Inspection of Pressure Vessels (Towers, Drums, Reactors, Heat Exchangers, and Condensers)

RECOMMENDED PRACTICE 572
SECOND EDITION, FEBRUARY 2001

American Petroleum Institute

Helping You Get The Job Done Right.SM

Inspection of Pressure Vessels (Towers, Drums, Reactors, Heat Exchangers, and Condensers)

Downstream Segment

RECOMMENDED PRACTICE 572
SECOND EDITION, FEBRUARY 2001

American
Petroleum
Institute

**Helping You
Get The Job
Done Right.**SM

SPECIAL NOTES

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

API is not undertaking to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations under local, state, or federal laws.

Information concerning safety and health risks and proper precautions with respect to particular materials and conditions should be obtained from the employer, the manufacturer or supplier of that material, or the material safety data sheet.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. Sometimes a one-time extension of up to two years will be added to this review cycle. This publication will no longer be in effect five years after its publication date as an operative API standard or, where an extension has been granted, upon republication. Status of the publication can be ascertained from the API Downstream Segment [telephone (202) 682-8000]. A catalog of API publications and materials is published annually and updated quarterly by API, 1220 L Street, N.W., Washington, D.C. 20005.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this standard or comments and questions concerning the procedures under which this standard was developed should be directed in writing to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the general manager.

API standards are published to facilitate the broad availability of proven, sound engineering and operating practices. These standards are not intended to obviate the need for applying sound engineering judgment regarding when and where these standards should be utilized. The formulation and publication of API standards is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

FOREWORD

This recommended practice covers the inspection of pressure vessels. It is based on the accumulated knowledge and experience of engineers and other personnel in the petroleum industry.

The information contained in this publication was previously presented as Chapter VI and Chapter VII of the Guide for Inspection of Refinery Equipment. The information in this recommended practice does not constitute and should not be construed as a code of rules, regulations, or minimum safe practices. The practices described in this publication are not intended to supplant other practices that have proven satisfactory, nor is this publication intended to discourage innovation and originality in the inspection of refineries. Users of this recommended practice are reminded that no book or manual is a substitute for the judgment of a responsible, qualified person.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any federal, state, or municipal regulation with which this publication may conflict.

Suggested revisions are invited and should be submitted to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

IMPORTANT INFORMATION CONCERNING USE OF ASBESTOS OR ALTERNATIVE MATERIALS

Asbestos is specified or referenced for certain components of the equipment described in some API standards. It has been of extreme usefulness in minimizing fire hazards associated with petroleum processing. It has also been a universal sealing material, compatible with most refining fluid services.

Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, asbestosis, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, Occupational Safety and Health Standard for Asbestos, Tremolite, Anthophyllite, and Actinolite, 29 *Code of Federal Regulations* Section 1910.1001; the U.S. Environmental Protection Agency, National Emission Standard for Asbestos, 40 *Code of Federal Regulations* Sections 61.140 through 61.156; and the U.S. Environmental Protection Agency (EPA) rule on labeling requirements and phased banning of asbestos products (Sections 763.160-179).

There are currently in use and under development a number of substitute materials to replace asbestos in certain applications. Manufacturers and users are encouraged to develop and use effective substitute materials that can meet the specifications for, and operating requirements of, the equipment to which they would apply.

SAFETY AND HEALTH INFORMATION WITH RESPECT TO PARTICULAR PRODUCTS OR MATERIALS CAN BE OBTAINED FROM THE EMPLOYER, THE MANUFACTURER OR SUPPLIER OF THAT PRODUCT OR MATERIAL, OR THE MATERIAL SAFETY DATA SHEET.

CONTENTS

CONTENTS

CONTENTS

Page

Inspection of Pressure Vessels
(Towers, Drums, Reactors, Heat Exchangers, and Condensers)

1 Scope

This Recommended Practice (RP) covers the inspection of pressure vessels. It includes a description of the various types of pressure vessels and the standards for their construction and maintenance. The reasons for inspection, causes of deterioration, frequency and methods of inspection, methods of repair, and preparation of records and reports are covered. Safe operation is emphasized.

2 References

The latest editions of the following standards, codes, and recommended practices shall, to the extent specified herein, form a part of this recommended practice.

API

IRE, Chapter II	*Guide for Inspection of Refinery Equipment, Conditions Causing Deterioration or Failures (out of print; to be replaced by RP 571, currently under development)*
Std 510	*Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
RP 574	*Inspection Practices for Piping System Components*
RP 575	*Inspection of Atmospheric and Low-Pressure Storage Tanks*
RP 576	*Inspection of Pressure-Relieving Devices*
RP 579	*Fitness-for-Service*
Std 660	*Shell-and-Tube Heat Exchangers for General Refinery Service*
Std 661	*Air-Cooled Heat Exchangers for General Refinery Services*
Publ 938	*An Experimental Study of Causes and Repair of Cracking of 1¼ Cr-½ Mo Steel Equipment*
Publ 939	*Research Reporting on Characterization and Monitoring of Cracking in Wet H_2S Service*
RP 941	*Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petroleum Plants*
RP 945	*Avoiding Environmental Cracking of Carbon Steels in Amine Units*
Publ 2214	*Spark Ignition Properties of Hand Tools*
Publ 2217A	*Guidelines for Work in Inert Confined Spaces in the Petroleum Industry*

ASME[1]

	Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels"

NB[2]

NB-23	*National Board Inspection Code*

TEMA[3]

	Standards of Tubular Exchanger Manufacturers Association

WRC[4]

Bulletin 411	*An Experimental Study of Causes and Repair of Cracking of 1¼ Cr-½ Mo Steel Equipment*

3 Definitions

For the purposes of this publication, the following definitions apply:

3.1 CUI: Corrosion under insulation, which includes stress corrosion cracking under insulation.

3.2 defect: In NDE usage, a defect is an imperfection of a type or magnitude exceeding the acceptable criteria.

3.3 inspector: An authorized pressure vessel inspector.

3.4 jurisdiction: A legally constituted government administration that may adopt rules relating to pressure vessels.

3.5 on-stream: Pressure vessels containing any amount of process fluid.

3.6 PT: Liquid penetrant testing.

3.7 pressure vessel: A container that falls within the scope of Section VIII of the *ASME Boiler & Pressure Vessel Code* and is subject to an external or internal design pressure greater than 15 lbf/in.^{2} (103 kPa).

3.8 pressure vessel engineer: One or more persons or organizations acceptable to the owner-user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics that affect the integrity and reliability of pressure vessels. The pressure vessel engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly address a technical requirement.

---

[1]ASME International, Three Park Avenue, New York, New York 10016-5990, www.asme.org.
[2]National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Ave, Columbus, Ohio 43229, www.nationalboard.com.
[3]Tubular Exchanger Manufacturers Association, 25 North Broadway, Tarrytown, New York 10591, www.tema.org.
[4]Welding Research Council, ThreePark Avenue, 27th Floor, New York, New York 10016, www.forengineers.org.

3.9 owner-user: An operator of pressure vessels who exercises control over the operation, engineering, inspection, repair, alteration, testing, and rerating of those pressure vessels.

3.10 repair: A repair is the work necessary to restore a pressure vessel to a condition suitable for safe operation at the design conditions. If any of the restorative changes result in a change of design temperature or pressure, the requirements for rerating also shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing pressure vessel component not specifically considered an alteration is considered a repair.

3.11 rerating: A change in either or both the design temperature or the maximum allowable working pressure of a pressure vessel. A rerating may consist of an increase, decrease, or a combination. Derating below original design conditions can be used as a means to provide additional corrosion allowance.

3.12 temper embrittlement: A loss of ductility and notch toughness in susceptible low-alloy steels (e.g., 1¼ Cr and 2¼ Cr) caused by prolonged exposure to high temperature service [(between 700ºF to 1070ºF (371ºC to 577ºC)].

3.13 thickness measurement locations (TMLs): Designated areas on pressure vessels where periodic inspections and thickness measurements are conducted.

3.14 UT: Ultrasonic testing

3.15 WFMT: Wet fluorescent magnetic particle testing.

4 Types of Pressure Vessels

4.1 DESCRIPTION

A pressure vessel is a container designed to withstand internal or external pressure. The pressure vessels may have been constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, other recognized pressure vessel codes, or as approved by the jurisdiction. These vessels typically are subject to an external or internal operating pressure greater than 15 lbf/in.^{2} (103 kPa). External pressure on a vessel can be caused by an internal vacuum or by fluid pressure between an outer jacket and the vessel wall. Vessels subject to external pressure are usually inspected in the same manner as those subject to internal pressure. Columns, towers, drums, reactors, heat exchangers, condensers, air coolers, bullets, spheres, and accumulators are common types of industry pressure vessels. [See Appendix A for an introduction to exchangers. Storage vessels subject to internal pressures up to 15 lbf/in.^{2} (103 kPa) are covered in API RP 575.]

Pressure vessels are designed in various shapes. They may be cylindrical (with flat, conical, toriconical, torispherical, semiellipsoidal, or hemispherical heads), spherical, spheroidal, boxed (with flat rectangular or square plate heads, such as those used for the headers of air-cooled exchangers), or lobed. They may be of modular construction.

Cylindrical vessels, including exchangers and condensers, may be either vertical or horizontal and may be supported by steel columns, cylindrical plate skirts, or plate lugs attached to the shell. Spherical vessels are usually supported by steel columns attached to the shell or by skirts. Spheroidal vessels are partially or completely supported by resting on the ground. Jacketed vessels are those built with a casing or outer shell that forms a space between itself and the main shell.

4.2 METHODS OF CONSTRUCTION

Prior to the development of welding, riveting was the most common method of construction. Seams were either lapped and riveted, or butted with butt straps and then riveted. To prevent leakage, the edges of the seams and rivet heads were caulked. At high temperatures, it was difficult to keep this caulking tight. After the technique of welding was developed, a light bead of weld was applied to the caulking edges. Although some vessels of this type can still be found in older refineries, this method of construction is seldom used today.

Today, several different methods are used to construct pressure vessels. Most pressure vessels are constructed with welded joints.

Shell rings are usually made by rolling plate at either elevated or ambient temperature. The cylinder is formed by welding the ends of the rolled plate together. This yields a cylinder with a longitudinal weld.

Hot forging is another method of making cylindrical vessels. Some vessel manufacturers use the formation of cylindrical shell rings by hot forging for high pressure, heavy wall vessels such as those used for hydrotreater or hydrocracker reactors. This method does not produce a longitudinal seam in the cylinder.

In the multilayer method, the cylindrical section is made up of a number of thin concentric cylinders fabricated together, one over the other, until the desired thickness is obtained. Multilayer construction is sometimes used for heavy-wall reactors and vessels subject to high pressure.

4.3 MATERIALS OF CONSTRUCTION

Carbon steel is the most common material used to construct pressure vessels. For special purposes, a suitable austenitic or ferritic alloy, Alloy 400, nickel, titanium, high nickel alloys or aluminum may be used. Copper and copper alloys (except Alloy 400) are seldom used in refinery vessels but may be found in petrochemical plant vessels.

Materials used to construct the various parts of exchangers are selected to safely handle the service and the heat load required. Materials that will most economically resist the type of corrosion expected are selected.

Exchanger shells are usually made of carbon steel but may be made of a corrosion-resistant alloy or clad with a corro-

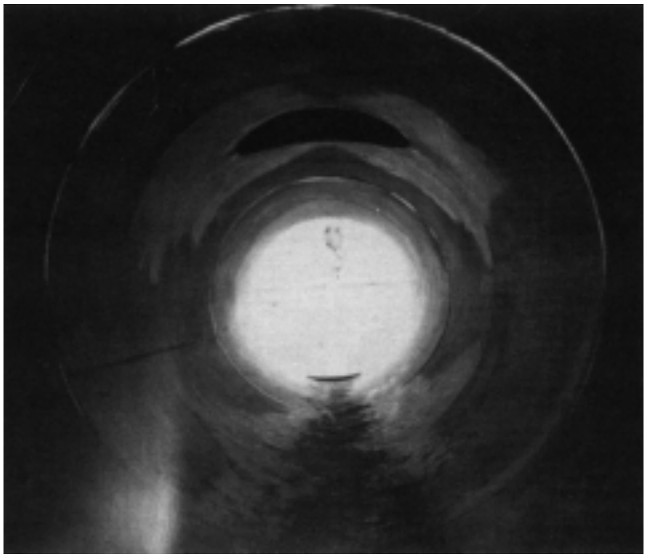


Figure 1—Type 316 Stainless-Clad Vessel

Figure 2—Weld Metal Surfacing

sion-resistant material. Exchanger channels and baffles are made of carbon steel or a suitable resistant alloy material, usually similar to the material of the tubes.

Tubes for exchanger bundles may be a variety of materials. Where water is used as a cooling or condensing medium, they are generally made of copper based alloys or steel. Titanium may be used in seawater applications. Where the exchange is between two different hydrocarbons, the tubes may be made of steel or a suitable corrosion-resistant alloy. Tubes, consisting of an inner layer of one material and an outer layer of a different material, may in some cases be required to resist two different corrosive mediums.

Tube sheets for exchanger bundles are made of a variety of materials. Where water is the cooling or condensing medium, they are usually made of naval brass or steel. Titanium may be used in seawater applications. Where the exchange of heat is between two hydrocarbons, the tube sheets may be composed of steel or a suitable corrosion resistant alloy. In some cases it may be necessary to face one side of the tube sheet with a material different from that facing the other to resist two different corrosive mediums.

If carbon steel would not resist the corrosion or erosion expected or would cause contamination of the product, vessels may be lined with other metals or nonmetals. A lined vessel is usually more economical than one built of a solid corrosion-resistant material. However, when the pressure vessel will operate at a high temperature, a high pressure, or both, solid alloy steels may be both necessary and economical.

Metallic liners are installed in various ways. They may be an integral part of the plate material rolled or explosion bonded before fabrication of the vessel. They may instead be separate sheets of metal fastened to the vessel by welding. Corrosion-resistant metal can also be applied to the vessel surfaces by various weld overlay processes. Metallic liners may be made of a ferritic alloy, Alloy 400, nickel, lead, or any other metal resistant to the corrosive agent.

Nonmetallic liners may be used to resist corrosion and erosion or to insulate and reduce the temperature on the walls of a pressure vessel. The most common nonmetallic lining materials are reinforced concrete, acid brick, refractory material, insulating material, carbon brick or block, rubber, glass, and plastic. Figures 1 through 4 show various methods of applying metallic linings. Figure 5 shows reinforced refractory lining for regenerator lines and slide valves.

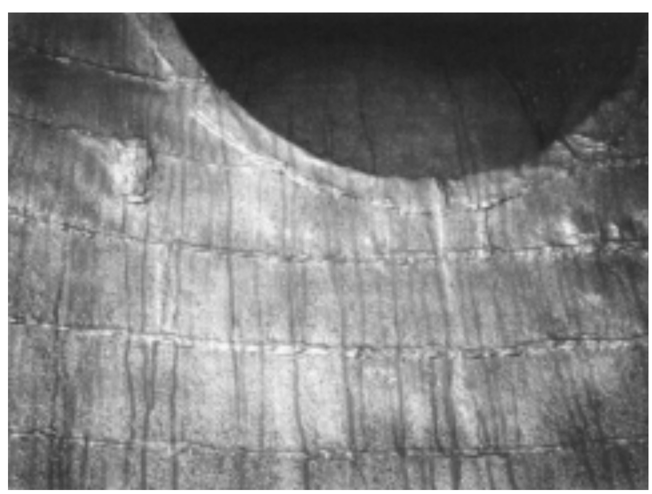


Figure 3—Strip-Lined Vessel

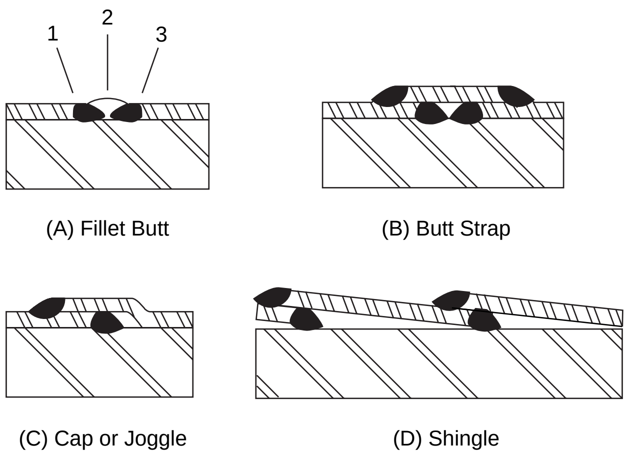


Figure 4—Principal Strip-Lining Methods

4.4 INTERNAL EQUIPMENT

Many pressure vessels have no internals. Others have internals such as baffles, distribution piping trays, mesh- or strip-type packing grids, catalyst bed supports, cyclones, pipe coils, spray nozzles, demister pads, and quench lines. Large spheroids may have internal bracing and ties and most vacuum vessels have either external or internal stiffening rings. Some pressure vessels have heat exchangers or reboilers located in the lower shell area.

