. Appurtenances:

Tank appurtenances include a variety of equipment, ranging from electrical, mechanical and passive equipment. The functions of these appurtenances vary from operational, gauging and the maintaining the quality of the stored fluid. The functional evaluation of these equipments is not in the scope of this manual. Qualified instrumentation technician should evaluate the specialized equipment of the tank. Following text only covers the evaluation of general condition of these equipments.

a. Mixers/agitators:

Tanks may be equipped with the mixers used to agitate the stored fluid and maintain the uniform composition. The mixers are mostly side mounted, but could be mounted on the top (roof) in smaller tanks. The evaluation of the mixer should include inspection of mounting and support structure for the motor and other mechanical components which, during operation, directly or indirectly deliver the mechanical energy to the tank shell. The electrical circuiting for the mixer should be inspected by qualified electrical inspector. Record any signs of leakage at the mounting system and the shaft packing. The mixer inspection should preferably be done while in mixer is in operation. Any unusual vibration or signs of malfunctioning should be recorded for further evaluation. Some mixers are equipped with the swiveling mechanism. There are higher chances of the leaks at the packing area of the swiveling ball joint. Normally the mixers are mounted on the manways or specially designed reinforced nozzles, however the mechanical movement and swiveling action can exert cyclic loads on the adjacent shell and welds. MPI should be done on the shell to the nozzles welds to look for any fatigue cracking. If the mixer is dismantled for maintenance, inspect the condition of the fan. Look for the erosion or dents on the fins. The damaged sections should be reported for replacement. Some tanks are equipped with the jet mixers which take the fluid from the tank and pump it back, through return piping. The inspection of these mixers will involve the visual and MPI on the inlet and outlet nozzles joints, because the turbulent flow may cause the fatigue cracking in these joints.

b. Gauges:

Tank level gauging system may vary from the ordinary swing line gauge, external transparent pipe indicator, floating roof position indicator to the advanced radar gauges. The inspection of smart gauging systems should be done thoroughly by the instrumentation technician, however tank inspector may assess the general condition of the components and evaluate if normal operation could be hampered due to any reason. In case of the mechanical float gauge check the proper movement of the float, and the float retrieval system should be checked. This subject is further discussed in the internal inspection of the tank.

c. Ventilation System:

Effective ventilation in the fixed roof tanks is must for its safety. Restricted ventilation can cause the development of above design vapor pressure which can deform the tank. The restricted breathing of tank may also accumulate explosive vapor concentration which can cause catastrophic accident. For evaluation of free ventilation of the tank, inspect the vents and breather systems on the top of the fixed roof tanks. The screens and air filters on the breathers should be checked for the plugging, debris and corrosion. Replace the deteriorating components rendered not able to survive until next outage. Inspects for free movement of gravity vents, thief hatches, and top manway (if available). If goose neck vent is installed on the top of the tank make sure the neck is not plugged by debris or bird nests.

d. Safety Devices:

The tanks holding the volatile refined products are also equipped with additional safety device like low pressure relief valves, vacuum breakers, flame arrestors and high level alarm etc. Over all condition and operability of these equipments should be assessed. The specialized equipment should be inspected by the instrumentation technicians.

e. Foam delivery:

For emergency firefighting the floating roof type tanks are often provided with the foam delivery nozzles (installed on shell) and dams (installed on floating roof). Inspect the foam deflector curved plates for corrosion and mechanical damage. Check the foam chambers and spray nozzles for obstruction or plugging with debris and bird’s nests. The foam supply piping and peripheral foam distribution header (around the tank top) should be inspected as per section 5 para-9. The condition of the foam dams should be assessed for proper function and structural integrity.

f. Some tanks such as acid storage tanks, where moisture control is required, are provided with the silicone gel capsules. Periodic replacement of these gel capsules is required for strict quality control. Inspect the condition of the gel capsule and the housing. Air seal packing should be provided if the capsule is not sitting tight in the housing.

g. Make sure all of the roof fittings are equipped with proper coverings to prevent contaminants from atmosphere. Especially in case of the tanks holding ultra refined products like jet fuels and gasoline. The inspection should also be done for the quality of the coating on the covering.

h. Check for the condition and proper operation of temperature and pressure gauges (in case tank is designed to operated in low pressure).

i. Some tanks may have internal fire tubes to heat up the stored contents. The inspection should be done for the mounting of the fire tubes, and the burner system of the fire tube.

10.3. Internal Inspection:

The tank should be prepared for internal inspection as per requirements of API-RP-2016. It is responsibility of inspector to ensure if all of the safety requirements have been fulfilled, before entering the tank.

10.3.1. Shell

a. The uncoated shell walls should be inspected as per General Requirements Para 1.2.2. The inspector should know the corrosive characteristics of the product normally stored in the tank. If the specific gravity of the stored product is lighter than water than the most susceptible areas for the corrosion are the bottom section, where water settles. In this case, careful inspection of the bottom section of the 1st course should be done. Other most susceptible areas include liquid vapor interface, top roof and girders, and vapor trap zone between fixed and floating roofs (in internal floating roof type tanks). The hydrogen blistering and the stepwise cracking can occur in the sour service tanks constructed with non HIC resistant materials. If blistering is found on some locations, further evaluation should be done with advanced ultrasonic inspection techniques. The heavily corroded sections of the shell should be evaluated for fitness for service as follows.

Determine the minimum thickness in the corroded areas by UT scanning from outside. The profile of the area should be drawn at various vertical lines within the corroded area. The spacing of the line should not be wider than 1 inch. However the inspector should make sure that the location of the minimum thickness is not missed in between the selected vertical profile lines. The closer spacing of profile lines can also be selected depending on the dimensions of corroded areas.

For each profile line determine the average thickness within the line. Select the lowest average thickness t_{ave}. Also find out minimum the remaining wall thickness t_{rem} in scanned area. In order to check if the areas is fit for continued service following steps should be taken.

Step-1: Determine the corrosion rate CR as

$$CR = \frac{t_{prev} \ - t_{rem}}{Years\ of\ service}$$

Step-2: Using the Corrosion rate determine the “expected lowest average thickness t_{ave} (expected)” and “expected remaining thickness t_{rem} (expected)” in the area at the time of next scheduled outage.

$$t_{ave}(expected) = t_{ave} - (expected\ years\ of\ next\ service) \times CR$$

$$t_{rem}(expected) = t_{rem} - (expected\ years\ of\ next\ service) \times CR$$

Step-3: Evaluation

In order to accept the area for continued service following conditions (both) must be satisfied.

a) t_{ave} *(expected) + CA* $\geq$ t_{min}
b) t_{rem} *(expected) + CA* $\geq$ *0.6* t_{min}

t_{min} being the design value for the affected shell course. CA is corrosion allowance (given in the design documents of the tank).

Supplementary Note: Above corrosion rate is the short term CR, if long term CR is also available for this area than the highest value of two corrosion rates should be used.

If any of above two conditions are not satisfied the corroded area of shell should be rebuild by overlay welding, Lap patch, or the cutout plate replacement. The repair procedure should be as per API-653 Para 9.3 & 9.4, and should be approved by the engineer experienced in the tank repairs.

If the repair is not permissible for the time being the fill height limit of the tank should be reduced. The new height can be calculated as follows.

$$New\ fill\ Height = \frac{1}{2.6}\left[\frac{SE \times t_{rem}(estimated)}{DG}\right]$$

Where S is the max allowable stress in lbf/in^2, given in table 4-1 of API-653.

E is the efficiency of the welds in the corroded area given in table 4-2 of API-653. Value of E = 1 if the corroded area away from the weld by 1” or twice the design thickness of plate.

D is the diameter of tank in feet, and G is the specific Gravity of the fluid stored.

Supplementary note: API 653 uses this technique for height calculation for tanks with diameter smaller than 200 ft, and allows using variable design point method for tanks bigger than 200 ft. The variable design point method is used by API 650 for design calculation of larger tanks and provided less stringent criteria than this technique. Since these areas are corroded, It is preferable to use this technique for all tanks.

If it is decided to put the tank back into service with reduced fill height, the corroded areas should be marked on the outside and monitored with ultrasonic at reduced frequency. The tank should be taken out of service whenever deemed necessary due to accelerated corrosion.

b. If the tank is internally coated, the integrity of the coating should be evaluated as per applicable section of general requirements Para 1.2.3.

c. The shell could be distorted due to excessive uneven settlement or rigid body tilt settlement of the tank. The settlement evaluation for the tank is given in Para 10.5. If the significant rigid body tilt or out or plane (differential) settlement is determined from the settlement analysis, the tank should be evaluated for out of plumpness or structural distortion. Any suitable technique available can be used for this measurement. The acceptable out of plumbness is 1:100 with the maximum of 5” (12.5 cm). Same criteria should be used for the evaluation of the out of plumbness of the structural columns.

d. In case of the floating roof (internal or extern), look for the excessive gouging on the shell due to the movement of the floating roof. Usually the floating roof seal is made of softer material than the shell however in some cases the damages component of the seal of the metallic debris caught between the seal and the shell can cause the gouging which may reduce the thickness below required minimum thickness of the shell.

e. All structural, nozzle and attachment welds should be evaluate as per applicable section of general requirements Para 1.3. The shell to bottom weld and the nozzle welds at the bottom course (if not coated) should be tested with MPI. The welds may be subject to the accelerated preferential corrosion in high hardness HAZ, especially if the contents in the tank are sour or acidic in nature. The vertical joints on lower sections of shell are more critical than the horizontal joints. MPI should be done on the Tee intersection of all of the horizontal to vertical weld intersections at the bottom course of the tank.

f. If the tank shows significant differential settlement, the deformation of the shell is also expected. In case the floor breakover point is closer to shell, the shell tends to bend outwards. If this condition is found the excessive bending on shell should be evaluated by the engineer experienced in structural designing of the tanks.

10.3.2. Internal Support Structure

The internal support structure consists of the column, wind girders, bottom cross beams (under the floor) and the rafters.

a. Careful inspection should be done on the column for corrosion and mechanical deformation. The piping columns are usually open/slotted at the top and bottom in order to avoid the pressure build up and free draining. These columns often tarp the sludge or debris which causes the internal corrosion of the columns. Light tapping by hammer can be done to evaluate the overall condition of pipe columns. The ultrasonic inspection should be done on suspected columns.

b. The columns, especially the central load bearing column often sinks relative to the outer periphery of the tank. The degree of deformation of the floor ususlaly gives the idea of the extent of sinking. If above normal sinking of this column is observed, there are chances of over stressing on the joints at both ends of the rafter. In this case MPI should be done on all of the structural joints of the rafters. Same is the case if the outer periphery sinks significantly either uniformly or locally.

c. The rafters should be inspected for the corrosion and welds defects. The deteriorated rafters should either be recommended for the replacement or reinforcement.

d. The bottom cross beam should be thoroughly inspected in case the floor plates of the tank are removed for replacement. If the tank is not catholically protected than small sections of the floor plates should be removed to inspect the bottom cross beams. If significant the corrosion is found, the scope of inspection should be increase accordingly.

e. Some of the auxiliary columns are provided with support I beam shoes, but these shoes are not usually welded to the floor plate. The provision is to allow the tank for expansion (within tolerance) due to heat or vapor build up (especially in case of low pressure tanks). These beams should be carefully looked after for the lateral displacement. The MPI should be done on the top joints with rafters. In some cases the stop brackets are welded to the floor, around the shoe to restrict lateral movement of these columns. MPI should be done to check the condition of the welds on these stop brackets.

f. The measurement for out of Plumpness should be done of the beams found slightly displaces. The maximum allows out of plumbness is 1:100 with the maximum of 5” (12.5 cm). The columns showing out of tolerance deviation should be evaluated by structural Engineer, and rectified if deemed necessary.

10.3.3. Floor

a. Top side corrosion is one the major deterioration mechanism for the tank floor. The inspector should know about the corrosion characteristics of the fluid contained and the contaminants in the tank. The dominant top side corrosion mechanisms include the biological corrosion caused by anaerobes, general corrosion due to the relatively low ph and water contaminants, under deposit pitting, and crevice corrosion in the narrow areas between floor and the welded attachments. Thorough visual inspection should be done on the floor and the annular ring as per recommendations of general requirements Para 1.2.2. Where ever suspected the visual inspection should be supplemented by NDT techniques. The evaluation and the repair should be given as per Para 10.3.3.d.

b. While performing the top side inspection, the inspector can use light hammer tapping to evaluate the generalized thinning of the plates due to bottom side corrosion. The ultrasonic thickness measurements should also be performed at various locations to look for the bottom side deterioration. For the larger tanks Magnetic flux leakage (MFL) technique must be used for evaluation of the bottom side corrosion of the floor. The localized pitting found by the MFL method should be confirmed by the ultrasonic inspection.

c. Erosions effects are also seen on the floor in the location where high sediments flow is induced. Special attention should be paid at the locations around inlet, near the mixer (fan or jet) where turbulence is highest, close to the steam jets (if installed). The ultrasonic or pit gauge measurement should be done to find out remaining thickness in the eroded areas.

d. The corrosion rates should be developed for the top side and the bottom side from previous inspection history. If this is the first out of service inspection, the corrosion rate should be calculated from original design thickness of floor. Following method should be used for evaluation.

$$Corrosion\ Rate\ = \frac{Measured\ thickness - previous\ thickness}{Years\ of\ service}$$

If CR_{top} is top side corrosion rate and CR_{btm} is the bottom side corrosion rate, and the next service interval is O years, then the expected thickness at the end of O years is

$$Expected\ Thickness = measured\ thickness - O(CR_{Top} + CR_{btm})$$

The acceptable value of the expected thickness is 0.05” (1.27mm) for coated tank and the tanks with leak detection systems, and 0.1” (2.54mm) uncoated tanks with no leak detection system.
If the expected thickness is lesser than these values the floor repair should be recommended. The repair procedures should be as per API-653 Para 9.10, and should be approved by the Engineer experienced in tank repairs.

e. Floor plate welds inspection should done as per General Recommendation Para 1.3. Where ever suspected the visual inspection should be supplemented by the magnetic particles inspection. The shell to floor chine weld is the most critical weld in the tank. If tank is not coated, 100% of this weld should be tested with MPI. If the tank shows the signs of the localized or uniform settlement, all of the welds in the affected area should be tested with the suitable NDT method. If the floor plates are lap welded than the lap welds on the settled sections of floor are subjected to shear stresses. The magnitude of the shear stressing depends of the orientation of the weld with respect to the settlement. These welds are often found torn or cracked. Other service related damages on the welds include the preferential corrosion washout if the stored fluid is corrosive in nature. All of the affected welds should be repaired with the approved welding repair procedure.

f. The edge settlement of floor should be evaluated as per the instruction given in Para 10.5.3, and the localized settlement as Para 10.5.4.

g. The water draw off systems in the tank should be inspected for integrity and proper function. There are different kinds of the water draw off setups depending on the size and the foundation design of the tank. Some smaller tanks on the elevated foundations are provided with the nozzles on the shell close to the floor to shell weld. These tanks floors are often sloped from the centre to out. However the larger tanks are provided with the sump pits with the suction pipe opening in the pits. The water is drawn by the gravity flow of by forced pumping. The sump location could be in the centre of the floor or near the outer edge. The inspector should look for the proper drainage towards the sump. The uneven settlements of the tank floor often shift the drainage pattern of the tank. The water draw off piping and the sump should be clean and free of debris.

10.3.4. <u>Internal Attachments:</u>

There are various kinds of internal attachments in the tank. The inventory of the attachments depends on the process, product stored and the type of the tank. All of the internal attachments of the tank should be inspected as per applicable sections of the General requirements Para 1.8. The attachments welds should be inspected as per General requirements Para 1.3. The attachments related to the floating roof, drain systems and support structures are also covered in Para 10.4.2 and 10.4.3.

a. Inlet piping is often extended into the tank with the provision of the deflectors. Look for the integrity of the inlet piping assembly and the support pedestals. The tanks with the floating roofs are also provided with the properly designed and sized slotted inlet diffusers. The designing of the diffuser is done according to the maximum possible pumping rate of the inlet fluid. The slots are often provided at 60 degree on each side from the top centre line of diffuser pipe (at 2 O clock and 10 O clock positions). The purpose of the diffusers is the proper distribution of the inject fluid inside the tank. Improper or turbulent injection in the tank may induce the ripples in the fluid which can induce the damaging uneven movement of the floating roof. For this reason close attention should be paid on the diffuser and inlet inspection in the floating roof tanks. If required the piping and diffusers should be dismantled for pressure wash cleaning. Heavily corroded or damaged diffusers should be reported for replacement.

b. Sample piping is provided in the fuel storage tank where the fuel quality is to be controlled. The piping attached with the shell usually opens at various heights in the tank to collect the sample at different locations. These piping should be free of the dirt or contaminants. The high pressure steam wash should be recommended to clean and unplug these piping. The air drying should follow to clean the condensed water.

c. Internal floating collator (or floating suction line) is often installed in the fuel storage tanks. The floater is either connected with the flexible synthetic material hose or the rigid pipe with the articulating joints. In both cases the suction line is designed to collect the flue from top and the axial centre of the tank. In case of the articulating joints pipe, the integrity of the articulating elbows (joints) should be checked for free movement. Look for the proper sitting of the pipe on the pedestals designed for low level pipe sitting. Means should be used to extend the pipe to it full height to properly inspect the swivel joints for fatigue or other mechanical defects. Make sure that means (tying chains) to restrict the full extension of the articulating pipe are in place and functional. This pipe if allowed to fully extend the on its axis, may lose its design position. Check if during extension the tip of the suction line stays in the centre of the tank. In case of the flexible synthetic material pipes inspection should be done for rips cuts or cracks in the pipe. The auxiliary guide system to keep the hose in the axial centre of the tank should also be inspected.

d. The tanks without floating roofs are fitted with the mechanical floating gauge assembly. This assembly should be inspected for proper functioning, look for the condition of the floater, guide wires and rollers. Ensure free movement of the floater.

e. In case of the floating roof tanks level gauge could either be in form of the slotted pole with the floater inside the pole. This pole also acts as the anti-rotation guide for the roof. The structural condition of the gauge pole should be assessed for plumbness and excessive corrosion, however floater movement of this type of gauge can be checked from outside only. Some tanks are equipped with the gauge pole on top of the floating roof which works with the roof movement. Inspection of such gauges is covered in the section for floating roof inspection.

f. Some crude oil tanks are provided with the skimmer pipes with the mechanical means to adjust the location of the skimmer (controlled from outside). Check for the integrity of the pipe, articulating joint, and the guy wire for positioning. Proper movement of the skimmer should be checked.

g. Tanks containing the sour fluids may be equipped with the internal sacrificial anodes for cathodic protection. Note the condition of the anode mounting, record the degree of consumption of anodes. If the anode is not consumes as expected the grounding with the shell should be checked.

h. Some tanks are provided with the steam coils for heating purposes to keep the viscosity of contents low for the transportation purposes and anti freezing (in the colder parts of the world). The integrity of the steam coil should be thoroughly checked. Look for the corrosion and other significant service related damages. The leaked coil may add water contamination of tank contents.

i. The tank may be installed with the fire tube for heating the contents. Thorough inspection of the fire tubes should be done if it is dismantled. Look for the defects like corrosion, flame impingement, fatigue or any other manufacturing or service related defects. The welds of the fire tube should be inspected as per General instruction Para 1.3.

10.4. Floating roofs:

The floating roofs are used to prevent the vapor losses in the highly volatile fluids, (usually the refined fuel product). As a rule of thumb the liquids for which have vapor pressure may exceed 12 RVP (Reid Vapor Pressure, the absolute Vapor pressure of a liquid at 100 °F), are stored in the tanks with the floating roof. There are three main categories of floating roof tanks, external floating roof tanks EFRT, and internal floating roof tank (IFRT) with secondary supported roof, and one with self supported roof doom type secondary roof. The construction of the floating roofs in all three categories is slightly different, but the inspection rules are same. Following text provided the inspection requirements of all three types of floating roof tanks. The inspector should apply the applicable section to the relevant tank. Design wise there are quite a few types of the floating roofs, which include but are not limited to Sandborn type (only for internal roofs), compartmented steel floating roofs, Internal Aluminum floating roofs, Internal plastic floating roofs, Pan-type floating roofs, and honeycomb sandwich double deck roofs. More designs are available depending of the manufactures and the user requirements. Inspector should know the type of the floating roof and plan the inspection activity accordingly.

10.4.1. In-service inspection:

Since the proper operation of the floating roof cannot be assessed during the out of service inspection, (when roof is sitting on its support structure), it is must that the periodic in-service inspection should be done on the floating roof when the tank caries substantial amount of the stored fluid. No physical access on the roof should ever be attempted, without gas testing, on roof while it is floating on the stored product. This inspection should be done from the top of the tank in case of open top roof, or from inspection hatches in case of fixed roof tanks. The applicable respiratory protection must be worn to avoid fumes inhalation. All other pertinent safety measures must also be adopted for this periodic inspection. Following are the most critical elements to look for in out of service inspection of the floating roof.

a. Most important is checking the level of the roof, at different heights. The uneven movement of the roof could be due to minor distortion in the shell at some locations, uneven ground settlements, and leaked (liquid filled) pontoons. The level comparison is done by measuring the height of the roof with respect to the circumferential weld just above the roof (or with respect to the top edge. Inspector should select the number of the measurement points depending on the size of the tank. The radar guns or any other optical level measuring instruments can be used for this purpose.

b. The Shell to the roof seal gap (annular space) should be checked at various locations at different heights. The data obtained from this inspection could be used to decide for the primary and secondary seal replacement.

c. Check the overall condition of the roof, amount of debris, water or the stored fluid accumulated on the roof.

d. In case the access is required on roof while tank is filled with product, all the safety precautions given in API Publ-2026 Para 8 and 9 should be fulfilled.

10.4.2. <u>Out of service inspection:</u>

a. <u>General Condition:</u>

The design of the floating roof, whether external or internal, is based on the process conditions. The process fluid conditions divide the floating roofs in two main classes, the contact type and non contact type. The detailed discussion of the process condition versus type of the roof is not in the scope of this manual. However the rule of thumb is that, if the stored fluid is sour it is preferred that no air is trapped between the roof and the stored fluid, so contact type roofs are used. While In case of the non-sour refined products the noncontact pontoon type roofs are preferred. The advantage of using these roofs is the additional buoyancy achieved from the accumulated vapor pressure (from the stored liquid) in the space between liquid and roof. The inspection requirements of both classes are slightly different from each other, only the common requirements are discussed below.

- The overall condition of the roof deck should inspected both from top and the bottom side as per General requirements Para 1.2.2. Assess and report any structural or localized deformation in the roof. Excessive structural deformation, involving whole roof, is more eminent in the single deck roofs, which could be caused by the accumulation of water or the leakage of store product from peripheral seal. However the double decked roofs often are deformed at the localized areas.

- Assess the corrosion on the deck plates by light hammering. The Ultrasonic thickness measurements should be done on the suspected locations. If previous thickness on the reduced section is available the corrosion rate should be developed otherwise the nominal thickness (obtained from design data) should be used for corrosion rate calculation. Report the significantly corroded plates for replacement.

- The drain nozzles should be inspected for corrosion and the plugging. The double deck roofs are also provided with emergency overflow openings to protect the tank roof from excessive rain or the seal leak. Check for the condition of the covers provided with the drain to protect from the plugging.

- All of the welding on the deck should be assessed as per applicable section of General requirements Para 1.3.

- Check the drainage on the top side of the roof. The roof plates should be leveled properly to allow the rain water or the leaked product to be drained to the roof drains.

- All of the attachments on the floating roof should be inspected as per General requirements Para 1.8. Proper NDT method should be used to supplement the inspection findings.

- Look at the condition of the foam dams attached near the outer end of the tank roof. Mechanically damages, corroded or broken dams should be reported for replacement. Note the debris collected between the dams and the peripheral seal.

- In case of the open roof type tank inspect the condition of the rolling ladder. Note the condition of the rollers, roller tracks, and the lateral displacement limits. Also check the condition of anti-static grounding connection and wire between the ladder and roof deck.

- The internal floating roofs are provided with the anti static grounding cable attached with the fixed roof. Check the condition of the grounding connections on both ends. Take the resistance measurements by resistance measurement between the shell and the roof to look for the proper grounding.

  Supplementary note: At the time of resistance measurement the peripheral seal fabric should be in good condition to avoid wrong reading from non-isolated roof/shell connection.

- Check the condition of all vents, breathers and the vacuum breakers. The instrumentation technician should assess the proper functioning of specialized equipment.

- Look for the condition of the seals on all the roof protrusions. All of the roof openings like manhole, anti rotation devices, fixed roof supports protrusions should have suitable sealing to stop the liquid ingress on top of the roof.

- Check for the condition and free movement of the rollers for the roof protrusions, like fixed roof support, gauge polls, and anti rotation devices
-

b. Peripheral Seal Inspection:

The peripheral seal is vital for the emission control and proper flotation of the roofs. Since floating roof sits on the supports during the out of service inspection and the performance of the seal cannot be assessed at different heights, the inspector should review the results of periodic in-service inspection of the seal to shell gap covered in 10.4.2.b. before conducting detailed out of service inspection.

- The inspection of the seals performance should start with the thorough inspection of the shell above the minimum designed height of the roof. Significant signs of localized scrapping on the shell show the high frictional movement of the roof at those locations. The seal at those areas should show excessive wear.

- Normally the seal materials are not abrasive and have lower hardness than the shell, however in some instances the trapped metallic debris or other conditions may cause deep gouging in the shell, which may not be able to withstand the static head hoop stresses and can cause rupture in tank. If evaluated as potential of failure the shell should be repaired at these locations.

- While performing the seal inspection the inspector should pay particular attention on the locations of vertical seams on the tank.

The seal can be worn out preferentially at the locations of vertical joints due to the rough surface and the excessive weld cap.

- All peripheral seals should have room to accommodate at least 4 inches of local deviation between the floating roof and the shell.

- In the mechanical shoe type seal the shoe is made of non abrasive metallic plate (usually SS or galvanized CS), covered with the coated fabric. The thickness of the fabric provides the required vapor seal. Closely look for the condition of the fabric between the seal and the shell. The seal should be pushed back mechanically in the suspected areas to do the close inspection. Look for the condition of the spring or counter weight hanger (whichever is applicable) designed to close the gap with shell. The corroded or the damaged parts of shoe and spring closure should be reported for replacement.

- In case of the liquid bag or the foam bag type seal the fabric covers the inflated bag. The condition of the fabric should be assessed. If the fabric is found damaged the seal should be pushed back to look at the condition of the liquid or foam bag.

- Most of the floating roofs in open top tanks are also equipped with the secondary seals above the primary seal. These seals are mostly flexible stainless steel strip bent upwards and mounted on the top edge of the roof. The sealing action is provided by the elasticity of the strip. The secondary seal does not provide significant vapor control. Main function of the secondary seal is to deflect the debris from getting between shell and primary. The secondary seal in some cases also acts in scarping the wax from the shell walls. This secondary seal should be inspected for dents, buckling, cracking or wear at the top edge (in contact with the shell). Check the angle of the seal at the point with the shell. Too shallow angle may exert excessive bending force on the strip while the roof is moving up.

c. <u>Roof support structure:</u>

All floating roofs are provided with the support legs (made with schedule 80 metallic pips of diameter 3” or 4”), on which the roof sits when the tank is empty. The support legs are the integral part of the roof. Each leg has corresponding landing pad welded on the floor on which the legs are supposed to land when the tank is drained.

- Inspect the legs for corrosion or any other service related damage. The ultrasonic inspection should be done at the selected locations to look for the internal corrosion on the legs.

- Inspect for the plumbness of the legs, excessively bent legs are subjected to shear loading by the weight of roof (while sitting). The roof may collapse while sitting on legs. (Usually more than one legs has to fail simultaneously for total of significant collapsing of the roof). If any of the legs are found plumbed the roof should be provided with the secondary temporary support to shift the load away from the plumbed leg. The bent legs should be replaced or corrected.

- In case of the single deck (pan type roof) particular attention should be paid at the legs attachment areas with to the roof. Normally the reinforcement is provided on these areas, however inspector should look for the localized bending or deformation around the reinforcing pads. All of these attachment welds must be inspected with MPI or LPI from both topside and the bottom side before any other work is done.

- Check if all of the legs have landed on their corresponding landing pads on the floor. If more than one legs have landed away from their pads, this is the sign of the roof rotation or out of tolerance localized structural deformation of the roof. Such conditions should be reported and detailed structural evaluation of the floating roof should be done by the engineers experienced in the floating roof design.

- Each leg is provided has cutouts at the lower sections to allow for the drainage of trapped liquid. Note the conditions which could prevent the free draining of the liquid from the legs.

- Some floating roofs are supported by suspension cables attached with the structural members of the fixed roofs. The reliable inspection of the suspension cables is not possible while roof is suspending. The rough assessment can be dome from the inspection hatches provided on the fixed roof. For safety, temporary auxiliary supports should be provided under the roof during the outage. The working load, during the outage, should never be exerted in the suspension cables.

d. <u>Pontoon inspection:</u>

The pontoons in the pontoon type floating roof (single pan or double) are the means of buoyancy. The pontoons are arranged under the roof in such a way that the weight of the roof is equally distributed over all pontoons. In case of the open top tanks the pontoons are over designed to carry the weight of excessive rain water estimated according to the average rainfall in the area. The pontoons are supposed to tightly sealed to keep the trapped air for effective buoyancy. The leaked pontoons may trap the liquid which can exert the above design load on the floating roof and the roof may deform or collapse. Check the mounting straps (metallic) of the pontoons for corrosion or any other service related damage. Assess the overall condition of the pontoons as per General Requirements Para 1.2.2. Look for the dents, cuts or excessive wear on the pontoons. The welds in the pontoons should be inspected with the Liquid penetrant testing for the cracks or porosity. Larger size pontoons are also provided with the inspection hatches with the liquid tight seals. These hatches should be opened for internal visual inspection.

e. Anti-rotation devices:
In case of supported fixed roof or open top tanks, the devices like gauge poles, leaders or the fixed roof supports act like the anti-rotational devices. In case of the self supporting dome type fixed roof tanks, two or more wires tied with the floor and the fixed roof are provided as anti rotational devices. The integrity of all of these devices for their intended function should be ensured. The inspection of these devices is covered in the inspection for the tank internal attachments.

10.5. Settlement Evaluation:

10.5.1. General:

The settlement evaluation is of vital importance in the beginning years of the tank service when the ground settles significantly. The settlement is the main concern for the large size tanks. These tanks are often not installed on the concrete pads due to the economical, and maintenance reasons. The proper compaction cannot be provided in the softer (sand) cushions which cause the settlement.

The settlements are of mainly categorized in four kinds.

a. Uniform Settlement:
b. Rigid Body Tilt (planer tilt)
c. Differential settlement (out of plane tilt).
d. Local Interior settlement.

The Uniform settlement does not cause any structural distortion in the tank, as the tank sinks uniformly. Only problem with the excessive uniform settlement is the above design stresses on the attached piping, which can be controlled by proper designing of the piping or adjusting the pipe supports. The rigid body or planer tilt tends to rotate the tank in one plane. The excessive tilting can raise the liquid level on the settled side which may eventually deform the tank and induce excessive ovality and out of plumbness in the shell. The operation of the floating roof is significantly affected by the planer tilt.

The differential settlement or out of the plane settlement is the most devastating kind and most commonly found in larger tanks (over 500,000 bbl Capacity). The out of plane settlement can cause differential stresses on the shell and shell to bottom (chine) weld. The excessive out of plane settlement also cause out of plumpness and irregular ovality in the tank shell. The operation of the floating roof is affected by this settlement.

All of these settlements can be detected from the external settlement survey as given in Para 10.5.2, and the internal settlement survey as given in Para 10.5.3. If the peripheral settlement is found unacceptable the tank shell can be jacked and the bottom can be can be filled with extra foundation sand, provided the tank bottom is not distorted. The settlement survey should be done periodically from the outside in the initial years of the tank service. Once determined that the settlement rate is not progressive the survey frequency can be reduced accordingly. Similarly if the excessive settlement is seen the tank should be taken out of service earlier than schedule, for the evaluation of the tank floor.

10.5.2. External Settlement Evaluation:

a. Survey:

Thorough tank foundation inspection should be done as per Para 10.1.6 prior to the settlement survey. Inspector should review the reports of Initial ground leveling survey and the survey done at the time of first hydro testing. Appropriate telescopic land survey instrument should be used for the settlement survey.

- The external settlement survey should preferably be done when the tank is at least more than 50 % full. The settled areas in empty tank may lift from the ground and tend to retain their original level.

- All survey points should be equally spaced. Maximum spacing between the survey points should not exceed 32 feet (or 9.75 Meters) on the circumference of the tank. The survey points should be clearly marked on the tank shell to help repeating survey at same locations. Same points should be used for the follow up surveys.

- Additional survey points should be added at the locations showing significant settlement.

- A permanent not settling reference point should be selected (preferably outside the dike area), which can be easily seen from most of the locations around the tank. This reference point could be a pipe support or any other permanent structure of reasonable height. The height of this structure should be used as absolute reference point for all surveys. (The survey Report should clearly identify the location of this reference point).

- While surveying the settlement on each point, the meter rod should always be placed on the end of the sketch plate (touching the Shell). The sketch plates should be exposed if buried under the sand, mud or vegetation. (Alternatively horizontal weld between course 1 & 2 can also be used as reference on the shell).

- The survey stations (the location of telescope tripod) should be selected around the tank in such a way that most of the survey points on the shell can be seen from one location. See the example of the survey station showed in the figure 10-1.

Supplementary Note: The locations of the survey stations (A to F in figure 10-1) do not need to be fixed. The fixed locations should only be the survey points on the shell (1 to 12) and the non- settling reference structure (shown as star in figure 10-1). However it is preferable that the inspector should follow the same arrangement of the survey stations in every successive survey.

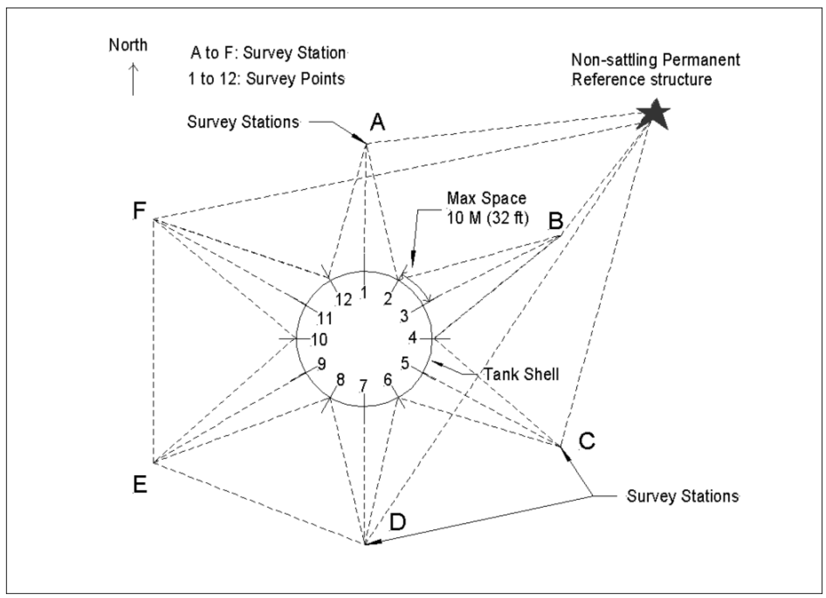


Figure 10-1: Survey points and survey stations arrangement

- The measured height on each point should be compared with the height of the permanent non settling reference point as measured from the particular survey station. This comparison gives the relative height of the survey point on the tank edge.

Supplementary Note: For the survey station from which the non settling reference ★ cannot be seen (behind the tank) for example Station E in figure 10-1, the relative heights of points 8, 9, and 10 should be determined by comparing the relative height of point 8 as measured from station D, and the relative height of point 10 as measured from station F.

- The data collected from this exercise should be evaluated for the progressive settlements trends as given in Para 10.5.2.b.

- The evaluation of the shifted stress distribution on the shell due to settlement and identification of the kind of settlement should be done as given in Para 10.5.2.c.
- The acceptance/rejection criteria given in Para 10.5.2.c should be adopted to for fitness for service evaluation of the settlement.

b. Progressive Settlement Trend Assessment:

For the evaluation technique an example of a tank showing the progressive out of plane (differential settlement) is used. Hypothetical survey data used includes the survey done at hydrostatic testing, and three years in-service surveys. The inspector conducting or reviewing the settlement survey is required to use the steps described in this example.

Example:
Diameter of Tank = 37.25 meter (122 feet) Approx.
Survey points = 12 (each survey point is 9.75 m (32') apart.
The Universal reference is top surface of Metallic Pipe support I beam (outside the dike).
H_{ref} = Height of selected Ref. From Survey Station
H_n = Height recorded at Survey Point
U_n = $H_{ref} - H_n$ (Relative height of Survey Point With respect to Non sinkable reference in tank Farm)
S_{min} = Minimum Relative Settlement
$S_n = H_n - S_{min}$ = Out of plane settlement at Survey Point.

The survey is done from 6 survey stations A through F around the tank. 12 survey point on tank are selected, each point is approx 10 meter apart. For sake of comparison and checking the accuracy of the data recorded, the relative height of the points 2, 4, 6, 8, 10, and 12 are repeated from successive survey station. As Follow

Survey Station	Point Surveyed
A	12, 1, 2
B	2, 3, 4
C	4, 5, 6
D	6, 7, 8
E	8, 9, 10
F	10, 11, 12

Table 10-1/A

However the inspector may reduce the survey stations and conduct survey as follows

Survey Station	Point Surveyed
A*	1, 2, 3
B*	4, 5, 6
C*	7, 8, 9
D*	10, 11, 12

Table 10-1/A

It does not matter how many survey stations are selected as long as the relative height of the survey point is compared accurately to the height of the non settling reference point in the tank farm (which should be preferably out of the dike area, and be visible from most of the areas around the tank).

<u>1: Settlement Survey at Initial Hydro test.</u>

Survey Point #	H_{ref}	H_n	$U_n = H_{ref} - H_n$	$S_n = H_n - S_{min}$
1 (North)	1020	1025	-5	5
2	1020	1015	5	15
3	1020	1015	5	15
4 (East)	1060	1060	0	10
5	1060	1050	10	20
6	1060	1040	20	30
7 (South)	990	970	20	30
8	990	970	20	30
9	990	980	10	20
10 (West)	1010	1010	0	10
11	1010	1020	-10	0
12	1010	1015	-5	5

Minimum Relative Settlement S_{min} = -10 mm

Table: 10-2 Settlement Survey at Initial Hydro test

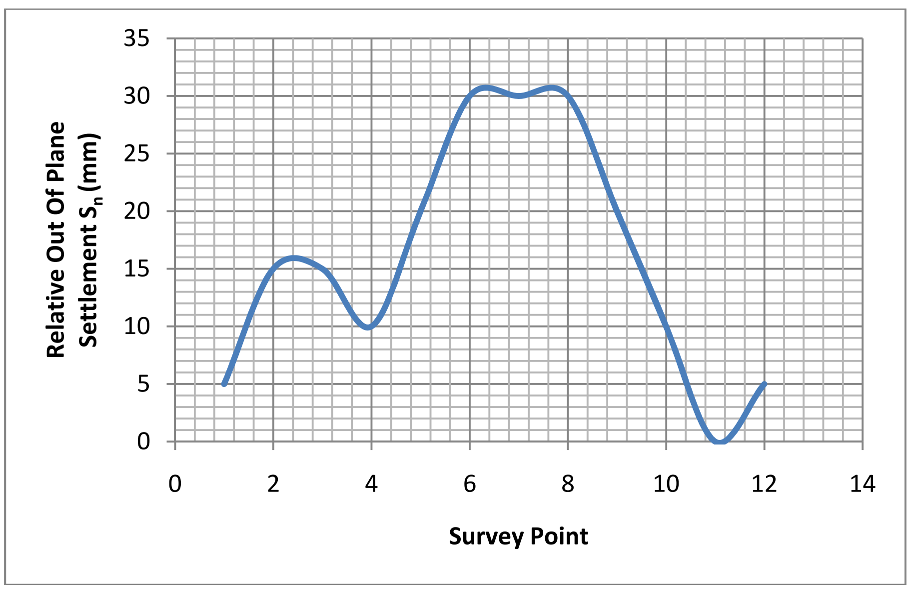


Figure: 10-2 Settlement Survey at Initial Hydro test

2: Settlement Survey at Year-1

Survey Point #	H_{ref}	H_n	$U_n = H_{ref} - H_n$	$S_n = H_n - S_{min}$
1 (North)	990	995	-5	0
2	990	980	10	15
3	990	980	10	15
4 (East)	1030	1025	5	10
5	1030	1020	10	15
6	1030	1020	10	15
7 (South)	960	945	15	20
8	960	940	20	25
9	960	945	15	20
10 (West)	980	980	0	5
11	980	980	0	5
12	980	985	-5	0

Minimum Relative Settlement S_{min} = -5 mm

Table: 10-3 Settlement Survey at Year - 1

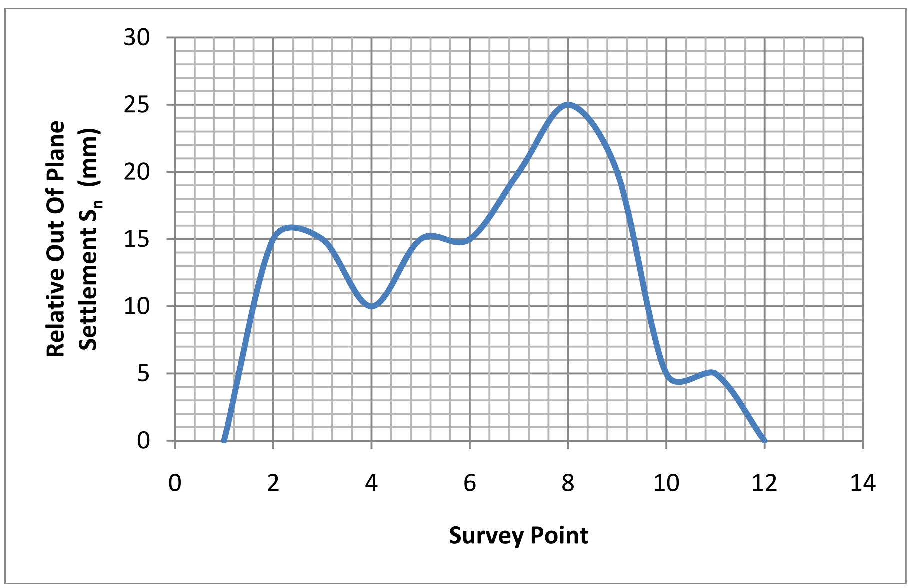


Figure: 10-3 Settlement Survey at Year - 1

3: Settlement Survey at Year-2

Survey Point #	H_{ref}	H_n	$U_n = H_{ref} - H_n$	$S_n = H_n - S_{min}$
1 (North)	1060	1060	0	0
2	1060	1055	5	5
3	1060	1050	10	10
4 (East)	1100	1095	5	5
5	1100	1090	10	10
6	1100	1095	5	5
7 (South)	1030	1015	15	15
8	1030	1005	25	25
9	1030	1005	25	25
10 (West)	1050	1045	5	5
11	1050	1045	5	5
12	1050	1045	5	5

Minimum Relative Settlement S_{min} = 0 mm

Table: 10-4 Settlement Survey at Year - 2

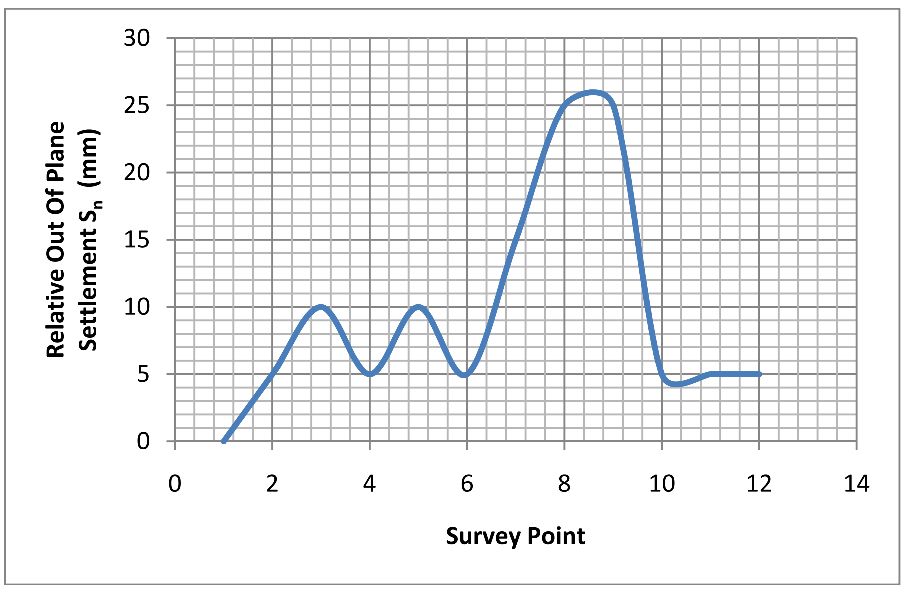


Figure: 10-4 Settlement Survey at Year - 2

4: Settlement Survey at Year-3

Survey Point #	H_{ref}	H_n	$U_n = H_{ref} - H_n$	$S_n = H_n - S_{min}$
1 (North)	960	965	-5	10
2	960	965	-5	10
3	960	960	0	15
4 (East)	1000	1000	0	15
5	1000	1005	-5	10
6	1000	1005	-5	10
7 (South)	930	925	5	20
8	930	925	5	20
9	930	920	10	25
10 (West)	950	950	0	15
11	950	960	-10	5
12	950	960	-10	5

Minimum Relative Settlement S_{min} = -10 mm

Table: 10-5 Settlement Survey at Year – 3

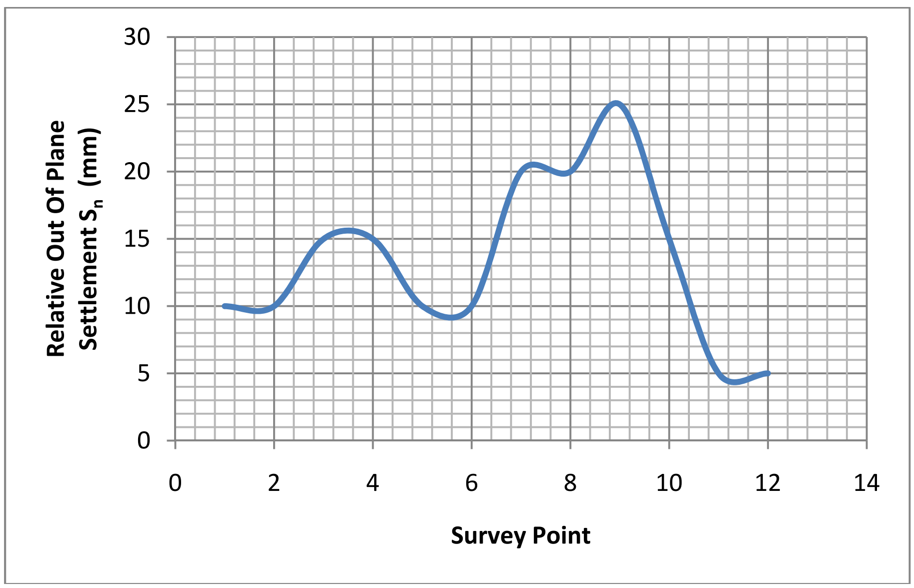


Figure: 10-5 Settlement Survey at Year – 3

By tabulating the each point Settlement and added to the previous year's settlements the actual variation in the elevation of the survey point from the design elevation can be determined. Similarly by the comparison between the magnitudes of the change in the elevation the rate of the settlement can be determined. However this rate should never be used to predict the future settlement.

Note: In actual practice the maximum settlement is seen in initial years and the rate of settlement reduces with time.

Survey Point #	Hydrotest Settlement Survey	Year-1 Survey	Year-2 Survey	Year- 3 Survey	Total Settlement
1 (North)	5	0	0	10	15
2	15	15	5	10	45
3	15	15	10	15	55
4 (East)	10	10	5	15	40
5	20	15	10	10	55
6	30	15	5	10	60
7 (South)	30	20	15	20	85
8	30	25	25	20	100
9	20	20	25	25	90
10 (West)	10	5	5	15	35
11	0	5	5	5	15
12	5	0	5	5	15

Table: 10-6 Progressive settlement data

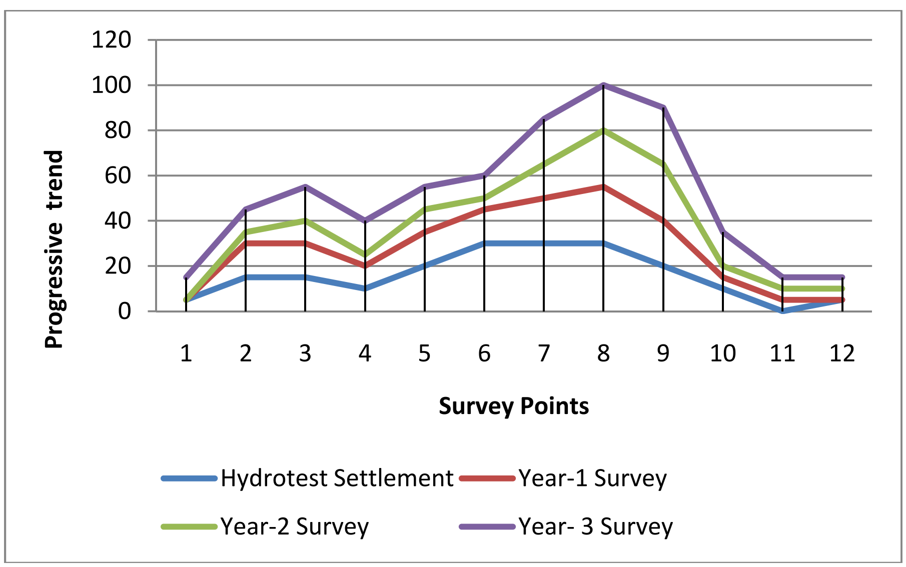


Figure: 10-6 Progressive settlement data

From this hypothetical survey it can be seen that the South west side of the tank is showing maximum settlement of upto 100 mm from the design value, after 3 years service.

The results obtained from this external survey evaluation should be used to predict the condition of the floor, and warrant the need of the earlier shutdown of the tank. However it should be noted the external survey alone cannot be taken as reason to call for earlier shutdown. The floor deterioration (like the over stressed welds) due to settlement is more devastating if the breakover point is closer to the shell, or radius of the settled area is shorter. This concept is discussed in detail in internal settlement analysis Para 10.5.3.b-ii. This condition cannot be predicted from the external survey alone. In order to take this decision, the inspector should know the layout pattern of the floor plates and be aware if the floor plates are lap welded or butt welded. The tanks with the annular ring have advantage in this case. Additional thickness of the annular ring plates, the layout arrangement, and butt welding of the plates provides extra tolerance to over stressing due to settlement.

c. <u>Evaluation of settlement data:</u>

In order to evaluate the condition of the tank, the analysis of the data gathered as given in 10.5.2.b, should be done every time new survey is done.
The shape of the obtained curve is the first qualitative measure of the problem or no-problem situation. The irregular curve with large vertical extremities shows more tendency of differential (out of plane) settlement. The regular curve with sinusoidal or close to sinusoidal shape shows the rigid body tilt tendency in the tank, and curve with shorter vertical distances from the datum line shows the uniform settlement tendency. The examples of different settlement curves are shown in figures 10-7, A, B and C.

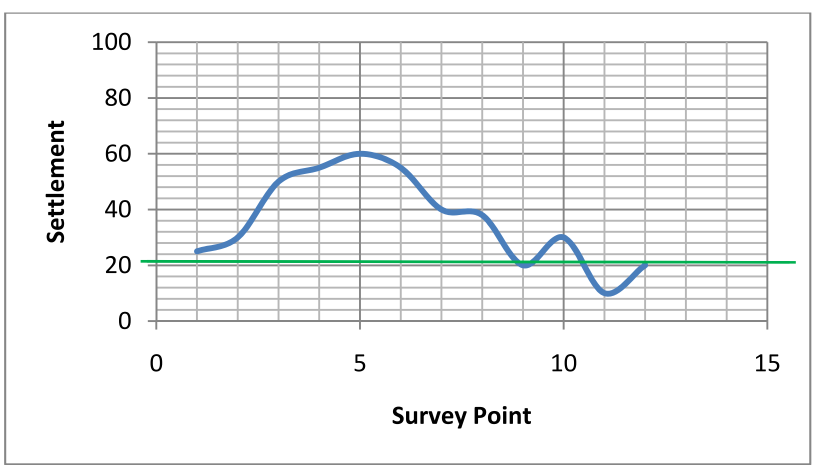


Figure 10-7/A Typical curve for uniform settlement.

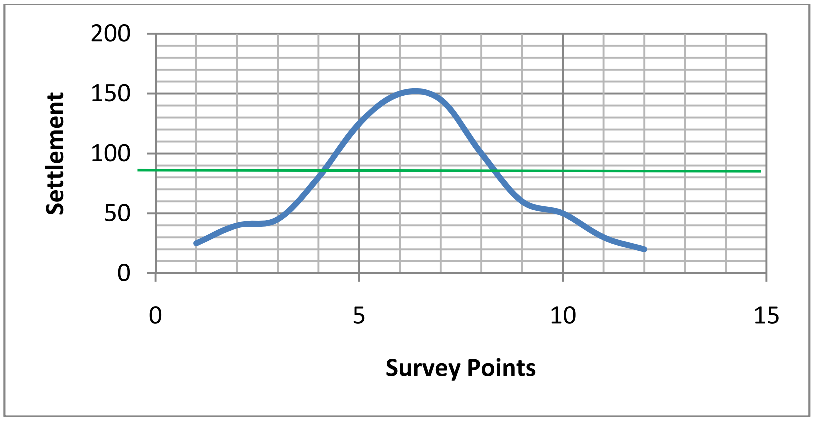


Figure 10-7/B Typical curve for rigid body tilt on the south side (point 7).

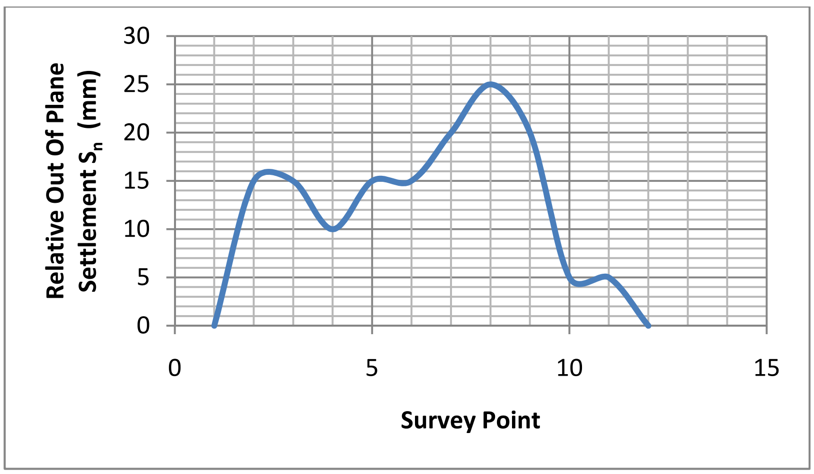


Figure 10-7/C Typical curve for differential settlement.

To determine if the tank shell settlement is acceptable or not we take the example of the same tank and used and the data obtained in the 2nd survey. For the analysis purpose (instead of minimum settlement) the average Settlement is determined from the data, and new Datum is selected at this average settlement. The settlement of other points with respect to average (datum) is drawn above and below datum, as shown in figure 10-8.

Survey Point #	H_{ref}	H_n	$U_n = H_{ref} - H_n$	$S = H_n - S_{ave}$
1 (North)	990	995	-5	-12
2	990	980	10	3
3	990	980	10	3
4 (East)	1030	1025	5	-2
5	1030	1020	10	3
6	1030	1020	10	3
7 (South)	960	945	15	8
8	960	940	20	13
9	960	945	15	8
10 (West)	980	980	0	-7
11	980	980	0	-7
12	980	985	-5	0

Average Relative Settlement S_{ave} = 7 mm

Table: 10-8 Data for settlement analysis.

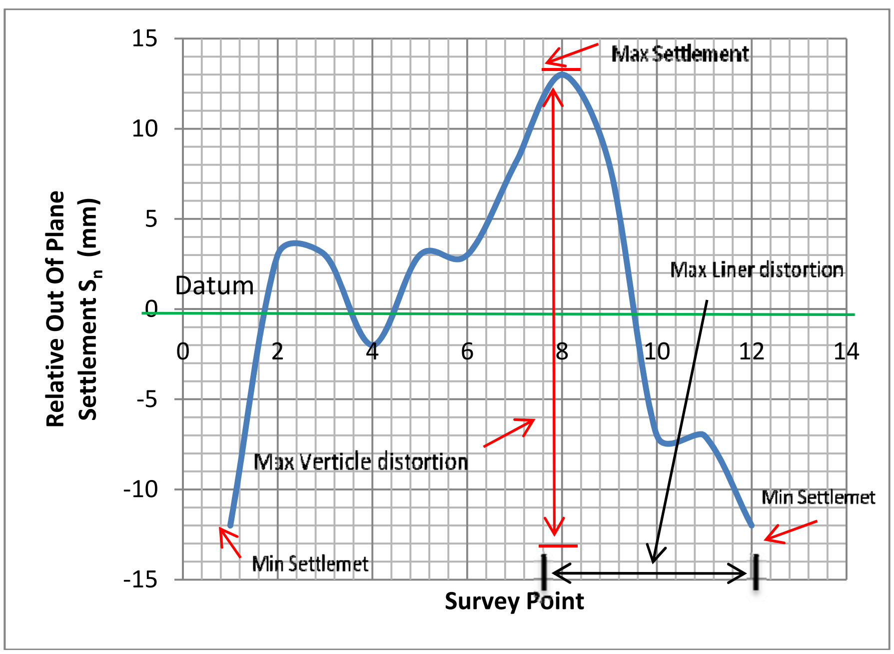


Figure 10-8: Settlement analysis measurement

For quantitative measurement the possible locations of the strains are determined on the curve. For determining the possible strain areas on shell look at the vertical extremities in the curve. Select the closest points with maximum vertical distortion. Greater the vertical distortion between two points and closer these points are, more strains exist on the shell. In our curve given in Figure 10-8 , the greatest and closest vertical extremes exist between point 8 and 12. Another case can be selected between points 8 and 10.

As per API-653 Para B-3.2 the shell settlement will be acceptable if

$$S \leq \frac{5.5\mathrm{L}^2\mathrm{Y}}{\mathrm{EH}}$$

S = Max settlement distortion (in feet) between two selected points.
L= Arc (circumferential) distance (in feet)between two selected points.
Y = yield Strength of the plate material (in lbf/in^2)
E = Young's modulus (elasticity) of shell plate material (in lbf/in^2)
H = Tank height.

If the settlement is found not acceptable, all of the welds in the strained areas should be checked with suitable NDT technique. The distortion data obtained for different points in this way should be analyzed by the engineer experienced with the tank structures and settlement analysis. As per API-653 Para B.2.2.4 h, the decision to open the tank for further evaluation should be taken by Engineer after rigorous stress analysis. Various computer based stress analysis techniques like finite element analysis are available for this evaluation. If the settlement is greater than acceptable limits, shell needs to be jacked up, and the foundation gap should to be filled. Any (shell or floor) plates found with excessive plastic deformation must be replaced.

10.5.3. Internal Edge Settlement Evaluation:

a. Survey:

This internal edge settlement survey is done to determine the deterioration of the floor near the periphery of the tank. It should be noted that the floor may lift from its natural settled height while tank is empty. Means should be provided to bring floor back to natural settlement height before taking the measurement. If internal settlement is found acceptable in one outage, the data obtained should be kept with the tank records to compare with the data from next outage. Following procedure should be adopted for the acquisition of the settlement data.

- The survey points should be selected at the locations corresponding to the external survey points. Additional points can me selected if the tank floor shows above normal deformation at some locations.

- The telescopic surveying tripod should be placed at exact centre of the tank. The measurement should be taken for all points from same location of tripod.

  Supplementary note: Instead of telescopic surveying, the laser leveling instruments can also be used to take the measurements inside the tank.

- The measurement should preferably be taken from shell to the centre at different location as follows.

  i. Within 1st 30 cm (1 ft) from shell, at every 25 mm (1”).
  ii. From 30 to 90 cm (1-3 ft) from shell at, every 50 mm (2”)
  iii. From 90 to 180 cm (3-6 ft) from shell at, every 150 mm (6”)
  iv. From 180 cm (6 ft) to Centre at every 300 mm (or 1 ft), only if floor profile is to be drawn.
  If the floor profiling (for topographic mapping) is not required, no measurements should be taken past 6 ft, unless the effects of edge settlement are extended beyond 6 feet. See figure 10-9 for the suggested arrangement of points and measurement locations.

  Supplementary Note:
  a. *The above arrangement of measurement points and interval is not a mandatory requirement. Inspector can change the spacing of measurements according to magnitude of floor deterioration.*
  b. *For detailed and accurate topography the surveyor can adjust the measurement locations*

and location of reference according to his requirements.

- Best visual judgment should be used to find out the floor "Breakover point" as described API-653 Para B-2.3.2.b. If the breakover point is not within first 2 feet from the shell, the measurement should be taken at the closer intervals at the breakover point than what is suggested above. Record the breakover radius for each survey point.

- The data obtained should be tabulated, and drawn on the graph to obtain the settlement profile of each survey point.

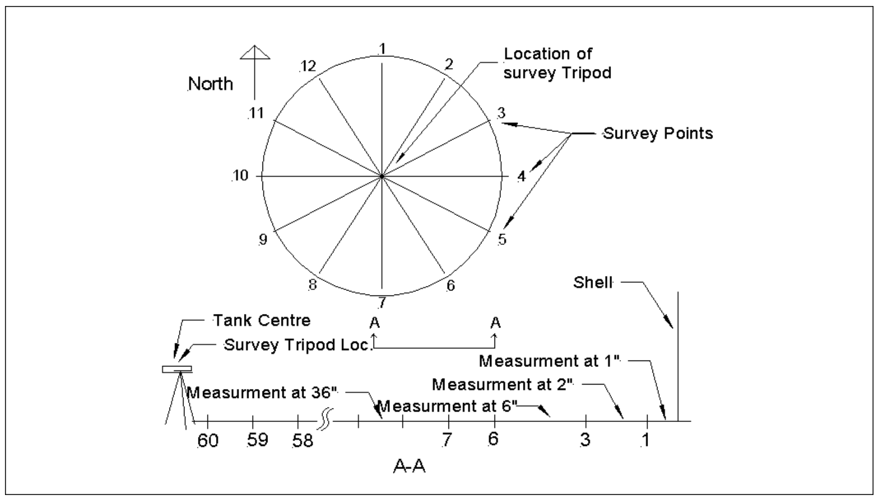


Figure: 10-9 Internal settlement survey points

b. <u>Evaluation:</u>

- The factors to consider while evaluating the severity of the settlement include

  i. **Breakover radius:** Breakover radius is the most critical factor in evaluation the floor settlement. Shorter radii should be evaluated by stringent approach. Settlement is rejected regardless of diameter of tank if it exceeds 2" (50 mm) depth and is within or less than 2" (50 mm) breakover radius.

  ii. **Weld orientation at settlement**: The welds parallel to the settlement orientation should be given lesser credibility for acceptance.

  iii. **Type of weld**: Butt welds are preferred over lap welds for acceptance.

  iv. **Corrosion thinning and corrosion rate of deformed floor plates:** Heavily corroded plates (or with high corrosion rate) should be given lesser credibility and stringent approach should be adopted for acceptance.

  v. **Degree of buckling of the shell at settled area (If any):** If the shell shows buckling at the settled areas, the repair must be done as if the buckling exceeds due to further settlement there exists the tendency of shell wrapping at these locations due to weight of shell plates above.

  vi. **Presence of the annular ring:** Annular rings can withstand more settlement because of the butt welds being perpendicular to the settlement orientation.

  vii. **Diameter of tank:** Larger diameters tank can withstand more settlement than smaller.

- Use API-653 Figure B-11 for non weld areas, lap welds perpendicular to settled areas within ±20 degrees, butt welded plates, and annular rings for acceptance/rejection criteria. If the breakover radius and the depth of settlement are above acceptance line for the specified tank diameter, the repair should be recommended.
- Use API-653 Figure B-10 for lap welds parallel to settled areas within ±20 degrees, for acceptance/rejection criteria. If the breakover radius and the depth of settlement are above acceptance line for the specified tank diameter, the repair should be recommended.

- If the angle α between the lap weld and the settlement is between 20 to 70 degree find out the acceptable value B_{ew} from figure B-10 (API-653) and B_e from figure B-11 (API-653) for the breakover radius and depth of settlement, corresponding to the specified tank diameter. Using these numbers determine the value of B_α as

$$B_\alpha = B_e - (B_e - B_{ew})Sin\alpha$$

If the depth of settlement is more than B_α the settlement should be rejected.

- The rejected settled areas for the tanks should be repaired. The repair includes the Jacking of the tank to its original design conditions and the replacement of the deformed floor plates. As per API 653 Para B-4.2 the re-leveling of tank should be done along with of the replacement of the deformed plates.

10.5.4. Local Internal settlemen:

The locations of the localized settlements or bulges away from edges, are evaluated as follows.

- Determine the radius R of the circle inscribed in the localized floor settlement or bulge, and determine the height or depth B_B of the settlement or bulge. If the height of the bulge or the depth of the localized settled areas

$$B_B = 0.37R \text{ or less}$$

the deformation is acceptable. Otherwise the area should be repaired by replacing the affected floor plates.

- The localized settlements are also seen at the roof support columns in the fixed roof tanks. Especially the centre column shows most settlement. These settlements cannot be repaired. The engineering evaluation should be done on these settlements. The evaluation should include the structural integrity of the roof support. If the tank is determined structurally sound and fit for service the settled areas should be filled with suitable grout to direct the drainage away from the settlement. The filled grout or material should not be dissolvable in the stored to fluid.

10.5.5. All floor settlement repairs or plate replacements must be done as per the requirements of API-653 Para 9.10, and should be approved by the engineer experienced in the tank repairs.