Exchangers have internal tube bundles with baffles or support plates, which vary with the service and heat load the exchanger is designed to handle. Pass partitions are usually installed in the channels and sometimes installed in the floating tube sheet covers to provide multiple pass flow through the tubes. The flow through the shell may be single pass, or longitudinal baffles may be installed to provide multiple passes. The baffling used in the shell determines the location and number of shell nozzles required. Figures A-10 and A-11 of Appendix A show various channel and shell baffle arrangements. Frequently, an impingement baffle or plate is placed below the shell inlet nozzle to prevent impingement of the incoming fluid on the tubes.

4.5 USES OF PRESSURE VESSELS

Pressure vessels are used in most processes in a refinery or petrochemical plant. They are used to contain process fluids . A pressure vessel can be used as a thermal reactor or a catalytic reactor to contain the chemical change required by the process; as a fractionator to separate various constituents produced in the reaction; as a separator to separate gases, chemicals, or catalyst from a product; as a surge drum for liquids; as a chemical treating unit; as a settling drum to permit separation of a chemical from a treated product; as a regenerator to restore a catalyst or chemical to its original properties; or as an exchanger, condenser, cooler, or other type of vessel for

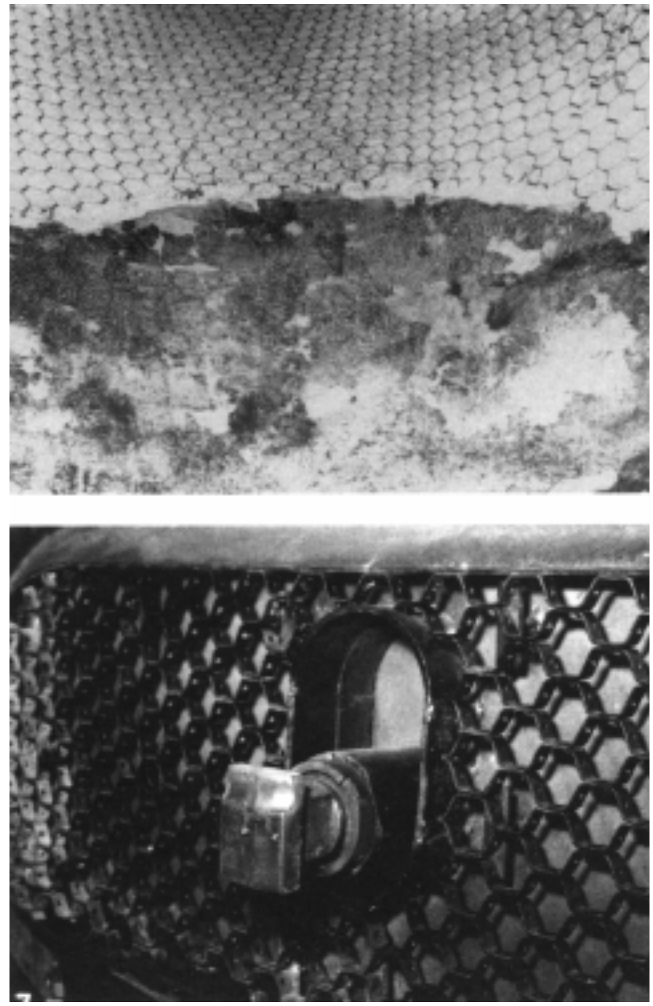


Figure 5—Reinforced Refractory Lining for Regenerator Lines and Slide Valves

any of various other purposes. Figures 6 through 11 illustrate various types of pressure vessels.

5 Construction Standards

Prior to the early 1930's, most unfired pressure vessels for refineries were built to the design and specifications of the user or manufacturer. Later, most pressure vessels in the U.S. were built to conform either to the API/ASME Code for Unfired Pressure Vessels for Petroleum Liquids and Gases or to Section VIII of the ASME Code. Publication of the API/ASME Code for Unfired Pressure Vessels for Petroleum Liquids and Gases was discontinued as of December 31, 1956, and it is no longer used for new vessels.

Section VIII of the ASME Code is divided into two parts. Section VIII, Division 2 of the ASME Code provides alternative and more stringent rules for the design, fabrication, and inspection of vessels than those found in Section VIII, Division 1, of the ASME Code. Most pressure vessels for U.S.

refineries are now built to conform to the latest edition of Section VIII, Division 1, of the ASME Code.

Some high pressure vessels are designed and built in accordance with the specifications of Section VIII, Division 2, of the ASME Code.

In the U.S., heat exchangers and condensers are designed and built in accordance with ASME Code; TEMA Standards, API Standard 660, and API Standard 661. (Other countries may have equipment design requirements other than ASME, TEMA, and API.)

Both Divisions 1 and 2 of Section VIII of the ASME Code require the manufacturer of a vessel to have a quality control system. Before the manufacturer can obtain a certificate of authorization from ASME, a written manual must be provided, and the system must be implemented. The quality control system requires detailed documentation of examinations, testing, and design data regarding the vessel and provides a history of the construction of the vessel. This documentation can useful when evaluating of vessels in service.

The ASME Code lists materials that may be used for construction, gives formulas for calculating thickness, provides rules on methods of manufacture, and specifies the proce-

Figure 6—Catalyst Storage Hoppers

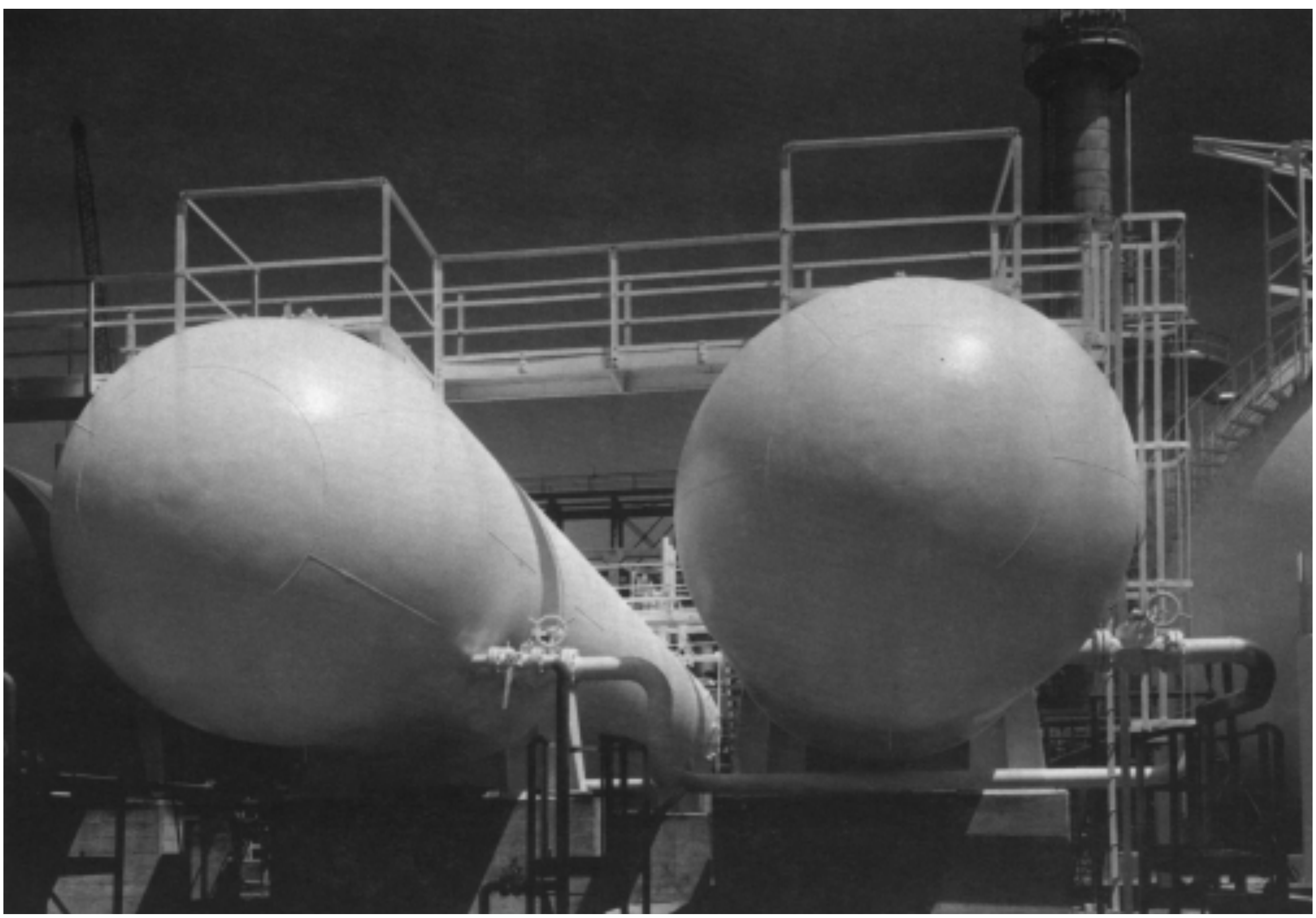


Figure 7—Horizontal Drums

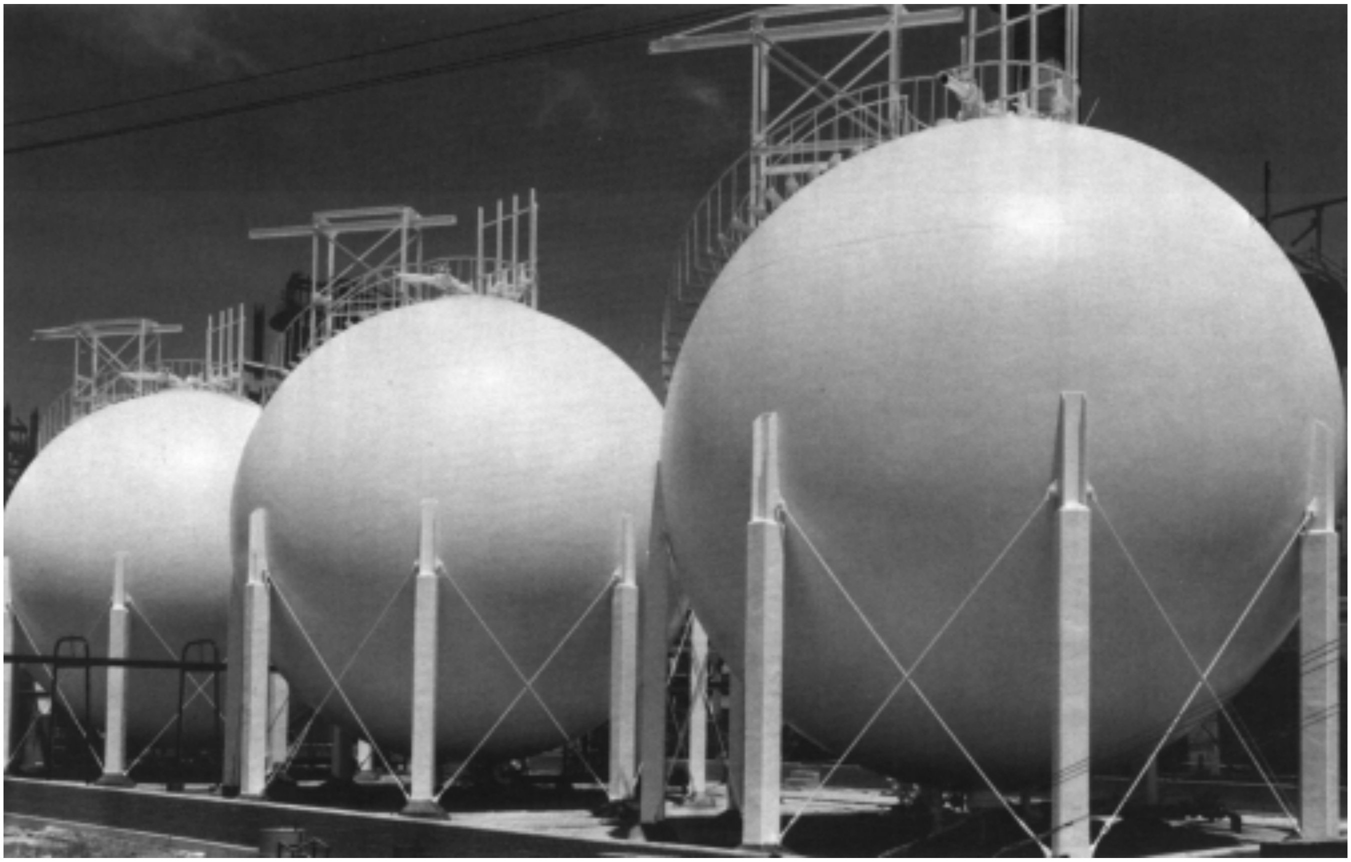


Figure 8—Spheres

dures for testing completed vessels. Inspection is required during construction and testing of vessels. The code also prescribes the qualifications of the persons who perform the construction inspections.

After a qualified construction inspector certifies that a vessel has been built and tested as required by the ASME Code, the manufacturer is empowered to stamp the vessel with the appropriate symbol of the ASME Code. The symbol stamped on a pressure vessel is an assurance that the vessel has been designed, constructed, tested, and inspected as required by the ASME Code.

Some states and cities and many countries have laws other than the regulations of the ASME Code (and other codes) that govern the design, construction, testing, installation, inspection, and repair of pressure vessels used in their localities. These codes may supersede the ASME Code's (and other code's) minimum requirements.

6 Maintenance Inspection

Construction codes are periodically revised as the designs of pressure vessels improve and as new construction materials become available. A pressure vessel should be maintained according to the requirements of the code under which it was designed and constructed. If rerated, it should be maintained according to the requirements of the code under which it was rerated. A refinery inspector should be familiar not only with the latest editions of codes but also with previous editions of the codes and with other specifications under which any vessels he inspects were built. The inspector should also familiarize himself with any regulations [including city, county, parish, provincial, state or national (such as OSHA[5]) regulations] governing inspection and maintenance of pressure vessels in the refinery. The inspector should be familiar with the contents of API 510 and NB-23, where applicable.

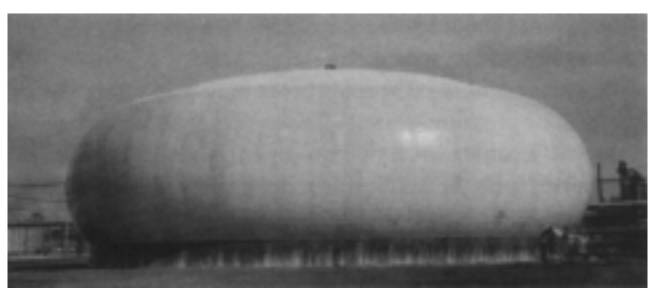


Figure 9—Horton Spheroid (Noded)

[5]Occupational Safety and Health Administration, 200 Constitution Avenue, N.W., Washington, D.C. 20210, www.osha.gov.

Figure 10—Process Towers and Drums

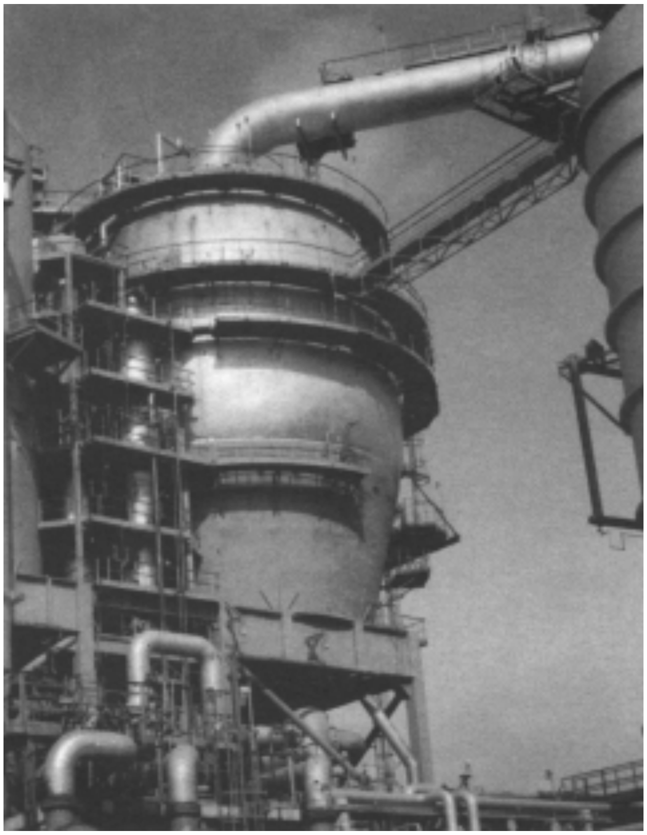


Figure 11—Fluid Catalytic Regenerator

7 Reasons for Inspection

7.1 GENERAL

The basic reasons for inspection are to determine the physical condition of the vessel and to determine the type, rate, and causes of deterioration. This information should be carefully documented after each inspection. With such data, safety can be maintained, the period of operation without a shutdown can be extended, the rate of deterioration can sometimes be reduced, and future repair and replacement requirements can be estimated.

7.2 SAFETY

Periodic scheduled inspections can reveal conditions that might result in an emergency or unscheduled shutdown, a leak or even a vessel failure if not corrected.

7.3 CONTINUITY

Periodic inspection can lead to a well-planned maintenance program. Corrosion rates and remaining corrosion allowances determined by inspection are the normal bases for predicting replacement or repair needs. These predictions provide for planned maintenance and continuity of operation and help to ensure a safe, reliable plant.

7.4 RELIABILITY

External inspections performed while the equipment is in operation using acoustic, ultrasonic, or radiographic instruments or other nondestructive techniques may reveal important information without requiring entry inside of the equipment. Defects such as leaks, cracks, improper installation of parts, plugged lines, undue vibration, unusual noises, and other evidence of malfunctioning may be found. If these symptoms are properly analyzed and corrective steps are taken, the overall reliability of operations will improve.

8 Causes of Deterioration

8.1 GENERAL

Deterioration is possible on all vessel surfaces in contact with any of a wide range of organic and inorganic compounds, with contaminated or fresh water, with steam or with the atmosphere. The form of the deterioration may be electrochemical, chemical, mechanical, or a combination of the three. The deterioration may be accelerated by temperature, stress, vibration, impingement, or high velocity or irregularity of flow. API IRE, Chapter II, covers this subject in detail. In addition to a discussion of deterioration modes, the relevant inspection methods for specific modes of deterioration are covered in this Section where appropriate. Additional comments on inspection methods are also discussed in Section 10.

8.2 CORROSION MECHANISMS

Corrosion is the prime cause of deterioration in a pressure vessel and may occur on any part of the vessel. The severity of the deterioration is influenced by the corrosion resistance of the construction materials. This section highlights these mechanisms and additional details may be found in API IRE, Chapter II.

Many of the contaminants in oil and chemicals handled in process units react with metals in such a way as to cause corrosion. Some process streams can cause erosion. In some operations, both erosion and corrosion occur. When this happens, the losses in metal thickness are often greatly in excess of losses that would be estimated from the separate effects of corrosion and erosion. In general, metal losses take place over a period of time. Accurate records of such losses are very important because it is from such records that proper inspection intervals and expected life of equipment are determined. However, metal losses are not always constant, but are a function of such variables as salt and sulfur content of crude oils, chemicals, caustics, inorganic acids, organic acids, water (especially water with a low pH), deposit or cellular attack chemicals. used in refining, and operating temperatures and pressures. It is essential, therefore, that the inspector be generally aware of the day-to-day operation of equipment and that he reestablish metal loss rates at frequent intervals.

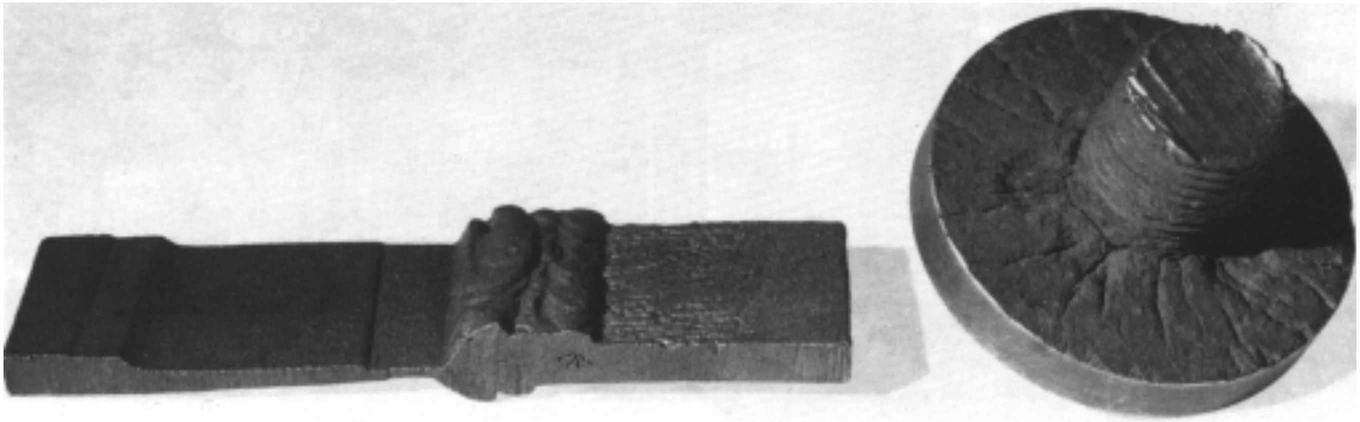


Figure 12—Caustic-Stress Corrosion

Figure 13—Severe Graphitic Corrosion of Floating-Head Cover

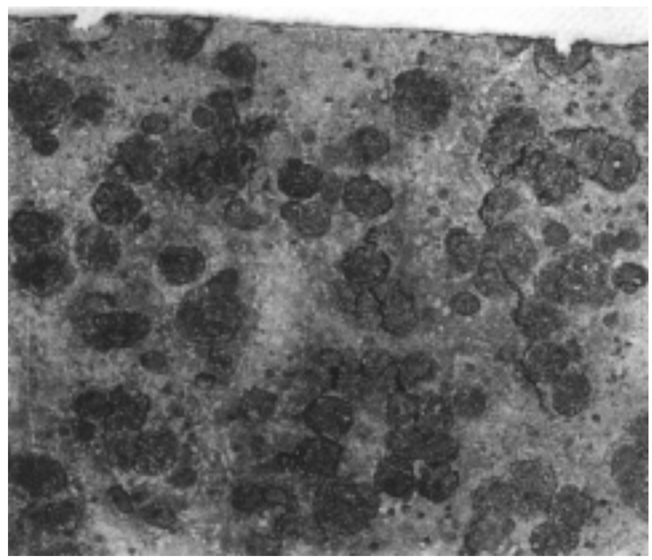


Figure 14—Plug-Type Dezincification

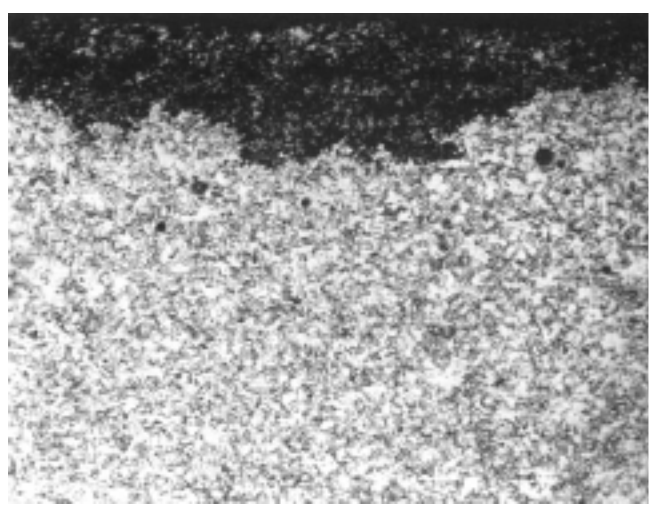


Figure 15—Layer-Type Dezincification

Figure 12 shows stress-corrosion cracking caused by a caustic. Figure 13 shows severe graphitic corrosion of a floating-head cover. Figures 14 and 15 show plug-type and layer-type dezincification of exchanger tubes. Figures 16 and 17 show fouling with and corrosion beneath marine growth.

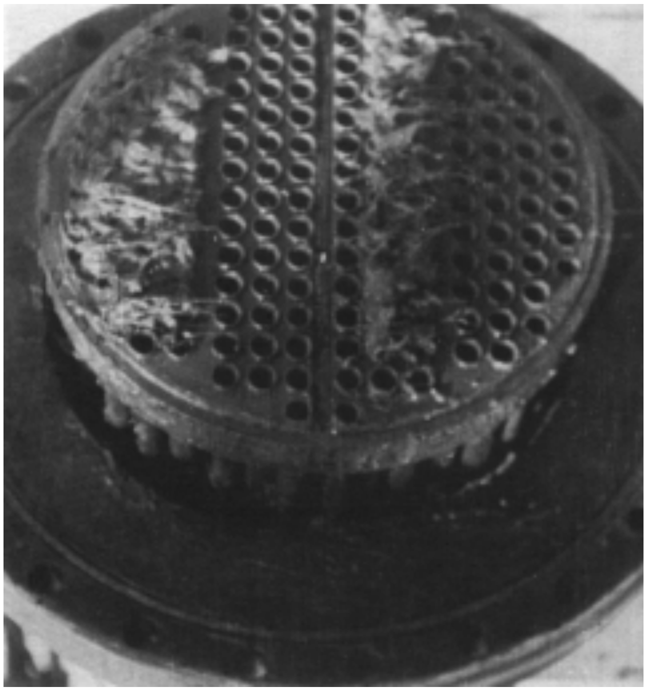


Figure 16—Tube Sheet Fouled With Marine Growth

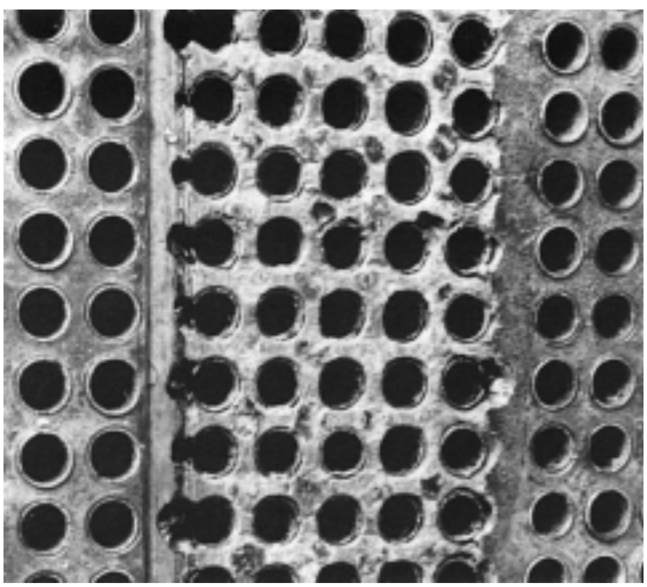


Figure 17—Tube Sheet Corroded Beneath Marine Growth

8.2.1 Corrosion Under Insulation (CUI)

External inspection of insulated vessels should include a review of the insulation system integrity for conditions that could lead to CUI as well as signs of on-going CUI. Sources of moisture may include: rain, water leaks, condensation, deluge systems, and cooling towers. The most common forms of CUI are localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels. This section provides guidelines for identifying potential CUI areas for inspection. The extent of a CUI inspection program may vary depending on the local climate and the coating/paint applied to the metal. Marine locations in warmer areas may require a very active program, whereas cooler, drier, mid-continent locations may not need as extensive a program.

Certain insulated vessels are potentially more susceptible to CUI, including:

a. Those exposed to mist over-spray from cooling water towers.
b. Those exposed to steam vents.
c. Those exposed to deluge systems.
d. Those subject to process spills or ingress of moisture or acid vapors.
e. Carbon steel vessels, including ones insulated for personnel protection, operating between 25°F (–4°C) and 250°F (121°C). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.
f. Carbon steel vessels that normally operate in service above 250°F (121°C), but are in intermittent service.
g. Austenitic stainless steel vessels operating between 150°F and 400°F (66°C and 204°C) (susceptible to chloride stress corrosion cracking).
h. Vessels with deteriorated insulation, coatings and/or wrappings. Bulges or staining of the insulation or jacketing system or missing bands (bulges may indicate corrosion product buildup).
i. Vessels susceptible to physical damage of the coating or insulation, thereby exposing the vessel to the environment.
j. Termination of insulation at flanges and other piping components.
k. Damaged or missing insulation jacketing.
l. Insulation jacketing seams located on the top of the vessel or improperly lapped or sealed insulation jacketing.
m. Termination of insulation in a vertical vessel.
n. Caulking which has hardened, separated, or is missing.

Several methods are available to inspect for CUI damage. These include removal of insulation and visual inspection, and profile radiography. Newer methods to detect CUI include real-time radiography, electromagnetic methods, and long-range ultrasonic methods (referred to as guided waves). In addition, techniques to screen areas for potential CUI damage include moisture detection in insulation and thermography.

8.2.2 Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles, or cavitation. It can be characterized by grooves, rounded holes, waves, and valleys in a directional pattern. Erosion is usually in areas of turbulent flow such as at

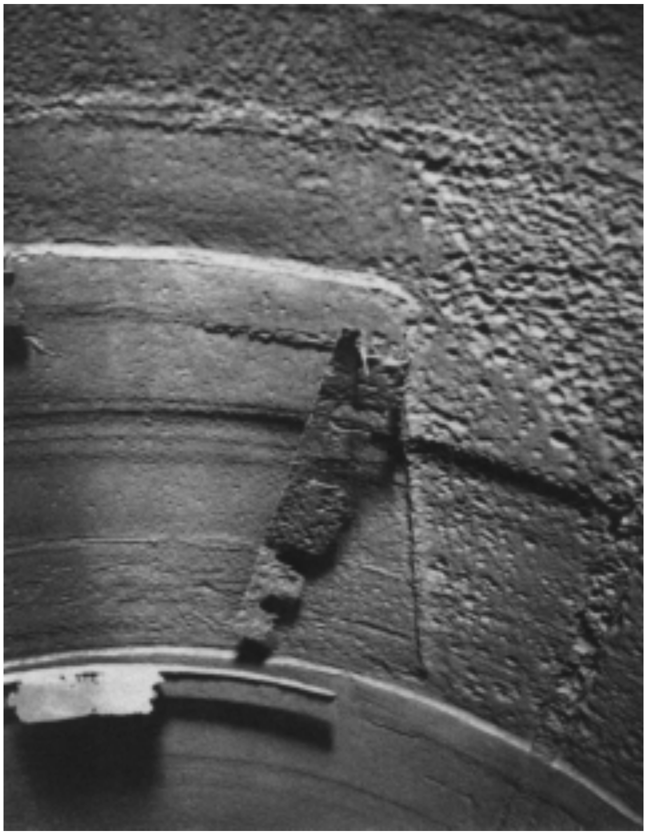


Figure 18—Internal Vessel Corrosion

changes of direction or downstream of nozzles or valves where vaporization may take place. Erosion damage is usually increased in streams with large quantities of solid or liquid particles and high velocities. This type of corrosion occurs at high velocity and high turbulence areas. Examples of places to inspect include:

a. Downstream of control valves, especially where flashing or cavitation is occurring.

b. Downstream of orifices.

c. Downstream of pump discharges.

d. At any point of flow direction change, such as impingement baffles.

Erosion is usually localized, but at times it is very general, and therefore it may be difficult to detect visually. Large eroded areas have a bright, shiny appearance and feel slick and irregular. Localized eroded areas are likely to occur where the streams change direction or are restricted, such as orifices, vessel inlet and outlet nozzles, grids, aeration connections, thermocouples, steam nozzles, cyclone separator internals, grid seals, exchanger internals, impingement baffles, and mixing columns.