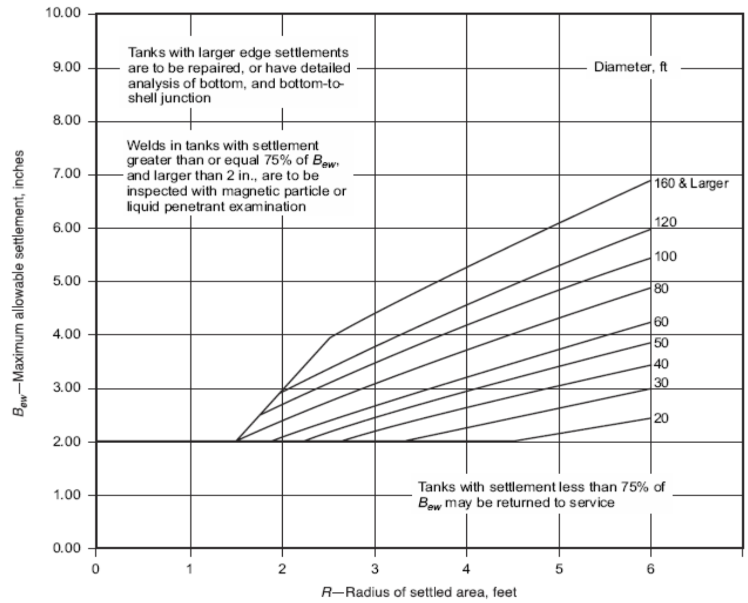


Figure B-10—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Parallel to the Shell

API-653 Fig B-10

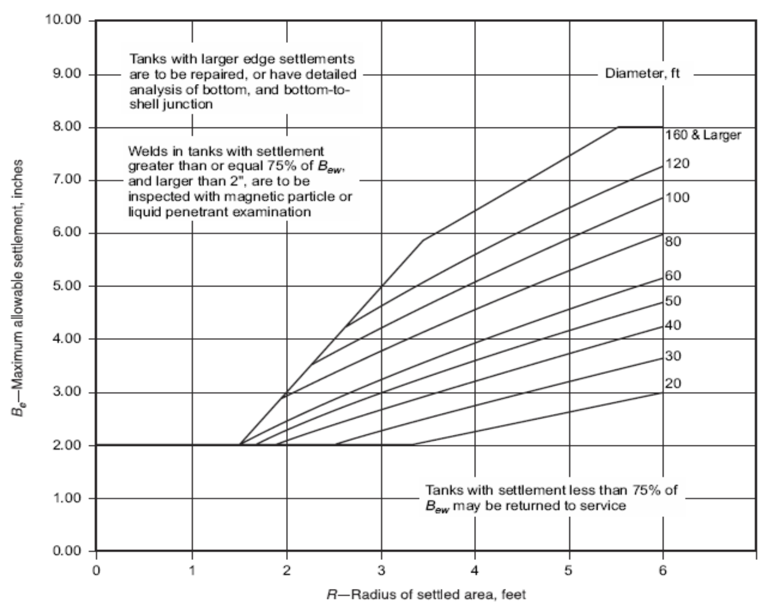


Figure B-11—Maximum Allowable Edge Settlement for Areas with Bottom Lap Welds Approximately Perpendicular to the Shell

API-653 Fig B-11

Section-6

Damage Mechanisms

General

There are various kinds of damage mechanisms associated with the in-service process industry equipments, which mainly depend on the compatibility of the materials, used to manufacture the equipment, with the process environment. Awareness of the damage mechanisms is important for the inspector to

1. Predict the potential damages and possible locations,
2. Focus the inspection activities according to the anticipated damage.
3. Conduct accurate Fitness For Service (FFS) assessment of the flaws.
4. Predict the rate of growth of flaws in order to determine equipment's safe operation limits till next available opportunity for repair.
5. Choosing the best monitoring techniques for flaws.

Consulting Service Department conducted a comprehensive study of the failure incidents in Saudi Aramco operating facilities from 1975 to 2008 and published a report in which most active Damage Mechanisms in Saudi Aramco operation facilities are identified. The survey shows that (various kinds of) corrosion, mechanical fatigue, hydrogen induced cracking (HIC), stress corrosion cracking, and sulfide stress corrosion cracking are some of the leading corrosion damage mechanisms in Saudi Aramco.

Following is the statistical distribution of the recorded incidents along with the associated root causes.

Damage Mech.	Oil Operations	Gas Operations	Refineries	Pipelines	Bulk plants	Other	Total # of Incidents	Percent
Corrosion	527	478	308	68	6	94	1481	40%
Fatigue	445	310	253	69	7	86	1170	32%
HIC	98	58	16	79	0	57	308	8%
SCC	89	75	71	26	0	17	278	7%
Mech. Damage	93	67	60	5	0	5	230	6%
SSC	62	62	36	5	0	4	169	5%
Manuf. Defects	19	31	15	3	0	3	71	2%
Total	1337	1069	779	253	14	235	3707	

Table-1: Saudi Aramco Incidents Statistics (1975-2008)

Some of the corrective actions recommended in this report for mitigation of the effect of these damage mechanisms are coatings, injection of corrosion inhibitors cathodic protection, usage of corrosion resistant alloys and nonmetallic materials, and education & training of the individuals involved in inspection operation and planning. The intent of this chapter is to supplement the training activities for the unit inspectors, which are intended to promote the awareness of active damage mechanisms in the process units in their direct responsibility. This section covers the most active damage mechanisms in the Saudi Aramco operating facilities. All of the possible damage mechanisms are not discussed in this part of the manual. It is the responsibility of the unit inspector and corrosion engineer to develop the corrosion loops and assign the most appropriate damage mechanism that can possibly affect the equipments within this loop. API-RP-571 is the best document to consult for identification of possible damage mechanisms in process equipment.

In the following text the most active damage mechanisms in Saudi Aramco downstream facilities are divided into four main categories of corrosion, fatigue, environmental cracking and metallurgical degradations.

1. Corrosion:

According to the incidents statistical survey shown in Table-1, corrosion had been the leading cause of failures in Aramco facilities. Following is the further segregation among the corrosion mechanisms.

Type Of Corrosion	Number of Incidents	Percentage
Pitting Corrosion	815	55%
Erosion Corrosion	241	16%
General corrosion	186	13%
Galvanic Corrosion	92	6%
Crevice corrosion	74	5%
Others	73	5%
Total	1481	

Table-2: Saudi Aramco Corrosion related Incident Distribution (1975-2008)

There are various damage mechanisms which induce the corrosion in the process equipments. The inspection plans can be developed for particular corrosion loop based upon the process conditions such as stream contents, pressure/temperature conditions, flow velocities, and metallurgical compatibility of equipment with the process. The most vulnerable locations within the corrosion loop can be identified based on these conditions and probable corrosion mechanisms. Further classification of the corrosion mechanisms is done in at least six subgroups; however some of the corrosion mechanisms associated with particular group can be associated with other group as well.

1.1. Pitting/Localized Corrosion

There are various corrosion mechanisms which fall under the category of pitting corrosion. The Pitting corrosion is the result of electrochemical oxidation/reduction reactions, which occurs in localized areas of metal. As compared to generalized corrosion, in which the corrosion cells keep moving from one location to other on the metal surface, the corrosion cells in the pitting corrosion are concentrated in one localized region. In all of the mechanisms of pitting corrosion, once the corrosion cell is formed the surrounding layer starts acting like cathode, hence the accelerated corrosion takes place due to small anode to cathode area ratio. This phenomenon is further elaborated in Galvanic corrosion Para 1.4. Depending on the type of corrosion mechanism, the rate of the pitting corrosion is usually 10 to 100 times higher than generalized corrosion in same environment.

In most of the cases the pitting corrosion is dangerous because of its difficulty of detection. The pre-warning is not very prominent as the weight loss due to the pitting corrosion is very minimal. The on-stream techniques using profile measurement such as Radiography, Ultrasonic B and C scan are best to detect the pitting corrosion however are not convenient and sometimes not possible to perform due to restrictions from the configuration. Following are some of commonly found pitting corrosion mechanisms.

1.1.1. Under Deposit Corrosion

Under deposit corrosion is a generalized term used for the active corrosion of bottom sections of process equipment and low velocity section of the process piping, under the substantial amount of accumulated semisolids. Usually the deposited corrosive sludge and the salts generated in the process are not removed from the process equipment due to inadequate design condition. These deposits with the addition of moisture create various kind of corrosive environment. The localized corrosion cells are formed under these deposits which act as the anode with respect to the surrounding metal and some time the deposits themselves and cause the aggressive localized corrosion. The example is the formation of HCl under the deposited chloride salts of ammonia and other non-metals inside the process streams.

Under deposit corrosion is difficult to control unless the deposits are mechanically removed. The depositing some times are removed by jetting (wash water or steam) in the process equipments like tanks and separators, or by scarping in the scrapable flow lines.

The primary under deposit corrosion mechanisms for refining equipments are as follows.

a) Ammonium Chloride Corrosion

Ammonium chloride salt is formed in various refining processes. These salts precipitate at ambient temperature and deposit at the low laying locations with stagnant flow conditions. Sever under-deposit type corrosion takes place which could be either localized in small areas of spread out in larger areas under bigger deposits. The primary contributors to the corrosion are also the HCl and

other acidic components present in the deposits. UT scanning and Profile RT are the best tools to detect this corrosion.
Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.3.

b) Ammonium Bisulfide Corrosion

In most of the processes the ammonia is generated from the nitrides in the feed stock. Sulfur can be originated from the desulfurization processes. The sulfur and ammonia combine chemically and generate ammonium bisulfide (NH_4HS) which is highly corrosive alkaline salt. Ammonium bisulfide induces aggressive generalized as well as localized corrosion at the concentration above 2% by weight. Most of the corrosion is found at the impingement areas of the piping holding high velocity and turbulent flow. However in case of low velocities the precipitation occurs readily. The deposited salts of ammonium bisulfide induce aggressive under deposited corrosion. Carbon steel is least resistant and can experience high corrosion rates. 300 series stainless steels, duplex stainless steels, aluminum alloys and nickel base alloys are relatively resistant, depending on ammonium bisulfide concentration and velocity. UT scanning and profile radiography on the impact points (such as direction changes, valves and reducers etc), are the best on-stream inspection tools for ammonium bisulfide corrosion.

Common locations for corrosion are in the inlet header box of the reactor effluent exchangers, piping elbows and welds with excessive I.D. weld metal penetration. Corrosion rates as high as 200 mpy have been observed in concentrated ammonium bisulfide solutions. Proper design of the piping to control the turbulence in the flow, avoiding high velocities and extensive water washing to keep the concentration of the salt down, are major methods to mitigate the Ammonium bisulfide corrosion. Ammonium Bisulfide Corrosion can also be easily categorized in the erosion corrosion group as erosion is the dominating factor in this damage mechanism. Erosion corrosion is discussed in details in Para 1.3 of this section.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.2

c) Chloride Salt deposits:

There is a range neutralizer used in the process industry to neutralize the acids formed as byproducts of main process. The chloride salts are formed as the result of neutralization action. In some cases the chloride are added into the streams for chlorination purposes or in order to activate the catalyst in the catalytic reformation process. These chloride salts when cooled down in the downstream ends, often deposit in the equipment and low laying piping with inadequate flow. Along with the inherent moisture in the process streams, these salts cause aggressive under deposit corrosion in carbon steel and stress cracking in the stainless steel. The chloride stress corrosion cracking is further discussed in Para. 3.1.3 of this section.

1.1.2. Microbiologically Induced Corrosion (MIC)

Microbiologically induced corrosion (MIC) is the corrosion induced by the living micro-organism. These micro-organisms include various kinds of bacteria and algae groomed in services where stagnant or low flowing water is present. There are various kinds of organisms which have ability to survive and grow in the harsh condition like high salinity, pH from 0 to 12, and absence of oxygen. Some of these organisms have ability to survive in the temperature range of -17^{o} C to 113^{o} C. However MIC is most active at the ambient temperature services. Bacteria are usually classified as aerobic or anaerobic due to their ability to grow with or without the presence of oxygen. Most common bacteria responsible for MIC are Anaerobic bacteria, which can survive without oxygen. Out of this group most notorious for corrosion are Sulphate Reducing Bacteria (SRB), The SRBs reduce the sulphates present in the process streams, which react with the adjacent metal and produces the ferrous sulfides. This process causes the localized cavitations in the process equipment where the reducing reaction takes place. Since there is no flow (or very little flow) the bacteria are not carried away so their colonies thrive in the cavities. Further reduction reaction makes these cavities grow in depths and diameter along with time. The cavities formed are usually cup shaped pits often filled with the blackish iron sulfide.

Most vulnerable equipment for the MIC are Storage tanks, untreated or sea water cooled heat exchangers, fire water and deluge system, and equipment from which the hydro-test water is not drained properly. Periodic ultrasonic scanning should be performed on the bottom of low laying areas in the equipment and piping having process conditions favorable for the MIC. Most of the time, due to unfavorable locations, the MIC is not detected unless the equipment is opened for inspection. Hence the lab samples should be tested for the presence of high counts of the SRBs in order to investigate for the potential of MIC.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.3.8.

1.1.3. <u>Corrosion due to Acidic Environment</u>

In corrosion of the ferrous alloys due to acidic environment the dominating chemical reaction is

$$F_e + 2H^+ \text{----------}\rightarrow F_e + H_2$$

There are various known damage mechanisms associated with the acidic environments of different kinds. Some of the important mechanisms in this group are given below.

a) Hydrochloric acid Corrosion

Dry Hydrogen Chloride is not corrosive, however in presence of moisture the aqueous hydrochloric acid is formed and very aggressive general and localized corrosion is caused by condensed vapors of aqueous HCl. Most affected are the vessels and the piping made with carbon and low alloy steels. The severity of corrosion increases with increasing HCl concentration and temperature. The HCl corrosion is not the problem only in the process streams where direct HCl is used or generated, but also in the processes involving chloride salts like ammonium chloride or amine hydrochloride. The deposits of these salts usually absorb the moisture in the process stream and transform into the aqueous hydrochloric acid which corrodes the metal in form of under deposited corrosion, as discussed in Para 1.1.1 of this section. Any equipment which can deposit these salts should be inspected by ultrasonic scanning or other on-stream inspection techniques while being in service.

Most Vulnerable locations include systems containing the overheads from crude atmospheric distillation tower, especially the condensing equipment. Similarly in the systems containing the chloride salts like hydroprocessing, catalytic reforming and the amine stripping can also be affected by generation of HCL as the process byproduct. Unit Inspector and the corrosion engineer should closely observe lab results for the chloride contents and pH of the process streams. The OSI and other inspection planning should be developed accordingly. The appropriate methods of detection are the profile radiography and ultrasonic scanning at the vulnerable location on the piping. And for the vessels the appropriate methods are the ultrasonic thickness measurement and thorough visual inspection at the shutdowns.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.4.

b) <u>CO_2 Corrosion/Sweet Corrosion</u>

When CO_2 is dissolved into water it generates week carbonic acid (H_2CO_3) which causes severe localized and general corrosion in carbon and low alloy steels, often referred as sweet corrosion (if H_2S component does not exists in the stream). The sweet corrosion mostly affects the carbon and low alloy steel, while the high alloy steel with higher chromium percentage, and stainless steels are relatively immune to the CO_2 corrosion.

The governing factors for this corrosion are the concentration of condensed CO_2, temperature, and stream flow velocities. That is why most vulnerable areas are the bottom of the vessels (near drain boot), and water drain lines. CO_2 corrosion heavily affects the welds in the water drain lines, causing the preferential corrosion of the HAZ and the welds. The preferential weld corrosion is further discussed in Para 1.5 of this section.

The CO_2 corrsion damage could be localized or genaralized, depending on the flow condition of the corrsive water. It may appear as localized thining or deep pitting in case of stagnemt condition, or as deep grooving in the areas of high flow velocities and terbulance. In case of the wider area with steady flow conditions (for example in tanks near the sump pit and the drain boot areas of large seperators) the corrsion damage appears as mesas produced in rock by wind and water erosion. Due to this reason CO_2 corrsion is also refered as Mesa Corrsion.

Visual testing, ultrasoninc thickness measurement and the profile radiography are the best tools for the inspection of the CO_2 corrsion. The inspector should pay special attention to the welds in drain lines handelling the dissolved CO_2. The experience has shown that welding qulity in the drain lines is often not as good as in the process lines. Such lines often show accelerated washout on the welds due to corrsion induced by CO_2.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.3.6

c) Sour Water Corrosion

Sour water corrosion occurs when the process water streams have substantial amount of dissolve H_2S. Usually the protective layer of blackish iron sulfide is formed on the internal surface of the piping and equipment handling the sour water. Unless very high turbulent flow is not involved, the corrosion due to sour water is not as aggressive as sweet corrosion (due to CO_2). Biggest concern in the sour system is the various hydrogen embrittlement damages which are discussed in Para 3.2 of this section.

The governing factors in the sour water corrosion are the concentration of H_2S, and temperature of the stream. At lower concentration of H_2S the pH of the water stays above 4.5. At this level of acidity the iron sulfide layer is relatively stable to protect the metal from corroding. However corrosion tends to increase with the temperature and increasing concentration of the H_2S, but the solubility of H_2S in water also reduces as the temperature increases. It is worth noting that the pH of process streams is not controlled by H_2S only, but other contaminants like HCl and CO_2 also tend to reduce the pH of the stream.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.10

d) Sulfuric Acid Corrosion

Some of the processes in chemical and refining industry use or generate the Sulfuric Acid as end product or byproduct, which causes both general and localized corrosion of carbon steel and other alloys. The major governing factors in the sulfuric acid corrosion are temperature, concentration, and flow velocity. The reactivity however is different with different Alloys. Most vulnerable locations are the un-tempered welds (without PWHT) and the flow direction changed in the piping. Ultrasonic thickness measurement and profile radiography of the piping are the most effective on-stream inspection methods.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.11

e) **Phosphoric Acid Corrosion:**

Phosphoric acid is used as the catalyst in the polymerization units. Dry crystalline phosphoric acid is not very corrosive, however the corrosion becomes aggressive if water is mixed into the stream. As per API-RP-571 Para 5.1.1.9.3.d the corrosion rate due to phosphoric acid with free water can be as high as 0.25" in 8 hours. Hence the operation practices must be closely watched in the plants involving phosphoric acid as process ingredient. The major governing factors in the phosphoric acid corrosion are temperature, concentration, contamination of chloride ions, and flow velocity. The reactivity however is different with different Alloys. Most of the corrosion due to phosphoric acid is believed to be occurring during water washing operations at shutdowns. Most vulnerable locations are the un-tempered welds (without PWHT) and the flow direction changed in the piping. Ultrasonic thickness measurement and profile radiography of the piping are the most effective on-stream inspection methods.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.9

f) **Hydrofluoric Acid Corrosion**

Hydrofluoric acid (HF) is used in alkylation units. Hydrofluoric acid (HF) is the strongest bonded acid in the halogen group of the acids, in other words its aqueous solution has lesser number of free H^+ ions. That is why concentrated hydrofluoric acid is not corrosive as compared to dilute acid with higher concentration of water. At higher concentration of HF (lesser water contents) the steel develops the protective fluoride layer. However in case of high flow velocities and turbulent flows this layers breaks apart and fresh layer is exposed for corrosion. Normal alkylation units run at concentration of 97% to 99% and the temperatures are generally below 150oF (66oC), however if water contents and temperature increase the potential of corrosion increases. The HF acid corrosion can be localized or general and is often accompanied by hydrogen cracking, blistering and/or HIC/SOHIC, as discussed in Para 3.1.1 of this section. Mostly the equipment and piping in the HF alkylation unit are affected by HF corrosion if the water contents are higher in the process.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.6.

g) **Naphthenic Acid Corrosion (NAC):** (See API-RP-571 Para 5.1.1.7 for details)

h) **Phenol (Carbolic Acid) Corrosion:** (See API-RP-571 Para 5.1.1.8 for details)

i) **Sulfuric Acid Corrosion:** (See API-RP-571 Para 5.1.1.11 for details)

1.2. Uniform/General Corrosion

The uniform or general corrosion is thinning/wall loss involving wider areas rather than being scattered/isolated pits with undamaged areas around. The attack is relatively evenly distributed over large area of affected metal. It is believed that In uniform corrosion mechanism, the local corrosion cells (anodes and cathodes) are not locked in one position on the metal surface. Rather the location of corrosion cells moves around randomly, causing a general dissociation of the metallic atoms (in from of ionic salts) from a wider area. The uniform corrosion could be the even washout of the surface or large concentration of the pitting, making the rough surface.

The general corrosion effects almost entire process system which is not lined by the protective coating, however the rate of corrosion phases out gradually due to formation of the oxide or sulfide layer, which act as protective barrier for further corrosion. However in most of the cases where the turbulent or high speed process fluid flow is involved, the protective layer is washed out and the corrosion of the impact area continues. This induces the accelerated localized corrosion also known as erosion corrosion. Erosion corrosion is further elaborated in Para 1.3 of this section.

Two main reasons behind the general corrosion wall loss are

- The material involved is not able to maintain the protective coating which can isolate the metal from environment.
- The concentration of the electrolyte does not vary significantly over the metal surface, so anodic and the cathodic reaction both occur in a wider area rather than being concentrated in isolated locations.

Any damage mechanism that carries both of these properties will be the contributing factor behind uniform corrosion. For carbon steal the process streams containing the acidic and alkaline compounds are the main causes of the generalized corrosion. Hence wherever such ingredients are found in the process streams the inspector should expect the aggressive generalized wall loss. However, depending on the conditions, the mechanisms responsible for the generalized corrosion can also cause the localized pitting corrosion. Some of the prominent damage mechanisms which can be grouped as uniform or generalized corrosion mechanisms are listed below.

1.2.1. Atmospheric Corrosion & Corrosion under insulation CUI

Atmospheric corrosion and corrosion under insulation & Fire Proofing are treated as two different categories of corrosion in API-571, however because of same origin and same governing condition both are discussed together in this manual.

The atmospheric conditions including the natural marine environment and air born industrial pollutant like H_2S and fly ash containing sulfur and chloride salts, cause the external corrosion of the equipment which are not effectively protected by the protective coating. For Carbon Steel this corrosion is active between -4^{o}C to 120^o C, and aggressive at the temperatures between 100^o to 120^o C. Outside this temperature range the surface of the equipment is usually too dry for oxidation. Most critical are the insulated equipments, as insulation has the tendency to trap the moisture and keep in contact with the metal surface for longer period of time. The broken, missing of damaged insulation cladding are the source of moisture ingress. Similarly the locations like insulation termination ends at the flanges, protrusion of the small bore piping (and tubing) and the TML cutouts and leaking steam tracings are major contributing factors to CUI.

As per Engineering Encyclopedia Corrosion failures Doc # COE-110.06, in Saudi Aramco operations, the general atmospheric corrosion is aggressive in the western coast rather than eastern and central regions. In the western region the winds coming from the Red Sea carry substantial amount of moisture and salinity in from of chlorides. Whereas in central and eastern provinces, for most part of the year the operating facilities get drier and less corrosive winds coming from the desert.

The equipment and piping involved in the chilling services condense substantial amount of moisture. During the shutdown periods the condensation thaws out and moist the insulation which can causes CUI even in the equipment with good cladding with no moisture ingress. For stainless steel grades the chloride stress corrosion cracking is major issue. These chlorides come from the environment or could be within the insulation. This mechanism is further discussed in the Para number 3.1.3 of this section.

While inspecting for CUI and atmospheric corrosion particular attention should be paid to the location which have potential for trapping the moisture. Some of the examples of such locations are stiffener joints, pipe support saddles, and bottom section of the insulated vessels. The corrosion between the saddles and the piping is also very common which causes the piping failure. Depending on the configuration and restriction for proper aeration, these locations also have tendency to induce the crevice corrosion.

Various NDT techniques are available (along with Visual inspection) for CUI monitoring. These techniques include infrared scanning (for dry/wet insulation spots), neutron back scattering technique, ultrasonic guided wave surveying, and profile radiography.

Further details on these damage mechanisms can be seen from API-RP-571 Para 4.3.2 and 4.3.3.

1.2.2. Rich Amine Corrosion:

Gas sweetening is typically done in the gas plants and the refineries by the amine absorption. The dissolved acidic gases like H_2S and CO_2 along with some amine salts cause the localized pitting corrosion and the generalized corrosion mainly in the bottom areas of the amine contactor towers downstream piping carrying the rich amine to the stripper tower. The main controlling factors for the corrosion are the concentration of the contaminants in rich amine, flow velocity and the temperature. However these problems can be controlled with proper design of the system and proper operation practices. Further the types of the Amine absorbent also plays significant role in the amine corrosion. The units using monoethanolamine (MEA), and diglycolamine (DGA) have most problems with amine corrosion. However the units using diethanolamine

(DEA), and methyldiethanolamine (MDEA) are relatively better in corrosion resistance. The unit inspector and the corrosion engineer should continuously review the lab reports and monitor the concentration of ammonia and cyanide salts such as HCN.

Most vulnerable locations in amine units are the regenerator overhead condenser and outlet piping as well as reflux piping, valves and pumps. The velocity of the fluids also plays major role so the piping downstream of the pumps, especially at the direction changes and turbulent flow locations must be closely monitored with ultrasonic. Whole system should be saved from oxygen ingress at the time of shutdown as the addition of oxygen aids in creating the heat stable salts in the system which cause sewer corrosion in the system.

The appropriate methods of detection are the profile radiography and ultrasonic scanning at the vulnerable location on the piping. And for the vessels the appropriate methods are the ultrasonic thickness measurement and thorough visual inspection at the shutdowns. Amine stress corrosion cracking is another prominent damage mechanism associated with the carbon steel amine systems. This mechanism is further discussed in Para number 3.1.5 of this section.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.1

1.2.3. Soil Corrosion

The localized deterioration and corrosion of metal at the areas in contact with soil is called as the soil corrosion. Most of the soil corrosion problems are associated with the buried pipelines. However process plants also have various buried piping tank bottoms and other equipment partially or fully buried in ground, which are prone to deteriorate due to soil corrosion. Experience has shown that in buried plant piping the most affected areas are the soil to interface. The corrosion in this area is found maximum if the air has higher moisture and salinity. It is recommended to excavate such pipes to at least 12” for proper inspection of Soil to air interface area.

Various factors control the susceptibility of the corrosion on the metallic surfaces in contact with the soil. These factors include,

- Moisture and oxygen contents in soil
- Electrical resistivity of soil (amount of electrolytes)
- Homogeneity (mixing of other types of soil and elements)
- Temperature,
- Availability of cathodic protection,
- Stray current currents in the area,
- Integrity and type of the coating on the equipment/piping.
- The corrosion resistivity of the equipment metal.

The soil resistivity measurement should be periodically done, in the areas where the ground water table keeps changing, as per recommendations of API-RP-574 Para 10.3.1.4. The lesser soil resistivity (higher conductivity) is the sign of the imminent corrosion problem.

Other than visual inspection and the pressure testing various on-stream inspection techniques are available for detection and quantitative measurement of the soil corrosion damage. For pipe lines various inline scrapping techniques are available. Similarly the guided waves technique is proved good for the buried plant piping. For tanks the acoustic emission measurement can be used to detect the deterioration of the floor due to internal or external (bottom side) soil corrosion.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.3.9

1.2.4. High Temp H_2/H_2S Corrosion

High temperature H_2/H_2S is a uniform corrosion mechanism predominant in the services which contain significant concentration if H_2S at higher temperatures (above 250^oC). This is another form of sulfidation attack which appears as generalized wall loss in affected equipment. This form of corrosion occurs in equipment all hydro processing units such desulfurizers, hydro-treaters and hydro cracking units where process streams carry H_2 and H_2S at high temperatures. Noticeable increases in corrosion may be found downstream of hydrogen injection points. Most affected materials are carbon and low alloy steels while 300 and 400 series stainless steel and chromium based alloy steels are relatively immune to this attack. Main controlling factors are the concentration of H_2S and the temperature. The attack is aggressive at higher temperature and higher concentrations of H_2S.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.1.5

1.3. Erosion Corrosion

Erosion corrosion is another generic term covering various corrosion damage mechanisms. The erosion corrosion is usually localized to certain areas of equipment. All of the erosion corrosion damage mechanisms usually have very high corrosion rate. The catastrophic failures in the industry have been attributed to the erosion corrosion. In all of the damage mechanisms in this group the basic principle is the aggressive corrosion wash out due mechanical impingement of abrasive particles in the fluids. The protective oxide layer is either not developed at all or keeps depleting fast exposing the fresh metal surface to the corrosive atmosphere. Most vulnerable locations are the direction and configuration changes in the piping, such as elbows, tee junctions. The examples of configuration changes which can cause the turbulence in the flow include downstream of the flow control valves, reducer sections, and downstream of pumps etc.

Erosion corrosion usually occurs at locations of high velocities and turbulence flows. The conditions could be developed by the mechanical reason like the configuration changes or due to intermixing of two streams of different velocities or phases. Erosion corrosion can occur both in the presence and in the absence of suspended matter in the flow streams, however un-dissolved abrasive sediments cause accelerated erosion.

Erosion corrosion is the major problem for the process piping, and less active in the process equipments like vessels and tanks, unless the design of equipments does not provide effective safeguard against the high velocity targets and turbulent flows. Proper designing, control of flow velocities and the control of flow stream conditions play major role in mitigation of the erosion corrosion. The safeguards for the equipment is usually provided in the configuration and the design of equipments, for example impingement plates, inlet deflectors, and vortex breakers etc.). Similarly in case of piping the proper design of the piping and control of the flow velocities is the first line of defense against the erosion, and erosion corrosion. SAES-L-132 (Material Selection for Piping Systems) table-1 gives the maximum recommended velocities for different materials in different process environments.

There are various damage mechanisms which can be grouped as the erosion corrosion phenomena. Most of the acid corrosions can be designated as erosion corrosions if flowing streams have these acids in significant components. Prominent erosion corrosion induced by the acidic corrosions are discussed in Para 1.1.3 of this Section. Ammonium bisulfide in the high speed flow, causes sewer erosion corrosion as discussed in Para 1.1.1.b.

Cavitation is a form of erosion in which various tiny vapor bubbles are formed and collapse immediately on the pump impellers. The shock waves generated by the collapsing bubbles causes the cavitation damage on the impeller. Further details of this phenomenon can be seen from API-RP-571 Para 4.2.15. Similar kind of phenomenon is responsible in the accelerated erosion of the pipe metal downstream of the welds on the high speed pump discharge lines. The vortices are formed in the high speed liquids flow downstream of the high root penetration. Tiny low pressure zones keep generating and collapsing inside vortices. The collapsing impact is usually high enough to break the metallic surface and cause accelerated erosion at these locations.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.2.14

1.4. Galvanic Corrosion

When two dissimilar metals (with different elector potential) are brought in contact in presence of an electrolyte, an electro-chemical cell is formed. The metal closer to the anodic end of the galvanic series becomes anode and one closer to the cathodic end becomes cathode. The Anode gives up the electrons which travel to the cathode through the electrolyte, as a result the anode atoms dissociate (or corrode away) from the main body and form the oxide or salt (depending on the environment). This corrosion of the anodic (or less noble) metals is called as Galvanic or bimetallic corrosion. The severity of the galvanic corrosion depends on following factors.

a. Difference in position of the metal pairs in galvanic series: father the metals are in the series more aggressive will be the corrosion of anodic metal.

b. Ratio of the anode to cathode area: If area of anode is smaller more current is concentrated on smaller anodic area and corrosion will be faster.

c. Conduction (or Concentration) of electrolyte: Stronger electrolytes promote aggressive corrosion.

The corrosion susceptibility always exists wherever there is a junction of two different metals through which electric current can easily pass, whether it is welded, bolted or riveted connection. Depending on the affected area and the junction characteristics, the galvanic corrosion can be easily grouped in localized or uniform corrosion mechanism.

The table below shows the inter-placing of galvanic series in the seawater as electrolyte.

Active *(or anodic or easy to corrode)*	1. Magnesium and magnesium alloys 2. Zinc
	3. Aluminum 1100 4. Cadmium 5. Aluminum 2024-T4 6. Iron and steel
	7. 304 Stainless steel (active) 8. 316 Stainless steel (active)
	9. Lead 10. 10.Tin
	11. Nickel (active) 12. Inconel nickel-chromium alloy (active) 13. Hastelloy Alloy C (active)
	14. Brasses (Cu-Zn alloys) 15. Copper 16. Bronzes (Cu-Sn alloys) 17. Copper-nickel alloys 18. Monel (70Ni-30Cu)
	19. Nickel (passive) 20. Inconel (80Ni-13Cr-7Fe) (passive)
	21. 304 Stainless steel (passive) 22. 316 Stainless steel (passive) 23. Hastelloy Alloy C (passive)
Noble *(or cathodic or resistant to corrosion)*	24. Silver 25. Titanium 26. Graphite 27. Gold 28. Platinum

Table -3: Galvanic Series

Intermixing of metals with different galvanic properties is the common mistake that is found in the process industry. These problems if unattended often lead to the leaks and fatal accidents. One of such careless practices often seen is the usage of Carbon steel bolting in the stainless steel flanges. The carbon steel and low alloy steels are more anodic as compared to stainless steel. The bolts provide smaller anodic area as compared to the flanges which concentrates the galvanic flow of current on the bolts. The accelerated corrosion takes place on the bolts which washes out the threads, resulting in loosening of the joint and hence leak of potentially hazardous fluids. Similar kind of the mistake often seen is in plugging on the hydro-test vents in the stainless steel lines. These mistakes are the result of poor quality control in the maintenance activities. The corrosion rate however is much slower in case of stainless steel plugs or bolts on the carbon steel flanges and pipes, due to higher anode to cathode area ratio.

In case of the flanged junction between stainless steel and carbon steel piping at the line spec. break or at the carbon steel vessels, the insulating gasket between the flanges should be selected. In case of non insulating gasket, the galvanic attack can take place at the carbon steel (or low alloy steel) flange face. Another common area of possible galvanic corrosion is the carbon steel support rings at the junction with stainless steel trays in hydro-treaters (or other towers of different services). Similarly some of the heat exchanger tube sheets and baffle plates preferentially corrode at the junction with the tubes made out of incompatible material. Inspector should also pay attention to the brazed joint or the dissimilar metal joints (eg at thermocouple tacks. These joints often have very high anode to cathode area ratio, so the aggressive galvanic corrosion is less likely, however these joints often have high fatigue in hot services due to different thermal expansion coefficients. These joints, if suspected, should be inspected with the liquid penetrant inspection for cracks and localized corrosion in the heat affected zone.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.3.1

1.5. Preferential Weld Corrosion (PWC)

Preferential Weld corrosion (PWC) is the accelerated corrosion of the weld metal and/or HAZ, as compared parent metal in a corrosive environment. It is a form of galvanic corrosion which the weld metal acts like anode as compared to the adjacent parent metal. The main causes of the preferential weld corrosion are

- Difference in composition of parent metal, HAZ and weld metal
- Difference in microstructure of parent metal, HAZ and weld metal.

Both of these causes are usually result of poor welding practices and poor quality control. Weld metal is seen to be severely affected with preferential corrosion when the manganese contents are higher. Further the corrosion occurs more rapidly in hardened steel in acidic environments than in fully tempered steel. Therefore welds in non post weld heat treated equipment and piping are more susceptible to preferential weld corrosion than post weld heat treated structures. Experience has shown that the preferential corrosion is found more in less critical service systems like sea water cooling, slop storage and drain water systems etc. This is because more stringent quality monitoring is done on the critical systems while these systems are often overlooked.

Like all other corrosion mechanisms the corrosive environment severity plays basic role in determining the rate of preferential corrosion. Fluids having high electrical conductivity, such as seawater or the acidic streams with lower pH are the main contributors in preferential corrosion. However, low conductivity environments like water streams with dissolved CO_2 can also play significant role in preferential corrosion. Similarly Alterations to the environment, such as the addition of a biocide, can change the corrosion characteristics of a system. For example, a joint may be totally resistant to corrosion in a particular environment, but with the addition of a biocide, the joint may become susceptible to preferential corrosion.

1.6. Crevice Corrosion

Crevice corrosion takes place when corrosive material is trapped in the tight areas where the normal flow of the streams is not possible. It normally takes place in the grooves or cracks of width 1/8-inch wide or smaller, where the normal flow conditions cannot be developed. Crevice corrosion is detrimental as the failure may occur without warning, due to the fact that it takes place on the locations which are almost impossible to inspect with the conventional on-stream inspection techniques.

The sequence of the corrosion mechanism involves the usual oxidation process in the metal inside the crevice. This creates the metal oxide and the crevice is depleted of the trapped oxygen.

Initial Anodic reaction inside crevice:	Oxidation	$M \dashrightarrow M^{+} + e^{-}$
Initial Cathodic Reaction inside Crevice:	Reduction	$O_2 + 2H_2O + 4e^{-} \dashrightarrow 4OH^{-1}$

As the oxygen is depleted no more reduction reaction takes place inside the crevice, rather it takes place in the open area close to the crevice. Further creation of the metal ions unbalances the charge distribution inside the crevice and more positively charged metal ions are generated. This charge imbalance attracts the chloride Cl^{-1} and OH^{-1} ions from outside the crevice. Due to stagnant situations lesser OH^{-1} ions migrate into the crevice as compared to smaller and more mobile chloride ions. The charge imbalance inside is neutralized by the creation of Metal chlorides inside the crevice. The metal chlorides than readily hydrolyze inside the crevice and generate the H^{+1} (acid ions).

Metal Chloride Hydrolysis Reaction $M^{+} + Cl^{-1} + H_2O \dashrightarrow MOH \downarrow + H^{+1} + Cl^{-1}$

The H^{+1} ions considerably reduces the pH inside the crevice causing aggressive HCl corrosion.

Crevice corrosion is equally effective for carbon steel and corrosion resistant grades of steel (such as stainless steel). For the corrosion resistant alloys the resistance comes from the Passive (corrosion resistant) films which are developed on the surface, however these films are very unstable in presence of high concentrations of Cl^{-1} and H^{+1} ions.

Most vulnerable locations for Crevice corrosion are Gaskets area of the flanged joints lap weld joints, tight areas between shell and liner (in case of incomplete liner welding), delaminated surface overlays, and metal to bolt heads or rivet heads crevice, Nut and bolt threads, etc.

2. Fatigue:

There are two main forms of fatigue on the metals, the mechanical fatigue and the thermal fatigues. Both of these fatigues result in weakening and failure of the metals at the localized areas which undergo the metallurgical changes due to applied cyclical stresses well below the plastic deformation stress values, for specified period of time.

As per 2009 corrosion report for CSD the fatigue is the second major cause of the failures in Saudi Aramco operating facilities. Most vulnerable are the unsupported small bore piping attached to the systems containing pumps and compressors which induce the cyclic stress on the adjacent structures. The anchoring points of the lines which shake due to liquid hammering and frequent rapid flow like relief piping are also affected by fatigue. Since all forms of fatigues are the metallurgical changes, the earlier detection of the fatigue is possible by the Eddy Current and electrical resistance measurement methods.

2.1. Mechanical Fatigue

Metals subjected to a repetitive dynamic loading for a certain period of time fail at a stress level much lower than that required to cause fracture on a single application of load. Such failures occurring under conditions of dynamic loading are called fatigue failures. The period after which the failure occurs varies and depends of the alloy composition. The ductile metals usually require higher number of loading before failure called as higher endurance. A fatigue failure is particularly dangerous because it occurs without any obvious warning. Fatigue results in a brittle-appearing fracture, with no gross deformation at the fracture.

A fatigue failure can usually be recognized from the appearance of the fracture surface, which shows

- A smooth region, due to the rubbing action as the crack propagated through the section, and
- A rough region, where the metal has failed in a ductile manner when the cross section was no longer able to carry the load.
- Mostly the progress of the fracture is indicated by a series of rings, or "beach marks", progressing inward from the point of initiation of the failure.

Because of widely varying response of different metals towards fatigue the exact prediction of the fatigue failure is not possible, however the empirical models can be developed to assess amplitude and safe number of cycle that can be applied on the metal to avoid failure. The main factors contributing to the fatigue of the metal are following.

- Number and amplitude of cyclic loadings.
- Maximum tensile stress on the metal.
- Orientation of cyclic stress as compared to the direction of rolling (or formation) on metal.
- Area of stress concentration.
- Corrosion at the stress location.
- Variation in the metallurgical structure at the location of loading, for example welding or segregation.

- Residual stresses in the area.
- Presence of defects at the stress concentration area, like notch, grinding mark or other welding or manufacturing defects.
- The comparison of the natural frequency and multiple harmonics of system with the frequency of applied stress.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.2.16

2.2. Corrosion Fatigue

Corrosion fatigue is basically the mechanical fatigue initiated at the areas weakened due to corrosion. The cracks develop under the combined effect of mechanical cyclic loading and corrosion. Cracking often initiates pits where stress concentration is usually higher and may propagate in multiple directions following the corrosion pattern and direction of the applied stress. In most of the cases the fatigued metal shows accelerated corrosion at the stress loading areas. This is because the micro-structure changes at the stress loading areas which can make it more anodic as compared to its surrounding.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.5.2

2.3. Fatigue at dissimilar metals weld joints.

Dissimilar metal joints are often used in refineries due to special process requirements. Tearing stress occurs on the joints of two dissimilar metals of widely different coefficient of thermal expansion, at higher temperatures. The amount of stress keeps varying at varying temperatures which induces fatigue in the joint at the side of lower thermal expansion coefficient.

Material	Coefficient of Linear Thermal Expansion (°F^{-1}) α
Carbon Steel	5.8×10^{-6}
Stainless Steel	9.6×10^{-6}
Aluminum	13.3×10^{-6}
Copper	9.3×10^{-6}
Lead	16.3×10^{-6}

Table-4: Thermal Expansion coefficients

The repeated stress on the joint even though within the elastic limits can have effects like mechanical stress at the junction. The fatigue crack can appear in the heat affected zone of the parent metal with lower thermal expansion and, joint can undergo premature failure after number of thermal stress loadings. The examples are the joints between the ferritic carbon steels and austenitic stainless steels, which often cracks at the carbon steel side. This rupture is often classified in the creep ruptures as well. The creep damage is discussed in details in para 4.1 of this section.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.2.12

2.4. Thermal fatigue

Thermal fatigue is induces either by short term overheating of the cyclic thermal variation on the metals. Like mechanical fatigue the metallurgical variations take place at the thermal fatigued areas and the metal loses its yield strengths, and unexpected premature failure can take place. Thermal fatigue is further discussed in high temperature damages in this section in Para number 4.2 of this manual and Para 4.2.9 of API-RP-571.

3. Environmental Cracking

Environmental Cracking also known as Stress corrosion cracking CSS is a group of damage mechanisms in which cracks are initiated and propagate under the simultaneous effect of a tensile stress and corrosion due to environment. The tensile stresses originate from processes like cold forming, welding, heat treatment, machining and grinding, while corrosive environment is introduced by various process conditions. Because most of the surface of affected material remains un-attacked, it is very difficult to detect or predict the failure. Fine cracks develop and penetrating into the material at accelerated rate. These cracks can have an intergranular or a transgranular morphology. All of the SCC mechanisms can result in catastrophic failure with minimal overall material loss. Macroscopically, SCC fractures have a brittle appearance.

There are mainly two mechanisms of crack propagation in SCC. One is called as "Active Path Dissolution" in which crack propagates as the metal dissolves at the tip of the crack due to corrosion. The second mechanism is "Hydrogen Embrittlement", in which hydrogen gas produced by electrochemical process is absorbed into the metal and breaks cohesive structure of the metal. The main difference between two mechanisms is that Active Path Dissolution is intergranular SCC, while Hydrogen Embrittlement is transgranular form of SCC.

3.1. Active Path Dissolution Stress Corrosion Mechanisms

There are various Stress corrosion cracking mechanisms which follow the inter-granular active path dissolution techniques. The most prominent damage mechanisms in this group are given below.

3.1.1. Hydrogen Related damage (Wet H_2S Damage)

Common material used in the manufacturing of the process equipment, especially the Carbon Steel and low alloy steel are susceptible to various types of Hydrogen related damages. These damages originate from Sour corrosion caused due the presence of wet H_2S in process streams and cause materials to fail at stress levels well below their normal yield strength. These damages occur when steel is exposed to a minimum of 50 ppm H2S and liquid water. Main course of all hydrogen related damage involves the migration of ionic hydrogen inside the material. The Hydrogen sulfide dissolved in water forms a weak acid generating high concentration of free H^+ ions. These ions can easily migrate through the lattice of the steel and are absorbed in the grain boundaries of the in the locations of discontinuities like laminations. The migrated ions than combine to form the hydrogen gas molecules H_2, which being because of larger size cannot migrate out of the steel. As the pressure of the trapped gas increases within cavity, it tears the material lattice causing the cracks within the grain boundaries. This results in the reduction of the material strength, hence failure at stresses well below the established yield strength of the material. These damages appear in form of blistering and/or cracking. Following are some of the most common hydrogen damages found in Saudi Aramco process facilities.

a. Hydrogen Induced Cracking (HIC) and Hydrogen Blistering

HIC or blistering appears as bulges on the ID surface of a pipe or pressure vessel of the susceptible material in wet H_2S service. The ions trapped in the locations of the inclusions combine to form Hydrogen which increases the pressure within the lamination and the localized bulging takes place in form of blistering. These blisters occur mostly in the base metal along the plate rolling direction in the absence of any stress, however the residual stress from the welding and the cold forming can increase the chances of HIC damage. The blisters in the susceptible material grow in the size due to accumulation of more hydrogen. Increasing hydrogen pressure increases the stress on the grain boundaries near the edges of the blisters. As the damage progresses the stress on the grain boundaries increases and appears as intergranuler cracking or tears at the edges of the blisters. The intergranuler cracking from the blisters at different depths join together, often referred as stepwise cracking. The material strength is considerably reduced due to the stepwise cracking.

Hydrogen induced cracking HIC mostly occurs in low-strength steel (typically < 80 ksi). Most commonly used plate materials for pressure vessels and the tanks is ASTM-516-70, and for the piping is ASTM A-106. Both of these materials are susceptible to HIC. Modern steel making techniques utilize better melting practices, which reduce the concentration of the contaminants in the steel, especially sulfur. HIC resistant steel is manufactured via the electric arc furnace with vacuum degassing techniques, which provides ultra clean and homogeneous steel. Hence the steels manufactured after 80s have better ability to resist the HIC. These steels are graded as HIC resistant steels after the batch testing for HIC.

Following are process conditions which favor initiation and propagation of HIC .

i. pH level of the process stream:

pH plays an important role in determining the aggressiveness of the environment and the likelihood of cracking or blistering in wet H_2S service. H_2S itself is not the main contributor to the pH of the streams, rather it is controlled by other solutes in streams like HCl, NH_4Cl, and alkaline materials.

- At low pH values (below 4) the solubility of H_2S in water is greatly reduced, hence the amount of atomic hydrogen available to enter the steel is lesser. Therefore the HIC cracking susceptibility is lesser at lower pH values (more acidic) of streams, however lower pH promotes the corrosion (generalized or localized) due to instability of iron sulfide layer in acidic condition. The end result at low pH is typically metal loss due to corrosion but moderate levels of cracking and blistering.

- The solubility of H_2S in water is high, making it easier for hydrogen to enter the steel if no protective iron sulfide scale exists, however at pH values 8 or above (alkaline conditions) the iron sulfide scale is more stable which can provide effective protective layer to control entry of hydrogen into the steel. Therefore the susceptibility of wet H_2S is lesser in alkaline services unless the iron sulfide layer keeps cracking die to high abrasive flow condition.

- The wet H_2S damage can be expected more prominent in mild acidic conditions with pH of 4 to 8.

ii. Temperature**:**

The concentration of the dissolved hydrogen reduces correspondingly as the temperature of the process streams increase. Hence, along with other condition, the ambient temperature promotes all kind of Wet H_2S damages.

iii. Partial Pressure of H_2S**:**

Higher partial pressure (concentration) of the H_2S provides more atomic hydrogen, increasing the susceptibility of the Wet H_2S damages.

b. Stress Oriented Hydrogen Induced Cracking (SOHIC)

Stress Oriented Hydrogen Induced Cracking (SOHIC) is a form of HIC associated with the low strength steels, which occurs in the base metal adjacent to the heat affected zones (HAZ) of a weld seams. At the locations of accumulated stress the diffused atomic hydrogen created micro cracks (HIC) oriented parallel to the rolling direction of steel. In case of extended damage these cracks join together with a series of vertical cracks which are oriented perpendicular to the rolling direction of the steel. The progressive damage often ends up with the through wall crack in and around the HAZ.

The stresses, weather applied or residual (from welding and cold forming process) contribute mainly to the susceptibility of SOHIC. Hence the most vulnerable locations for the SOHIC are the welds in the vessels and piping (spiral and butt). SOHIC can also occur at the locations where metal is subjected to cyclic stresses or tensile stress. Post weld heat treatment considerably mitigates the chances of damage due to SOHIC.

Further details of HIC and SOHIC damage can be seen from API-RP-571 Para 5.1.2.3.

c. High temperature Hydrogen Attack (HTHA)

High temperature Hydrogen attach is another hydrogen related damage discussed in details in Para 4.6 of this section.

3.1.2. Sulfide Stress Corrosion Cracking (SSC)

Sulfide Stress cracking SSC is the trans-granular cracking caused by absorbed atomic hydrogen, at the locations of high stress and hardness in the weld and the HAZ. Zones of high hardness are found in weld cover passes and attachment welds which are not tempered (softened) by subsequent passes. The hard areas of weldments, including both the weld deposit and heat affected zone which contain un-tempered martensite and bainite microstructures. These microstructures possess hardness greater than 230 HB. Atomic hydrogen from the process stream is absorbed into these microstructures and causes cracking. The crack once initiated propagates quickly through the localized hard zone, but slow down or stop when it enters a softer region (< 200 HB). However in presence of the stresses due to local deformation or cyclic stresses the SSC can propagate to the areas of hardness levels upto150 HB. SSC can be avoided by reducing the stresses and hardness by post weld heat treatment.

Sulfide stress cracking is also often grouped into the hydrogen embrittlement damages discussed in Para 3.2 of this section. Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.2.3.1.d and Para 4.5.6.

3.1.3. Chloride Stress Corrosion Cracking (Cl–SCC)

Chloride stress corrosion cracking (Cl–SCC) is caused in the stainless steel equipment when it comes in contact with the aqueous chloride ions from the process streams. Most susceptible locations are the locations of accumulated stresses weather from welding, tensile stress from the cold forming or the cyclic stress from vibration or frequent thermal shocks. Almost all kind of stainless steels are susceptible to Cl-SCC, but most affected are the 300 series of SS. However carbon steel and low alloy steels are not susceptible to this kind of damage. The critical factors which promote this kind of damage are, high concentration of Chloride ions, higher temperature, lower pH, and accumulated stresses.

Chloride stress corrosion cracking is caused by internal as well as external process environments. Stainless steel equipment handling the process streams containing the chlorides often shows unwarned cracking due to Cl-SCC. The SS expansion bellows are also highly susceptible to this kind of CSS due to accumulated stresses. If the SS equipment is insulated, proper inspection of these equipments is must to avoid accumulation of moisture in the insulation wool. The marine and industrial environments usually have high chloride concentration which can accelerate the external Cl–SCC.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.5.1

3.1.4. Caustic Stress Corrosion Cracking (Caustic Embrittlement)

Caustic stress corrosion cracking often referred as caustic cracking or Caustic Embrittlement is another very common environmental damage associated with the carbon, low alloy steels and 300 series stainless steels. Most susceptible are the Carbon steel equipment which are not Post Weld Heat treated.

The caustics (soda NaOH and potash KOH) are often used for neutralization propose in the process streams and also in treating the boiler feed water. The cracking occurs in the equipment which have accumulated stress due to welding and cold forming. Caustic SCC cracking often follows the heat affected zone boundaries. Damage becomes aggressive with higher concentrations of the Caustic and increasing temperature. This cracking can be effectively mitigated by using proper Post Weld heat treatment and by controlling the concentration of Caustic in the process streams.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.5.3

3.1.5. Amine Stress Corrosion Cracking

Amine Stress Corrosion cracking is also referred as Amine cracking, is another form of alkaline stress corrosion cracking found in the equipment handling various alkanolamines used for the H_2S stripping. The cracking is more common in the equipments which carry the residual stressed from welding and cold forming. Most critical factors for this kind of cracking are the process temperature, and amount of accumulated stresses, however concentration of the amine does not appear to have a significant effect on the tendency of cracking. The susceptible equipments manufactured with carbon steel and low alloy steels in amine stripping units, especially in the sections handling lean amine. Post weld heat treatment is the best method to mitigate this damage. Other amine related damage mechanism is the generalized corrosion caused by rich amine (with high concentration of dissolved H_2S), as discussed in Para number 1.2.2 on this section.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.2.2

3.1.6. Polythionic Acid Stress Corrosion Cracking (PASCC)

For details on this damage mechanism please consult API-RP-571 Para 5.1.2.1 and Saudi Aramco Best Practice SABP-A-001

3.1.7. Ammonia Stress Corrosion Cracking

For details on this damage mechanism please see API-RP-571 Para. 4.5.4

3.1.8. Carbonate Stress Corrosion Cracking

For details on this damage mechanism please see API-RP-571 Para. 5.1.2.5

3.1.9. Hydrogen Stress Cracking – HF

For details on this damage mechanism please see API-RP-571 Para 5.1.2.4

3.2. Hydrogen Embrittlement

Hydrogen Embrittlement is a form of HIC associated with the high strength steels with 300 BHN, and tensile strength above 150 KSI. Other vulnerable materials include titanium and aluminium alloys. The affected material loses its toughness and can undergo the brittle failure at the application of stresses well below the yield strength of the material. The damage involves the ingress of the atomic hydrogen in the material causing cracking and reduction in the load bearing ability of the material. The atomic hydrogen source could be from manufacturing (of steel), pickling, welding, contact with wet H_2S, or any corrosion reaction process which releases the atomic hydrogen. The low hydrogen electrodes are preferred while welding to avoid the hydrogen ingress into the welded metals at the time of welding. Similarly in order to avoid the delayed cracking due to dissolved hydrogen, the hydrogen bake out heating is must to perform while performing the weld repairs in the equipment which had been in sour service. Sulfide stress corrosion cracking and various other hydrogen induced cracking phenomenon like delayed cracking, hydrogen flaking and under bead cracking can be grouped as hydrogen embrittlement damages.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.5.6.

4. High Temperature/Metallurgical Damage

There are various types of metallurgical damages which are associated with the operation at high temperature in aggressive environment. Almost all of the metallurgical degradations take place progressively depending upon operating temperature, length of exposure, and metallurgy of exposed metal. Unless the damaging environment is not restricted in one area, the damage in all of the metallurgical degradations is usually wide spread over large areas. Most of the damages can be predicted with timely inspection using appropriate inspection techniques like eddy currents, back scattered ultrasonic spectroscopy, and metallographic replicas. Out of all the inspection techniques the metallurgical replica is the most reliable techniques to accurately assess extent of damage.

There are numerous kinds of metallurgical degradation damages which highly depend on the process conditions and compatibility of the affected metal to these conditions. Following text outlines most commonly found metallurgical damages in process industry.

4.1. Creep/Stress Rupture

Creep is the metallurgical damage caused due to exposure of the metal under tensile stress, at high temperature for prolonged period of time. Micro-voids are formed at the location of the stress at high temperature. The failure takes place well below the minimum yield strength of the material due to the micro-voids. The main controlling factors in creep deformation are material creep resistance, temperature and the magnitude of load. The susceptible materials include the tubes in furnaces, heaters, catalytic reformer reactors, and the piping carrying high temperature fluids. The most of the creep failures initiate at the Heat Affected Zones (HAZ) of welds. Similarly the welds joining dissimilar materials also suffer creep damage due to differential thermal expansion stresses. Earlier stages of the creep can be detected by the metallurgical replicas. While later stages can be detected any the conventional NDT methods.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.2.8

4.2. Thermal Fatigue and short term overheating

Thermal fatigue and short term overheating are similar kind of damage mechanisms which result reduction in the yield strength and later on failure due to sudden (or cyclic) changes in the temperature. The sudden change in the temperature could be due to shutdown and startup, temperature runaway, gas or liquid quenching etc.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.2.9 & 4.2.10

4.3. Sulfidation

Sulfidation is the corrosion of carbon steels and other alloys due to the reaction of H_2S with Fe resulting in an iron sulfide scale at high temperatures (above 500-575°F). Sulfidation reaction depends on H_2S concentration and temperature. It is one of the major corrosion types attacking Sulfur Recovery Unit and normally takes place in the reaction furnace, auxiliary burners, and thermal oxidizer

Further details on this damage mechanism can be seen from API-RP-571 Para 4.4.2

4.4. Carburization and Metal Dusting

Carburization is the migration of the carbon into the metal lattice due to high temperature exposure of metal with the carbon rich atmosphere. The carburization takes place on the inside surface of the in the furnace tubes in catalytic reformers and coker units or other heaters at decoking cycles. Metal dusting is an extreme form of carburization. The carburization results in hardening the upper layer of the metal which causes cracking.

Further details on this damage mechanism can be seen from API-RP-571 Para 4.4.3 & 4.4.5.

4.5. Decarburization

Decarburization is the reverse process of carburization in which the carbon migrates out of the metal lattice at high temperature. The decarburization caused loss of the creep and tensile strength of material. The decarburization can take place in all kind of steel product in the high temperature service. Most vulnerable are the tubes in the Catalytic reformer and other high temperature furnaces

Further details on this damage mechanism can be seen from API-RP-571 Para 4.4.4

4.6. High Temperature Hydrogen Attack (HTHA)

High temperature hydrogen attack takes place due to exposure of metallic surface results from exposure to hydrogen at elevated temperatures. The carbides in the metal lattice reacts with the hydrogen and forms Methane CH_4 which cannot diffuse through the metal. The loss of carbides causes the reduction in the overall strength of the material. As the methane pressure builds the cavities are formed which cause cracking in the material like hydrogen blistering.

Further details on this damage mechanism can be seen from API-RP-571 Para 5.1.3.1

4.7. Other High Temperature Metallurgical Damages:

Some other common thermal damages include Graphitization, Spherodization, temper embrittlement, Strain Aging, 885^{o}F Embrittlement, and Sigma Phase Embrittlement.

Summary

American Petroleum institute documents API-RP-571 and API-RP-580 summarize the damage mechanisms associated with most common process units in refining industry. Following charts are generated from these documents.

For the Saudi Aramco downstream facilities which have process units not identical to the following units, or units with different flow regimes, it is responsibility of Corrosion Engineer and the senior unit inspector to perform the identical exercise and break the process units into corrosion loops and identify damage mechanisms for the units under their direct responsibility.

Table -5: Damage Mechanisms for Different refining process units

DM#	Damage Mechanism	Crude unit	Delayed Coker	Fluid Catalytic Cracking	FCC Light Ends Recovery	Catalytic Reforming – CCR	Catalytic Reforming – Fixed Bed	Hydroprocessing - Hydrotreating, Hydrocracking	Sulfuric Acid Alkylation	HF Alkylation	Amine Treating	Sulfur Recovery	Sour Water Stripper	Isomerization	Hydrogen Reforming
1	Sulfidation	x	x	x				x				x			
2	Wet H2S Damage (Blistering/HIC/SOHIC/SSC)	x	x	x	x			x			x	x	x		
3	Creep / Stress Rupture	x	x	x		x	x	x							x
4	High temp H2/H2S Corrosion						x	x							
5	Polythionic Acid Cracking	x		x				x							x
6	Naphthenic Acid Corrosion	x	x					x							
7	Ammonium Bisulfide Corrosion		x		x			x			x		x		
8	Ammonium Chloride Corrosion	x	x	x	x	x	x	x							
9	HCl Corrosion	x				x	x	x						x	
10	High Temperature Hydrogen Attack					x	x	x						x	x
11	Oxidation	x	x	x		x	x					x			x
12	Thermal Fatigue		x	x			x								x
13	Sour Water Corrosion (acidic)														
14	Refractory Degradation			x			x					x			x
15	Graphitization			x											
16	Temper Embrittlement			x		x		x							x
17	Decarburization			x											
18	Caustic Cracking	x							x	x				x	
19	Caustic Corrosion								x					x	
20	Erosion / Erosion-Corrosion	x	x	x	x	x		x		x	x		x		
21	Carbonate SCC			x	x										
22	Amine Cracking							x			x				x

23	Chloride Stress Corrosion Cracking	x		x				x					x		x
24	Carburization		x	x		x	x								
25	Hydrogen Embrittlement					x		x							
26	Steam Blanketing			x								x			x
27	Thermal Shock		x												x
28	Cavitation														
29	Graphitic Corrosion (see Dealloying)														
30	Short term Overheating – Stress Rupture	x	x	x		x		x							x
31	Brittle Fracture							x							
32	Sigma Phase/ Chi Embrittlement			x				x							x
33	885oF (475oC) Embrittlement	x	x	x				x							
34	Softening (Spheroidization)														
35	Reheat Cracking			x		x									x
36	Sulfuric Acid Corrosion								x			x			
37	Hydrofluoric Acid Corrosion									x					
38	Flue Gas Dew Point Corrosion											x			
39	Dissimilar Metal Weld (DMW) Cracking	x								x					x
40	Hydrogen Stress Cracking in HF									x					
41	Dealloying (Dezincification/ Denickelification)		x												
42	CO2 Corrosion	x													x
43	Corrosion Fatigue														
44	Fuel Ash Corrosion	x													
45	Amine Corrosion							x			x				x
46	Corrosion Under Insulation (CUI)		x						x					x	
47	Atmospheric Corrosion														
48	Ammonia Stress Corrosion Cracking	x	x			x									
49	Cooling Water Corrosion					x									
50	Boiler Water / Condensate Corrosion			x								x			x

51	Microbiologically Induced Corrosion (MIC)		x												
52	Liquid Metal Embrittlement	x													
53	Galvanic Corrosion									x					
54	Mechanical Fatigue					x	x								
55	Nitriding														
56	Vibration-Induced Fatigue														
57	Titanium Hydriding										x		x		
58	Soil Corrosion														
59	Metal Dusting					x	x								x
60	Strain Aging														
61	Steam Blanketing														
62	Phosphoric Acid Corrosion														
63	Phenol (carbolic acid) Corrosion														

Table-6: Corrosion Damage Mechanisms

Ref: API-RP-580 First Edition May 2002, Appendix A Table-1 (Details to be added in Next Revision of this Manual)

Table-7: Stress Corrosion Cracking Mechanisms

Ref: API-RP-580 First Edition May 2002, Appendix A Table-2 (Details to be added in Next Revision of this Manual)

Table-8: High Temperature/Metallurgical Damage Mechanisms

Ref: API-RP-580 First Edition May 2002, Appendix A Table-3 (Details to be added in Next Revision of this Manual)

Table-9: Mechanical & Fatigue Damage Mechanisms

Ref: API-RP-580 First Edition May 2002, Appendix A Table-4 (Details to be added in Next Revision of this Manual)

Table 10: Materials and Corrosion tendency in different corrosive environment

Reference: http://www.engineeringtoolbox.com/metal-corrosion-resistance-d_491.html

Corrosion Resistance Legend: 1= Good, 2 = Low 3= Poor, NA= Data not available												
	Metal											
Fluid	Carbon Steel	Cast Iron	302 and 304 Stainless Steel	316 Stainless Steel	Bronze	Durimet	Monel	Hasteloy B	Hasteloy C	Titanium	Cobalt base alloy 6	416 Stainless Steel
Acetaldehyde	1	1	1	1	1	1	1	NA	1	NA	NA	1
Acetic acid, air free	3	3	2	2	2	1	2	1	1	1	1	3
Acetic acid, aerated	3	3	1	1	1	1	1	1	1	1	1	3
Acetic acid, vapors	3	3	1	1	2	2	2	NA	1	1	1	3
Acetone	1	1	1	1	1	1	1	1	1	1	1	1
Acetylene	1	1	1	1	NA	1	1	1	1	NA	1	1
Alcohols	1	1	NA	1	1	1	1	1	1	1	1	1
Aluminum Sulfate	3	3	1	1	2	1	2	1	1	1	NA	3
Ammonia	1	1	1	1	3	1	3	1	1	1	1	1
Ammonium chloride	3	3	2	2	2	1	2	1	1	1	2	3
Ammonium Nitrate	1	3	1	1	3	1	3	1	1	1	1	3
Ammonium Phosphate	3	3	1	1	2	2	2	1	1	1	1	2
Ammonium Sulfate	3	3	2	1	2	1	1	1	1	1	1	3
Ammonium Sulfite	3	3	1	1	3	1	3	NA	1	1	1	2
Asphalt	1	1	1	1	1	1	1	1	1	NA	1	1
Benzene (benzol)	1	1	1	1	1	1	1	1	1	1	1	1
Benzoic acid	3	3	1	1	1	1	1	NA	1	1	NA	1
Boric acid	3	3	1	1	1	1	1	1	1	1	1	2
Butane	1	1	1	1	1	1	1	1	1	NA	1	1
$CaCl_2$ (alkaline)	2	2	3	2	3	1	1	1	1	1	NA	3
Calcium hypochlorite	3	3	2	2	2	1	2	3	1	1	NA	3
Carbolic acid	2	2	1	1	1	1	1	1	1	1	1	

Carbon dioxide, dry	1	1	1	1	1	1	1	1	1	1	1	1
Carbon dioxide, wet	3	3	1	1	2	1	1	1	1	1	1	1
Carbon disulfide	1	1	1	1	3	1	2	1	1	1	1	2
Carbon tetrachloride	2	2	2	2	1	1	1	2	1	1	NA	3
Carbonic acid	3	3	2	2	2	1	1	1	1	NA	NA	1
Chlorine gas	1	1	2	2	2	1	1	1	1	3	2	3
Chlorine gas, wet	3	3	3	3	3	3	3	3	2	1	2	3
Chlorine, liquid	3	3	3	3	2	2	3	3	1	3	2	3
Citric acid	3	3	2	1	1	1	2	1	1	1	NA	2
Coke oven gas	1	1	1	1	2	1	2	1	1	1	1	1
Copper sulfate	3	3	2	2	2	1	3	NA	1	1	NA	1
Ethane	1	1	1	1	1	1	1	1	1	1	1	1
Ether	2	2	1	1	1	1	1	1	1	1	1	1
Ethyl chloride	3	3	1	1	1	1	1	1	1	1	1	2
Ethylene	1	1	1	1	1	1	1	1	1	1	1	1
Ethylene glycol	1	1	1	1	1	1	1	NA	NA	NA	1	1
Ferric chloride	3	3	3	3	3	3	3	3	2	1	2	3
Formaldehyde	2	2	1	1	1	1	1	1	1	1	1	1
Formic acid	3	3	2	2	1	1	1	1	1	3	2	3
Gasoline	1	1	1	1	1	1	1	1	1	1	1	1
Glucose	1	1	1	1	1	1	1	1	1	1	1	1
HCl	3	3	3	3	3	3	3	1	2	2	2	3
Hydrochloric acid, air free	3	3	3	3	3	3	3	1	2	2	2	3
HF, aerated	2	3	3	2	3	2	3	1	1	3	2	3
Hydrofluoric acid, air free	1	3	3	2	3	2	1	1	1	3	NA	3
Hydrogen	1	1	1	1	1	1	1	1	1	1	1	1
Hydrogen peroxide	3	1	1	1	3	1	3	2	2	1	NA	2
Hydrogen sulfide, liquid	3	3	1	1	3	2	3	1	1	1	1	3
Magnesium Hydroxide	1	1	1	1	2	1	1	1	1	1	1	1
Mercury	1	1	1	1	3	1	2	1	1	1	1	1
Methanol	1	1	1	1	1	1	1	1	1	1	1	1
Methyl ethyl ketone	1	1	1	1	1	1	1	1	1		1	1

NAtural gas	1	1	1	1	1	1	1	1	1	1	1	1
Nitric acid	3	3	1	2	3	1	3	3	2	1	3	3
Oleic acid	3	3	1	1	2	1	1	1	1	1	1	1
Oxalic acid	3	3	2	2	2	1	2	1	1	2	2	2
Oxygen	1	1	1	1	1	1	1	1	1	1	1	1
Petroleum oils	1	1	1	1	1	1	1	1	1	1	1	1
Phosphoric acid, aerated	3	3	1	1	3	1	3	1	1	2	1	3
Phosphoric acid, air free	3	3	1	1	3	1	2	1	1	2	1	3
Phosphoric acid vapors	3	3	2	2	3	1	3	1		2	3	3
Picric acid	3	3	1	1	3	1	3	1	1	NA	NA	2
Potassium chloride	2	2	1	1	2	1	2	1	1	1	NA	3
Potassium hydroxide	2	2	1	1	2	1	1	1	1	1	NA	2
Propane	1	1	1	1	1	1	1	1	1	1	1	1
Sodium acetate	1	1	2	1	1	1	1	1	1	1	1	1
Sodium carboNAte	1	1	1	1	1	1	1	1	1	1	1	2
Sodium chloride	3	3	2	2	1	1	1	1	1	1	1	2
Sodium hydroxide	1	1	1	1	3	1	1	1	1	1	1	2
Sodium hypochloride	3	3	3	3	3	2	3	3	1	1	NA	3
Sodium thiosulfate	3	3	1	1	3	1	3	1	1	1	NA	2
Stannous chloride	2	2	3	1	3	1	2	1	1	1	NA	3
Stearic acid	1	3	1	1	2	1	2	1	1	1	2	2
Sulfate liquor	1	1	1	1	3	1	1	1	1	1	1	
Sulfur	1	1	1	1	3	1	1	1	1	1	1	1
Sulfur dioxide, dry	1	1	1	1	1	1	1	2	1	1	1	2
Sulfur trioxide, dry	1	1	1	1	1	1	1	2	1	1	1	2
Sulfuric acid, aerated	3	3	3	3	3	1	3	1	1	2	2	3
Sulfuric acid, air free	3	3	3	3	2	1	2	1	1	2	2	3
Sulfurous acid	3	3	2	2	2	1	3	1	1	1	2	3
Tar	1	1	1	1	1	1	1	1	1	1	1	1
Trichloroethylene	2	2	2	1	1	1	1	1	1	1	1	2
Turpentine	2	2	1	1	1	1	2	1	1	1	1	1
Water, steam, BFW	2	3	1	1	3	1	1	1	1	1	1	2

Water, distilled	1	1	1	1	1	1	1	1	1	1	1	2
Water, sea	2	2	2	2	1	1	1	1	1	1	1	3
Zinc chloride	3	3	3	3	3	1	3	1	1	1	2	3

<u>Figure-1 Damage Mechanisms for Crude Unit</u>

Ref: API-RP-571 First Edition December 2003, Figure: 5-42 (Details to be added in Next Revision of this Manual)

Figure-2 Damage Mechanisms for Delayed Coker Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-43 (Details to be added in Next Revision of this Manual)

Figure-3 Damage Mechanisms for Fluid Catalytic Cracker Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-44 (Details to be added in Next Revision of this Manual)

Figure-4 Damage Mechanisms for FCC light ends Recovery Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-45 (Details to be added in Next Revision of this Manual)

Figure-5 Damage Mechanisms for Continuous Catalytic Reforming Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-46 (Details to be added in Next Revision of this Manual)

Figure-6 Damage Mechanisms for Fixed bed Catalytic Reforming Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-47 (Details to be added in Next Revision of this Manual)

Figure-7 Damage Mechanisms for Hydroprocessing/Hydrotreating/Hydrocracking Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-48 (Details to be added in Next Revision of this Manual)

Figure-8 Damage Mechanisms for Sulfuric Acid Alkylation Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-49 (Details to be added in Next Revision of this Manual)

Figure-9 Damage Mechanisms for HF Alkylation Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-50 (Details to be added in Next Revision of this Manual)

Figure-10 Damage Mechanisms for Amine treating Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-51 (Details to be added in Next Revision of this Manual)

Figure-11 Damage Mechanisms for Sulfur Recovery Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-52 (Details to be added in Next Revision of this Manual)

Figure-12 Damage Mechanisms for Sour Water Stripper Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-53 (Details to be added in Next Revision of this Manual)

Figure-13 Damage Mechanisms for Isomerization Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-54 (Details to be added in Next Revision of this Manual)

Figure-14 Damage Mechanisms for Hydro Reforming Unit

Ref: API-RP-571 First Edition December 2003, Figure: 5-55 (Details to be added in Next Revision of this Manual)

A-1 Entering and Working in Confined Spaces

Introduction:

Entering and working in confined spaces has been and will continue to be an integral part of daily activities for Saudi Aramco employees. Following document has been developed to ensure the safety of inspection personnel required to enter and conduct inspection activity in confined spaces. As it is the policy of Saudi Aramco to provide its employees with the safest work environment possible, the company requires compliance with the procedures set forth its safety manuals. A site-specific program or the safety manual may be used, providing it meets or exceeds the requirements set forth in this part of inspection.