A combination of corrosion and erosion (corrosion/erosion) results in significantly greater metal loss than can be expected from corrosion or erosion alone. Corrosion/erosion

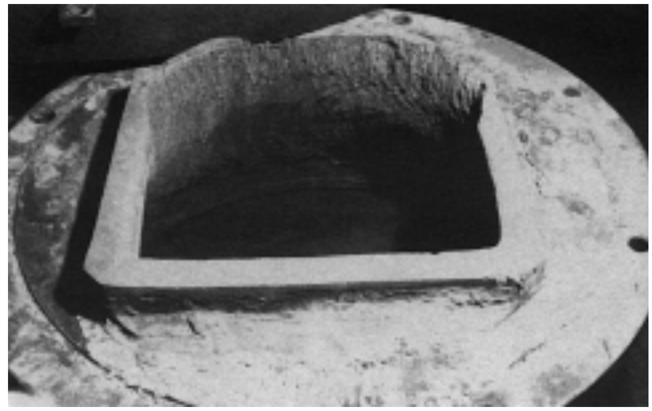


Figure 19—Erosion

may occur opposite nozzles in the bottom fluid catalytic cracking unit fractionators. Figures 18 and 19 illustrate corrosion and erosion. Figure 20 illustrates condensate grooving of an exchanger tube in the area adjoining a tube sheet; it also shows a combination of erosion and corrosion. API IRE, Chapter II, covers erosion/corrosion in detail.

This type of corrosion occurs at high velocity and high turbulence areas. Examples of places to inspect include:

a. Downstream of control valves, especially where flashing or cavitation is occurring.

b. Downstream of orifices.

c. Downstream of pump discharges.

d. At any point of flow direction change, such as impingement baffles.

Suspect areas in vessels can be inspected using appropriate nondestructive examination (NDE) methods that will yield thickness data over a wide area, such as ultrasonic and scanning, electromagnetic scanning, and radiograpohic profiling. Newer methods include laser profiling and flux leakage methods.

In boiler and heat exchanger tubes, suspect areas can be inspected using appropriate NDE methods that quantify thickness such as ultrasonic, eddy current, remote field eddy current, and laser profilometric methods. In addition, acoustic ranging (similar to radar technology) can be used to detect discontinuities.

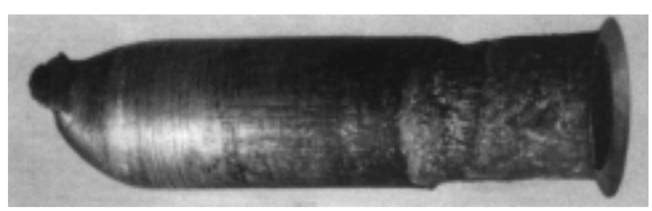


Figure 20—Condensate Grooving of Tube in Area Adjoining Tube Sheet

8.2.3 Environmental Cracking

Vessel materials of construction are normally selected to resist the various forms of stress corrosion cracking. Some vessels may be susceptible to environmental cracking due to upset process conditions, corrosion under insulation, unanticipated condensation, or exposure to wet hydrogen sulfide or carbonates. Problems with environmental cracking have been experienced in regions of high hardness, areas of high stress, or both.

Examples of this include:

a. Chloride stress corrosion cracking of austenitic stainless steels due to moisture and chlorides under insulation. Often, there will be no general corrosion. Both residual and applied stresses must be considered. The stress concentrator leads to cracking under tensile stress. Subsequent cycles may increase cracking to failure.
b. Polythionic acid stress corrosion cracking (PSCC) of sensitized austenitic alloy steels due to exposure to sulfide/moisture/oxygen. This corrosion is normally found during shutdowns. Keeping the surface dry, free from air or alkaline with soda ash solutions are all possible control methods.
c. Caustic stress corrosion cracking (sometimes known as caustic embrittlement). Depending on the alloy, cracking may occur at welds or other points of high stress when temperatures are over 400°F (204°C). Figure 15 illustrates this condition.
d. Amine stress corrosion cracking in non-stress relieved vessels. API RP 945 provides details of these mechanisms for carbon steels exposed to amine service.
e. Carbonate stress corrosion cracking in alkaline systems
f. Wet hydrogen sulfide stress cracking, hydrogen induced cracking, and hydrogen blistering. API Publ 939 provides details of these mechanisms.

When the inspector suspects or is advised that specific vessels may be susceptible to environmental cracking, the inspector should schedule supplemental inspections. Such inspections can take the form of surface NDE such as liquid penetrant or wet fluorescent magnetic particle testing (PT or WFMT) or ultrasonic examination (i.e., zero-degree or angle beam). Other eddy current methods are available for surface and near-surface crack detection. In some cases, acoustic emission testing may be appropriate as a screening method.

8.2.4 Corrosion Beneath Linings and Deposits

If external or internal coatings, refractory linings, and corrosion-resistant linings are in good condition, and there is no reason to suspect a deteriorated condition behind them, it is usually not necessary to remove them for inspection of the vessel.

The effectiveness of corrosion-resistant linings is greatly reduced due to breaks or holes in the lining. The linings should be inspected for separation, breaks, holes, and blisters. If any of these conditions are noted, it may be necessary to remove portions of the internal lining to investigate the effectiveness of the lining and the condition of the metal beneath the lining. Alternatively, ultrasonic scanning examination from the external surface can be used on certain types of linings, such as explosion bonded clad or weld overlayed clad, to measure wall thickness and to detect separation, holes, and blisters.

Refractory linings may spall or crack in service with or without causing any significant problems. Corrosion beneath refractory linings can result in separation and bulging of the refractory. If bulging or separation of the refractory lining is detected, then portions of the refractory may be removed to permit inspection of the metal beneath the refractory. Alternatively, ultrasonic thickness scanning may be made from the external metal surface. Thermography may also be useful in detecting refractory or lining deterioration.

Where operating deposits, such as coke, are present on a vessel surface, it is particularly important to determine whether such deposits have active corrosion beneath them. This may require a thorough inspection in selected areas. Larger vessels should have the deposits removed in selected critical areas for spot examination. Smaller vessels may require that NDE methods, such as radiography or external ultrasonic scanning examination be performed in selected areas.

8.2.5 Fatigue Cracking

Fatigue cracking of vessels may result from excessive cyclic stresses that are often well below the static yield strength of the material. In some cases, cracking can be induced through pressure, mechanical, or thermal stresses. Damage may be characterized as either low cycle fatigue where the maximum cyclic stresses imposed approach the yield strength of the material, or as high cycle fatigue where the cyclic stresses imposed are significantly less than the yield strength of the material. In coke drum circumferential welds, the onset of low cycle fatigue cracking is often directly related to the number of heat-up/cool-down cycles experienced. Excessive vibration of rotating equipment or flow-induced vibration can cause high cycle fatigue damage. A special category of fatigue cracking is referred to as corrosion fatigue. This occurs under the simultaneous action of corrosion and cyclic stresses. Cracking observed in deaerator vessels is a typical example of corrosion fatigue.Fatigue cracking can typically be first detected at points of high localized stress such as areas subject to high vibration, weld peaking, and at internal or external attachments. Locations where metals having different coefficients of thermal expansion are joined by welding may be susceptible to thermal fatigue. The preferred NDE methods for detecting fatigue cracking include liquid penetrant testing, magnetic particle testing, eddy current testing, and angle beam ultrasonic examination. See API 570 for fatigue considerations relative to threaded connections.

Acoustic emission may also be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

It is important for the owner-user and the inspector to understand that fatigue cracking is likely to cause vessel failure before detection with any NDE methods. Of the fatigue cycles required to produce failure, the vast majority are required to initiate cracking and relatively few cycles are required to propagate he crack to failure. As such, design and installation to prevent fatigue cracking are important.

Mechanical forces can cause a vessel to fail or to operate inefficiently unless adequate provision for the forces has been made. Thermal shock (Figure 22 shows thermal and pressure damage), cyclic temperature changes, vibration (Figure 23 shows fatigue cracking caused by vibration), excessive pressure surges from any cause, and external loads are examples of sources of mechanical forces. Cracks, bulges, distortion, and upset internal equipment are visual signs of the application of mechanical forces. IRE, Chapter II, covers mechanical forces in detail.

8.2.6 Creep Cracking

Creep is dependent on time, temperature, and stress. Creep damage may be difficult to detect until significant damage has occurred. Cracking is accelerated by creep/fatigue interaction when operating conditions in the creep range are cyclic. Particular attention should be given to areas of high stress concentration. If excessive temperatures are encountered, mechanical property and microstructural changes in metals also may take place. These changes permanently weaken equipment. An example of where creep cracking has been experienced in the industry is in 1¼ Cr steels above 900°F (482°C). NDE methods suitable for detecting creep cracking in the latter stages of damage include liquid penetrant, magnetic particle, ultrasonic examination, radiography, and in-situ metallography. Acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

8.2.7 High-Temperature Hydrogen Attack

Some refining operations involve the use or production of hydrogen at high temperatures and pressures. At these conditions, molecular hydrogen dissociates into atomic hydrogen which can penetrate the microstructure of a metal. Cracking may result from overstressing. Susceptibility to attack increases with increasing carbon content. Coarse-grained steels are more susceptible to attack than fine-grained steels. API RP 941 presents safe operating limits for use of different steels in hydrogen service. WRC Bulletin 411 (cross reference API Publ 938) provides additional details on the cause of cracking in 1¼Cr-½Mo steels at temperatures over 800°F (427°C). Ultrasonic methods such as the backscatter method, the velocity ratio method, spectrum frequency analysis, and spacial averaging are useful in detecting high temperature hydrogen attack. These methods require special transducers and equipment. Surface replication of internal vessel surfaces are also appropriate.

8.2.8 High Temperature Sulfide Corrosion

In the absence of water, corrosion rates are relatively low at metal temperatures less than 450°F (232°C). The exact composition of the crude, and in particular the reactive sulfur content, will be an important factor that determines the corrosion rate. High temperature sulfide corrosion is typically manifested by a general material wastage. Inspection methods discussed in 8.2.2 are appropriate for detecting sulfidic corrosion.

8.2.9 Soil-to-Air (S/A) Interface

Inspection at grade should include checking for coating damage and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is localized to the S/A interface or may be more pervasive to the buried system. Thickness readings at the S/A interfaces may expose the metal and accelerate corrosion, if coatings and wrappings are not properly restored. If the buried system has satisfactory cathodic protection as determined by monitoring, excavation is required only if there is evidence of coating or wrapping damage. If the buried vessel is uncoated at grade, consideration should be given to excavating 6–12 in. (15–50 cm) deep to assess the potential for hidden damage. Coatings that are in good condition should not typically be removed to inspect for damage.

At concrete-to-air and asphalt-to-air interfaces for buried vessels without cathodic protection, the inspector should look for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on systems over ten years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint. When partially buried vessels are inspected internally to assess external corrosion, the inspection methods discussed in 8.2.2 are appropriate for detecting external corrosion at S/A interfaces. Additional information on S/A interfaces can be found in API 570.

8.2.10 Biological Corrosion

Certain primitive living organisms may influence corrosion in one of the following ways: by directly influencing the rate of corrosion; by permitting the development of an environment corrosive to the metal; or by producing electrolytic concentration cells leading to contact or crevice corrosion.

The most important microorganisms that directly influence the rate of metallic corrosion are the sulfate-reducing bacteria found in many soils. There are many species and strains of

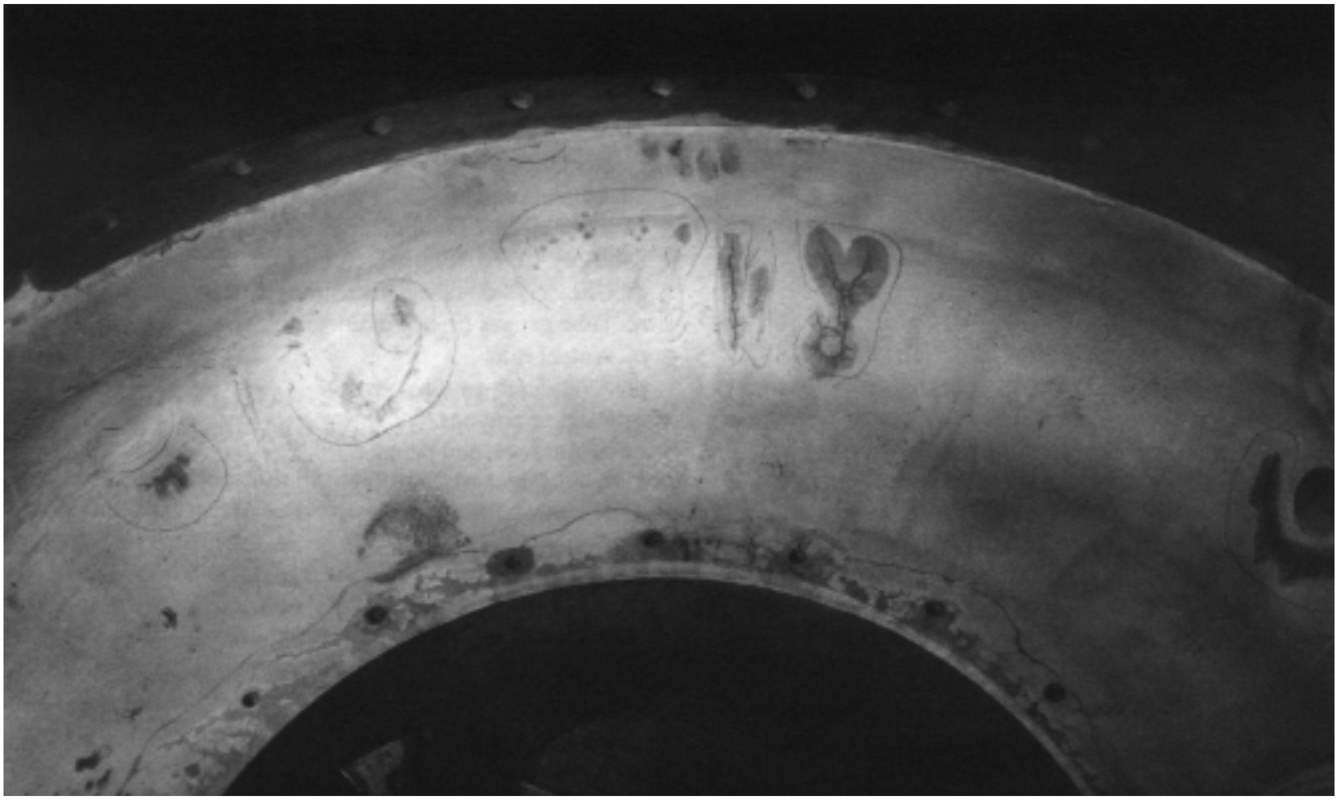


Figure 21—Intergranular Corrosion

these bacteria, but they all have one common characteristic in that they use hydrogen to reduce sulfate contained in the soils. Corrosion of metals always results in the release of hydrogen at some point on the metal surface. If this hydrogen is not removed in some way, it forms a blanket over the metal and reduces the rate of corrosion. Sulfate-reducing bacteria consume this hydrogen, thus speeding up the rate of corrosion. The reduction of sulfate results in the formation of hydrogen sulfide; which, in turn, causes further corrosion. This type of biological corrosion may result in severe pitting of underground vessels.

Macroorganisms may cause contact or crevice corrosion. Figures 16 and 17 show fouling with corrosion beneath marine growth. During internal inspections, surfaces should be cleaned for vessel inspection. During external inspections, the inspection methods discussed in 8.2.2 are appropriate for detecting damage caused by biological corrosion.

8.3 METALLURGICAL AND PHYSICAL CHANGES

Pressure vessel metals are exposed to service conditions that may cause microstructural or metallurgical changes in the metal. These changes often affect the mechanical properties of the metal and may result in cracking or other deterioration. Microstructural changes may result either from improper heating and cooling of the metal or from metallurgical chemical changes in the metal. Examples of these changes

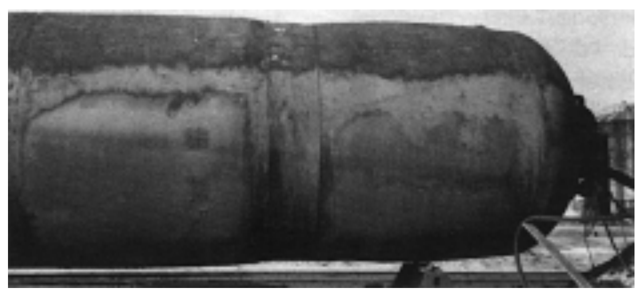


Figure 22—Thermal and Pressure Damage

Figure 23—Fatigue Cracking at Nozzle

are graphitization, high-temperature hydrogen attack, carbide precipitation and intergranular corrosion (see Figure 21), and embrittlement. More detailed descriptions of metallurgical and physical changes may be found in API IRE, Chapter II.