Careful planning of the job in the confined space is first step to take. Four key elements of the planning are

a. Identification of the confined space,
b. Identification of the hazards in the confined space,
c. Identification of the responsibilities for personnel involved.
d. Hazard control procedures.

Identifying Confined Spaces:

As per scope of this document, any space will be considered as confined space for which any of the following conditions apply.

a. It has limited or restricted means for entry or exit.
b. It is not designed for human occupancy, under normal conditions.
c. Contains or has a potential to contain a hazardous atmosphere.
d. Contains a material that has the potential for engulfing an entrant.

Note: Various definitions of the confined space are available in different safety standards. All definitions have same essence.

Identifying Confined Space Hazards:

Once a space has been identified as confined, the hazards that may be present within the confined space must be identified. Confined-space hazards can be grouped into four types of hazards.

1. **Oxygen-Deficient Atmospheres:**

   The normal atmosphere is composed of approximately 21% oxygen and 79% nitrogen. An atmosphere containing less than 19.5% oxygen shall be considered oxygen-deficient. The oxygen level inside a confined space may be decreased as the result of either consumption or displacement of oxygen by other fluids stored in confined space.

   There are a number of processes that consume oxygen in a confined space. Oxygen is consumed during combustion of flammable materials, such as in welding, cutting, or brazing. Oxygen can also be consumed during chemical reactions such as in the formation of rust on the exposed surfaces of a confined space. The number of people working in a confined space and the amount of physical activity can also influence oxygen consumption. Oxygen levels can also be reduced as the result of oxygen displacement by other gases.

Other oxygen related hazard in the confined space is oxygen rich atmosphere. Though this is less likely encountered hazard in the petroleum industry, but due to the reduction reactions in some of the processes (especially in the chemical plants), the atmosphere inside the vessel of tank can become oxygen rich. This atmosphere has high potential of the spontaneous fires.

2. **Oxygen Rich Atmosphere:**

Oxygen-enriched atmospheres contain oxygen concentration greater than 22%. An oxygen-enriched atmosphere will cause flammable materials such as clothing and hair to burn violently when ignited.

There is a list of other adverse effect of breathing in the oxygen rich atmospheres called as hyperoxia or oxygen toxicity. The main short term effects is damage to the lung walls, the formation of fluid in the lungs which causes a feeling of shortness of breath combined with a burning throat and chest. The research has also shown that the prolonged exposure to the mildly oxygen rich atmosphere may also damage the central nervous system. The short term symptoms of hyperoxia include in visual disturbances, ringing in the ears, dizziness, mood swings, convulsions and finally coma.

3. **Flammable Atmospheres**:

Flammable atmospheres are generally the result of flammable gases, vapors, dust mixed in certain concentrations with air, or an oxygen-enriched atmosphere. Combustible gases or vapors can accumulate within a confined space when there is inadequate ventilation. Gases that are heavier than air will accumulate in the lower levels of a confined space. Therefore, it is especially important that atmospheric tests be conducted near the bottom of all confined spaces.

The work being conducted in a confined space can generate a flammable atmosphere. Work such as spray painting, coating, or the use of flammable solvents for cleaning can result in the formation of an explosive atmosphere. Welding or cutting with oxyacetylene equipment can also be the cause of an explosion in a confined space and shall not be allowed without a hot work permit. The hot work permit must address all issues related to the potentials of explosive atmosphere. Oxygen and acetylene hoses may have small leaks in them that could generate an explosive atmosphere and, therefore, should be removed when not in use. The atmosphere shall be tested continuously while hot work is being conducted within the confined space.

4. **Toxic atmospheres**:

Toxic atmospheres may be present within a confined space as the result of one or more of the following:

a) The Product Stored in the Confined Space

When a product is stored in a confined space, the product can be absorbed by the walls and give off toxic vapors when removed or when cleaning the residual material. The product can also produce toxic vapors that will remain in the atmosphere due to poor ventilation.

b) The Work Conducted in the Confined Space

Toxic atmospheres can be generated as the result of work being conducted inside the confined space. Examples of such work include: Welding or brazing with metals capable of producing toxic vapors, painting, scraping, sanding, etc. Many of the solvents used for cleaning and/or degreasing produce highly toxic vapors.

c) Areas Adjacent to the Confined Space

Toxic fumes produced by processes near the confined space may enter and accumulate in the confined space. For example, if the confined space is lower than the adjacent area and the toxic fume is heavier than air, the toxic fume may "settle" into the confined space.

5. Mechanical and Physical Hazards:

Problems such as rotating or moving mechanical parts or energy sources can create hazards within a confined space. All rotating or moving equipment such as pumps, process lines, electrical sources, etc., within a confined space must be identified and de-energized unless engineered safeguards are available to protect the occupants of confined space. None of the moving parts should ever be moved when the occupants are inside the confined space, unless it is necessary for inspection purpose and all precautions are taken to avoid injuries.

Physical factors such as, tripping, heat, cold, noise, vibration, and fatigue can contribute to accidents. These factors must be evaluated for all confined spaces.

Excavations could present the possibility of engulfment. Employees shall be protected from cave-ins by sloping, benching, or shoring systems when the depth of the excavation is more than four feet.

Safe work planning for Confined Space:

Preparation of the confined space for working is the responsibility of the operation, and maintenance. All confined spaces should be prepared according to the company confined space safety standards. Once all of the conditions for safe working are resorted the operation should issue the safe work permit. After obtaining the safe work permit the work planning should be done. Each confined space should be evaluated separately depending upon the hazards associated. Following are the minimum essentials in safe work planning in the confined space. However extra precautions should be taken depending upon the hazards in the Confined space.

1. Prepare the PJHA identifying all of the hazards inside the confined space. The precautionary measured taken/required should be identified clearly. Identify all extra personal protective

equipment required inside the confined space.

2. Review the rescue plan in place for the confined space. If any flaws are found in the rescue plan, identify it to the operations. Ensure all of the rescuers assigned are qualified and are aware of their job. Also ensure all of the means required for rescue are readily available and are in good condition.

3. Gas testing should be witnessed by the team leader or his representative (member of the team). The testing should not be done at the entrance of the confined space. The testing should be done at the lowest areas of the confined space and at each section if the confined space is large and is divided into sections. The minimum acceptable levels (by empirical measurements) should not be other than Oxygen between 19.5 to 21.5 %, LELs less than 10 %, CO, H_2S and other toxic gases as 0%.

4. The gas testing should be done at following intervals.

   a. Beginning of each work shift.

   b. After every four hours.

   c. At the time of entry if the confined space was left unoccupied for more than four hours, if the atmosphere was controlled by the mechanical movement of air.

   d. At the time of entry if the confined space is left unoccupied for more than one hour, if no means of air movement are adopted or the air movement was inactive for most of the time when the confined space was left unoccupied.

5. A log of Gas testing results must be displayed at the manway of the confined space, in which the time and the tests results should be diligently entered. The responsible gas tester (operator) must initial (sign) the entries every time it is updated.

6. Ensure all of the blinds are in place on the piping connected to the confined space, by the walk around the confined space. Never rely on the documented blinding list.

7. Ensure all mechanical and/or electrical hazards (if any) are isolated.

8. Ensure that enough lighting is available inside the confined space to clearly illuminate the attachments and different sections of the confined space.

9. Ensure the safety watch/confined space attendant is qualified for his job, and has all of the necessary means to effectively perform his assigned task. Following are the minimum essentials for a safety watch person.

   a. Must be literate (able to read and write).

   b. Must have a clear awareness about his duties as safety watch.

c. Must know that he should not enter the confined space under any circumstances, unless some other equally capable person takes over his responsibilities.

d. Must not engage himself in any other activity, at any time, that may affect his attendance from the assigned position.

e. Must possess the radio, or should be in the close proximity of the emergency telephone in working condition, to alert the rescue team of any emergency situation that could happen in the confined space.

f. Must have a horn or other communication means to alert the entrants of the confined space of any emergency situation outside the confined space.

g. Should be able to keep in the constant visual or verbal contact with the entrants. If the verbal contact is not possible, the contact should be maintained by radio or a life line.

Supplementary Note: Life line is a rope tied to the entrant, other end of rope is held by the safety watch. The confined space entrant and the safety watch mutually develop a tug code for the "all okay", and emergency situations.

h. More than one safety watch person should be used if multiple teams have to work in one confined space, having different sections, (such as columns). One safety watch should not be assigned to attend more than one entry points in same to two different confined spaces, no matter how close these confined spaces are.

i. Must have an equally capable replacement person in case one has to leave. The confined space, if occupied, must never be left unattended.

j. Safety watch person should never be assigned a parallel job no matter how minor it is.

10. The buddy system should always be preferred while working inside the confined space.

Supplementary Note: Buddy system is defined as two persons working together in the confined space. (Whether both individuals perform same job (helping each other), or perform different jobs). One person should keep eye on the other. If one suspects that other is over come by the gas or is injured due to any other condition. A cautious help could be provided. However the buddy should evaluate the situation before extending the help.

11. Preferably each entrant in the confined space should hold a personal 4 head monitor able to quantitatively measure H_2S, CO, LELs and Oxygen. The personal gas monitors should be bump tested before each use.

12. Use half mask respirator for the precaution against toxins inside confined space, even if the atmosphere inside the confined space is declared breathable. The respirator filters should be selected depending upon the usual contents of confined space. (Use organic filters for potential aromatics, and particulate filters for NORMS).

A-2: Hydrogen Sulfide

H_2S Factsheet

Hydrogen sulfide H_2S, is an extremely hazardous, toxic compound. It is a colorless, flammable gas that can be identified in relatively low concentrations by a characteristic rotten egg odor. In the oil and gas industry H_2S is very common toxin found in oil as well as gas streams, at varying concentrations. Hydrogen sulfide has a very low odor threshold, with its smell being easily perceptible at concentrations well below 1 part per million (ppm) in air. The odor increases as the gas becomes more concentrated, with the strong rotten egg smell recognizable up to 30 ppm. Above this level, the gas is reported to have a sickeningly sweet odor up to around 100 ppm. However, at concentrations above 100 ppm, a person's ability to detect the gas is affected by rapid temporary paralysis of the olfactory nerves in the nose, leading to a loss of the sense of smell. This means that the gas can be present at dangerously high concentrations, with no perceivable odor. Prolonged exposure to lower concentrations can also result in similar effects of olfactory fatigue. This unusual property of hydrogen sulfide makes it extremely dangerous to rely totally on the sense of smell to warn of the presence of the gas.

Health Effects related to Hydrogen Sulfide

H_2S is classed as a chemical asphyxiant, similar to carbon monoxide and cyanide gases. It inhibits cellular respiration and uptake of oxygen, causing biochemical suffocation. Minor prolonged exposure can cause the production of water in the lungs which can cause the death within 24 hours if unattended.

Typical exposure symptoms include:

	Concentration	Exposure Symptoms
Low	0 - 10 ppm	Irritation of the eyes, nose and throat
Moderate	10 - 50 ppm	Headache Dizziness Nausea and vomiting Coughing and breathing difficulty
High	50 - 200 ppm	Severe respiratory tract irritation Eye irritation / acute conjunctivitis Shock Convulsions Coma Death in severe cases

Prolonged exposures at lower levels can lead to bronchitis, pneumonia, migraine headaches, pulmonary edema, and loss of sensual coordination.

Safe work planning with Hydrogen Sulfide

With a vapor density of 1.19, hydrogen sulfide is approximately 20 percent heavier than air, so this invisible gas will collect in depressions in the ground and in confined spaces. A typical permissible exposure limit widely adopted by the governing bodies all over the world is 10 ppm. While working in the areas with potential of hydrogen sulfide, following minimum precautions must be adopted.

1. The work shell not commence before the quantitative measurement of the H_2S in the atmosphere.

2. Direct reading gas detection instrumentation should be used before entering confined spaces such as manholes, tanks, pits, and reaction vessels that could contain an accumulation of H_2S gas. Each worker should carry a personal H_2S detector. All detectors should be bump tested prior to use every day.

3. Wherever possible, exposure should be minimized by employing adequate engineering controls and safe working practices. Such methods include ensuring good ventilation and changing work procedures and practices.

4. Where engineering controls cannot adequately control levels of exposure, it may be necessary to supplement the controls with the use of suitable personal protective equipment (PPE) such as continuous supply of breathing air. A qualified industrial hygienist or safety professional should be available for guidance on the suitability and correct use of supplied breathing air apparatus. All of the personnel using breathing apparatus should be qualified for proper use and should be fit tested for the respirator size and configuration, as per industry standards. It is responsibility of the inspection unit to conduct the fit testing, and train its employees with the proper usage of the berating apparatus. A log of fit tested and trained employees should be maintained. Each worker should be given a certificate for fit testing, mentioning the size and brand of the respirator which proves to fit best with his facial features.

5. At least two portable breathing apparatus sets (such as scott packs) should be made available all the time at the work site. The air cylinders should be full and the apparatus as whole should be free of all kind of physical and mechanical defects. A thorough physical check should be done by the qualified worker prior to each shift.

6. Should a co-worker ever be overcome by H_2S gas, no rescue attempt should be done until the rescuers workers are properly equipped by supplied air breathing apparatus. The rescuer can very easily get caught out by venturing into a confined space without adequate protection.

7. A safety watch person is a must in the areas where the H_2S hazard is present. Safety watch person should stay out of the hazardous area, yet keeping continuous visual or verbal contact with the workers within the boundaries of hazard area. The safety watch person should be equipped with all of the means to initiate the emergency response plan. Safety watch person should not be assigned any other job while he is engaged in

the task job of safety watch.

8. The Emergency response should be planned prior to the beginning of the job in H_2S areas.

9. In case of emergency the safety watch should initiate rescue procedure by informing the rescue team by radio or telephone. The emergency response team should be properly trained in rescue procedures and the initial revival procedures such as CPR and first aid. The victim should be kept in the constant care of the emergency team until the paramedics take over.

10. In case the concentration of H_2S is above zero and no engineering controls are available to bring the level down to zero, or the job is too critical and time constrained, the work will be allowed under the continuous supplied air. In this case only the workers trained/qualified for working in H_2S atmosphere under supplied air breathing apparatus will be allowed in the work site. Qualified air bottles watch person will be assigned to control/monitor the flow of breathing air.

Notes:

a) OSHA guidelines should be followed while planning the work in H_2S areas.

b) The safety manual should provide complete details of the safety procedures and the rescue plan for the facility, having potential of H_2S.

A-3: Naturally Occurring Radioactive Materials NORMs

NORMS Factsheet

Naturally occurring radioactive materials (NORM) are one of the persistent Hazards encountered in oil and gas exploration, and processing operations. NORM exist in the subsurface formation of the earth in form of Uranium, Thorium and their daughter products, Radium 226, Radium 228 and Radon 222. These materials are transported out with the oil and gas streams, and dislodged from the streams due to the processing operations. As a result the Oil-field equipment usually contains high traces of radioactive material in the scale and accumulated sludge. Most common NORMs are the radium isotopes Radium 226 (half-life =1,600 years) and Radium 228 (half-life =5.8 years), usually found in produced water. These two isotopes are produced by radioactive decay of uranium and thorium present in rocks of the oil-producing formations.

The maximum concentration or radium in oil-field scale has been measured to several thousand pCi/g (up to 400, 000 pCi/g). For comparison, most natural soils and rocks contain approximately 0.5–5 pCi/g of total radium.

<u>Health Effects related to NORMs</u>:

Radium radio-nuclides emit alpha and beta particles as well as gamma rays. The radiation emitted from a Radium 226 atom is 96% alpha particle and 4% gamma ray. The alpha particle is the most dangerous particle associated with NORM. Alpha particles are highly ionized helium nucleus. Because of their large size and high reactivity these particle travel short distances in the air (only 2-3 centimeters). Hence cannot penetrate through a dead layer of skin on the human body. If the Radium atoms are not expelled from the body, they concentrate in areas where Chloride ions are prevalent, such as bone tissue. That is why these elements are sometimes referred to as "bone seekers", because when inside the body, these elements migrate to the bone tissue and start concentrating there. The half-life for Radium 226 is approximately 1620 years which is significantly long and can stay in the body for the lifetime. Additional damage that Alpha particles can cause is reaction with water in the human body. Most common toxins which are produced due to this reaction are hydrogen peroxide and alcohols.

NORMS enter the body through inhalation and ingestion. The hazards associated with the NORMs are long term. Due to longer half life of radio-nuclides, the damage caused by alpha particles could be potentially unstoppable. Therefore the employees, exposed to the NORMS over several years could develop bone cancer, and other kind of genetic disorders related to the radiations. The gamma rays emitted from Radium 226, on other hand account to for 4% of the radiation. Gamma rays are high energy electromagnetic radiations which can pass through the human body. Hence gamma radiations are less harmful to the human body as compared to Alpha Radiations.

Radium 228 emits 100% beta particles, which are also a concern for human health through inhalation and ingestion. Beta particles are similar in size to an electron and travel farther than alpha particles in air. Beta particles can breach a thin sheet of paper, but are still prevented by a dead layer of skin on human body. Beta particles are also the ionizing radiations, so the damage caused by the beta is similar to Alpha, however this damage is significantly less in magnitude as compared to Alpha Particles.

NORM deposits may also accumulate in gas-plant equipment in form of radon-222 (radon) gas. The radon gas mostly originates in underground formations and combines with the gas streams. It is dislodged from the main gas stream during the fractionation process and deposits in the gas processing equipment. Gas-plant NORM deposits differ from oil production scales and sledges. The NORM contaminated scale in the gas plant is very fine. Typically the internal surfaces of the pipes, valves and other gas-plant equipment are contaminated with the Radon and its daughter traces. Radon has a half life of 3.8-days. It decays into lead-210, which has a half life of 22-years. Lead-210 decays by beta emission along with the emission of very low-energy gamma rays.

The equipment surfaces can be evaluated for the presence of the NORMs by Geiger counters and the Alpha/beta detectors. Though the norms can never be absolutely eliminated but exposure level from the radiation can be brought down to the occupation acceptable limits. The measures include the thorough cleaning of the contaminated surfaces, and use of suitable respiratory protection. In order to avoid the migration of the NORMs into the potable water sources, the contaminated sludge and scales should be disposed in the containments.

Safe work planning with NORMs:

All of the facilities which have potential of the NORMS exposure should implement the NORMs awareness program. The health hazards associated and the prevention methods from the NORMs should be discussed in the in-house workshops and seminars. Inspection units should incorporate the NORMS awareness in the safety programs.

The NORMS baseline survey data should be developed for the operation facility as per requirements of SAEP-358 Para 4.1. The follow up surveys at the T&I and normal operation times should be conducted as per SAEP 358 Para 4.2 and 4.3. It is responsibility of Inspection unit supervisor to make sure that latest update of this data is available for the inspection team for review. After reviewing this data the inspection team should plan the inspection activity as follows.

While working with the equipment with potential of NORMs following minimum precautions should be adopted. The work shell not commence before the quantitative measurement of the NORMs is done, and means of the exposure prevention are adopted.

1. The potential of NORMs existence should be considered in the PJHA and planning. All members of the inspection team and support staff will be made aware of the NORMs and the health hazard associated with norms. The protective equipment from the exposure should be made available to all of the personnel directly exposed to the contaminated surface.

2. Whenever the exposure to the NORMS is imminent due to activities like the internal surface inspection of the piping, valves, tanks and vessels etc the surface and the contents attached to the surface should be thoroughly checked for Alpha, Beta and Gama counts. The equipment used for the detection and quantitative measurement should be calibrated according to manufacturers recommendation and governing standards for the NORMs.

3. If the radioactivity level is found above the acceptable limits than following precautions must be adopted.

a. No entry shall be permitted without proper respiratory protection.

b. Disposable protective clothing (such as Tyvac paper coverall) must be work over the FRC.

c. If the work scope requires the longer time exposure to the contaminated surface. (for example during the T&I, and internal inspections. Thorough cleaning with high pressure jet wash shall be done on the contaminated surfaces. The waste water, after cleaning, should not be allowed to drain into the common drain lines. All necessary means should be adopted to save the environmental contamination word it properly.

d. The NORMs count will be taken after cleaning, until the counts are reduced down to the acceptable range.

4. The initial entry into the vessels and Tanks must not be allowed without the protective gear for NORMs regardless the potential of NORMs exists or not.

Acceptable Exposure Limits:

Following are the industry acceptable values of NORMS.

	NCRP (OSHA) (National Council Or Radiation Protection)	**ICRP** (International commission of Radiation Protection)
General Public:		
Annual	1 mSv	1 mSv
Radiation Workers:		
Annual	50 mSv	20 mSv
Cumulative	10 mSv x age	--
During Pregnancy	5 mSv	2 mSv

A-4 Aromatics-Benzene Hazard.

Benzene Fact Sheet:

Benzene is a clear, colorless liquid with sweet aromatic odor. It is a flammable in liquid as well as vapor forms. Other commonly used names of Benzene are benzol, carbon oil, coal naphtha, cyclohexatriene, and phenyl hydride. Toluene and Xylene are other member chemical in the Benzene family, which can be found integrated with Benzene in small quantities. Benzene vapors are heavier than air so benzene tends to accumulated In the lower areas and may spread long distances. Liquid benzene can float on water and may travel to distant locations.

The most commonly required physical data of the benzene is as follows.

Boiling point:	80°C
Melting point:	6°C
Relative density (water = 1):	0.88
Solubility in water, g/100 ml at 25°C:	0.18
Flash point:	-11°C c.c.
Auto-ignition temperature:	498°C
Explosive limits, vol% in air:	1.2-8.0

Naturally, benzene exits in liquid form with the boiling point of 80.1°C in at the atmospheric pressure. Due to double bonded ring structure the valence electrons are delocalized inside the Benzene ring which induced the differential charge in the benzene. Therefore the solubility of benzene increases in water as compared to other hydrocarbons.

Most people can smell benzene at 1.5-4.7 ppm concentration in air. And most people can taste benzene in water at 0.5-4.5 ppm concentration.

Benzene is a natural part of crude oil and gasoline. Accord**ing** to a **crude oil** analysis the average **benzene** content is 0.52% by weight. However the compositions of **crude oil** and the fraction of **benzene** differ between the **oil** fields. According to known statistics different parts of world following average concentration of benzene in the crude oil.

Crude Oil Field	Benzene % (by weight)	Benzene concentration ppm
Norwegian cont**in**ental shelf	0.28%	2800
Canada	0.28%	2800
Central Asia	0.20 to 1.73%	2000 to 17300
West Africa	0.20 to 1.73%	2000 to 17300
Far East	0.20 to 1.73%	2000 to 17300

Similarly the statistical estimates for the average benzene contents in the Brine in some areas is as follows.

Production field	Benzene Contents ppm
Mississippi	18.6
Bough	10.7
Golden Spike Alberta	7.1
Lampman Saskatchewan	7.0
Statler Alberta	6.0
Keystone	5.6

Health Effects related to Benzene:

According to OSHA statistic, as many as 238,000 people may be occupationally exposed to benzene in the United States every year. These industries along with other include petrochemicals, and petroleum processing. Benzene is a known human carcinogen. The health effects of the benzene depend upon the amount of benzene to which the victim is exposed and the length of exposure time. The work place exposure of the benzene is mostly through breathing in the contaminated atmosphere. Benzene entering the body through lungs and passes through the lining of lungs and enters your bloodstream. A small amount of benzene can also enter your body by passing through skin upon direct contact to the benzene. Once in the bloodstream, benzene travels throughout body and transfuses into the bone marrow and fat. Inside the liver and bone Marrow the stored benzene is converted to products called metabolites. Some of the harmful effects of benzene exposure are believed to be caused by these metabolites. Workers performing cleaning and maintenance of tanks and pressure vessels containing crude oil or residues of crude oil had higher levels of exposure than workers performing other tasks, including work near open hydrocarbon-transport systems.

The health effects can be broadly divided into short term and long term effects.

Short Term Effects.

- Brief exposure (5-10 minutes) to very high levels of benzene in air (10,000-20,000 ppm) (1% to 2%) can result in death.
- Lower levels (700-3,000 ppm) (0.07% to 0.3%) can cause drowsiness, dizziness, rapid heart rate, headaches, tremors, confusion, and unconsciousness.
- Eating or drinking foods containing high levels of benzene can cause vomiting, irritation of the stomach, dizziness, sleepiness, convulsions, rapid heart rate, coma, and death.
- Contact with the skin may cause redness and sores.
- Contact with eyes may cause general irritation and damage to cornea.

Long term effects:

The list of long term effects is longer than the short term effects.

- Benzene causes problems in the blood. People who breathe benzene for long periods may experience harmful effects in the tissues that form blood cells, especially the bone marrow. These effects can disrupt normal blood production and cause a decrease in important blood components.

- A decrease in red blood cells can lead to anemia. Reduction in other components in the blood can cause excessive bleeding.
- Benzene settles inside the bone marrow where new blood cells are produced. The damage to the bone marrow results in aplastic anemia, which can lead to leukemia.
- Excessive exposure to benzene can be harmful to the immune system, increasing the chance for infection and perhaps lowering the body's defense against cancer.
- Benzene can cause cancer of the blood-forming organs. This condition is called leukemia.
- Exposure to benzene has also been linked with damage to chromosomes which are the parts of cells that are responsible for the development of hereditary characteristics.
- Benzene may cause effects on the peripheral nerves and/or spinal cord. Other effects on the nerves system include headaches, fatigue, difficulty in sleeping and memory loss.
- Studies of workers have found changes in the immune system, which are at least partially related to the changes in the blood system discussed above.
- Benzene exposure has also been associated with cancer of the lymph system (lymphoma), lung cancer and bladder (urothelial) cancer.
- Exposure to benzene may also be harmful to the reproductive organs. Some women workers who breathed high levels of benzene for many months had irregular menstrual periods. When examined, these women showed a decrease in the size of their ovaries.
- Studies with pregnant animals show that breathing benzene has harmful effects on the developing fetus. These effects include low birth weight, delayed bone formation, and bone marrow damage.
- In the body benzene is converted to products called metabolites. The conversion is very fast due to this it is very difficult to estimate the correct exposure level unless the blood and urine tests are taken rapidly. Due to the overwhelming health effects of benzene exposure, the industries all over the world has set up the benchmark exposure limits to the workers.

Acceptable Exposure Limits:

The immediately dangerous to life and health IDLH Concentration of benzene is established as 500 ppm

Some of the commonly used recommended limits of the industrial benzene exposure are given in following table.

Proponent Organization.	Recommended exposure limit
Occupational Safety and Health Administration **OSHA**	• 1 ppm 8-hour workday, 40-hour workweek. • 5 ppm should not be exceeded in any 10 minute period.
Canadian Centre of Occupational Health & Safety **CCOHS**	• 1 ppm 8-hour workday, 40-hour workweek. • 5 ppm should not be exceeded in any 10 minute period.
American Conference of Governmental Industrial Hygienists **ACGIH**	• 0.5 ppm averaged over an 8-hour work shift • 2.5 ppm as a short-term exposure limit.
NIOSH National Institute for Occupational Safety and Health	1 ppm should not be exceeded during any 60 minute period.

Safe Work Planning:

Benzene is and active Hazard while working in the confined space, especially at the time of the initial opening (before cleaning) of the vessels and the tanks. The accumulated sludge may have high concentrations of Benzene, similarly the refined product storage tanks may also have higher than permissible values of benzene.

The Quantitative measurement of the benzene level should be done by the direct reading benzene detector. If the hazard is found over the acceptable limits than a safe work plant must be formulated. The safe work planning in the areas with the potential hazard of benzene should include but not limited to the following.

1. The work shell not commence before the quantitative measurement of the Benzene in the atmosphere.

2. Direct reading gas detection instrumentation should be used before entering confined spaces.

3. Wherever possible, exposure should be minimized by through jet washing and vacuuming the slugs and the substrates.

4. Engineering control methods like mechanical ventilation should also be preferred to reduce hazardous levels. However ventilation of high quantities of benzene into the air should be avoided at all costs.

5. Where cleaning is not permissible or benzene concentration cannot be brought down to the acceptable levels, the planning should be done to perform the job under the supplied breathing air. A qualified industrial hygienist or safety professional should be available to monitor the job performed under supplied breathing air. All of the personnel using breathing apparatus should be qualified for proper use the breathing apparatus. All workers should be fit tested for the respirator size and configuration, as per industry standards.

6. The fist aid and the medical aid planning should be done prior to work. All safety working showers and the eye wash stations should be indentified identified in case anybody comes in contact with benzene.

7. Even if the benzene level is brought down well below the permissible levels, all personnel working in the confined space must wear suitable half mask respirator with the organic vapor filters suitable to eliminate the benzene.

8. Chemical resistant gloves, coveralls, boots, and goggles must be worn where the skin and eyes contact is possible.

9. Remove contaminated clothing immediately after work. Keep contaminated clothing in closed containers.

Notes:

a) OSHA guidelines should be followed while planning the work in Benzene areas.

b) The safety manual should provide complete details of the safety procedures and the rescue plan for the facility, having potential of Benzene.

A-5 Working at heights

Height Hazards Fact sheet.

The actual definition of the height depends upon the personal interpretation, however according to prevalent industry definitions "any work activities undertaken at an elevated position from which falling can cause injuries which can hinder workers normal life activities, is categorized as working on height". This height is measured from a solid/unbreakable ground or deck which cannot be broken by the force of normal falling human body. As a rule of thumb, in oil and gas industry minimum 6 feet elevation is taken as height for which engineered fall arrest systems are mandated. Following are the main Hazards associated with working on heights.

1: Falling from height:

Falling from height is the biggest hazard of working on heights. The injuries from falling vary from normal cuts and bruises to permanent disabilities and death. A falling body accelerates with the acceleration of approx 10 m/sec^2. This means the speed of a falling body increases by 10 m/sec of each second it falls. Hence greater is the height of falling greater will be velocity when it hits the ground.

On hitting the ground the falling body undergoes the sudden stoppage and all of the acquired momentum is brought to zero in very short interval of time. The quantitative analysis of the force on falling body is assessed as follows.

Any moving body of mass m and the velocity v has a momentum M defined as product of mass and velocity.

$$M = mv$$

Anybody at complete rest position is zero momentum.

The change in momentum is called as impulse, which is the product of force "f" and time interval "Δt" in which force f is applied to cause the change the momentum. Therefore Impulse of force is

$$f\Delta t = m\Delta v$$

$$f = m\frac{\Delta v}{\Delta t}$$

Therefore shorter the time interval to stop greater will be the force applied on a stopping body.

For analysis purpose we use the unfortunate scenario of a 60 Kg human worker falling from height. It takes 1/10 seconds to stop on the concrete ground, and assume it takes ½ seconds on soft sandy ground. Following will be the empirical value of the stopping force in his body.

$$Height\ h = \frac{1}{2}gT^2$$

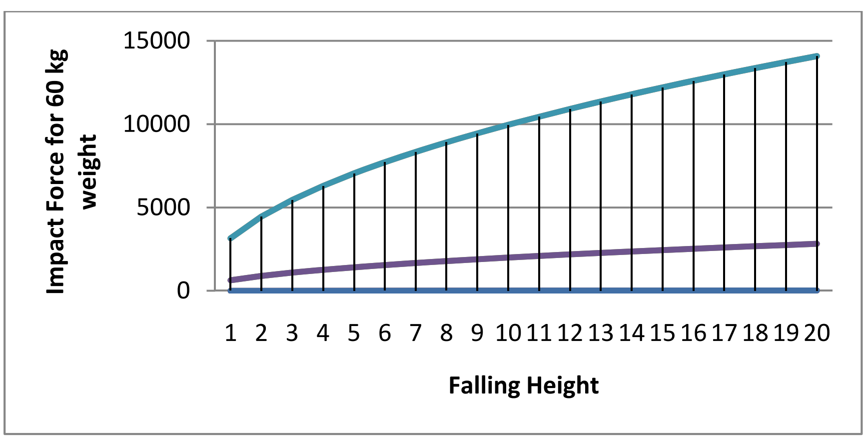
Time of falling T $\quad T = \sqrt{2h/g} \quad = \sqrt{h/5}$ (for g=10 m/sec^2)

Velocity at time of impact V_f $\quad Vf = gT \quad = 4.5\sqrt{h}$

Impact Force f $$f = \frac{m\Delta v}{\Delta t}$$

For mass of 60 Kg the impact force on falling from different heights is given in table below.

Falling Height (Meters)	Velocity at the time of hitting the ground. (m/sec)	Change in momentum at time of hitting the ground	Impact force f at the softer sandy ground. ($\Delta t = \frac{1}{2}\ sec$) (Kg-m/sec)	Impact force f at the hard concrete floor ($\Delta t = \frac{1}{10}\ sec$) (Kg-m/sec)
1	4.5	315.0	630.0	3150.0
2	6.4	445.5	891.0	4454.8
3	7.8	545.6	1091.2	5456.0
4	9.0	630.0	1260.0	6300.0
5	10.1	704.4	1408.7	7043.6
6	11.0	771.6	1543.2	7715.9
7	11.9	833.4	1666.8	8334.1
8	12.7	891.0	1781.9	8909.5
9	13.5	945.0	1890.0	9450.0
10	14.2	996.1	1992.2	9961.2
11	14.9	1044.7	2089.5	10447.4
12	15.6	1091.2	2182.4	10911.9
13	16.2	1135.7	2271.5	11357.5
14	16.8	1178.6	2357.2	11786.2
15	17.4	1220.0	2440.0	12199.9
16	18.0	1260.0	2520.0	12600.0
17	18.6	1298.8	2597.6	12987.8
18	19.1	1336.4	2672.9	13364.3
19	19.6	1373.1	2746.1	13730.5
20	20.1	1408.7	2817.4	14087.2



The above analysis shows that the impact time plays major role in reducing the chances of injury. Therefore the first and foremost strategy in planning for working on heights is to avoid falling, however if falling occurs the 2nd line of defense is to reduce the impact force. The impact force reduction can be achieved by delaying the time of stopping, by using the shock absorbing of extendable lanyards (on full body harness).

2: Falling Objects:

Another hazard associated with the working on heights is the falling objects. The tools and equipments being used in jobs at higher elevations can fall and hit the workers below. Common sense precautions like tying the equipment, or keeping in the enclosed bags can be adopted to avoid these hazards. However the scaffolds and the decks are also equipped with toe boards and safety meshes to avoid tipping over of the large size objects. Precautions are also required when lifting the objects and descending them from heights. The use of rope should be adopted where ever possible. Second precautionary measure is barricading the areas below by caution ribbons. The caution ribbon should have tags showing the potential of falling objects.

3: Psychological aspect of working at heights:

Height phobia is a natural instinct which every human has to some extent. Height phobia is a psychological passion which varies from person to person. Some people have it so much that normal working at height is not possible for them. Chance of panicking and mistakes is very high for these people, which could become a contributing factor towards an accident. It is advisable for the workers with height phobia not to volunteer for the jobs at height. Further it is must for these workers to inform the job planner about this problem.

Acceptable means to facilitate the working at the heights.

Since working at the heights is the integral part of all of the occupation in Oil and Gas industry. The industry has developed various means to perform these jobs as safely as possible. The precautions are adopted according to the scope of the job. Some of the common measures adopted are following.

1. Permanent decks and platforms:

   Permanent decks and platforms should be provided at the high altitude locations which need to be accessed quite often during the normal operation. The permanent decks are usually designed with the toe boards, and waist height barriers. No additional fall restraint is required if the work is done on the level of the permanent deck and within the permanent barriers provided on the deck. However if the work to be performed is above the level of deck or is out of the safety barriers of the deck, addition fall restraints are required.

2. Ladders:

   As per HSE statistics 1/3rd of all reported fall-from-height incidents involve ladders and stepladders. On average this accounts for 14 deaths and 1200 major injuries to workers each year. Many of these injuries are caused by inappropriate or incorrect use of the ladders. Each ladder whether, fixed, extendable or step ladder have limits of usage. The manufacturer’s recommendations should always be followed while loading the ladder. Following are the main precautions which should be adopted while using the ladders.

   a. Leaning ladders:

      1. Always tied the ladder on top.

2. Restrain the ladder from slipping at the bottom.

3. The ladder should be used with such an angle that it provides approximately 1:4 ratio of horizontal and vertical openings form the edge.

4. Always remain in 3 point contact formation on the ladder, especially while ascending and descending. This means both feet in ladder, and one hand on the ladder rung. If the work requires both hands for the task then means other ladder should be adopted.

5. The positioning of the ladder should be so adjusted that the total centre of gravity of the system (ladder, worker, and associated tools) remains within the plain of ladder. Never over extend from the ladder so that the centre of gravity shifts out of the plain of ladder.

6. Stay away from over head hazards like electrical lines, and other mechanically moving parts.

7. Be cautious of extremely hot or cold contact points.

8. Only one person should climb or work from a ladder, at a time.

b. Step ladders:

1. Step ladder should always be fully extended.

2. Always use the ladder of appropriate height.

3. Never step on the 3rd last step and above.

4. The step ladder should never be used as leaning ladder.

5. Always remain in 3 point contact formation on the ladder, especially while ascending and descending. This means both feet in ladder, and one hand on the ladder rung. If the work requires both hands for the task then means other ladder should be adopted.

6. The positioning of the ladder should be so adjusted that the total centre of gravity of the system (ladder, worker, and associated tools) remains within the plain of ladder. Never over extend from the ladder so that the centre of gravity shifts out of the plain of ladder.

7. Stay away from over head hazards like electrical lines, and other mechanically moving parts.

8. Be cautious of extremely hot or cold contact points.

9. Stepladders should not be used sideways.

10. Only one person should climb or work from a ladder at same time.

3. Scaffolding:

Scaffolding is the most common practice used to provide the temporary access to the heights, if the work requires more than one persons and the scope of the work is extended. The scaffolds are erected according to the engineered standards. In the usual industry practice, after completion a senior scaffold erector, inspects the scaffold and assigns the tag to the scaffold. The assigned tag includes the extra precautionary measures required and limitations of the scaffold. The scaffold tag is always updated, after reinspection whenever any modification takes place in the scaffold, or the certification is expired. Incomplete and unusable scaffolds are tagged Red, similarly the scaffolds with limitations and extra precautions required are tagged yellow. Similarly the scaffolds good to use without extra precautions are tagged green. Following are the precautions that should always be kept in mind before planning to use the scaffold.

i. Never use a scaffold without tag. Always adopt the extra precautionary measures mentioned in the tag. No tag on scaffold should always be taken as red tagged scaffold. Scaffold with no tag should be inspected, certified and tagged by responsible scaffold erector.
ii. Never jump on the scaffold, or cause movement which is resonant to the natural frequency of the scaffold.
iii. Never over extend out from the scaffold without wearing the full body harness and anchoring with a load bearing anchor point.
iv. Never over load the scaffold above its recommended weight bearing capacity.
v. Stay away from over head hazards like electrical lines, and other mechanically moving parts.
vi. Be cautious of extremely hot or cold contact points.

4. Mechanical man lifting devices (JLGs, Scissor lift, Crane man baskets, etc):

JLGs, Scissor lift, Crane man baskets, etc are mechanized means of lifting humans to the work locations on height. These equipments should never be used unless the user is properly trained and qualified in their use. Using the full body harness is mandatory while working on these equipments. Following are the precautions that should always be kept in mind before planning to use these devices.

i. The device should be mechanically fit to use. As per usual industry practice, these devices are always checked and certified as fit for service after specified interval of time. Always look at the certification sticker, before using these devices.
ii. The user should be trained and fully capable to use this device.
iii. Never over load these devices above the manufacturer's recommendations.
iv. The ground on which these devices are positioned to use should be reasonably leveled. Never extend the boom if the ground is not leveled.

v. Always wear full body harness, anchoring on the engineered anchor points on the device or other load bearing anchor points.
vi. Stay away from over head hazards like electrical lines, and other mechanically moving parts.
vii. Be cautious of extremely hot or cold contact points.

5. Full body Harness:

Full body harness is most important and last line of defense against the hazard of falling from the height. The full body harness is not taken as the only precaution but is relied upon the in case other defense measures fail. Proper training like fall arrest courses should be held to train the employees in proper usage of the full body harness. The fundamental constituents which come into play while planning the safe use of full body harness are following.

a) Anchor Point & Assembly:

Anchor point is a secure point of attachment for lifelines, or lanyard. The selection of the anchor point is based on the strength of the point, configuration of the point and the assembly. The strength should be estimated, based upon the number of the people which are to be tied to on this anchor point. commonly used rule in the industry is that the anchor point should be able to support 10 times the weight of the individual or sum of individuals tying to this point. This includes the shock loading in case of fall. In case of the long term work and the areas where the potential of catastrophic falling is very high, a certified engineer should design the anchor point and the assembly. A careful Personal judgment is very essential while planning the selection of the anchor point. It should be considered how the anchor point will behave in case of fall. Tying to the scaffold should be avoided in all cases.

The height of the anchor point should be selected keeping in mind the height of the person, the location of D-ring and the stretching length of the shock absorbing lanyard. In no case the anchor point should be selected at the lower levels where there is chance of contact with the ground or hard surface in case of fall. Similarly the selection should be such that falling person should not swing into any other neighboring structure. Most preferable location of anchor point is directly above the working position.

b) Harness:

Various kind of full body harnesses are available in the industry. The storage and maintenance of the harness should be according to manufactures recommendations. The harness should always be carefully checked, before every use, for rips, cuts, stitching deterioration or any other damages. The damaged harness should never be used no matter how minor the damage is.

The best practice is to develop a checklist to go through the harness. Each harness should be assigned an inventory number. A check list should filed before and after each use.

An example of the harness inspection check list is given in Figure-1 & 2.

c) Shock Absorbing Lanyard:

According to OSHA requirements the stopping force on the falling body should never exceed 1800 pounds. In order to achieve this the stopping time is extended, by using the shock absorbing lanyards. Always use the shock absorbing lanyards, the ropes or any other non-stretchable slings are strictly prohibited to be used as it can cause sewer muscular trauma. Other potential is the high shock stress on the heart due to sudden stoppage of the blood flow, which can be life threatening. In case the worker needs to move beyond the clearance length of the lanyard, double lanyard should be proffered to keep hundred percent tie off situation.

d) Rescue Plan:

The proper rescue plan is the most important part in the safe work planning at heights. If all else works properly, the failure to rescue the falling person with in the shortest possible time can be equally fatal. Worker who falls and hangs in the air with the help of proper harness and shock absorbing lanyards may not be able to rescue himself. While in the hanging position the reaction whole body weight is exterted on the legs crotch area (where the harness straps are in contact of body). The prolonged hanging in the harness can stop the blood flow in the lower part of the body, hence can result in permanent disability or death. The time of the injury from the hanging depends upon the personal health and the weight of the hanging person. Available data has shown that there are more chances of the permanent disability if the person hangs for over 15 minutes and the death may occur with in 30 minutes. No worker should work on the heights with the safety harness unless proper rescue plan is not available. Make sure medical and rescue teams can get in the areas within reasonably short time.

Full Body Harness inspection log.

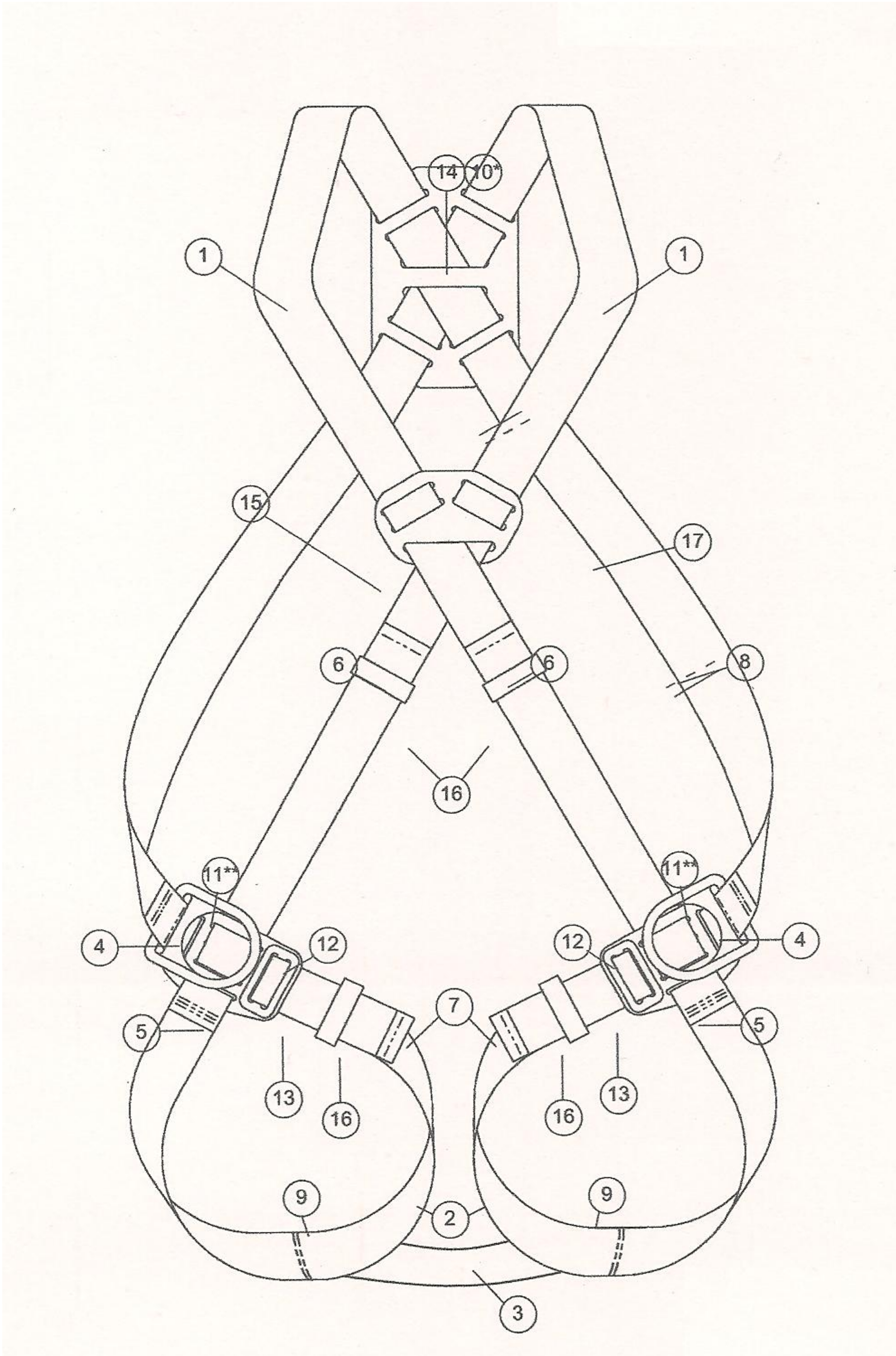


Figure-1: Components of Full body harness

Model No. ____________________ Inspector ____________________

Serial No. ____________________ Inspection Date ____________________

Date Made ____________________ Disposition ____________________

INSP. POINT	DESCRIPTION	QTY / H	PASS/FAIL COMMENTS
	FABRIC (FIBROUS) PARTS		
	WEBBING (STRAPS)		
1	Shoulder	2	
2	Thigh	2	
3	Sub Pelvic	1	
	STITCHING		
4	Shoulder straps	2	
5	Thigh straps	2	
6	Shoulder strap tips	2	
7	Thigh strap tips	2	
8	Label	2	
9	Sub Pelvic straps	2	
	METALLIC PARTS		
10	D-ring, back	1	
11	D-rings, hip (if present)	2	
12	Adjuster/buckle	2	
13	Thigh strap buckle	2	
	PLASTIC PARTS		
14	Back D-ring locater pad	1	
15	Chest strap guide	1	
16	Strap collar	4	
17	Label	1	

Figure-2: Full body harness inspection checklist

A-6: Weather Extremes

The weather extremes are one of the significant hazards which come into play, and should be given equal importance, while planning the work. The potential weather extremes in Kingdom of Saudi Arabia include the hot temperatures, dust and thunder/rain storms. The most important is the hot weather which extends to over 7 to 8 months in most of the areas. Some of the important factors to consider in the safe work planning are following.

1: <u>Hot Weather and associated Hazards:</u>

Most Important factor in the hot weather is the Humidex, which is measure of how hot we feel. It is basically the combination of warm temperatures and humidity. For a given temperature, the Humidex increases as the relative humidity (moisture content) of the air becomes higher. The body attempts to maintain a constant internal temperature of 37°C at all times. In hot weather, the body produces sweat, which cools the body as it evaporates. As the humidity or the moisture content in the air increases, sweat does not evaporate as readily. Sweat evaporation stops entirely when the relative humidity reaches about 90 percent. Under these circumstances, the body temperature rises and may cause illness.
Figure-1 shows the cart that is normally used to determine the Humidex.

OSHA determines the human body response to the Humidex in terms of thermal comfort.

Humidex and Thermal Comfort

Humidex Range (°C)	Degrees of Comfort
20 - 29	Comfortable
30 - 39	Varying degrees of discomfort
40 - 45	Uncomfortable
46 and Over	Many types of labour must be restricted

Further instructions are devised in terms of the physical work done in the Humidex.

Exposure to heat stress can cause physical problems which impair workers' efficiency and may cause adverse health effects. The risk of heat-related illness varies from person to person. A person's general health also influences how well the person adapts to heat (and cold). The overweight people often have trouble in hot situations, because their body has difficulty maintaining a good heat balance. Age (particularly for people about 45 years and older), poor general health, and a low level of fitness will make people more susceptible to feeling the extremes of heat. Medical conditions can also increase how susceptible the body is. People with heart disease, high blood pressure, respiratory disease and uncontrolled diabetes may need to take special precautions. In addition, people with skin diseases and rashes may be more susceptible to heat.

Heat exposure effects can be divided into short term and long term effects.

1: Immediate or short term heat exposure related illnesses:

a. Heat stroke and hyperpyrexia:

Heat stroke and hyperpyrexia (elevated body temperature) are the most serious types of heat illnesses, and can be fatal if the victim is not given immediate medical treatment. Signs of heat stroke include body temperature often greater than 41°C, and complete or partial loss of consciousness. The signs of heat hyperpyrexia are similar except that the skin remains moist. Sweating is not a good symptom of heat stress as there are two types of heat stroke – “classical” where there is little or no sweating (usually occurs in children, persons who are chronically ill, and the elderly), and “exertional” where body temperature rises because of strenuous exercise or work and sweating is usually present. Heat stroke and heat hyperpyrexia require immediate first aid and medical attention. Delayed treatment may result in damage to the brain, kidneys and heart. Treatment may involve removal of the victim's clothing and spraying the body with cold water. Fanning increases evaporation and further cools the body. Immersing the victim in cold water more efficiently cools the body but it can result in harmful overcooling which can interfere with vital brain functions so it must only be done under close medical supervision.

b. Heat cramps:

Heat cramps are sharp pains in the muscles that may occur alone or in combination with one of the other heat stress disorders. The main cause of heat cramps is salt imbalance resulting from the failure to replace salt lost with sweat. Cramps most often occur when people drink large amounts of water without sufficient salt (electrolyte) replacement.

c. Heat exhaustion:

Heat exhaustion is caused by loss of body water and salt through excessive sweating. Signs and symptoms of heat exhaustion include, heavy sweating, weakness, dizziness, visual disturbances, intense thirst, nausea, headache, vomiting, diarrhea, muscle cramps, breathlessness, palpitations, tingling and numbness of the hands and feet. Recovery occurs after resting in a cool area and consuming cool salted drinks.

d. Heat edema:

Heat edema is swelling which generally occurs among people who are not acclimatized to working in hot conditions. Swelling is often most noticeable in the ankles. Recovery occurs after a day or two in a cool environment.

e. Heat Rash:

Heat rashes are tiny red spots on the skin which cause a prickling sensation during heat exposure. The spots are the result of inflammation caused when the sweat glands become plugged.

f. Heat syncope:

Heat syncope is heat-induced giddiness and fainting induced by temporarily insufficient flow of blood to the brain while a person is standing. It occurs mostly among unacclimatized people. It is caused by the loss of body fluids through sweating, and by lowered blood pressure due to pooling of blood in the legs. Recovery is rapid after rest in a cool area.

g. Dehydration:

Dehydration is the Loss or deficiency of water in body tissues caused by excessive sweating.

2: Chronic or long term effects of heat exposure?

a. Certain kidney, liver, heart, digestive system, central nervous system and skin illnesses are linked to long-term heat exposure. However, the evidence supporting these associations is not conclusive.

b. Chronic heat exhaustion, prolonged sleep disturbances.

c. Because the lens of the eyes has no heat sensors and lacks blood vessels to carry heat away, Cataracts is developed in the eyes, because of to the exposure of eyes to heat, specially the infra red radiations from the red hot surfaces.

d. A possible link between heat exposure and reproductive problems has been suggested. In men, repeatedly raising testicular temperature 3 to 5°C decreases sperm counts. There is no conclusive evidence of reduced fertility among heat-exposed women. However so far there are no adequate data from which a firm conclusion could be drawn by researchers.

3: Prevention from the heat related illnesses.

It is Employers responsibility to take every reasonable precaution to protect workers from heat stress disorders. Following are necessary precautions to be considered while planning the work in the hot and humid environment.

a. Rehydration:

The rehydration with the water, Fruit juice or sport and electrolyte drinks is necessary, for the workers working in the hot environment. This is done by the frequent intake of the water along with the salt and fluid supplements like juices and ORS mixtures. The rate of rehydration should be equal to the rate of dehydration. No fixed quantity of the fluid intake can be determined, it varies with the individual. Rule of thumb is that fluids intake should be within the comfortable limits. Extreme care is required in the intake of the salt supplements as the excessive salt in the body tends to increase the body temperature and blood pressure. Drinks with caffeine (coffee or tea) should never be taken during of before the wok in the hot environment, as caffeine tends to dehydrate the body.

b. Co-Working Or Buddy System:

People are generally unable to notice their own heat stress related symptoms. Their survival depends on their coworker's ability to recognize these symptoms and seek timely first aid and medical help. Hence it is required that the work should be done in form of team where workers keep eye on the health of others.

c. Frequent Brakes:

Continuous work should not be encouraged. The work should be planned with margin of frequent short cooling breaks.

d. Environmental Controls:

The controls to mitigate the harsh effect of hot environment should be adopted if possible. These controls include but are not limited to the air conditioning, fans, provision of the temporary shades etc.

e. Emergency Action Plan:

In extreme environments, an emergency plan is needed. The plan should include procedures for providing affected workers with first aid and medical care.

f. Maximum allowable Humidex:

Though no strict standers exist in this subject as each situation is different from other however depending upon the nature on the job a considerate employer must set up a maximum permissible limit of Humidex, beyond which, it permissible, workers should be mandated to stop and reschedule the work at the times when the heat is not high.

Figure -2 Gives the guidelines of the personal response to heat (as compiled by OSHA)

4: Dust/Sand Storms:

Dust and sand storms are most common in the desert. The strength of these storms often creates massive hazards for the people caught in these storms. Some of the major hazards in a sand storm are following

a. The visibility is significantly reduced, often down to few meters which is a major cause of fatal accidents on the highways.

b. Breathing in the dust storm effects the respiratory tracks. This effect varies with the people.

c. Dust can get into eyes which causes the irritation in the eyes.

d. Sand impingement on the bare skin can cause the injuries on the tender parts of the skin like face.

e. Changing land forms causes another hazard. The prolonged sand storm can create the dunes by shifting sand form one place to other.

f. Vehicle roll over is possible in extremely high winds.

<u>Necessary Precautions</u>

a. The sand storm warnings from weather bureau should be taken in account while planning the work.

b. Driving should be avoided in the sand storm.

c. Staying inside the sturdy building structures should be encouraged.

d. Dust masks should be used to avoid the breathing problems.

e. Eye goggles must be worn to protect the eyes.

f. Thick cloth should be used to cover the face from impinging sand.

g. Refuge should be taken in the covered place, preferably at the highest available location, as the dense and heavy sand move at lower levels. Always avoid taking refuge in the ditches.

5: <u>Thunder Storms:</u>

Thunder storms are another weather extremities with fatal hazards associated. Extreme winds, rain and lighting make the driving treacherous on the roads. The biggest hazard in the thunder storm is the lightening. All work in the columns and towers should be avoided while there is thunder storm

6: <u>Safe work planning in with the weather extremes:</u>

Following are some of the necessary minimum precautions required while planning the work in the weather extremes.

a. Make plenty of the cold drinking water at 10-15°C, and salt supplements, available on the job site. All workers should be encouraged to drink water every 15 to 20 minutes even if they do not feel thirsty.

b. Proper clothing should be work to protect from over heat and over cold.

c. Take frequent cooling breaks while working in hot environment.

d. If desert travelling is involved, inform or log the exit time and arrival time on the destination authorities. Never plan travelling without the proper notification to the authorities on the plant sites. Carry plenty of water and non perishable food.

e. A rescue plan should be made and notified to all of the involved personnel.

f. Avoid working in the towers and columns in case of thunder storm.

g. Avoid going into areas where there is a sand storm warning. A dust mask and the goggle must be kept for each worker to use in case of un warned sand storm. Driving should be avoided if the visibility becomes issue.

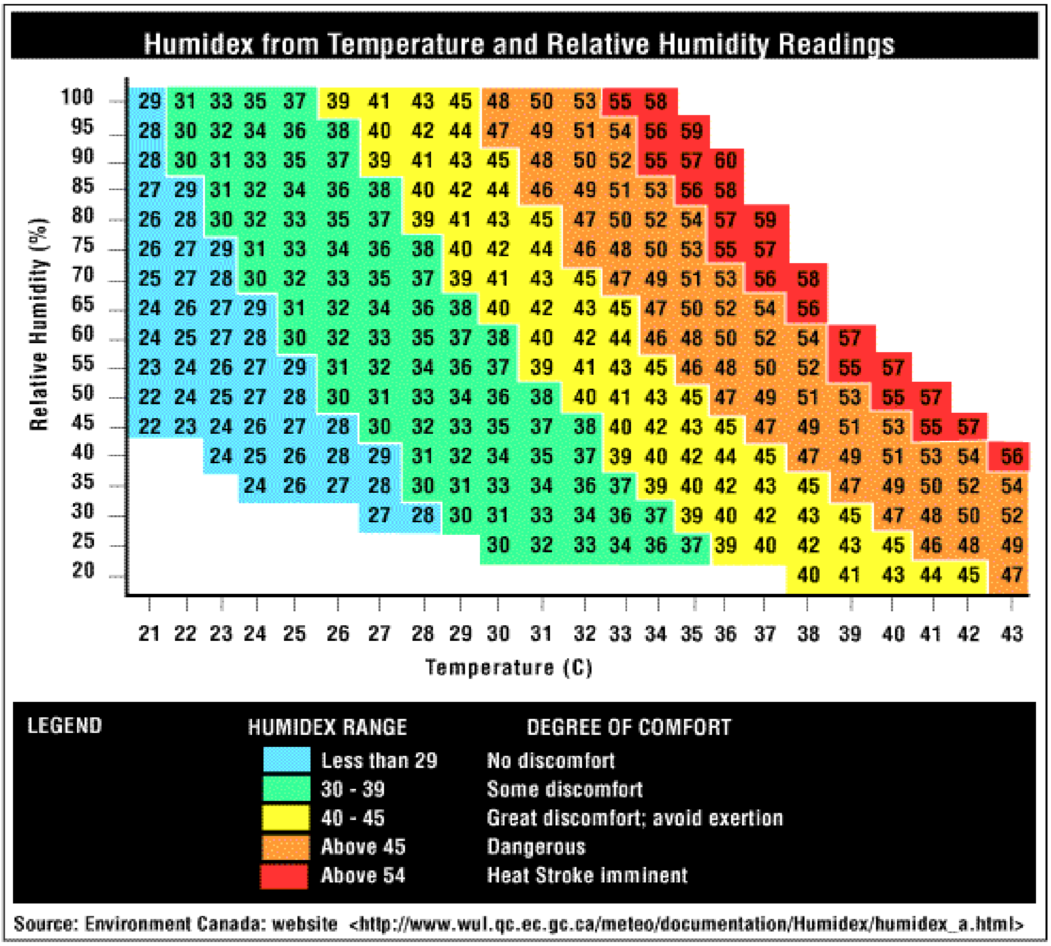


Figure-1: Humidex Chart

Humidex 1 – Moderate physical work, unacclimatized worker. OR Heavy physical work, acclimatized worker	**Response**	Humidex 2 – Moderate physical work, acclimatized worker. OR Light physical work, unacclimatized worker
25-29	• supply water to workers on an "as needed" basis	32-35
30-33	• post Heat Stress Alert notice • encourage workers to drink extra water • start recording hourly temperature and relative humidity	36-39
34-37	• post Heat Stress Warning notice • notify workers that they need to drink extra water • ensure workers are trained to recognize symptoms	40-42
38-39	• provide 15 minutes relief per hour • provide adequate cool (10-15°C) water • at least 1 cup (240 mL) of water every 20 minutes • workers with symptoms should seek medical attention	43-44
40-42	• provide 30 minutes relief per hour in addition to the provisions listed previously	45-46*
43-44	• if feasible provide 45 minutes relief per hour in addition to the provisions listed above • if a 75% relief period is not feasible then stop work until the Humidex is 42°C or less	47-49
45 or over	• stop work until the Humidex is 44°C or less	50* and over

Source: Occupational Health Clinics for Ontario Workers (OHCOW) - "Humidex Based Heat Response Plan", http://www.ohcow.on.ca/menuweb/hhrplan.pdf

Figure-2: Personal response towards heat extremes

A-7 Noise

Noise Fact Sheet:

The exact definition of noise is not possible, it varies with the personal perspectives. Some people call hard metal rock composing as music, while some call it noise. The technical definition of the noise is “a random fluctuations that obscurer, or do not contain meaningful data or other information”. This definition fits with the auditory signals as well as electromagnetic noises. However in the audible terms any random or continuous loud sound can be categorized as a noise if its amplitude is above the comfortable level.

Humans ears can detect sound waves with frequencies that vary from approximately 20 to 20,000 Hz. But all of the people don’t have ability to hear the sounds in this range. The sensitivity of the upper limit of frequency significantly reduces with the age. In general human ears are most sensitive to sounds between 1,000 and 5,000 Hz. The frequencies near the upper auditory limits are generally painful on the ears, so the occupational characterization of the noise is not only based upon the amplitude but also depend upon the frequency. So the sounds with higher volume and higher frequencies are both classified as noise.

Generally the loudness of the sounds also called as sound pressure level SPL, is measured in decibels unit (dB). The loudness of ordinary conversation is normally taken as 55 to 60 dB. The loud sounds are characterized as the sounds above 78 dB, which is 6 times higher in amplitude than ordinary conversation.

Health effects of Noise:

Noise exposure can cause two kinds of health effects, auditory and non-auditory.

1. Auditory Effects:

   The auditory effects of the noise depend upon the amount and the time of the exposure as well as the frequency of the noise. At a given level, low-frequency noise (below 100 Hz) is less damaging compared to noise in the mid-frequencies (1000 - 3000 Hz). Noise-induced hearing loss occurs randomly in exposed persons. Some individuals are more susceptible to noise-induced hearing loss than others. In the initial stages, noise-induced hearing loss is most pronounced at 4000 Hz but it spreads over other frequencies as noise level and/or exposure time increases.

   Following are some auditory damages induced due to high noise levels.

   a. **Acoustic trauma:** Sudden hearing damage caused by short burst of extremely loud noise such as a gunshot.

   b. **Tinnitus:** Ringing or buzzing in the ear.

   c. **Temporary hearing loss:** Also known as temporary threshold shift (TTS) which occurs immediately after exposure to a high level of noise. There is gradual recovery when the affected person spends time in a quiet place. Complete recovery may take several hours.

d. **Permanent hearing loss:** Permanent hearing loss, also known as permanent threshold shift (PTS), progresses constantly as noise exposure continues for months. The hearing impairment is noticeable only when it is substantial enough to interfere with routine activities. At this stage, a permanent and irreversible hearing damage has occurred. Noise-induced hearing damage cannot be cured by medical treatment and worsens as noise exposure continues.