8.3.1 Decarburization

Decarburization may be defined as the loss of carbon from the surface of a ferrous alloy as a result of heating in a medium that reacts with carbon. So far as refinery equipment is concerned, decarburization is usually the result of restricted high-temperature oxidation. When carbon is removed from the surface of a steel, the surface layer is converted to almost pure iron, which results in considerably lower tensile strength, hardness, and fatigue strength. The appearance of the decarburized layer is usually not serious unless fatigue is a problem. However, its occurrence in operating equipment is evidence that the steel has been overheated, and other effects may also be present. Decarburization can be found only by metallurgical examination. For all practical purposes, decarburization is limited in refinery service to the ferritic steels, and is most often found in steam and hydrogen services.

8.3.2 Graphitization

Certain ferritic steelsoperating for long periods of time in the range of 825°F to 1400°F (440°C to 760°C) may suffer a type of structural change called graphitization. The most susceptible steels to graphitization are carbon and carbon ½-molybdenum steels. In this temperature range, the carbide may decompose into ferrite crystals and graphite nodules. Random graphitization distributes nodules throughout the steel, which lowers the room temperature tensile strength, but does not usually affect creep resistance. Localized graphitization results in highly concentrated graphite-nodule formation which may lead to mechanical failure. Localized graphitization has most frequently been found in narrow bands at the low-temperature edge of the zone of the parent metal which was heat affected during welding. In-situ metallography is one method of detecting graphitization.

8.3.3 Dealloying

Dealloying occurs in certain material/environment systems. It is characterized by the selective leaching of one or more of the alloy components in the material. There are three common forms of dealloying which affect certain copper alloys and are referred to as dezincification, dealuminization, and denickelification. Each form of dealloying refer to the loss of specific elemental phase from the alloy microstructure (i.e., zinc from brass, aluminum brasses or bronzes, and nickel from cupronickels or Monels).

Dezincification can occur in copper-zinc alloys (brasses) containing less that 85% copper when used in water service. Zinc is lost from the brass and leaves a residue, reducing the mechanical strength of the remaining copper. Dezincification may be localized (i.e. plug-type attack) or general (layer-type attack). Figures 14 and 15 show plug-type and layer-type dezincification of exchanger tubes. Cupronickels are more prone to layer-type attack Monel alloys have undergone dealloying when exposed to steam containing sulfur compounds. Dealumification of duplex aluminum bronzes has occurred in both high and low pH waters.

NDE methods for detecting dealloying include ultrasonic and eddy current test methods.

8.3.4 Temper Embrittlement

A change occurs in some normally ductile Cr-Mo alloy steels when exposed to temperatures from 750°F to 1000°F (400°C to 538°C). Upon slow cooling from these temperatures, the steels are brittle at ambient temperatures (under 200°F (93°C)). This so-called embrittlement occurs most rapidly near 885°F (475°C). It can be eliminated by annealing the alloy steel to restore original physical properties. Ferritic chromium steels are susceptible to 885 embrittlement. However, the higher chromium alloys, such as 9 Cr-1 Mo steels, are not susceptible because of the molybdenum addition. Most cases of embrittlement are found in the form of cracking occurring when the equipment is removed from service for routine maintenance. The cracking appears in both wrought and cast (i.e. weld) structures. High stress levels in exchanger tubes leads to rapid failures in these structures.

8.3.5 Brittle Fracture

Carbon, low-alloy, and other ferritic steels may be susceptible to brittle failure at or below ambient temperatures. In some cases the refrigerating effect of vaporizing liquids such as ammonia or C_2 hydrocarbons may chill vessels and promote brittle fracture in material that may not otherwise fail. Brittle fracture usually is not a concern with relatively thin wall vessels. Most brittle fractures have occurred on the first application of a particular stress level (that is, the first hydrotest or overload) unless critical defects are introduced in service. Special attention should be given to low-alloy steels (especially 2¼ Cr - 1 Mo material), because they may be prone to temperature embrittlement, and to ferritic stainless steels. Brittle failures will occur without warning. In addition to a sufficiently low temperature (e.g., below its transition temperature), a notch or stress concentration will also be present. In most pressure vessel failures, a welding defect is believed to have been the stress concentrator.

Information on the prevention of brittle fracture in pressure vessels is contained in API RP 579.

8.3.6 Freeze Damage

At subfreezing temperatures, water and aqueous solutions contained in vessels may freeze and cause failure because of the expansion of these materials. After severe freezing weather, it is important to visually check for freeze damage to exposed vessel components before the system thaws. If rupture has occurred, leakage may be temporarily prevented by the frozen fluid. Low points containing water should be carefully examined for damage. Visual inspection for bulging or leaks is the most common method of detecting freeze damage to equipment.

8.3.7 Hydriding of Titanium Alloys

Titanium alloys are subject to loss of ductility in certain environments due to the absorption of hydrogen and the subsequent formation of embrittling titanium hydride phases. The rate of hydrogen intake into the alloy depends on the temperature and pH of the environment. Galvanic charging of hydrogen into these alloys may occur when titanium alloys are in contact with more chemically active materials. Cathodic currents produced by the dissimilar metal couple may accelerate hydrogen uptake. Eddy current testing has been used to detect hydriding damage. It is necessary to utilize appropriate reference samples for comparison when inspecting for hydriding damage in titanium alloys.

8.4 FAULTY MATERIAL

Many of the troubles that may develop in pressure vessels can be traced to faulty material or fabrication. Some of the problems due to faulty material or fabrication are cracking, leakage, blockage, and excessive corrosion.

The material used to construct a vessel may contain laminations, away from the edges of a plate, that may not be discovered before or during fabrication. After the vessel has been in operation, a lamination may open and manifest itself as a surface crack or internal blister.

Castings may contain defects not visible on the surface. After corrosion has occurred, such defects may result in leaks. If the leaks are of sufficient magnitude or if many occur in close proximity, they may result in failure.

Lack of experience with a new process may result in the selection of improper material that leads to excessive corrosion. Materials with properties unsuitable for repair work may also lead to excessive corrosion or to failure.

8.5 FAULTY FABRICATION

8.5.1 General

Faulty fabrication includes poor welding, improper heat treatment, fabrication with dimensions outside the tolerances allowed by the ASME Code, improper installation of internal equipment, assembly of flanged or threaded joints that result in an improper fit, and the use of improper materials.

8.5.2 Poor Welding

The use of improper welding techniques or careless welding may result in incomplete penetration, lack of fusion, cracking, undercutting, slag inclusion in the welds, and the development of porous welds. Any of these conditions may result in cracking or failure

8.5.3 Improper Heat Treatment

Improper heat treatment may leave high residual stresses near welds and may affect the physical properties and the corrosion resistance of the metal. It may also result in a hard material that may crack under shock.

High residual stresses may produce latent cracks, particularly around nozzle and reinforcement attachments, that may not be detected until the vessel has been operated for an extensive period of time. Under corrosive conditions, high residual stresses may also lead to stress-corrosion cracking. A change in the properties of corrosion-resistance may also result.

Materials heated above the proper heat-treating temperature or held too long at the proper temperature can be damaged so that their physical properties may not meet specification.

8.5.4 Dimensional Intolerance

Poor fabrication techniques can cause tolerances outside of the range permitted by the ASME Code, which can lead to stress concentrations and subsequent failure.

8.5.5 Improper Installation

Improper installation of internal equipment may result in inefficient operation, blockage of passages, and, in the case of a pressure surge, the displacement of the internal equipment.

8.5.6 Improper Fit

Improper fitting or tightening of flanged or threaded joints may result in leaks and, in the case of threaded joints, complete failure.

8.5.7 Improper Materials

The use of improper materials may also result in failure due to excessive corrosion or environmental cracking. Failure of pressure-containing components due to the use of improper materials may occur rapidly, or it may many years depending on the corrosivity of the process stream. In order to prevent failure of equipment caused by improper material use, positive metal identification (PMI) of alloy materials may be necessary during fabrication or maintenance activities.

9 Frequency and Time of Inspection

9.1 FACTORS GOVERNING FREQUENCY OF INSPECTION

The frequency with which a pressure vessel should be inspected depends on several factors. The most important factor is the rate of deterioration and the remaining corrosion allowance (see API 510).

Corrosion rates will vary markedly with the types of crude oil or stocks processed, the temperature of exposure, and the materials of construction. Each condition must be individually appraised to establish the initial inspection period for new equipment.

A service history record should be established after the first inspection by on-stream methods or internal examination. On the basis of this history, an inspection interval based on time, condition, or risk-based factors can be set in accordance with API 510 or jurisdictional requirements. The period between inspections is normally planned so at least half the remaining corrosion allowance should remain at the next scheduled inspection. The predetermined frequency of inspection should allow for unanticipated changes in corrosion rates where appropriate.

Insurance and legal requirements may also affect the inspection of pressure vessels. Those responsible for inspection and maintenance of equipment should familiarize themselves with the applicable requirements. Recommendations in API 510, in NB-23, and in jurisdictional requirements should be followed where appropriate.

When changes in process operations are expected, they should be reviewed to determine whether they might affect the deterioration rate. When a change in the deterioration rate occurs or is anticipated, the recommended inspection interval should be changed accordingly.

Visual checks of the external parts of a vessel should be made periodically. Such inspections can be made without removing the vessel from service. These inspections may be made at comparatively short intervals, the interval depending on the service and previous condition of the particular equipment involved. Thorough external inspection of unfired pressure vessels should be conducted in accordance with API 510.

On most units, operating needs such as the minimum permissible internal cleanliness, especially for towers and exchangers, and the maintenance of required heat-transfer rates, for exchangers or coolers, may determine the length of a unit run.

9.2 OPPORTUNITIES FOR INSPECTION

The actual time for inspection will usually be determined through the collaboration of process, mechanical, and inspection groups, or by the mandate of a jurisdiction.

Unscheduled shutdowns due to mechanical or process difficulties often present opportunities for checks of vessel areas where rapid corrosion, erosion, or other deterioration is known or suspected to occur. Partial shutdowns of units for process reasons also provide opportunities for making some internal inspections to determine conditions and verify on-stream inspection findings and for making needed repairs. However, internal inspections during unscheduled shutdowns should be motivated by specific process or inspection observations.

Inspections during the following opportunities are possible:

a. When exchangers are normally taken out of service for cleaning. When it is anticipated that an exchanger will have to be cleaned at more frequent intervals than permitted by the normal run of the process unit, it is customary to install spare exchangers valved so that any exchanger can be bypassed and opened for cleaning. Advantage should be taken of the opportunity to inspect exchangers so bypassed and removed from service during operation so that the work load when the process unit is shut down for a turnaround is reduced.

b. When vessels or process towers are removed from service to clean trays and the like.

c. When a vessel or an exchanger is removed from service at other than the scheduled time. When this occurs, the most critical parts of the vessel or exchanger could be inspected.

d. External inspections may be made while a vessel or an exchanger is in service. Inspection work performed while the equipment is in service will reduce the workload when it is out of service. These inspections should cover the condition of the foundation, supports, insulation, paint, ladders, platforms, and other structural elements. The existence and location of abnormally high metal temperatures or hot spots on internally insulated units can also be detected. On-stream inspection methods may be used to detect defects and to measure wall thickness. For example, thickness can be determined by using ultrasonic equipment or profile radiography where applicable.

e. An occasional check of the operating record while equipment is in service is sometimes helpful in determining and locating the cause of functional deterioration. An increased drop in pressure may indicate blockage from excessive corrosion deposits. Reduced exchange of heat from exchangers or coolers may indicate heavy corrosion deposits on or in the bundle tubes. The inability to draw the product of fractionation or distillation from certain trays may indicate fouling or loss of tray parts in a process tower. Product deterioration may indicate loss of trays, tray parts, or other internal equipment in process vessels. The inspector should always keep in close touch with operations.

f. When process variables drift beyond pre-established limits for the materials, external inspections may be conducted to reassess equipment integrity.

9.3 INSPECTION SCHEDULE

Maximum internal or external inspection intervals should be in accordance with API 510. Scheduling of shutdowns for maintenance or inspection is usually arranged through the collaboration of process, maintenance, and inspection groups or as mandated by a jurisdiction. Efforts should be made to schedule unit shutdowns evenly throughout the year to distribute the workload on the inspection and maintenance groups.

The safety and the reliability of operation are the most important considerations in scheduling units for inspection. Occasionally, seasonal demands for certain products may make some units available for inspection and maintenance work without serious interruption of supply. New vessels should be inspected at a reasonable time interval after being placed in service. This interval will depend on the service. The past records on vessels in similar units may be used as a guide.

9.4 ALTERNATIVE RULES FOR EXPLORATION AND PRODUCTION VESSELS

API 510, Section 8, provides alternative rules for pressure vessels in exploration and production service. API 510, Section 8, also describes a vessel classification scheme that will influence the extent and frequency of vessel inspection. In the absence of establishing a classification scheme, all vessels will be treated as higher risk. In addition to the two specifically identified classes (higher and lower), intermediate classes may also be defined.

Both the potential for vessel failure and consequence of a failure may be considered when grouping vessels into a class. The owner/user is responsible for devising and documenting the classification scheme. The scheme may be qualitative, quantitative, or a combination of both. API 510 requires that the following items, as a minimum, be considered in establishing the classification:

a. Potential for Failure
   - minimum design metal temperature
   - potential for cracking, corrosion, erosion
   - mitigating factors

b. Vessel History, Design, and Operating Conditions
   - type/history of repairs and alterations
   - age
   - remaining corrosion allowance
   - properties of contained fluids
   - operating pressure/temperature relative to design

c. Consequence of a Failure
   - location relative to employees or public
   - potential for equipment damage
   - environmental consequences

Additional information that may be considered includes:

1. on-stream or periodic inspections
2. effectiveness and results of previous inspections
3. consequences of service change (if any)
4. estimated corrosion rate
5. nature of corrosion and probability of detecting deterioration
6. capability to monitor for process upsets
7. nature of failure
   - leak or rupture
   - release rate
   - leak, explosion, fire, and toxicity likelihood
8. time required to detect failure

10 Inspection Methods and Limitations

10.1 GENERAL

Before starting the inspection of a pressure vessel, especially one in severe service, the inspector should determine the pressure, temperature, and service conditions under which the vessel has been operated since the last inspection. The inspector should also be aware of equipment construction details including materials of construction, the presence of internal attachments, and weld details. He should also confer with operations to determine whether there have been any abnormal operating conditions or disturbances such as excessive pressures or temperatures. This data may offer valuable clues to the type and location of corrosion and to other forms of deterioration that may have occurred such as scaling, bulging, and warping. The inspector should develop and exercise sound judgment on the extent and kinds of inspection required for each vessel.

Careful visual inspection of every vessel is of paramount importance to determine other forms of inspection that may need to be made. Appropriate surface preparation is essential to all inspection methods. The extent to which special surface preparation may be required depends on the particular circumstances involved. Wire brushing, sandblasting, high-pressure water blasting, chipping, grinding, or a combination of these operations may be required in addition to routine cleaning.

If external or internal coverings such as insulation, refractory linings, or corrosion-resistant linings are in good condition and without evidence of an unsafe condition behind them, it may not be necessary to remove them for inspection of the vessel. However, it may sometimes be advisable to remove small portions to investigate their condition and the condition of the metal behind them, particularly if previous inspections have indicated corrosion. When any covering is found to be defective, a sufficient amount of the covering in the vicinity of the defect should be removed to find out whether the base metal is deteriorating and to determine the extent of the deterioration.

Where operating deposits such as coke are normally permitted to remain on a vessel surface, it is important to determine the condition of the vessel surface behind the deposits.

This may require thorough removal of the deposit in selected critical areas for spot check examination.

Where vessels are equipped with removable internals, the internals need not be completely removed, provided reasonable assurance exists that deterioration is not occurring beyond that found in more readily accessible parts of the vessel.

10.2 SAFETY PRECAUTIONS AND PREPARATORY WORK

10.2.1 Safety

Safety precautions must be taken before entering a vessel including consulting and complying with all applicable safety regulations. This includes, but not limited to, "lockout/ tagout" and "confined space" regulations. Because of limited access and confined spaces, safety precautions are probably more important in vessel inspection work than in the inspection of any other type of equipment.