2. Non-Auditory Effects:

The non-auditory effects cannot be easily diagnosed, or quantitatively measured. There are several kinds of minor and major non-auditory disorders that have been associated with the work place noise. Non-auditory effects can be further divided into two categories - physiological effects and performance effects.

a. Psychological Effects:

Psychological effects are very hard to determine, however the work place noise can generate disorders, which leads to various physiological effects. Depending upon the victim, these effects can be an be temporary or permanent. Some of the noise related physiological effects are following.

- Startling response to loud noise.
- Muscle tension response: When muscles tend to contract in the presence of loud noise.
- Respiratory reflexes: When the respiratory rhythm tends to change when noise is present.
- Cardiovascular function effects which involve hypertension, (changes to blood pressure) and change in the heart rate and/or heart beat pattern.
- Annoyance.
- Sleeping problems.
- Physical health and mental health.
- Absenteeism appears to be higher among workers in noisy industries. However it has not been concluded whether this is from psychological aversion to noise or from physiological consequences of noise stress.

b. Performance Effects:

The noisy condition also affects the performance of the employee. Following are main contributing factors to the performance of the employee in the noisy conditions.

- The presence of noise interferes with the understanding of what other people say. This includes face-to-face talks, telephone conversations, and speech over a public address system. In order to be intelligible the sound level of speech must be greater than the background noise. In the noisy condition the workers develop the habit of short conversations and gesture language which could be easily misinterpreted, and lead an injury or other hazardous conditions.

- Depending of the type of activity, noise can affect efficiency of a task performance, due to inability of concentration to the task.

- The audible alarms might not be heard in a noisy environment that could create an additional hazard to the worker.

- a noisy environment interferes with oral communication and thus, interferes with the activity.

Acceptable Limits

Table-1 shows OSHA established acceptable occupational exposure limits to the noise. These limits are according to the length of exposure in the working shift. The hearing protection should be mandated if the time and amplitude exceeds these limits.

Duration per day, hours	Sound level dBA
16	85.0
15	85.5
14	86.0
13	86.5
12	87.1
11	87.7
10	88.4
9	89.2
8	90
6	92
4	95
3	97
2	100
1.5	102
1	105
1/2	110
1.4 or less	115

Table-1 OSHA Acceptable Workplace noise levels

Safe work planning:

If the noise level is above the limits given in table-1, the noise hazard should be added into the PJHA. There is no need to have any noise meter in order to establish the level of the noise. The Rule of thumb is that, when a person has to shout in order to be heard 3 feet away, the noise levels are probably 85 dB or more and hearing protection is recommended.

The hearing protection should be ear plugs or ear muffs. There might be some areas where both will be required to increase protection. Further plan work sequence in such a way that minimum time is spent in the areas with higher level of noise.

Appendix-B

Useful Data

This appendix provided usual data which inspector usually needs for inspection jobs.

Table B-1 Commonly used Materials and the max Allowable stress:

Complete range of the maximum allowable tensile stress values permitted for different materials are given in ASME Section II, Part D Sunpart-1. Following is the data for some commonly used materials for pressure vessels. Also consult Apepndix-A of ASME B31.3 for full list of materials for process Piping.

	Material	Form	Ambient Strength	Max Allowable Stress	Max design temp ºF
Carbon Steels	**SA-36**	Plate	16,600	16,600	900
	SA-106 B	Seamless Pipe	17,100	17,100	1,000
	SA-234 WPB	Fittings	17,100	17,100	1,000
	SA-105	Forging	20,000	19,300	1,000
	SA-516 70	Plate	20,000	19,850	1,000
	SA-414 G	Sheet	21,400	21,400	900
Stainless Steel 316L	**SA-213 TP316L**	Seamless Tube	16,700	14,600	850
	SA-240 316L	Plate	16,700	14,600	850
	SA-312 TP316L	Seamless and Welded Pipe	16,700	14,600	850
	SA-403 316L	Seamless and Weld Fittings	16,700	14,600	850
	SA-479 316L	Bar	16,700	14,600	850
Stainless Steel 316	**SA-213 TP316**	Seamless Tube	20,000	17,750	1,500
	SA-240 316	Plate	20,000	17,750	1,500
	SA-312 TP316	Seamless and Welded Pipe	20,000	17,750	1,500
	SA-403 316	Seamless and Weld Fittings	20,000	17,750	1,500
	SA-479 316	Bar	20,000	17,750	1,500
Stainless Steel 304L	**SA-213 TP304L**	Seamless Tube	16,700	14,525	1,200
	SA-240 304L	Plate	16,700	14,525	1,200
	SA-312 TP304L	Seamless and Welded Pipe	16,700	14,525	1,200
	SA-403 304L	Seamless and Weld Fittings	16,700	14,525	1,200
	SA-479 304L	Bar	16,700	14,525	1,200

Stainless Steel 304	**SA-213 TP304**	Seamless Tube	20,000	12,750	1,500
	SA-240 304	Plate	20,000	12,750	1,500
	SA-312 TP304	Seamless. and Welded. Pipe	20,000	17,275	1,500
	SA-403 304	Seamless and Weld Fittings	20,000	17,275	1,500
	SA-479 304	Bar	20,000	17,275	1,500

Table B-2: Pipe dimensions and nominal thickness.

*** Note-1:** Mill tolerance of 12.5% is to compensate for the dimensional changes at the manufacturing stage. It applies for the piping and fittings up to 24" diameter. Pipes above 24" dia (usually made from rolled sheets) have mill tolerance of 0.01". While fittings above 24" still have mill tolerance of 12.5%

**** Note-2:** Min-t required is the initial thickness of pipe at time of commissioning. Ultimate t-min of corded pipe should be calculated using Barlow's Equation as per Section-5 Para 9.3.4 of this manual.

Pipe Dimension Chart										
Nominal Pipe Size Inches	Nominal Pipe Size mm	OD Inches	OD mm	Schedule	Wall Thickness (inch)	Wall Thickness mm * See Note-1	Min-t allowed (In) t nom - mill tol (12.5%) ** See Note-2	Min-t allowed (mm) t nom - mill tol (12.5%) ** See Note-2	Lbs/Ft	Kg/M
1/8	6	0.405	10.3	10/10S	0.049	1.24	0.043	1.085	0.1863	0.28
1/8	6	0.405	10.3	STD /40/40S	0.068	1.73	0.060	1.514	0.2447	0.36
1/8	6	0.405	10.3	XS/80/80S	0.095	2.41	0.083	2.109	0.3145	0.47
1/4	8	0.54	13.7	10/10S	0.065	1.65	0.057	1.444	0.3297	0.49
1/4	8	0.54	13.7	STD /40/40S	0.088	2.24	0.077	1.960	0.4248	0.63
1/4	8	0.54	13.7	XS/80/80S	0.119	3.02	0.104	2.643	0.5351	0.8
3/8	10	0.675	17.1	10/10S	0.065	1.65	0.057	1.444	0.4235	0.63
3/8	10	0.675	17.1	STD 40/40S	0.091	2.31	0.080	2.021	0.5676	0.84
3/8	10	0.675	17.1	XS 80/80S	0.126	3.2	0.110	2.800	0.7388	1.1
1/2	15	0.84	21.3	5/5S	0.065	1.65	0.057	1.444	0.5383	0.8
1/2	15	0.84	21.3	10/10S	0.083	2.11	0.073	1.846	0.671	1
1/2	15	0.84	21.3	STD 40/40S	0.109	2.77	0.095	2.424	0.851	1.27
1/2	15	0.84	21.3	XS 80/80S	0.147	3.73	0.129	3.264	1.088	1.62
1/2	15	0.84	21.3	160	0.188	4.78	0.165	4.183	1.309	1.95
1/2	15	0.84	21.3	XX	0.294	7.47	0.257	6.536	1.714	2.55
3/4	20	1.05	26.7	5/5S	0.065	1.65	0.057	1.444	0.6838	1.02
3/4	20	1.05	26.7	10/10S	0.083	2.11	0.073	1.846	0.8572	1.28

3/4	20	1.05	26.7	STD /40/40S	0.113	2.87	0.099	2.511	1.131	1.68
3/4	20	1.05	26.7	XS/80/80S	0.154	3.91	0.135	3.421	1.474	2.19
3/4	20	1.05	26.7	160	0.219	5.56	0.192	4.865	1.944	2.89
3/4	20	1.05	26.7	XX	0.308	7.82	0.270	6.843	2.441	3.63
1	25	1.315	33.4	5/5S	0.065	1.65	0.057	1.444	0.8678	1.29
1	25	1.315	33.4	10/10S	0.109	2.77	0.095	2.424	1.404	2.09
1	25	1.315	33.4	STD /40/40S	0.133	3.38	0.116	2.958	1.679	2.5
1	25	1.315	33.4	XS/80/80S	0.179	4.55	0.157	3.981	2.172	3.23
1	25	1.315	33.4	160	0.25	6.35	0.219	5.556	2.844	4.23
1	25	1.315	33.4	XX	0.358	9.09	0.313	7.954	3.659	5.45
1-1/4	32	1.66	42.2	5/5S	0.065	1.65	0.057	1.444	1.107	1.65
1-1/4	32	1.66	42.2	10/10S	0.109	2.77	0.095	2.424	1.806	2.69
1-1/4	32	1.66	42.2	STD /40/40S	0.14	3.56	0.123	3.115	2.273	3.38
1-1/4	32	1.66	42.2	XS/80/80S	0.191	4.85	0.167	4.244	2.997	4.46
1-1/4	32	1.66	42.2	160	0.25	6.35	0.219	5.556	3.765	5.6
1-1/4	32	1.66	42.2	XX	0.382	9.7	0.334	8.488	5.214	7.76
1-1/2	40	1.9	48.3	5/5S	0.065	1.65	0.057	1.444	1.274	1.9
1-1/2	40	1.9	48.3	10/10S	0.109	2.77	0.095	2.424	2.085	3.1
1-1/2	40	1.9	48.3	STD /40/40S	0.145	3.68	0.127	3.220	2.718	4.05
1-1/2	40	1.9	48.3	XS/80/80S	0.2	5.08	0.175	4.445	3.631	5.4
1-1/2	40	1.9	48.3	160	0.281	7.14	0.246	6.248	4.859	7.23
1-1/2	40	1.9	48.3	XX	0.4	10.16	0.350	8.890	6.408	9.54
2	50	2.375	60.3	5/5S	0.065	1.65	0.057	1.444	1.604	2.39
2	50	2.375	60.3	10/10S	0.109	2.77	0.095	2.424	2.638	3.93
2	50	2.375	60.3	STD /40/40S	0.154	3.91	0.135	3.421	3.653	5.44
2	50	2.375	60.3	XS/80/80S	0.218	5.54	0.191	4.848	5.022	7.47
2	50	2.375	60.3	160	0.344	8.74	0.301	7.648	7.462	11.11
2	50	2.375	60.3	XX	0.436	11.07	0.382	9.686	9.029	13.44
2-1/2	65	2.875	73	5/5S	0.083	2.11	0.073	1.846	2.475	3.68
2-1/2	65	2.875	73	10/10S	0.12	3.05	0.105	2.669	3.531	5.26
2-1/2	65	2.875	73	STD /40/40S	0.203	5.16	0.178	4.515	5.793	8.62
2-1/2	65	2.875	73	XS/80/80S	0.276	7.01	0.242	6.134	7.661	11.4

2-1/2	65	2.875	73	160	0.375	9.53	0.328	8.339	10.01	14.9
2-1/2	65	2.875	73	XX	0.552	14.02	0.483	12.268	13.69	20.37
3	80	3.5	88.9	5/5S	0.083	2.11	0.073	1.846	3.029	4.51
3	80	3.5	88.9	10/10S	0.12	3.05	0.105	2.669	4.332	6.45
3	80	3.5	88.9	STD /40/40S	0.216	5.49	0.189	4.804	7.576	11.27
3	80	3.5	88.9	XS/80/80S	0.3	7.62	0.263	6.668	10.25	15.25
3	80	3.5	88.9	160	0.438	11.13	0.383	9.739	14.32	21.31
3	80	3.5	88.9	XX	0.6	15.24	0.525	13.335	18.58	27.65
3-1/2	90	4	101.6	5/5S	0.083	2.11	0.073	1.846	3.472	5.17
3-1/2	90	4	101.6	10/10S	0.12	3.05	0.105	2.669	4.973	7.4
3-1/2	90	4	101.6	STD 40/40S	0.226	5.74	0.198	5.023	9.109	13.56
3-1/2	90	4	101.6	XS 80/80S	0.318	8.08	0.278	7.070	12.5	18.6
3-1/2	90	4	101.6	XX	0.636	16.15	0.557	14.131	22.85	34.01
4	100	4.5	114.3	5/5S	0.083	2.11	0.073	1.846	3.915	5.83
4	100	4.5	114.3	10/10S	0.12	3.05	0.105	2.669	5.613	8.35
4	100	4.5	114.3	STD 40/40S	0.237	6.02	0.207	5.268	10.79	16.06
4	100	4.5	114.3	XS 80/80S	0.337	8.56	0.295	7.490	14.98	22.29
4	100	4.5	114.3	120	0.438	11.13	0.383	9.739	19	28.28
4	100	4.5	114.3	160	0.531	13.49	0.465	11.804	22.51	33.5
4	100	4.5	114.3	XX	0.674	17.12	0.590	14.980	27.54	40.99
5	125	5.563	141.3	5/5S	0.109	2.77	0.095	2.424	6.349	9.45
5	125	5.563	141.3	10/10S	0.134	3.4	0.117	2.975	7.77	11.56
5	125	5.563	141.3	STD 40/40S	0.258	6.55	0.226	5.731	14.62	21.76
5	125	5.563	141.3	XS 80/80S	0.375	9.53	0.328	8.339	20.78	30.93
5	125	5.563	141.3	120	0.5	12.7	0.438	11.113	27.04	40.24
5	125	5.563	141.3	160	0.625	15.88	0.547	13.895	32.96	49.05
5	125	5.563	141.3	XX	0.75	19.05	0.656	16.669	38.55	57.37
6	150	6.625	168.3	5/5S	0.109	2.77	0.095	2.424	7.585	11.29
6	150	6.625	168.3	10/10S	0.134	3.4	0.117	2.975	9.289	13.82
6	150	6.625	168.3	STD 40/40S	0.28	7.11	0.245	6.221	18.97	28.23

6	150	6.625	168.3	XS 80/80S	0.432	10.97	0.378	9.599	28.57	42.52
6	150	6.625	168.3	120	0.562	14.27	0.492	12.486	36.39	54.16
6	150	6.625	168.3	160	0.719	18.26	0.629	15.978	45.35	67.49
6	150	6.625	168.3	XX	0.864	21.95	0.756	19.206	53.16	79.12
8	200	8.625	219.1	5S	0.109	2.77	0.095	2.424	9.914	14.75
8	200	8.625	219.1	10/10S	0.148	3.76	0.130	3.290	13.6	19.94
8	200	8.625	219.1	20	0.25	6.35	0.219	5.556	22.36	33.28
8	200	8.625	219.1	30	0.277	7.04	0.242	6.160	24.7	36.76
8	200	8.625	219.1	STD /40/40S	0.322	8.18	0.282	7.158	28.55	42.49
8	200	8.625	219.1	60	0.406	10.31	0.355	9.021	35.64	53.04
8	200	8.625	219.1	XS/80/80S	0.5	12.7	0.438	11.113	43.39	64.58
8	200	8.625	219.1	100	0.594	15.09	0.520	13.204	50.95	75.83
8	200	8.625	219.1	120	0.719	18.26	0.629	15.978	60.71	90.35
8	200	8.625	219.1	140	0.812	20.62	0.711	18.043	67.76	100.84
8	200	8.625	219.1	XX	0.875	22.23	0.766	19.451	72.42	107.78
8	200	8.625	219.1	160	0.906	23.01	0.793	20.134	74.69	111.16
10	250	10.75	273.1	5S	0.134	3.4	0.117	2.975	15.19	22.61
10	250	10.75	273.1	10S	0.165	4.19	0.144	3.666	18.7	27.83
10	250	10.75	273.1	20	0.25	6.35	0.219	5.556	28.04	41.73
10	250	10.75	273.1	30	0.307	7.8	0.269	6.825	34.24	50.96
10	250	10.75	273.1	STD /40/40S	0.365	9.27	0.319	8.111	40.48	60.24
10	250	10.75	273.1	XS/60/80S	0.5	12.7	0.438	11.113	54.74	81.47
10	250	10.75	273.1	80	0.594	15.09	0.520	13.204	64.43	95.89
10	250	10.75	273.1	100	0.719	18.26	0.629	15.978	77.03	114.64
10	250	10.75	273.1	120	0.844	21.44	0.739	18.760	89.29	132.89
10	250	10.75	273.1	140/XX	1	25.4	0.875	22.225	104.13	154.97
10	250	10.75	273.1	160	1.125	28.58	0.984	25.008	115.64	172.1
12	300	12.75	323.9	5S	0.156	3.96	0.137	3.465	20.98	31.22
12	300	12.75	323.9	10S	0.18	4.57	0.158	3.999	24.2	36.02
12	300	12.75	323.9	20	0.25	6.35	0.219	5.556	33.38	49.68
12	300	12.75	323.9	30	0.33	8.38	0.289	7.333	43.77	65.14
12	300	12.75	323.9	STD /40S	0.375	9.53	0.328	8.339	49.56	73.76

12	300	12.75	323.9	40	0.406	10.31	0.355	9.021	53.52	79.65
12	300	12.75	323.9	XS/80S	0.5	12.7	0.438	11.113	65.42	97.36
12	300	12.75	323.9	60	0.562	14.27	0.492	12.486	73.15	108.87
12	300	12.75	323.9	80	0.688	17.48	0.602	15.295	88.63	131.9
12	300	12.75	323.9	100	0.844	21.44	0.739	18.760	107.32	159.72
12	300	12.75	323.9	120/XX	1	25.4	0.875	22.225	125.49	186.76
12	300	12.75	323.9	140	1.125	28.58	0.984	25.008	139.67	207.86
12	300	12.75	323.9	160	1.312	33.32	1.148	29.155	160.27	238.52
14	350	14	355.6	10S	0.188	4.78	0.165	4.183	27.73	41.27
14	350	14	355.6	10	0.25	6.35	0.219	5.556	36.71	54.63
14	350	14	355.6	20	0.312	7.92	0.273	6.930	45.61	67.88
14	350	14	355.6	STD /30/40S	0.375	9.53	0.328	8.339	54.57	81.21
14	350	14	355.6	40	0.438	11.13	0.383	9.739	63.44	94.41
14	350	14	355.6	XS/80S	0.5	12.7	0.438	11.113	72.09	107.29
14	350	14	355.6	60	0.594	15.09	0.520	13.204	85.05	126.58
14	350	14	355.6	80	0.75	19.05	0.656	16.669	106.13	157.95
14	350	14	355.6	100	0.938	23.83	0.821	20.851	130.85	194.74
14	350	14	355.6	120	1.094	27.79	0.957	24.316	150.9	224.58
14	350	14	355.6	140	1.25	31.75	1.094	27.781	170.21	253.32
14	350	14	355.6	160	1.406	35.71	1.230	31.246	189.1	281.43
16	400	16	406.4	10S	0.188	4.78	0.165	4.183	31.75	47.25
16	400	16	406.4	10	0.25	6.35	0.219	5.556	42.05	62.58
16	400	16	406.4	20	0.312	7.92	0.273	6.930	52.27	77.79
16	400	16	406.4	STD /30/40S	0.375	9.53	0.328	8.339	62.58	93.13
16	400	16	406.4	XS/40/80S	0.5	12.7	0.438	11.113	82.77	123.18
16	400	16	406.4	60	0.656	16.66	0.574	14.578	107.5	159.99
16	400	16	406.4	80	0.844	21.44	0.739	18.760	136.61	203.31
16	400	16	406.4	100	1.031	26.2	0.902	22.925	164.82	245.29
16	400	16	406.4	120	1.219	30.96	1.067	27.090	192.43	286.38
16	400	16	406.4	140	1.438	36.53	1.258	31.964	223.64	332.83
16	400	16	406.4	160	1.594	40.49	1.395	35.429	245.25	364.99
18	450	18	457.2	10S	0.188	4.78	0.165	4.183	35.76	53.22

18	450	18	457.2	10	0.25	6.35	0.219	5.556	47.39	70.53
18	450	18	457.2	20	0.312	7.92	0.273	6.930	58.94	87.72
18	450	18	457.2	STD /40S	0.375	9.53	0.328	8.339	70.59	105.06
18	450	18	457.2	30	0.438	11.13	0.383	9.739	82.15	122.26
18	450	18	457.2	XS/80S	0.5	12.7	0.438	11.113	93.45	139.08
18	450	18	457.2	40	0.562	14.27	0.492	12.486	104.67	155.78
18	450	18	457.2	60	0.75	19.05	0.656	16.669	138.17	205.63
18	450	18	457.2	80	0.938	23.83	0.821	20.851	170.92	254.37
18	450	18	457.2	100	1.156	29.36	1.012	25.690	207.96	309.5
18	450	18	457.2	120	1.375	34.93	1.203	30.564	244.14	363.34
18	450	18	457.2	140	1.562	39.67	1.367	34.711	274.22	408.11
18	450	18	457.2	160	1.781	45.24	1.558	39.585	308.5	459.13
20	500	20	508	10S	0.218	5.54	0.191	4.848	46.06	68.55
20	500	20	508	10	0.25	6.35	0.219	5.556	52.73	78.48
20	500	20	508	STD /20/40S	0.375	9.53	0.328	8.339	78.6	116.98
20	500	20	508	XS/30/80S	0.5	12.7	0.438	11.113	104.13	154.97
20	500	20	508	40	0.594	15.09	0.520	13.204	123.11	183.22
20	500	20	508	60	0.812	20.62	0.711	18.043	166.4	247.65
20	500	20	508	80	1.031	26.19	0.902	22.916	208.87	310.85
20	500	20	508	100	1.281	32.54	1.121	28.473	256.1	381.14
20	500	20	508	120	1.5	38.1	1.313	33.338	296.37	441.07
20	500	20	508	140	1.75	44.45	1.531	38.894	341.09	507.63
20	500	20	508	160	1.969	50.01	1.723	43.759	379.17	564.3
24	600	24	609.6	10/10S	0.25	6.35	0.219	5.556	63.41	94.37
24	600	24	609.6	STD /20/40S	0.375	9.53	0.328	8.339	94.62	140.82
24	600	24	609.6	XS/80S	0.5	12.7	0.438	11.113	125.49	186.76
24	600	24	609.6	30	0.562	14.27	0.492	12.486	140.68	209.37
24	600	24	609.6	40	0.688	17.48	0.602	15.295	171.29	254.92
24	600	24	609.6	60	0.969	24.61	0.848	21.534	238.35	354.72
24	600	24	609.6	80	1.219	30.96	1.067	27.090	296.58	441.39
24	600	24	609.6	100	1.531	38.89	1.340	34.029	367.39	546.77
24	600	24	609.6	120	1.812	46.02	1.586	40.268	429.39	639.04
24	600	24	609.6	140	2.062	52.37	1.804	45.824	483.1	718.97

24	600	24	609.6	160	2.344	59.54	2.051	52.098	542.13	806.83
30	750	30	762	10	0.312	7.92	0.273	6.930	98.93	147.23
30	750	30	762	STD /40S	0.375	9.53	0.328	8.339	118.65	176.58
30	750	30	762	XS/20/80S	0.5	12.7	0.438	11.113	157.53	234.44
30	750	30	762	30	0.625	15.88	0.547	13.895	196.08	291.82
36	900	36	914.4	10	0.312	7.92	0.273	6.930	118.92	176.98
36	900	36	914.4	STD /40S	0.375	9.53	0.328	8.339	142.68	212.34
36	900	36	914.4	XS/80S	0.5	12.7	0.438	11.113	189.57	282.13

Table B-3: Pipe dimensions and Maximum Allowable pressures Vs Temperature

Reference: http://www.engineeringtoolbox.com

Maximum allowable pressure and temperature ratings for grade commonly used B Process Piping (ASTM A53, A106, A523, API 5L PSL-1)

Maximum Allowable Pressure *(kPa)*											
Nominal Size *(mm)*	Schedule no.		Wall Thickness *(mm)*	Temperature (°C)							
				-67	205	260	350	370	400	430[1)]	450
				Maximum Allowable Stress *(kPa)*							
				137800	137800	130221	117130	115752	89570	74412	59943
15	STD	40	2.77	34416	34416	32528	29255	28910	22372	18589	14972
	XS	80	3.73	48092	48092	45466	40878	40396	31260	25969	20918
		160	4.78	62830	62830	59378	53404	52777	40837	33929	27333
	XXS		7.47	98245	98245	92836	83507	82522	63857	53053	42739
20	STD	40	2.87	28070	28070	26526	23860	23578	18245	15158	12209
	XS	80	3.91	39418	39418	37247	33506	33106	25617	21283	17142
		160	5.56	58152	58152	54955	49429	48843	37799	31398	25293
	XXS		7.82	83107	83107	78539	70643	69809	54024	44881	36152
25	STD	40	3.38	26251	26251	24804	22310	22048	17060	14173	11417
	XS	80	4.55	36283	36283	34285	30862	30474	23584	19595	15785
		160	6.35	52481	52481	49594	44606	44082	34112	28339	22827

	XXS		9.09	77030	77030	72793	65476	64704	50070	41595	33506
32	STD	40	3.56	21614	21614	20421	18369	18155	14049	11672	9404
	XS	80	4.85	30178	30178	28518	25651	25348	19616	16295	13125
		160	6.35	40596	40596	38364	34505	34099	26389	21924	17659
	XXS		9.7	64601	64601	61045	54906	54266	41988	34884	28097
40	STD	40	3.68	19444	19444	18375	16529	16329	12636	10550	8454
	XS	80	5.08	27402	27402	25900	23295	23019	17811	14800	11919
		160	7.14	39738	39738	37599	33816	33416	25858	21483	17308
	XXS		10.16	58779	58799	55547	49966	49374	38205	31742	25569
50	STD	40	3.91	16378	16378	15468	13925	13759	10645	8847	7124
	XS	80	5.54	23653	23653	22351	20105	19871	15378	12774	10287
		160	8.74	38866	38866	36731	33037	32652	25266	20987	16908
	XXS		11.07	50793	50793	48003	43173	42670	33017	27429	22096
65	STD	40	5.16	17914	17914	16929	15227	15048	11644	9674	7793
	XS	80	7.01	24818	24818	23447	21097	20849	16129	13401	10797
		160	9.53	34615	34615	32714	29420	29076	22503	18693	15055
	XXS		14.02	53081	53081	50159	45116	44585	34498	28662	23088
80	STD	40	5.49	15558	15558	14969	13222	13063	10108	8399	6766
	XS	80	7.62	21986	21968	20780	18693	18472	14290	11871	9563
		160	11.13	33079	33079	31253	28111	27780	21497	17859	14386

	XXS		15.24	46976	46976	44392	39928	39459	30536	25369	20436
100	STD	40	6.02	13187	13187	12464	11210	11079	8571	7124	5739
	XS	80	8.56	19058	19058	18010	16198	16012	12388	12094	8289
		120	11.13	25190	25190	23805	21407	21159	16371	13601	10995
		160	13.49	31019	31019	29310	26368	26058	20160	16750	13208
	XXS		17.12	40348	40348	38129	34298	33892	26230	21786	17549
125	STD	40	6.55	11561	11561	10921	9825	9708	7510	6243	5038
	XS	80	9.53	17060	17060	16122	14503	14331	11093	9212	7421
		120	12.7	23130	23130	21855	19657	19430	15034	12492	10059
		160	15.88	29407	29407	27787	24997	24701	19113	15881	12795
	XXS		19.05	35897	35897	33926	30516	30158	23337	19388	15620
150	STD	40	7.11	10550	10550	9928	8924	8819	6828	5370	4568
	XS	80	10.97	16474	16474	15571	14007	13842	10707	8895	7165
		120	14.27	21745	21745	20553	18448	18265	14138	11747	9460
	XXS	160	18.26	28325	28325	26768	24074	23784	18410	15296	12319
200		20	6.35	7138	7138	6745	6063	5994	4637	3852	3100
		30	7.04	7924	7924	7489	6732	6656	5147	4279	3445
	STD	40	8.18	9246	9246	8737	7855	7765	6008	4995	4024
		60	10.31	11741	11741	11093	9977	9860	7627	6339	5105
	XS	80	12.7	14572	14572	13766	12388	12237	9474	7868	6338

		100	150.9	17452	17452	16488	14834	14655	11341	9426	7593
		120	18.26	21345	21345	20174	18148	17935	13876	11527	9288
		140	20.62	24308	24308	22971	20656	20415	15799	13125	10569
	XXS		22.23	26334	26334	24877	22386	22124	17115	14221	11458
		160	23.01	27340	27340	25838	23240	22964	17769	14765	11892
250		20	6.35	5698	5698	5388	4844	4789	3707	3080	2480
		30	7.8	7028	7028	6642	5974	5905	4568	3796	3059
	STD	40	9.27	8385	8385	7923	7131	7048	5450	4527	3652
	XS	60	12.7	11596	11596	10955	9853	9736	7538	6263	5043
		80	15.09	13863	13863	13098	11781	11644	9012	7483	6028
		100	18.26	16922	16922	15992	14386	14214	10996	9136	7359
		120	21.44	20036	20036	18934	17032	16825	13022	10817	8716
	XXS	140	25.4	23998	23998	16474	20394	20153	15599	12960	10438
		160	28.58	27229	27229	25734	23143	22875	17700	14703	11844
300		20	6.35	4795	4795	4534	4072	4024	3114	2591	2088
		30	8.38	6359	6359	6008	5402	5540	4134	3431	2763
	STD		9.53	7241	7241	6842	6153	6084	4706	3914	3149
		40	10.31	7854	7854	7421	6676	6601	5015	4244	3417
	XS		12.7	9722	9722	9191	8268	8165	6318	5250	4230
		60	14.27	10969	10969	10363	9322	9212	7131	5925	4768

		80	17.48	13525	13525	12850	11492	11362	8792	7303	5884
		100	21.44	16736	16736	15819	14227	14062	10879	9040	7283
	XXS	120	25.4	20015	20015	18913	17011	16811	13008	10804	8702
		140	28.58	22682	22682	21435	19278	19051	14744	12244	9866
		160	33.32	26740	26740	25273	22730	22461	17383	14441	11630
350		10	6.35	4361	4361	4120	3707	3665	2831	2356	1895
		20	7.92	5457	5457	5161	4644	4589	3548	2949	2377
	STD	30	9.53	6580	6580	6222	5595	5533	4279	3555	2866
		40	11.13	7717	7717	7310	6559	6477	5016	4168	3355
	XS		12.7	8833	8833	8351	7510	7421	5739	4768	3845
		60	15.09	10541	10541	9963	8964	8861	6855	5691	4589
		80	19.05	13421	13421	12684	11410	11272	9723	7248	5836
		100	23.83	16949	16949	16019	14407	14242	11017	9157	7372
		120	27.79	19933	19933	18837	16943	16743	12960	10762	8675
		140	31.75	22964	22964	21703	19519	19292	14931	12402	9990
		160	35.71	26051	26051	24618	22144	21883	16936	14069	11334
400		10	6.35	3810	3810	3603	3238	3197	2474	2060	1660
		20	7.92	4768	4768	4507	4051	4004	3100	2577	2074
	STD	30	9.53	5746	5746	5429	4885	4830	3734	3100	2501
	XS	40	12.7	7703	7703	7283	6545	6470	5009	4126	3349

		60	16.66	10176	10176	9618	8654	8550	6614	5498	4430
		80	21.44	13208	13208	12478	11224	11093	8585	7131	5746
		100	26.19	16274	16274	15378	13835	13670	10576	8785	7076
		120	30.96	19409	19409	18341	16481	16302	12616	10480	8440
		140	36.53	23130	23130	21855	19657	19430	15034	12492	10059
		160	40.49	25824	25824	24404	21952	21697	16784	13945	11238
450		10	6.35	3383	3383	3197	2873	2839	2198	1826	1474
		20	7.92	4230	4230	3996	3597	3555	2749	2287	1839
	STD		9.53	5099	5099	4816	4334	4286	3314	2756	2219
	XS	30	11.13	5967	5967	5643	5071	5016	3879	3225	2598
			12.7	6835	6835	6456	5808	5739	4437	3686	2969
		40	14.27	7696	7696	7276	6545	6463	5002	4155	3349
		60	19.05	10349	10349	9784	8799	8695	6725	5588	4499
		80	23.83	13043	13043	12326	11086	10955	8475	7042	5670
		100	29.36	16219	16219	15323	13787	13622	10542	8757	7055
		120	34.93	19464	19464	18389	16543	16350	12650	10507	8468
		140	39.67	22282	22282	21056	18941	18713	11483	12030	9694
		160	45.24	25638	25638	24225	21793	21531	16660	13842	11155
		10	6.35	3038	3038	2873	2574	2556	1977	1640	1323
	STD	20	9.53	4582	4582	4327	3893	3852	2976	2474	1991

	XS	30	12.7	6139	6139	5801	5216	5154	3989	3314	2666
		40	15.09	7317	7317	6911	6215	6146	4754	3948	3183
500		60	20.62	10080	10080	9522	8564	8468	6552	5443	4382
		80	26.19	12898	12898	12188	10962	10831	8385	6966	5608
		100	32.54	16171	16171	15287	13746	13580	10514	8730	7035
		120	38.1	19085	19085	18037	16226	16033	12409	10307	8302
		140	44.45	22475	22475	21242	19106	18879	14614	12140	9777
		160	50.01	25450	25450	24094	21675	21421	16577	13766	11093
		10	6.35	2529	2529	2391	2150	2129	1647	1364	1102
	STD	20	9.53	3810	3810	3603	3238	3197	2474	2060	1660
	XS		12.7	5097	5097	4816	4334	4286	3314	2756	2219
		30	14.27	5739	5739	5423	4878	4823	3734	3100	2494
		40	17.48	7055	7055	6670	5994	5925	4589	3810	3066
600		60	24.61	10018	10018	9467	8516	8420	6511	5409	4361
		80	30.96	12691	12691	12002	10783	10659	8254	6856	5519
		100	38.89	16102	16102	15220	13690	10528	10466	8695	7007
		120	46.02	19223	19223	18168	16336	16150	12491	10383	8364
		140	52.37	22048	22048	20835	18741	18520	14331	11906	9591
		160	59.54	25279	25279	23888	21489	21235	16433	13649	10996

Table B-4: Joint Efficiencies for Pressure Vessels welds:

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TABLE UW-12
MAXIMUM ALLOWABLE JOINT EFFICIENCIES FOR ARC AND GAS WELDED JOINTS

Type No.	Joint Description	Limitations	Joint Category	Degree of Radiographic Examination (a) Full [Note (1)]	(b) Spot [Note (2)]	(c) None
(1)	Butt joints as attained by double-welding or by other means which will obtain the same quality of deposited weld metal on the inside and outside weld surfaces to agree with the requirements of UW-35. Welds using metal backing strips which remain in place are excluded.	None	A, B, C & D	1.00	0.85	0.70
(2)	Single-welded butt joint with backing strip other than those included under (1)	(a) None except as in (b) below	A, B, C & D	0.90	0.80	0.65
		(b) Circumferential butt joints with one plate offset; see UW-13(b)(4) and Fig. UW-13.1, sketch (i)	A, B & C	0.90	0.80	0.65
(3)	Single-welded butt joint without use of backing strip	Circumferential butt joints only, not over 5/8 in. (16 mm) thick and not over 24 in. (600 mm) outside diameter	A, B & C	NA	NA	0.60
(4)	Double full fillet lap joint	(a) Longitudinal joints not over 3/8 in. (10 mm) thick	A	NA	NA	0.55
		(b) Circumferential joints not over 5/8 in. (16 mm) thick	B & C [Note (3)]	NA	NA	0.55
(5)	Single full fillet lap joints with plug welds conforming to UW-17	(a) Circumferential joints [Note (4)] for attachment of heads not over 24 in. (600 mm) outside diameter to shells not over 1/2 in. (13 mm) thick	B	NA	NA	0.50
		(b) Circumferential joints for the attachment to shells of jackets not over 5/8 in. (16 mm) in nominal thickness where the distance from the center of the plug weld to the edge of the plate is not less than 1 1/2 times the diameter of the hole for the plug.	C	NA	NA	0.50

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TABLE UW-12
MAXIMUM ALLOWABLE JOINT EFFICIENCIES FOR ARC AND GAS WELDED JOINTS (CONT'D)

Type No.	Joint Description	Limitations	Joint Category	Degree of Radiographic Examination (a) Full [Note (1)]	(b) Spot [Note (2)]	(c) None
(6)	Single full fillet lap joints without plug welds	*(a)* For the attachment of heads convex to pressure to shells not over ⅝ in. (16 mm) required thickness, only with use of fillet weld on inside of shell; or	A & B	NA	NA	0.45
		(b) for attachment of heads having pressure on either side, to shells not over 24 in. (600 mm) inside diameter and not over ¼ in. (6 mm) required thickness with fillet weld on outside of head flange only	A & B	NA	NA	0.45
(7)	Corner joints, full penetration, partial penetration, and/or fillet welded	As limited by Fig. UW-13.2 and Fig UW-16.1	C & D [Note (5)]	NA	NA	NA
(8)	Angle joints	Design per U-2(g) for Category B and C joints	B, C & D	NA	NA	NA

GENERAL NOTES:
(a) The single factor shown for each combination of joint category and degree of radiographic examination replaces both the stress reduction factor and the joint efficiency factor considerations previously used in this Division.
(b) E = 1.0 for butt joints in compression.

NOTES:
(1) See UW-12(a) and UW-51.
(2) See UW-12(b) and UW-52.
(3) For Type No. 4 Category C joint, limitation not applicable for bolted flange connections.
(4) Joints attaching hemispherical heads to shells are excluded.
(5) There is no joint efficiency E in the design formulas of this Division for Category C and D corner joints. When needed, a value of E not greater than 1.00 may be used.

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Table B-5: Materials and Corrosion tendency in different corrosive environment

Reference: http://www.engineeringtoolbox.com/metal-corrosion-resistance-d_491.html

Corrosion Resistance Legend: **1= Good, 2 = Low 3= Poor, NA= Data not available**

	Metal											
Fluid	Carbon Steel	Cast Iron	302 and 304 Stainless Steel	316 Stainless Steel	Bronze	Durimet	Monel	Hasteloy B	Hasteloy C	Titanium	Cobalt base alloy 6	416 Stainless Steel
Acetaldehyde	1	1	1	1	1	1	1	NA	1	NA	NA	1
Acetic acid, air free	3	3	2	2	2	1	2	1	1	1	1	3
Acetic acid, aerated	3	3	1	1	1	1	1	1	1	1	1	3
Acetic acid, vapors	3	3	1	1	2	2	2	NA	1	1	1	3
Acetone	1	1	1	1	1	1	1	1	1	1	1	1
Acetylene	1	1	1	1	NA	1	1	1	1	NA	1	1
Alcohols	1	1	NA	1	1	1	1	1	1	1	1	1
Aluminum Sulfate	3	3	1	1	2	1	2	1	1	1	NA	3
Ammonia	1	1	1	1	3	1	3	1	1	1	1	1
Ammonium chloride	3	3	2	2	2	1	2	1	1	1	2	3
Ammonium Nitrate	1	3	1	1	3	1	3	1	1	1	1	3
Ammonium Phosphate	3	3	1	1	2	2	2	1	1	1	1	2
Ammonium Sulfate	3	3	2	1	2	1	1	1	1	1	1	3
Ammonium Sulfite	3	3	1	1	3	1	3	NA	1	1	1	2
Asphalt	1	1	1	1	1	1	1	1	1	NA	1	1
Benzene (benzol)	1	1	1	1	1	1	1	1	1	1	1	1
Benzoic acid	3	3	1	1	1	1	1	NA	1	1	NA	1
Boric acid	3	3	1	1	1	1	1	1	1	1	1	2
Butane	1	1	1	1	1	1	1	1	1	NA	1	1
$CaCl_2$ (alkaline)	2	2	3	2	3	1	1	1	1	1	NA	3
Calcium hypochlorite	3	3	2	2	2	1	2	3	1	1	NA	3
Carbolic acid	2	2	1	1	1	1	1	1	1	1	1	

Carbon dioxide, dry	1	1	1	1	1	1	1	1	1	1	1	1
Carbon dioxide, wet	3	3	1	1	2	1	1	1	1	1	1	1
Carbon disulfide	1	1	1	1	3	1	2	1	1	1	1	2
Carbon tetrachloride	2	2	2	2	1	1	1	2	1	1	NA	3
Carbonic acid	3	3	2	2	2	1	1	1	1	NA	NA	1
Chlorine gas	1	1	2	2	2	1	1	1	1	3	2	3
Chlorine gas, wet	3	3	3	3	3	3	3	3	2	1	2	3
Chlorine, liquid	3	3	3	3	2	2	3	3	1	3	2	3
Citric acid	3	3	2	1	1	1	2	1	1	1	NA	2
Coke oven gas	1	1	1	1	2	1	2	1	1	1	1	1
Copper sulfate	3	3	2	2	2	1	3	NA	1	1	NA	1
Ethane	1	1	1	1	1	1	1	1	1	1	1	1
Ether	2	2	1	1	1	1	1	1	1	1	1	1
Ethyl chloride	3	3	1	1	1	1	1	1	1	1	1	2
Ethylene	1	1	1	1	1	1	1	1	1	1	1	1
Ethylene glycol	1	1	1	1	1	1	1	NA	NA	NA	1	1
Ferric chloride	3	3	3	3	3	3	3	3	2	1	2	3
Formaldehyde	2	2	1	1	1	1	1	1	1	1	1	1
Formic acid	3	3	2	2	1	1	1	1	1	3	2	3
Gasoline	1	1	1	1	1	1	1	1	1	1	1	1
Glucose	1	1	1	1	1	1	1	1	1	1	1	1
HCl	3	3	3	3	3	3	3	1	2	2	2	3
Hydrochloric acid, air free	3	3	3	3	3	3	3	1	2	2	2	3
HF, aerated	2	3	3	2	3	2	3	1	1	3	2	3
Hydrofluoric acid, air free	1	3	3	2	3	2	1	1	1	3	NA	3
Hydrogen	1	1	1	1	1	1	1	1	1	1	1	1
Hydrogen peroxide	3	1	1	1	3	1	3	2	2	1	NA	2
Hydrogen sulfide, liquid	3	3	1	1	3	2	3	1	1	1	1	3
Magnesium Hydroxide	1	1	1	1	2	1	1	1	1	1	1	1
Mercury	1	1	1	1	3	1	2	1	1	1	1	1
Methanol	1	1	1	1	1	1	1	1	1	1	1	1
Methyl ethyl ketone	1	1	1	1	1	1	1	1	1		1	1

NAtural gas	1	1	1	1	1	1	1	1	1	1	1	1
Nitric acid	3	3	1	2	3	1	3	3	2	1	3	3
Oleic acid	3	3	1	1	2	1	1	1	1	1	1	1
Oxalic acid	3	3	2	2	2	1	2	1	1	2	2	2
Oxygen	1	1	1	1	1	1	1	1	1	1	1	1
Petroleum oils	1	1	1	1	1	1	1	1	1	1	1	1
Phosphoric acid, aerated	3	3	1	1	3	1	3	1	1	2	1	3
Phosphoric acid, air free	3	3	1	1	3	1	2	1	1	2	1	3
Phosphoric acid vapors	3	3	2	2	3	1	3	1		2	3	3
Picric acid	3	3	1	1	3	1	3	1	1	NA	NA	2
Potassium chloride	2	2	1	1	2	1	2	1	1	1	NA	3
Potassium hydroxide	2	2	1	1	2	1	1	1	1	1	NA	2
Propane	1	1	1	1	1	1	1	1	1	1	1	1
Sodium acetate	1	1	2	1	1	1	1	1	1	1	1	1
Sodium carboNAte	1	1	1	1	1	1	1	1	1	1	1	2
Sodium chloride	3	3	2	2	1	1	1	1	1	1	1	2
Sodium hydroxide	1	1	1	1	3	1	1	1	1	1	1	2
Sodium hypochloride	3	3	3	3	3	2	3	3	1	1	NA	3
Sodium thiosulfate	3	3	1	1	3	1	3	1	1	1	NA	2
Stannous chloride	2	2	3	1	3	1	2	1	1	1	NA	3
Stearic acid	1	3	1	1	2	1	2	1	1	1	2	2
Sulfate liquor	1	1	1	1	3	1	1	1	1	1	1	
Sulfur	1	1	1	1	3	1	1	1	1	1	1	1
Sulfur dioxide, dry	1	1	1	1	1	1	1	2	1	1	1	2
Sulfur trioxide, dry	1	1	1	1	1	1	1	2	1	1	1	2
Sulfuric acid, aerated	3	3	3	3	3	1	3	1	1	2	2	3
Sulfuric acid, air free	3	3	3	3	2	1	2	1	1	2	2	3
Sulfurous acid	3	3	2	2	2	1	3	1	1	1	2	3
Tar	1	1	1	1	1	1	1	1	1	1	1	1
Trichloroethylene	2	2	2	1	1	1	1	1	1	1	1	2
Turpentine	2	2	1	1	1	1	2	1	1	1	1	1
Water, steam, BFW	2	3	1	1	3	1	1	1	1	1	1	2

Water, distilled	1	1	1	1	1	1	1	1	1	1	1	2
Water, sea	2	2	2	2	1	1	1	1	1	1	1	3
Zinc chloride	3	3	3	3	3	1	3	1	1	1	2	3

Table B-6: Galvanic Series

Galvanic series for Reactivity in with sea water as electrolyte.

	Corroded End Anodic—More Active		
1	Magnesium	17	Nickel
2	Magnesium alloys	18	Brass
3	Zinc	19	Copper
4	Aluminum	20	Bronze
5	Aluminum alloys	21	Copper-Nickel
6	Steel	22	Monel
7	Cast iron	23	Nickel (passive state)
8	Type 410 SS	24	Type 410 SS
9	(active state)	25	(passive state)
10	Ni-Resist	26	Type 304 SS
11	Type 304 SS	27	(passive state)
12	(active state)	28	Type 316 SS
13	Type 316SS	29	(passive state)
14	(active state)	30	Titanium
15	Lead	31	Graphite
16	Tin	32	Gold
		33	Platinum
			Protected End—Cathode - More Noble

Table B-7: Hardness Conversion table

Rockwell						Rockwell Superficial				Brinell		Vickers	Shore	
A	B	C	D	E	F	15-N	30-N	45-N	30-T	3000 kg	500 kg	136		Approx Tensile Strength (psi)
60kg Brale	100kg 1/16" Ball	150kg Brale	100kg Brale	100kg 1/8" Ball	60kg 1/16" Ball	15kg Brale	30kg Brale	45kg Brale	30 kg 1/16" Ball	10mm Ball Steel	10mm Ball Steel	Diamond Pyramid	Sciero-scope	
86.5	---	70	78.5	---	---	94.0	86.0	77.6	---	---	---	1076	101	---
86.0	---	69	77.7	---	---	93.5	85.0	76.5	---	---	---	1044	99	---
85.6	---	68	76.9	---	---	93.2	84.4	75.4	---	---	---	940	97	---
85.0	---	67	76.1	---	---	92.9	83.6	74.2	---	---	---	900	95	---
84.5	---	66	75.4	---	---	92.5	82.8	73.2	---	---	---	865	92	---
83.9	---	65	74.5	---	---	92.2	81.9	72.0	---	739	---	832	91	---
83.4	---	64	73.8	---	---	91.8	81.1	71.0	---	722	---	800	88	---
82.8	---	63	73.0	---	---	91.4	80.1	69.9	---	705	---	772	87	---
82.3	---	62	72.2	---	---	91.1	79.3	68.8	---	688	---	746	85	---
81.8	---	61	71.5	---	---	90.7	78.4	67.7	---	670	---	720	83	---
81.2	---	60	70.7	---	---	90.2	77.5	66.6	---	654	---	697	81	320,000
80.7	---	59	69.9	---	---	89.8	76.6	65.5	---	634	---	674	80	310,000
80.1	---	58	69.2	---	---	89.3	75.7	64.3	---	615	---	653	78	300,000
79.6	---	57	68.5	---	---	88.9	74.8	63.2	---	595	---	633	76	290,000
79.0	---	56	67.7	---	---	88.3	73.9	62.0	---	577	---	613	75	282,000
78.5	120	55	66.9	---	---	87.9	73.0	60.9	---	560	---	595	74	274,000
78.0	120	54	66.1	---	---	87.4	72.0	59.8	---	543	---	577	72	266,000
77.4	119	53	65.4	---	---	86.9	71.2	58.6	---	525	---	560	71	257,000
76.8	119	52	64.6	---	---	86.4	70.2	57.4	---	500	---	544	69	245,000
76.3	118	51	63.8	---	---	85.9	69.4	56.1	---	487	---	528	68	239,000
75.9	117	50	63.1	---	---	85.5	68.5	55.0	---	475	---	513	67	233,000

75.2	117	49	62.1	---	---	85.0	67.6	53.8	---	464	---	498	66	227,000
74.7	116	48	61.4	---	---	84.5	66.7	52.5	---	451	---	484	64	221,000
74.1	116	47	60.8	---	---	83.9	65.8	51.4	---	442	---	471	63	217,000
73.6	115	46	60.0	---	---	83.5	64.8	50.3	---	432	---	458	62	212,000
73.1	115	45	59.2	---	---	83.0	64.0	49.0	---	421	---	446	60	206,000
72.5	114	44	58.5	---	---	82.5	63.1	47.8	---	409	---	434	58	200,000
72.0	113	43	57.7	---	---	82.0	62.2	46.7	---	400	---	423	57	196,000
71.5	113	42	56.9	---	---	81.5	61.3	45.5	---	390	---	412	56	191,000
70.9	112	41	56.2	---	---	80.9	60.4	44.3	---	381	---	402	55	187,000
70.4	112	40	55.4	---	---	80.4	59.5	43.1	---	371	---	392	54	182,000
69.9	111	39	54.6	---	---	79.9	58.6	41.9	---	362	---	382	52	177,000
69.4	110	38	53.8	---	---	79.4	57.7	40.8	---	353	---	372	51	173,000
68.9	110	37	53.1	---	---	78.8	56.8	39.6	---	344	---	363	50	169,000
68.4	109	36	52.3	---	---	78.3	55.9	38.4	---	336	---	354	49	165,000
67.9	109	35	51.5	---	---	77.7	55.0	37.2	---	327	---	345	48	160,000
67.4	108	34	50.8	---	---	77.2	54.2	36.1	---	319	---	336	47	156,000
66.8	108	33	50.0	---	---	76.6	53.3	34.9	---	311	---	327	46	152,000
66.3	107	32	49.2	---	---	76.1	52.1	33.7	---	301	---	318	44	147,000
65.8	106	31	48.4	---	---	75.6	51.3	32.5	---	294	---	310	43	144,000
65.3	105	30	47.7	---	---	75.0	50.4	31.3	---	286	---	302	42	140,000
64.7	104	29	47.0	---	---	74.5	49.5	30.1	---	279	---	294	41	137,000
64.3	104	28	46.1	---	---	73.9	48.6	28.9	---	271	---	286	41	133,000
63.8	103	27	45.2	---	---	73.3	47.7	27.8	---	264	---	279	40	129,000
63.3	103	26	44.6	---	---	72.8	46.8	26.7	---	258	---	272	39	126,000
62.8	102	25	43.8	---	---	72.2	45.9	25.5	---	253	---	266	38	124,000
62.4	101	24	43.1	---	---	71.6	45.0	24.3	---	247	---	260	37	121,000
62.0	100	23	42.1	---	---	71.0	44.0	23.1	82.0	240	201	254	36	118,000
61.5	99	22	41.6	---	---	70.5	43.2	22.0	81.5	234	195	248	35	115,000

61.0	98	21	40.9	---	---	69.9	42.3	20.7	81.0	228	189	243	35	112,000
60.5	97	20	40.1	---	---	69.4	41.5	19.6	80.5	222	184	238	34	109,000
59.0	96	18	---	---	---	---	---	---	80.0	216	179	230	33	106,000
58.0	95	16	---	---	---	---	---	---	79.0	210	175	222	32	103,000
57.5	94	15	---	---	---	---	---	---	78.5	205	171	213	31	100,000
57.0	93	13	---	---	---	---	---	---	78.0	200	167	208	30	98,000
56.5	92	12	---	---	---	---	---	---	77.5	195	163	204	29	96,000
56.0	91	10	---	---	---	---	---	---	77.0	190	160	196	28	93,000
55.5	90	9	---	---	---	---	---	---	76.0	185	157	192	27	91,000
55.0	89	8	---	---	---	---	---	---	75.5	180	154	188	26	88,000
54.0	88	7	---	---	---	---	---	---	75.0	176	151	184	26	86,000
53.5	87	6	---	---	---	---	---	---	74.5	172	148	180	26	84,000
53.0	86	5	---	---	---	---	---	---	74.0	169	145	176	25	83,000
52.5	85	4	---	---	---	---	---	---	73.5	165	142	173	25	81,000
52.0	84	3	---	---	---	---	---	---	73.0	162	140	170	25	79,000
51.0	83	2	---	---	---	---	---	---	72.0	159	137	166	24	78,000
50.5	82	1	---	---	---	---	---	---	71.5	156	135	163	24	76,000
50.0	81	0	---	---	---	---	---	---	71.0	153	133	160	24	75,000
49.5	80	---	---	---	---	---	---	---	70.0	150	130	---	---	73,000
49.0	79	---	---	---	---	---	---	---	69.5	147	128	---	---	---
48.5	78	---	---	---	---	---	---	---	69.0	144	126	---	---	---
48.0	77	---	---	---	---	---	---	---	68.0	141	124	---	---	---
47.0	76	---	---	---	---	---	---	---	67.5	139	122	---	---	---
46.5	75	---	---	---	99.5	---	---	---	67.0	137	120	---	---	---
46.0	74	---	---	---	99.0	---	---	---	66.0	135	118	---	---	---
45.5	73	---	---	---	98.5	---	---	---	65.5	132	116	---	---	---
45.0	72	---	---	---	98.0	---	---	---	65.0	130	114	---	---	---
44.5	71	---	---	100.0	97.5	---	---	---	64.2	127	112	---	---	---

44.0	70	---	---	99.5	97.0	---	---	---	63.5	125	110	---	---	---
43.5	69	---	---	99.0	96.0	---	---	---	62.8	123	109	---	---	---
43.0	68	---	---	98.0	95.5	---	---	---	62.0	121	107	---	---	---
42.5	67	---	---	97.5	95.0	---	---	---	61.4	119	106	---	---	---
42.0	66	---	---	97.0	94.5	---	---	---	60.5	117	104	---	---	---
41.8	65	---	---	96.0	94.0	---	---	---	60.1	116	102	---	---	---
41.5	64	---	---	95.5	93.5	---	---	---	59.5	114	101	---	---	---
41.0	63	---	---	95.0	93.0	---	---	---	58.7	112	99	---	---	---
40.5	62	---	---	94.5	92.0	---	---	---	58.0	110	98	---	---	---
40.0	61	---	---	93.5	91.5	---	---	---	57.3	108	96	---	---	---
39.5	60	---	---	93.0	91.0	---	---	---	56.5	107	95	---	---	---
39.0	59	---	---	92.5	90.5	---	---	---	55.9	106	94	---	---	---
38.5	58	---	---	92.0	90.0	---	---	---	55.0	104	92	---	---	---
38.0	57	---	---	91.0	89.5	---	---	---	54.6	102	91	---	---	---
37.8	56	---	---	90.5	89.0	---	---	---	54.0	101	90	---	---	---
37.5	55	---	---	90.0	88.0	---	---	---	53.2	99	89	---	---	---
37.0	54	---	---	89.5	87.5	---	---	---	52.5	---	87	---	---	---
36.5	53	---	---	89.0	87.0	---	---	---	51.8	---	86	---	---	---
36.0	52	---	---	88.0	86.5	---	---	---	51.0	---	85	---	---	---
35.5	51	---	---	87.5	86.0	---	---	---	50.4	---	84	---	---	---
35.0	50	---	---	87.0	85.5	---	---	---	49.5	---	83	---	---	---
34.8	49	---	---	86.5	85.0	---	---	---	49.1	---	82	---	---	---
34.5	48	---	---	85.5	84.5	---	---	---	48.5	---	81	---	---	---
34.0	47	---	---	85.0	84.0	---	---	---	47.7	---	80	---	---	---
33.5	46	---	---	84.5	83.0	---	---	---	47.0	---	79	---	---	---
33.0	45	---	---	84.0	82.5	---	---	---	46.2	---	79	---	---	---
32.5	44	---	---	83.5	82.0	---	---	---	45.5	---	78	---	---	---
32.0	43	---	---	82.5	81.5	---	---	---	44.8	---	77	---	---	---

31.5	42	---	---	82.0	81.0	---	---	---	44.0	---	76	---	---	---
31.0	41	---	---	81.5	80.5	---	---	---	43.4	---	75	---	---	---
30.8	40	---	---	81.0	79.5	---	---	---	43.0	---	74	---	---	---
30.5	39	---	---	80.0	79.0	---	---	---	42.1	---	74	---	---	---
30.0	38	---	---	79.5	78.5	---	---	---	41.5	---	73	---	---	---
29.5	37	---	---	79.0	78.0	---	---	---	40.7	---	72	---	---	---
29.0	36	---	---	78.5	77.5	---	---	---	40.0	---	71	---	---	---
28.5	35	---	---	78.0	77.0	---	---	---	39.3	---	71	---	---	---
28.0	34	---	---	77.0	76.5	---	---	---	38.5	---	70	---	---	---
27.8	33	---	---	76.5	75.5	---	---	---	37.9	---	69	---	---	---
27.5	32	---	---	76.0	75.0	---	---	---	37.5	---	68	---	---	---
27.0	31	---	---	75.5	74.5	---	---	---	36.6	---	68	---	---	---
26.5	30	---	---	75.0	74.0	---	---	---	36.0	---	67	---	---	---
26.0	29	---	---	74.0	73.5	---	---	---	35.2	---	66	---	---	---
25.5	28	---	---	73.5	73.0	---	---	---	34.5	---	66	---	---	---
25.0	27	---	---	73.0	72.5	---	---	---	33.8	---	65	---	---	---
24.5	26	---	---	72.5	72.0	---	---	---	33.1	---	65	---	---	---
24.2	25	---	---	72.0	71.0	---	---	---	32.4	---	64	---	---	---
24.0	24	---	---	71.0	70.5	---	---	---	32.0	---	64	---	---	---
23.5	23	---	---	70.5	70.0	---	---	---	31.1	---	63	---	---	---
23.0	22	---	---	70.0	69.5	---	---	---	30.4	---	63	---	---	---
22.5	21	---	---	69.5	69.0	---	---	---	29.7	---	62	---	---	---
22.0	20	---	---	68.5	68.5	---	---	---	29.0	---	62	---	---	---
21.5	19	---	---	68.0	68.0	---	---	---	28.1	---	61	---	---	---
21.2	18	---	---	67.5	67.0	---	---	---	27.4	---	61	---	---	---
21.0	17	---	---	67.0	66.5	---	---	---	26.7	---	60	---	---	---
20.5	16	---	---	66.5	66.0	---	---	---	26.0	---	60	---	---	---
20.0	15	---	---	65.5	65.5	---	---	---	25.3	---	59	---	---	---

---	14	---	---	65.0	65.0	---	---	---	24.6	---	59	---	---	---
---	13	---	---	64.5	64.5	---	---	---	23.9	---	58	---	---	---
---	12	---	---	64.0	64.0	---	---	---	23.5	---	58	---	---	---
---	11	---	---	63.5	63.5	---	---	---	22.6	---	57	---	---	---
---	10	---	---	62.5	63.0	---	---	---	21.9	---	57	---	---	---
---	9	---	---	62.0	62.0	---	---	---	21.2	---	56	---	---	---
---	8	---	---	61.5	61.5	---	---	---	20.5	---	56	---	---	---
---	7	---	---	61.0	61.0	---	---	---	19.8	---	56	---	---	---
---	6	---	---	60.5	60.5	---	---	---	19.1	---	55	---	---	---
---	5	---	---	60.0	60.0	---	---	---	18.4	---	55	---	---	---
---	4	---	---	59.0	59.5	---	---	---	18.0	---	55	---	---	---
---	3	---	---	58.5	59.0	---	---	---	17.1	---	54	---	---	---
---	2	---	---	58.0	58.0	---	---	---	16.4	---	54	---	---	---
---	1	---	---	57.5	57.5	---	---	---	15.7	---	53	---	---	---
---	0	---	---	57.0	57.0	---	---	---	15.0	---	53	---	---	---

Appendix-C

Reporting Requirements

Temporary Note:

This section will be replaced by SAEP-1161 in later editions.

Appendix –D

Inspection tools

It is responsibility of the inspection unit to provide all kind of logistic support to the inspector and the inspection team to perform the inspection jib effectively. This Appendix of inspection manual suggests the list of inspection and safety tools required for performing the inspection job effectively and safely. Para D-1 provided the list of mandatory Safety gear which an inspector and his team members must carry to perform the inspection job. However Para D-2 list of inspection equipment is not mandatory. The inspector and his team should select the equipment according to the job requirements.

<u>D-1: Safety Gear</u>

Following are the essential minimum requirements for the inspector and inspection team to perform the job safety. Additional requirements must be fulfilled according to the safe work plan, and the safety standards requirements of the operation facility.

D-1.1 <u>Essential PPE</u>

a. 4 Head Gas monitor to detect, Oxygen level, CO, H_2S and LELs
b. Fire retardant top clothing. (under clothing should never be made with nylon or synthetic fibers. Only Cotton clothing is allowed)
c. Certified steal toe foot wear.
d. Certified Hard Hat
e. Safety Glasses. (Workers using prescription glasses are responcible for having custom made safety prescription glasses. Ordinary glasses with side shields are not allowed.
f. Gloves.

D-1.2 <u>Job specific Safety gears:</u>

1. <u>For working at heights.</u>

   a. Full Body harness.
   b. Double tale lanyard for 100% Tie off.
   c. Engineered Lifeline if reliable anchor points are not available.
   d. Steel wire slings for tying around the sharp edge anchor points.
   e. Certified Carabineers' suitable shock load bearings.

2. <u>For working in confined Spaces.</u>

   a. Half Mask with suitable filters from particulates and hydro carbon vapors.
   b. Full body harness for rescue purpose (without lanyard, could be worn under the coveralls).
   c. Communication means like radio or horns.

d. Supplied air breathing apparatus for emergency situations.
e. Paper or other water resistant coveralls in case of toxic compounds inside the confined space.
f. Non slipping paper booties to cover the foot wear.

3. Other Job specific Safety gears.

a. Goggles for drafty conditions.
b. Full face shield of mask for grinding and buffing jobs.
c. Suitable liquid resistant Rain gear for working with toxic substances.
d. Barricade ribbons with caution (yellow) or danger (red) signs, depending on the hazard due to inspection activity.
e. Orange safety vest for high visibility for working in high traffic areas.
f. First aid kit.
g. Radio or cellular phone for remote areas.
h. Satellite phones if the work location is out of the cellular phone coverage areas.
i. Global positioning system GPS for jobs in remote areas.
j. Sufficient Desert survival essentials for at least 4 days if the job is deeper into remote areas.

D-2: Visual inspection tools.

D-2.1: Necessary tool for Visual Inspector

The list of Necessary tools which should be readily available for visual inspector include but is not limited to.

a. Flashlight
b. Straight edge/Steel ruler
c. Tape measure
d. Level
e. Magnifying glass
f. Mirror
g. Plumb bob line.
h. Wire brush
i. Scraper
j. Measuring tape
k. Chipping hammer/ Small ball peen hammer (preferably copper alloy)
l. Chalk or paint marker
m. Camera for photographs.
n. Magnets.
o. Pit gauge.
p. Micrometer.
q. Vernier calipers

r. Paint or crayon. (non Chloride)
s. Notebook /pencil (or audio recording device).
t. Pocketknife.
u. Megger ground tester.
v. Plastic bags for corrosion product samples.
w. Assorted screwdrivers set.
x. Crescent Wrench
y. Rags
z. Power buffer/grinder

D-2.2 Tank settlement survey Equipment

a. Distance measuring week
b. Tripod
c. Surveyor’s level (telescopic or laser).
d. Meter rod.
e. Adjustable Magnets
f. Magnetic Strips.

D-2.3 Conventional Non destructive Testing tools

Conventional Non destructive Testing tools which inspector might need to confirm the findings.

a. Magnetic Particle testing equipment

- AC Yoke
- BC Yoke for the under surface defects especially in castings.
- Ultra Violet light (black light) for Fluorescent MPI.
- Magna glow fluorescent magnetic Inc.
- Contrast aid paint.
- Black magnetic ink.
- Pie Gauge for magnetic field intensity measurement.
- Gause meter for residual field measurement.
- Rags.
- Light meter.
- Magnifying glass.
- More MPI related equipment depending on the job requirements.

b. Liquid Penetrant Inspection equipment

- Water soluble or solvent removable color contrast Penetrant.

- Cleaner, water or solvent.
- Developer.
- Rags.
- Fluorescent penetrant for fluorescent LPI.
- Ultra Violet light (black light) for Fluorescent LPI.
- Magnifying glass.
- Light meter.
- More MPI related equipment depending on the job requirements.

c. Ultrasonic Inspection Equipment

- Ultrasonic Flaw detector.
- Zero degree normal wave single transducers for thickness over ¾”
- Zero degree normal wave dual transducers for thickness under ¾”
- Zero degree normal wave single transducers with delay line for thickness under ¼”
- Shear Wave transducers for at least 70o, 60o and 45o (single transducers with replaceable wedges can also be used).
- Calibration samples like step wedge, FBH cal blocks, IIW, DSC or DIN blocks for shear wave calibration, ASME basic for DAC curve formation. Note: The size of the transducers should be selected as per requirement.

d. Radiographic Inspection Equipment.

- Source of radiation (Gamma Ray source or X-Ray machine) of suitable power.
- X-Ray films.
- Developing and fixing facility.
- Viewing facility.
- Densito meter.

e. Eddy Current Equipment

- Eddy current flay detector
- Surface probes (Range of probes differential and absolute probes depending on the job requirement)
- Internal Tubular probes Range of differential and absolute probes depending on the job requirement)

f. Hardness testing Equipment.

- Brinnell kit with calibration samples
- Mocrodor type digital hardness tester. (Range of manufacturers)
- Known Calibration samples.

g. Remote Visual Inspection Equipment.

Remote visual inspection techniques are used for the inspection of the areas which are normally inaccessible due to size and configuration. A variety of the remote visual inspection tools are available which range from ordinery, boroscope to sophisticated robotic crawlers. A variety of equipments also provide the facility of recording the visual inspection.

h. Magnetic Flux leakage Equipment:

Two main usages of MFL are the tank floor evaluation and the tube inspection for the exchangers and Fin fan coolers. The tank floor inspection equipment includes various kinds of manual driven to motorized crawlers. Some motorized crawlers also provide capability for acquiring the data and storing it along with the encoder location.

The tubular MFL has the principle of operation quite similar to eddy current however the sensitivity of the MFL is not as good as Eddy current inspection.

i. Automated Ultrasonic Testing Equipment:

The inspector can call for the AUT if the initial inspection warrants need for further evaluation. The AUT equipment includes a range of specialized equipments depending on the job requirements. Normally used ATU techniques include Phased Array, Time of Flight Diffraction, C and P Scans etc.