The vessel should be isolated from all sources of liquids, gases, or vapors, using blinds or blind flanges of suitable pressure and temperature rating. The vessel should be drained, purged, cleaned, and gas tested before it is entered. This preparation will minimize danger from toxic gases, oxygen deficiency, explosive mixtures, and irritating chemicals. Clothing that will protect the body and eyes from the hazards existing in the vessel to be entered should be worn. Details of the precautions to be followed are covered in, API Publ 2217A.

On occasion, it may be desirable to enter a vessel before it has been properly cleaned to search for internal causes of poor operation. In this case, the inspector should exercise the special precautions for such entry as given in API Publ 2217A.

The use of nondestructive devices for inspection is subject to safety requirements customarily met in gaseous atmospheres, which are listed in API Publ 2214. The use of hydrocarbon-based magnetic particle and/or liquid penetrant can change the environment of a confined inspection space. Therefore, procedures should be in place that recognize the potential change in the gaseous atmosphere. Such procedures may include periodic gas tests, limiting other activities in or near the subject vessel, housekeeping requirements to minimize the accumulation of accelerants and rags.

Before the inspection starts, all persons working around a vessel should be informed that people will be working inside the vessel. The posting of tags on the manways of tall towers is a worthwhile precaution. Usually a safety guard is stationed at the manway nearest the area under inspection. Workers inside a vessel should be informed when any work will be done on the exterior of the vessel to prevent their becoming alarmed by unexpected or unusual noise.

10.2.2 Preparatory Work

The tools needed for vessel inspection, including tools and equipment needed for personnel safety, should be checked for availability and proper working condition prior to the inspection. Any necessary safety signs should be installed prior to work in vessels.

Some of the tools that should be available for pressure vessel inspections follow:

a. Portable lights, including a flashlight.
b. Flashlight with bulb on flexible cable.
c. Thin-bladed knife.
d. Broad chisel or scraper.
e. Pointed scraper.
f. Mirrors.
g. Inside calipers.
h. Outside calipers.
i. Pocket knife.
j. Steel tape [50 feet (15 meters)].
k. Flange square.
l. An inspector's hammer or ball peen hammer (4 ounce or 8 ounce).
m. Ultrasonic thickness-measurement equipment.
n. Tube gages (inside diameter).
o. Steel rule.
p. Pit depth gage.
q. Paint or crayons.
r. Notebook and pencils.
s. Straightedge.
t. Wire brush.
u. Plumb bob and line.
v. Magnet.
w. Magnifying glass.
x. Hook gage.
y. Plastic bags for corrosion product samples.

The following tools should be available if required:

a. Surveyor's level.
b. Carpenter's or plumbers level.
c. Magnetic particle inspection equipment.
d. Micrometer.
e. Radiographic equipment.
f. Megger ground tester.
g. Sandblasting equipment.
h. High-pressure water blasting equipment.
i. Portable hardness-testing equipment.
j. Eddy-current testing equipment.
k. Sonic and radiation-measuring equipment.
l. Fiber optic flexible scopes.
m. Surveyor's transit.
n. Temperature-indicating crayons.
o. Thermocouples.
p. Metal sample-cutting equipment.
q. Material identification kit or machine.

r. Camera.
s. Ultrasonic flaw-detection equipment.
t. Liquid penetrant inspection equipment.
u. Test-hole drilling equipment (drill, tap, and plugs).
v. Sand- or water-blasting equipment.
w. Borescope.
x. Plumb lines and levels.
y. Spotting scope or binoculars.
z. Neutron backscatter equipment for moisture detection.
aa. Magnetic flux leakage equipment.

Other related equipment that might be provided for inspection includes planking, scaffolding, boson's chairs, chain or rope ladders, safety devices for climbing flares or ladders without cages, stages for lifting by cranes, radios, and portable ladders. If external scaffolding is necessary, it may be possible to erect it before the inspection starts.

10.3 EXTERNAL INSPECTION

10.3.1 General

As indicated in Section 9, much of the external inspection can be made while the vessel is in operation. Any inspection made during vessel operation will reduce the period during which the vessel will be out of surface.

10.3.2 Ladders, Stairways, Platforms, and Walkways

The external inspection of pressure vessels and exchangers should start with ladders, stairways, platforms, or walkways connected to or bearing on the vessel.

A careful visual inspection should be made for corroded or broken parts, cracks, the tightness of bolts, the condition of paint or galvanizing material, the wear of ladder rungs and stair treads, the security of handrails, and the condition of flooring on platforms and walkways. Visual inspection should be supplemented by hammering and scraping to remove oxide scales or other corrosion products; floor plates can be removed to check their supporting members. The tightness of bolts can be determined by tapping with an inspector's hammer or a small ball peen hammer or by trying the nuts with a wrench. Wear on metal stair treads and flooring may not only weaken them but also make them slippery if worn smooth. Depressions in platforms should be closely checked, because water lying in depressions can accelerate corrosion. Crevices should be checked by picking at them with a pointed scraper. Loose or broken parts are easily found by tapping with a small ball peen hammer or an inspector's hammer. If desired, thickness measurements of the platforms and structural members can be made with transfer calipers.

Corrosion is most likely to occur where moisture can collect. On ladders and stairs, corrosion is likely to concentrate where rungs or treads fit into the runners or stringers. Crevice corrosion may exist around the heads of bolts and nuts, at bracket connections between stair treads and angle supports, and at connections between intermediate supports and the vessel wall. Welded bracket connections are particularly susceptible to corrosion as the welds are usually rough, and it is difficult to apply a good, void-free paint coating to them. Corrosion may exist beneath a paint film and will be indicated by rust stains showing through the paint or by a blistering or a general lifting of the paint film.

The condition of most parts can be determined by hammering. Where corrosion appears to be severe, the actual thickness should be determined by calipering or by other means.

10.3.3 Foundations and Supports

Foundations for vessels are almost invariably constructed of steel-reinforced concrete or structural steel fireproofed with concrete. They should be inspected for deterioration such as spalling, cracking, and settling.

The foundations for exchangers usually consist of steel cradles on concrete piers. Occasionally the supports are made entirely of steel. Figure 24 shows a typical exchanger foundation.

The crevice formed between an exchanger shell or a horizontal vessel and a cradle support should be carefully checked. Moisture lying in the crevice can cause rapid attack on carbon steel and on low-chrome-molybdenum steels. If the cradle is sealed with a mastic compound, this seal should be checked by judiciously picking at the mastic with a scraper to make sure that it is intact. Cradles are often seal welded to vessel shells to prevent moisture from accumulating in the crevice and causing corrosion.

Excessive heat, mechanical shock, corrosion of reinforcing steel, or the freezing of entrapped moisture. Inspection for this type of damage should consist of visual observation and scraping. Measurements of the depth of such damage can usually be made with a straightedge or a steel rule.

Cracks in concrete or fireproofing may be caused by excessive heat, poor design or material, mechanical shock, or unequal settlement. Inspection for cracks should be mostly visual. Some picking with a pointed scraper may be helpful.

Very small openings or cracks in concrete or fireproofing caused by high temperature or by temperature changes can usually be identified by their hair-like appearance. Such cracks are not usually serious unless they expose the steel to corrosion.

When major cracks appear and propagate, and measurements indicate that no settlement has taken place, the cracks are probably the result of poor design or poor material. A complete check or engineering study may be required. If such investigations show that the design is correct, the cracks are most likely caused by the use of poor concrete material. Careful visual examination and minor chipping with a hammer

Figure 24—Exchanger Installation and Foundation

will usually confirm the diagnosis, but removal of a core for testing may be required.

Some settling is expected in any foundation. When settlement is even and of a nominal amount, no trouble should be experienced. However, if it is excessive or uneven, the settlement should be corrected before serious damage occurs. When foundation or support settlement has occurred, the condition of connected pipe lines should be checked.

Records of settlement should be maintained on vessels known to be settling. A rough check for uneven settling can be made with a plumb line and steel rule. When accurate measurements are desired, a surveyor's level may be used. When settlement is appreciable, it can be observed by noting the misalignment of the foundation with the surrounding paving or ground. The frequency with which settlement measurements should be taken depends on the rate and the seriousness of the settlement. Measurements should be taken until the settlement stops. Vessels supported on long concrete slabs or on two or more separate foundations are more likely to undergo uneven settlement.

10.3.4 Anchor Bolts

Although the condition of anchor bolts cannot always be completely determined by visual inspection, the area of contact between the bolts and any concrete or steel should be scraped and closely examined for corrosion. Although this will not reveal the condition below the top surface of the base plate or lugs, a sidewise blow with a hammer may reveal complete or nearly complete deterioration of the anchor bolt below the base plate (see Figure 25). Distortion of anchor bolts may indicate serious foundation settlement. The nuts on anchor bolts should be inspected to determine whether they are properly tightened. Ultrasonics may also be used to test bolts.

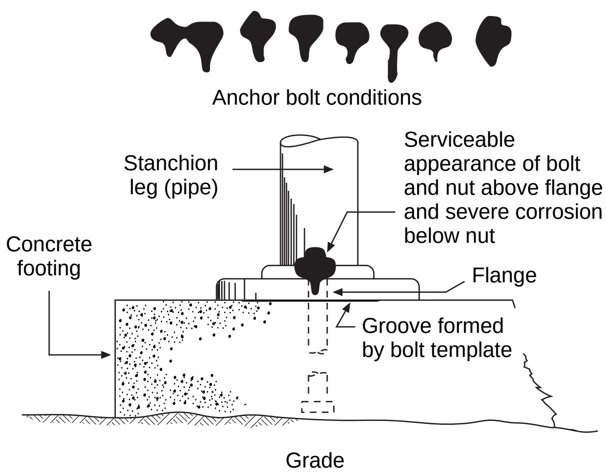


Figure 25—Severe Deterioration of Anchor Bolts

10.3.5 Concrete Supports

Inspection of concrete supports is similar to inspection of concrete foundations. The opening between concrete supports and a vessel shell or head should be sealed to prevent water from seeping between the supports and the vessel. A visual inspection with some picking and scraping should disclose the condition of the seal. A concentration cell could develop there and cause rapid corrosion.

10.3.6 Steel Supports

Steel supports should be inspected for corrosion, distortion, and cracking.

The remaining thickness of corroded supporting elements (skirts, columns, and bracing) is of primary importance. It can usually be determined by taking readings with transfer or indicating calipers in the most severely corroded areas. The readings should be compared with the original thickness (if known) or with the thickness of uncorroded sections to establish a corrosion rate. Visual examination of the support surfaces should be supplemented by wire brushing, picking and tapping with a hammer. On large skirt supports, ultrasonic thickness measuring devices can be used. Often corrosion of structural elements can be virtually eliminated simply by keeping the structural elements properly painted. Galvanizing is one of the best methods of protecting steel structures from corrosion.

Columns and load-carrying beams should be inspected for buckling or excessive deflection. This can be inspected visually with the aid of a straightedge or plumb line. Taking diameter measurements at several points approximately 60 degrees (1.0 radian) apart can check distortion of cylindrical skirts.

The inside surface of a skirt sheet is often subject to attack by condensed moisture, especially when the temperature in the enclosed area is less than approximately 100ºF (38ºC) or when steam is put in the skirt to warm the bottom of the vessel. Visual inspection will usually disclose the condition of the metal surface. If a scale or rust layer has built up, it should be wire brushed or scraped off before the inspection is made.

Vessel support lugs should be inspected to see that they are sound. Scraping will usually reveal corrosion. Tapping with a hammer will disclose extreme thinning. Connecting fasteners should be checked for corrosion and general tightness. Any crevices found should be examined for crevice corrosion by picking. Cracks can occur in all types of supporting structures and lugs. However, they are most likely to appear in welded structures. The welds and the areas adjacent to the welds are the common locations of cracks. If the vessel is in service, the inspection will probably be limited to visual methods of detecting cracks. Magnetic particle (wet or dry), liquid penetrant, or ultrasonic shear-wave methods may be used to supplement visual examination. These methods will often require further surface preparation.

If supporting skirts are insulated, the insulation should be inspected. Visual inspection will usually disclose any deterioration of the insulation. If there is reason to suspect that water or moisture is seeping through to the steel, enough insulation should be removed to determine the extent of any corrosion.

Inspect fixed and supporting supports on horizontal vessels. Floating ends of vessels must be free to allow for thermal growth and not against stops. Air fan tubes will buckle if shipping pins are not pulled from floating supports.

Piping attachments to vessels (i.e. supports and guides) should be inspected for evidence of distortion due to pipe movement.

Fire proofing on support beams and skirts should be inspected. It is usually made of bricks or concrete. Visual examination aided by scraping will disclose most defects. Very light taps with a hammer will disclose lack of bond between concrete fire proofing and the protected steel. If moisture can get behind the fire proofing, the steel may corrode and may cause the fire proofing to bulge. The bulge in the fire proofing would indicate the corrosion. Rust stains on the surface of the fire proofing would indicate possible corrosion of the metal underneath.

10.3.7 Guy Wires

Most vessels are self-supporting structures. Some towers or columns are guyed for support by steel cables. These cables radiate to the ground and terminate in the concrete deadman anchors beneath the ground surface.

The connections to the tower and to each ground anchor point should be inspected for tightness and correct tension. Visual examination should be sufficient. If there is a question regarding the correct tension in the cables, a structural engineer should be consulted.

The cable should be inspected for corrosion and broken strands. The threaded parts of any turnbuckles are subject to crevice corrosion. Picking with a pointed scraper will disclose this corrosion.

The wire rope clips on the guy wire cable at the tower and at the ground anchor point should be checked for correct installation. The clips should be attached to the cable with the base against the live or long end and the U-bolt against the dead or short end of the wire rope. The clips should be spaced at least six rope diameters apart to insure maximum holding power. The number of clips necessary for each wire rope end depends upon the diameter of the wire rope. This number can be found in wire rope catalogs and in engineering handbooks.

10.3.8 Nozzles

If any settling of the vessel has occurred, nozzles and adjacent shell areas should be inspected for distortion and cracking. Excessive pipeline expansions, internal explosions, earth quakes, and fires may also damage piping connections. Flange faces may be checked with a flange square for distortion. If there is any evidence of distortion or cracks in the area around the nozzles, all seams and the shell in this area should be examined for cracks. The area should be abrasive-grit blasted or wire brushed. Magnetic particle (wet or dry), liquid penetrant, angle beam ultrasonic, or replication techniques may be used to supplement visual examination (Catalytic reformer equipment operating at temperature more than 900ºF (482ºC) may experience creep embrittlement damage during operation. Replication is a useful technique in detecting this damage).

When accessible, nozzles should be internally inspected for corrosion, cracking, and distortion. The inspection can be visual with a scraper and a flashlight.

Exposed gasket surfaces should be checked for scoring and corrosion. The surfaces should be cleaned thoroughly and carefully for a good visual inspection.

The grooves of ring joint flanges should be checked for cracks due to excessive bolt tightening. Also, stainless steel ring joint grooves should be checked for stress-corrosion cracking. Nondestructive testing (NDT) methods such as magnetic particle (wet or dry), liquid penetrant, or ultrasonic shear-wave techniques may be used to supplement visual examination.

Lap joint flanges or slip flanges such as Van Stone flanges should be checked for corrosion between the flange and the pipe. The check can be made from inside the pipe by special probes and ultrasonic thickness-measuring devices. The flanges can also be moved for inspection after bolt removal, and the nozzle thickness checked with calipers.

Wall thickness of nozzles should be measured. Calipers, ultrasonic thickness instruments, or radiographic techniques may be used. Internal diameter measurements may be taken with inside calipers to monitor corrosion: the pipe does not have to be removed for this measurement, but the vessel must be open and approved for internal inspection. These measurements should be recorded and compared with previous or original thickness readings. Any losses should be analyzed, and appropriate action such as renewal if thickness is near or at minimum, consideration of lining installation if feasible, monitoring on shorter intervals, and use corrosion inhibitors should be taken.

Leaks are likely to occur at piping attachments to the vessel wall. Leaks can be located visually while the vessel is in service or under test conditions. Evidence of a leak is usually left in the form of discoloration to the vessel, insulation, pireprofing or paint, or as damage to or wetting of the insulation.

10.3.9 Grounding Connections

Grounding connections should be visually examined to verify that good electrical contact is maintained. These connections provide a path for the harmless discharge of lightning or static electricity into the ground. The system usually consists of a stranded copper conductor with one end bolted to the vessel and the other end brazed or bolted to an iron or copper rod placed deep in the ground. The cable connections should be checked for tightness and positive bonding to the vessels and corrosion where it penetrates the foundation, slab or ground. The continuity of all ground wires should be checked. No break should exist in the grounding circuit. Test the system to see that the resistance to ground does not exceed the accepted values in the area. Recommended resistance is 5 ohms or less, and resistance is not to exceed 25 ohms. In some areas, jurisdictional requirements will differ from these values, will govern, and need to be checked.

10.3.10 Auxiliary Equipment

Auxiliary equipment, such as gauge connections, float wells, sight glasses, and safety valves, may be visually inspected while the unit is in service. Undue vibration of these parts should be noted. The vibrations should be arrested by adding supports, or calculations should be performed by a qualified engineer to assure that the vibrations will not cause a fatigue failure. Also, check for proper construction of auxiliary equipment and connecting piping beyond vessel block valves as they can be improperly modified during unit operation for contingency reasons.

10.3.11 Protective Coatings and Insulation

The condition of the protective coating or insulation on a vessel shell should be determined. Rust spots, blisters, and film lifting are the types of paint failures usually found. Rust spots and blisters are easily found by visual examination. Film lifting is not easily seen unless the film has bulged appreciably or has broken. It can be found by picking at the film with a scraper or knife in suspect areas. Scraping paint away from blisters and rust spots often reveals pits in the vessel walls. The depth of such pitting can be measured with a pit gauge or a depth gauge. The most likely spots to search for paint failure are in crevices, in constantly moist areas, and at welded or riveted vessel seams. The bottom heads of vessels supported on skirts in humid locations are other likely points of paint failure.

Visual examination of insulation is normally sufficient to determine its condition. A few samples may be removed to better determine the condition of the insulation and the metal wall under it. The supporting clips, angles, bands, and wires should all be examined visually for corrosion and breakage. Occasionally, special blocks of insulation may be installed so that they are easily removable. These blocks are installed where it is desirable to make periodic inspections, usually at welded seams.

Inspection for corrosion under insulation (CUI) shall be considered for externally insulated vessels subject to moisture ingress and which operate between 25°F and 250°F (–4°C to 121°C), or are in intermittent service. This inspection may require removal of some insulation. However, visual inspection at ports used for thickness measurement locations may not adequately assess external corrosion at other locations. Often, moisture sealing and insulation type/consistency at these thickness measuring locations is not representative of the vessel insulation in general. Neutron backscatter methods can provide an on-stream assessment of areas with high moisture and can provide a screening assessment for CUI. Thermographic data may provide a similar on-stream screening assessment. Alternatively, shell thickness measurements done with ultrasonics or magnetic flux leakage at typical problem areas (e.g., stiffening rings, nozzles, and other locations which tend to trap moisture or allow moisture ingress) may be performed during internal inspections.

10.3.12 External Metal Surfaces

The external metal surfaces of a vessel may be inspected visually by picking, scraping, and limited hammering to locate corroded areas.

CAUTION: Extreme care should be used on operating equipment containing hot, harmful, or high-pressure material.

If conditions warrant, scaffolding may be erected around a vessel to permit access to all surfaces.

The degree of surface preparation required for external inspection will depend on the type and extent of deterioration expected. Under normal conditions, thorough cleaning to bare metal will be needed only at those points where ultrasonic thickness measurements are taken. When cracking or extensive pitting is suspected, thorough cleaning of a large area (possibly the entire vessel shell) may be required.

Hand tools such as a pointed scraper, an inspector's hammer, a wire brush, a scraper, and a file can be used to clean small spots. For larger areas, power wire brushing or abrasive blasting will usually be cheaper and more effective than the use of hand tools.

Any evidence of corrosion should be investigated and the depth and extent of the corrosion should be determined.

Thickness measurements of the vessel walls, heads, and nozzles are usually required at each complete vessel inspection. Whether these measurements are taken from the outside of a vessel or the inside will depend on the location and accessibility of the corroded areas.

Under normal conditions, at least one measurement in each shell ring and one measurement on each head should be taken. However, if much corrosion is evident, several readings should be taken in the most corroded areas. Also, if no history exists on a particular vessel, getting readings in each quadrant of each shell ring and head should be considered. Ultrasonic instruments may be used for these measurements. Under abnormally clean service conditions, fewer readings may be taken.

Inspect vessels in cyclic service at external supports using either liquid penetrant (PT) or magnetic particle (MT) testing for fatigue cracking.

10.3.13 External Evidence of Corrosion

Certain types of corrosion may be found on external surfaces of a vessel. Among these are atmospheric corrosion, caustic embrittlement, hydrogen blistering, and soil corrosion. These types of corrosion are covered in detail by IRE, Chapter II,

The extent of atmospheric corrosion on the outside of a vessel will vary with local climatic, coating, and service conditions. In humid areas and in areas where corrosive chemical vapors are present in the air, corrosion of external shell surfaces may be a problem. Vessels operating in a temperature range that will permit moisture to condense are most susceptible. Corrosion of this type is usually found by visual inspection (see 10.3.11).

If a caustic is stored or used in a vessel, the vessel should be checked for caustic embrittlement. This type of attack is most likely to occur at connections for internal heating units and in areas of residual or other high stress. The more susceptible areas are around nozzles and in or next to welded seams. Frequently, visual inspection will disclose this type of attack. The caustic material seeping through the cracks will often deposit white salts that are readily visible. Magnetic particle (wet or dry), liquid penetrant, and angle beam ultrasonic examinations may also be used to check for caustic embrittlement.

Those areas below the liquid level in vessels that contain acidic corrodents are more likely to be subject to hydrogen blistering. Hydrogen blistering is typically found on the inside of a vessel. However, hydrogen blisters may be found either ID or OD surface depending on the location of the void that causes the blistering. Blisters are found most easily by visual examination. A flashlight beam directed parallel to the metal surface will sometimes reveal blisters. When many small blisters occur, they can often be found by running the fingers over the metal surface.

Attention should be given to metal surfaces in contact with concrete saddles. In humid atmospheres, severe attack at the points of support may require weld repairs and subsequent application of protective coatings.

Vessels that are partially or completely underground are subject to soil corrosion wherever they are in contact with the ground. This corrosion will be particularly intense in areas where cinder fills were used or where acid splash-over has occurred. Inspection of the vessel surface will require thorough cleaning. Abrasive blasting will usually provide the best surface preparation. Visual examination, supplemented by picking and tapping, will disclose most faults. The location of any deep pitting should be recorded. Good judgment should be used in determining how much of the surface should be uncovered to permit this inspection. The most severe corrosion will usually be found between ground level and up to several inches below. Any vessel in contact with the ground is a candidate for connection to cathodic protection, and if so designed, this should be inspected.

The external surfaces of the vessels should be examined not only for corrosion but also for leaks, cracks, buckles, bulges, defects in the metal plates, and deformation and corrosion of any external stiffeners. If the vessel is insulated, small sections of insulation should be removed, particularly where moisture might accumulate, to gain a general idea of whether external corrosion is occurring.

Unless readily visible, leaks are best found by pressure or vacuum testing the vessel. If there are visual or other indications that a leak comes through a crack, more thorough methods of examination should be employed.

In welded vessels, cracks are most commonly found at nozzle connections, in welded seams, and at bracket and support welds. In riveted vessels, the most common location is at metal ligaments between the rivets. Usually, close visual inspection with some picking or scrapping will disclose most cracks. When cracking is suspected in an area, the entire area should be cleaned by an appropriate method such as wire brushing, high-pressure water blasting, or abrasive-grit blasting to facilitate inspection. If visual inspection is not sufficient (often the case in the detection of amine and deaerator cracking), wet or dry magnetic particle, angle beam ultrasonic, liquid penetrant, or acoustic emission analysis may be used to locate and provide additional information on the structural significance of cracks or other discontinuities. The wet fluorescent magnetic particle analysis is more sensitive than dry magnetic particle techniques.

Buckles and bulges will normally be quite evident. Small distortions can be found and measured by placing a straightedge against the shell of the vessel. While some distortion is normal, determining the cause of distortion is very important. Causes of distortion such as internal vapor explosions or excessive internal corrosion will be disclosed by the internal inspection. Settlement, earthquakes, extensive distortion in connected piping, and other sources can often be determined by external inspection. The extent of bulging or buckling can be determined by measuring the changes in circumferences or by making profiles of the vessel wall. Profiles are made by taking measurements from a line parallel to the vessel wall (see Figure 26). A surveyor's transit or a 180-degree optical plummet may also be used.

Hot spots that have developed on the shell or heads of vessels that are internally insulated should be inspected at frequent intervals while the vessel is in service. Evidence of bulging should be noted and recorded. A check of the skin temperature of the metal in the hot spot area can be made by using a portable thermocouple, infrared equipment, or temperature-indicating crayons or special paints. A complete dimensional check in the hot spot area should be made when the vessel is shut down. Using replication techniques or taking a material sample (a boat or other sample) should be considered if carbon steel temperatures were in the range of

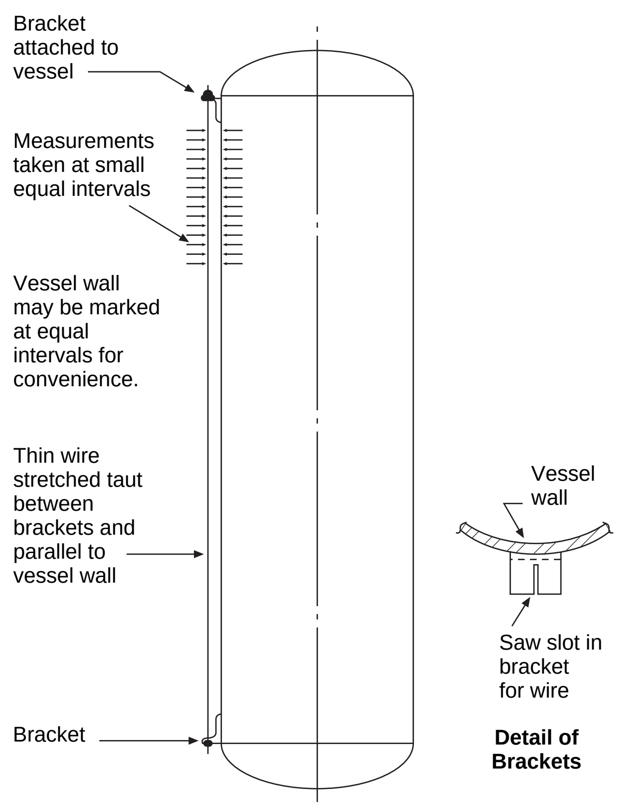


Figure 26—Method of Obtaining Vessel Profile Measurements

750ºF to 1000ºF (399°C to 538°C) for an extended period of time. Depending on operating conditions and alloy (or if hydrogen attack is possible), or if temperatures in the creep range are suspected, an experienced metallurgist or engineer should be consulted.

The external surfaces should be checked for laminations and mechanical damage. Laminations that come to the surface can be detected by visual inspection. Mechanical damage such as gouges and dents should be inspected. The depth and extent of any surface gouge should be measured when the gouge seems large enough to affect the strength of the vessel. All gouges should be reported.

Usually a certain amount of external auxiliary equipment is attached to a pressure vessel. This equipment includes items such as the following:

a. Drain lines and other connected piping (see API RP 574).

b. Gages for liquid level, pressure, and temperature and other instruments.

c. Safety and relief valves (see API RP 576).

d. External water sprays and other fire-fighting equipment.

e. Instrument or utility station stantions.

f. Structural steel for platforms, supports and lifting lugs.

10.4 INTERNAL INSPECTION

10.4.1 General

All necessary inspection equipment (including tools, ladders, and lights) should be assembled in advance to minimize downtime for the vessel. Austenitic stainless steels are particularly susceptible to PSCC and chloride corrosion. Local conditions and materials should be assessed to determine satisfactory protection measures required during down time. Not all internal inspections have to be carried out from the inside of the vessel. Techniques are available to inspect aspects of the vessel non-intrusively using acoustic emission, magnetic scanning and automated ultrasonic systems. If flaw mechanisms are well defined the techniques may frequently be applied from the outside of the vessel, while the plant is in service. This on stream information can be used to extend the running time of the plant or as a planning tool for future outages. A risk-based assessment should be used to determine when extensions to the run time can be allowed and to define the additional volumetric inspection applied from the outside.

10.4.2 Surface Preparation

The degree of surface preparation needed for internal inspection will vary with several factors. Foremost among these factors are the following:

a. The type of deterioration expected.

b. The location of any deterioration.

Usually the cleanliness required by the vessel operators will be sufficient for inspection purposes. This would entail the usual cleaning methods of washing with hot water, steaming, using solvents, and ordinary scraping. Where better cleaning is needed, the inspector's hand tools will sometimes be adequate.

The cleaning methods mentioned should be supplemented by power wire brushing, abrasive-grit blasting, grinding, high pressure water blasting [e.g. 8,000 to 12,000 lbf/in.^{2} (55.2 to 82.7 MPa)] or power chipping when warranted by circumstances. These extra cleaning methods are necessary when stress-corrosion cracking, wet sulfide cracking, hydrogen attack, or other metallurgical forms of degradation are suspected. Extensive cracking, deep pitting, and extensive weld deterioration require thorough cleaning over wide areas. If the entire inside of the vessel is not accessible from one opening, the procedures discussed in 10.4.3 should be followed at each access opening.

10.4.3 Preliminary Visual Inspection

If this is not the first inspection, the initial step in preparation for an internal inspection is to review the previous records of the vessel to be inspected.

When possible, a preliminary general visual inspection is the next step. The type of corrosion (pitted or uniform), its location, and any other obvious data should be established. In refinery process vessels, certain areas corrode much more rapidly than others do. This unevenness of corrosion is covered in detail in API IRE, Chapter II. Data collected for vessels in similar service will aid in locating and analyzing corrosion in the vessel being inspected.

The bottom head and shell of fractionators processing high-sulfur crude oils are susceptible to sulfide corrosion. This corrosion will usually be most intense around the inlet lines. In general, high temperature sulfur corrosion tends to be uniform compared to more localized corrosion from high naphthenic acids.

The upper shell and the top head of the fractionation and distillation towers are sometimes subject to chloride attack. The liquid level lines at trays in towers and in the bottom of overhead accumulators are points of concentrated attack. Corrosion in the form of grooving will often be found at these locations.

Fractionation and distillation towers, knock out drums, reflux accumulators, exchanger shells, and other related vessels that are subject to wet hydrogen sulfide (H_2S) or cyanide environments are susceptible to cracks in their welds and weld heat-affected zones.

In vessels where sludge may settle out, concentration cell corrosion sometimes occurs. The areas contacted by the sludge are most susceptible to corrosion. This corrosion may be rapid if the sludge contains acidic components.

If steam is injected into a vessel, corrosion and erosion may occur at places directly opposite the steam inlet. Bottom heads and pockets that can collect condensate are also likely to be corroded.

Often a reboiler will be used at the bottom of a tower to maintain a desired temperature. The point where the hot process stream returns to the tower may be noticeably corroded. This is especially true if the process stream contains components that may decompose with heat and form acid compounds, as in alkylation units and soap or detergent plants.

Because of metallurgical changes caused by the heat of welding at welded seams and adjacent areas, corrosion often accelerates there. Most of the cracks that occur in pressure vessels will be found in these areas. Areas opposite inlet streams maybe subject to impingement attack or erosion.

Vessels in water service, such as exchangers or coolers, are subjected to maximum corrosion where the water temperatures are highest. Thus, when water is in the tubes of an exchanger, the outlet side of the channel will be the most corroded. Figure 27 shows pitting in a channel.

In any type of vessel, corrosion may occur where dissimilar metals are in close contact. The less noble of the two metals will corrode. Carbon steel exchanger channel's gasket surfaces near brass tube sheets will often corrode at a higher rate than it would elsewhere.

Cracks in vessels are most likely to occur where there are sharp changes in shape or size or near welded seams, especially if a high stress is applied. Nozzles, exchanger channel and shell-cover flanges, baffles in exchanger channels, floating tube-sheet covers, and the like should be checked for cracks.

When materials flow at high velocities in exchanger units, an accelerated attack can be expected if changes are made in the direction of flow. Tube inlets in tubular units, return bends in double-pipe units, and condenser box or air cooler coils are likely to be attacked.

Shells of vessels adjacent to inlet impingement plates are susceptible to erosion. This is especially true when velocities are high.

The preliminary inspection of the vessel interior may indicate that additional cleaning is needed. If large areas are deeply corroded, abrasive blasting may be necessary. Normally, it is not necessary to remove light coatings of rust on more than a spot basis with a wire brush.

The preliminary inspection may reveal unsafe conditions, such as those due to loose internals that may fall or due to badly corroded or broken internal ladders or platforms. These parts must be repaired or removed immediately before a more detailed inspection may proceed.

10.4.4 Detailed Inspection

Inspectors should understand the function of the vessel, internals, and each nozzle to assess findings. If access to the inside of the vessel is available, detailed inspection should start at one end of the vessel and work toward the other end. A systematic procedure should be followed to avoid overlooking obscure but important items. Certain key areas such as internal attachment welds, seam welds and tray supports can be inspected from the outside of the vessel using manual and automated ultrasonic techniques. This may be applied if access to the inside of the vessel is not available.

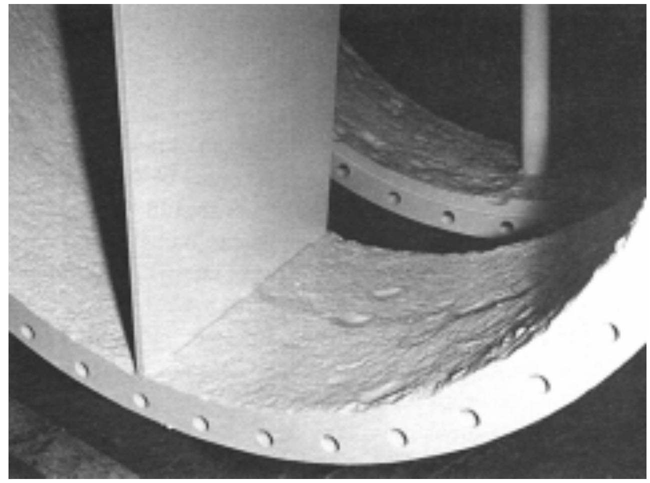


Figure 27—Pitting in Channel

All areas of the vessel should be inspected for corrosion, erosion, hydrogen blistering, deformation, cracking, and laminations. A careful record should be made of the types and locations of all deterioration found.

Thickness measurements should be taken at those locations that show the most deterioration. When deterioration appears to be widespread, enough readings should be taken to assure an accurate determination of the remaining thickness. When deterioration is slight, one thickness measurement on each head and each shell course may be sufficient on small vessels, but more measurements should be taken on large vessels. Ultrasonic instruments can be used to obtain the necessary measurements. Other special methods of measuring wall thickness are discussed in 10.5.

Pitting corrosion can usually be found by scratching suspected areas with a pointed scraper. When extensive and deep pitting or grooving is found, and depth measurements are wanted, the areas may have to be abrasive blasted. The depths of pits or grooves can be measured with a depth gauge, a pit gauge, or (in the case of large pits or wide grooves) with a straightedge and a steel rule. A depth can be estimated by extending the lead of a mechanical pencil as a depth gage. Depressions or pockets that can hold sludge or water should be scraped clean and carefully examined for evidence of corrosion.

A hammer can be used to inspect for thin areas of vessel shells, nozzles, and parts. Naturally, experience is needed before the hammer can be used effectively. When striking the shell, nozzle, or part, an experienced inspector can often find

Figure 28—Crack in Shell Weld

thin spots by listening to the resulting sound and by noting the feel of the hammer as it strikes.

When cracks are suspected or found, their extent can be checked with liquid penetrant or magnetic particle (wet or dry) techniques. Angle beam ultrasonic inspection methods provide a volumetric inspection of potential flaw areas. To use any of these methods effectively, the suspected areas must be prepared by abrasive blasting, grinding, or other methods acceptable to the inspector. Figure 28 shows a crack in a shell weld.

Heavy wall hydroprocessing reactors operate at high pressure and have special inspection requirements. Usually these vessels are constructed from C-½ Mo, 1¼ Cr-½ Mo, or 2¼ Cr-1 Mo steels. Experience has identified the following major areas of concern with respect to crack damage:

- attachment weld(s) of an internal component
- main weld seams
- gasket grooves (ring joint flanges)
- nozzle attachment welds

Secondary areas of concern include base metal and overlay disbonding and integrity of the weld overlay. Ultrasonic inspection performed from the outside of the vessel can be used to locate and measure the extent of disbond and cracked areas. If ultrasonic scanning techniques are used the defect areas can be recorded and assessed simultaneously.

Welded seams in vessel shells should be closely checked when the service is amine, wet hydrogen sulfide (H_2S), caustic, ammonia, cyclic, high temperature, or other services that may promote cracking. In addition, welds in vessels constructed of high-strength steels [(above 70,000 lbf/in.^{2} tensile (483 Mpa)] or coarse grain steels should be checked. Welds in vessels constructed of the low-chrome materials and in high-temperature service should receive careful inspection. In all cases, cracks may occur in or adjacent to the welded seams. The wet fluorescent magnetic particle technique is considered the best means for locating surface indications. Eddy Current, AC current and ultrasonic methods are also available for the detection of surface breaking defects, these new techniques have an advantage of increased impaction speed. In addition, a number of the methods have a limited depth measuring capability.

Nozzles connected to the vessel should be visually examined for internal corrosion. The wall thickness of nozzles can best be obtained with ultrasonic instruments. In some cases, a record of inside diameter measurements of nozzles may be desirable. These measurements can be made with a pair of internal, spring-type transfer calipers or with direct reading, scissors-type, inside diameter calipers. When the piping is disconnected, actual nozzle wall thickness can be obtained by calipering around the flange. In this way, any eccentric corrosion of the nozzle will be revealed. Nozzles, especially PSV inlets, should be inspected for deposits.

In most instances, inspection of internal equipment should be made when adjacent shell areas are inspected. This may be very difficult in some large vessels.

The supports for trays, baffles, screens, grids, piping, internal stiffeners, and other internal equipment should be inspected carefully. Most of this inspection will be visual. Light tapping with a hammer can be used as a check for soundness. If there appears to be any metal loss, the thickness of the support should be measured and checked against the original thickness. Transfer or direct-reading calipers, micrometers, or ultrasonic thickness instruments can be used for these measurements.

The general condition of trays and related equipment should be noted. Shell and tray surfaces in contact with tray packing should be examined for possible loss of metal by corrosion. The condition of trays and related equipment will not affect the strength of the vessel but will affect the efficiency and continuity of operation. Normally only visual inspection will required for such equipment. If measurements are required, they can be obtained with calipers or ultrasonic instruments.

The performance of some trays is dependent upon the amount of leakage. If tray leakage is appreciable, then efficiency is lost, and the withdrawal of side streams from the tower or vessel may be almost impossible. Therefore, tray leakage should be minimized. The process design will usually specify the amount of leakage that can be tolerated. Tests for leakage may be made by filling the tray with water to the height of the overflow weir and observing the time it takes for all of the water to leak through the gasket surfaces of the tray. Excessive leaks can be located by observing the underside of the tray during the test. If difficulty is encountered in determining the location of leaks, plug the weep or drain holes in the low sections of the tray prior to the test. Because of their design, ballast and valve type trays cannot be checked for leakage.

All internal piping should be thoroughly inspected visually, especially at threaded connections. Hammer testing of the pipe by an experienced inspector is a quick way to determine its condition. The sound, the feel, and any indentation will indicate any thinness or cracking in the pipe. If excessive metal loss is indicated, the remaining wall thickness may be measured.

The internals of vessels such as catalytic reactors are very complicated. Figure 29 is an illustration of this internal equipment. Inspection of this equipment may be mostly visual, although some scraping, picking, and tapping may be necessary. Thickness measurements and corrosion rate calculations may be required in some areas, although operating efficiency rather than strength is the most important consideration.

Erosion usually differs in appearance from corrosion. Figure 19 shows erosion while Figure 20 shows erosion and corrosion. Erosion is characterized by a smooth, bright appearance; marked absence of the erosion product; and metal loss, usually confined to a clearly marked local area. On the other hand, corroded areas are not commonly smooth or bright. See 8.2 for more detailed information on corrosion and 8.2.2 for more detailed information on erosion.

The shells of exchangers, next to bundle baffles and inlet impingement plates should be checked for erosion. Turbulence near the impingement plate and increased velocity around exchanger bundle baffles sometimes cause erosion of the adjacent shell areas. Erosion or corrosion at the baffles of exchangers will often show up as a series of regularly spaced rings when a flashlight beam is place parallel to the shell surface. Sometimes, a lack of scale will indicate this type of erosion.

Erosion occurs not only in exchangers but also in any vessel that has wear plates, baffles, or impingement plates. In catalytic reactors and regenerators, the catalyst and air distribution facilities are especially susceptible to erosion and should be examined closely for this type of attack. These areas such as internal impingement plates, attachment welds, seam welds and tray supports can be inspected from the outside of the vessel using manual and automated ultrasonic techniques. This may be applied if access to the inside of the vessel is not available.

Areas directly above and below the liquid level in vessels containing acidic corrodents are subject to hydrogen blistering. Blisters are most easily found by visual examination. A flashlight beam directed across the metal surface will sometimes reveal blisters; the shadows created by the blisters can be observed. When many small blisters occur, they can often be found by running the fingers over the metal surface. The metal thickness of large blisters should be measured so the remaining effective wall thickness can be determined. Usually this can be done by using an ultrasonic thickness instrument or by drilling a hole at the highest point of the blister and measuring the thickness with a hook scale. If an ultrasonic thickness instrument is used, the blister size must allow a transducer to be placed on to obtain an ultrasonic (UT) reading. When the blister is near a weld, UT readings may be difficult to obtain because of the weld surface roughness. Figures 30 and 31 illustrate hydrogen blistering.

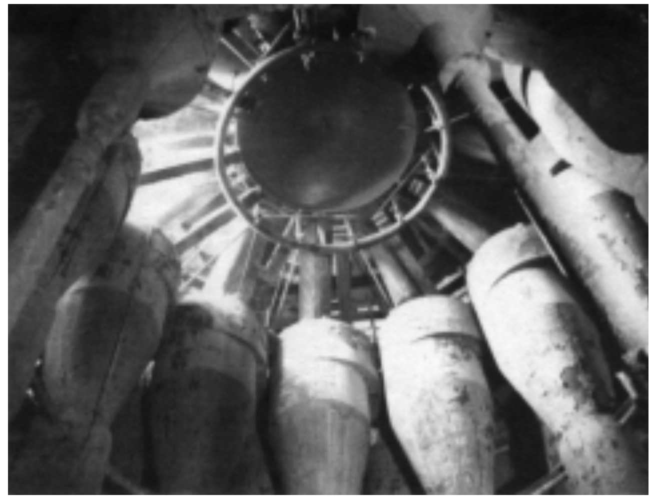


Figure 29—Catalytic-Reactor Internals—Cyclones

Both the shell and heads of vessels should be inspected for deformation. Normally the shell is more likely to suffer deformation than the heads. However, some older vessels have heads formed with a small knuckle radius, which may be seriously deformed. Unless dimensions of head parts, such as

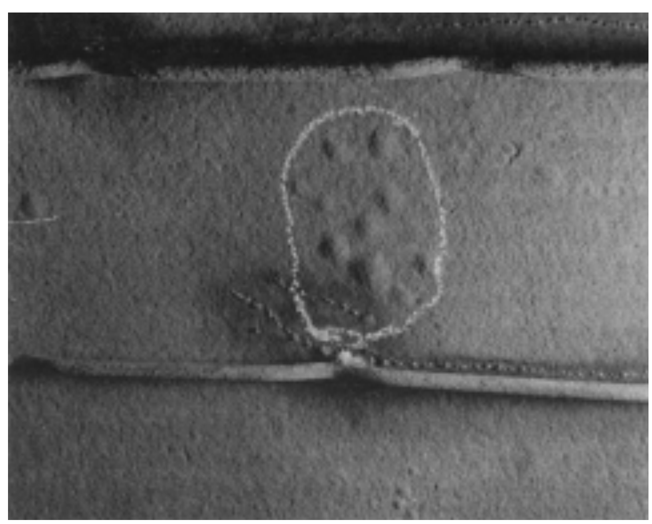


Figure 30—Hydrogen Blistering

Figure 31—Cross Section Through Hydrogen Blisters Showing Various Types of Crack Propagation

crown radius or knuckle radius, are already on record, these dimensions should be taken and recorded at the time of the first inspection. If deformation is suspected or indicated later, these measurements should be repeated and compared with the original values.

Excessive deformation of the shell by either bulging or collapsing can usually be detected visually from the outside of the vessel, unless it is externally insulated. Out-of-roundness or bulging may be evaluated by measuring the inside diameter of the vessel at the cross section of maximum deformation and comparing it with the inside diameter at the cross section of minimum deformation.

Exchanger shells should be checked closely for any deformation, particularly after repairs or alterations. Out-of-roundness caused by welding can make installation of tube bundles extremely difficult, and extractions after difficult installations can be nearly impossible.

If the out-of-roundness occurs at intervals throughout the length of the vessel, measurements should be taken at each interval to compare with the original shell dimensions or measurements. In this case, the center wire method or the plumb line (or optical plummet) method can be used to measure the deformation. In the center wire method, a steel wire is positioned on the centerline of the vessel and stretched taut. If no manways or nozzles exist in the centers of the heads, a plumb line or an optical plummet may be used. When the deformation is restricted to one side of the vessel, it may be more convenient to measure offsets from a wire stretched parallel and adjacent to the wall rather than along the vessel axis (as in the method shown in Figure 26 with the brackets and wire inside the shell instead of outside). In horizontal vessels, some special method may have to be required to hold the wire in position. The wire furnishes a reference line from which to measure the deformation. Sufficient measurements can be taken at intervals along the wire to permit drawing a profile view of the vessel wall. Local deformation can sometimes be measured by placing a straightedge parallel to the vessel axis against the vessel wall and using a steel rule to measure the extent of bulging. One method for locating suspected deformation is to direct a flashlight beam parallel to the surface. Shadows will appear in depressions and on the unlighted side of internal bulges.

A careful inspection should be made for evidence of cracking. A strong light and a magnifying glass will be helpful when doing this work visually. If cracking is suspected or any evidence of cracking is found using visual means, a more thorough method of investigation must be used. The most sensitive method of locating surface cracking is the wet fluorescent magnetic particle method. Other valuable methods are the dry magnetic particle, liquid penetrant, ultrasonic, or radiographic methods.

Vessels containing amines (absorbers, accumulators, coalescers, condensers, coolers, contactors, extractors, filter vessels, flash drums, knockout drums, reactivators, reboilers, reclaimers, regenerators, scrubbers, separators, settlers, skimmers, sour gas drums, stills, strippers, surge tanks, treating towers, treated fuel gas drums, etc.) are subject to cracks in their welds and the heat-affected zones of the welds. Wet fluorescent magnetic particle testing is a very sensitive inspection method for detecting surface cracks and discontinuities and is the primary recommended inspection method. See API RP 945 for more detailed information. Also, eddy current, alternating current and ultrasonic methods are also available for the detection of surface breaking defects, these new techniques have an advantage of increased impaction speed. In addition, a number of the methods have a limited depth measuring capability. Ultrasonic scanning techniques can also be used to scan from the outside surface to avoid entering the vessel.

Deaerators on boilers should have their welds and heat-affected zones checked for possible deaerator cracking. Wet fluorescent magnetic particle testing is the primary recommended inspection method. Care should be taken in cleaning surfaces prior to wet fluorescent magnetic particle testing because mechanical cleaning with grinders or wire brushes can hide fine cracks. Ultrasonic scanning techniques can also be used to scan from the outside surface to avoid entering the vessel.

Supports are almost always welded to the shell. The point of attachment should be examined closely for cracking. A good light and a scraper will usually be sufficient for this examination.

The attachment points of baffles to exchanger channels and heads should also be checked closely for cracks. Usually, visual inspection with the aid of a light, a magnifying glass, a scraper, and a brush is sufficient.

Laminations in vessel plates have an appearance similar to cracks, but they run at a slant to the plate surface, while cracks run at right angles to the surface. If open sufficiently for a thin feeler to be inserted, the angle of the lamination can be observed. If a lamination is suspected but not open enough for a feeler to be inserted, heating to approximately 200ºF (93ºC) with a torch will usually cause the edge of the lamination to lip upward. Manual and scanning ultrasonic techniques may be used to trace the lamination.

10.4.5 Inspection of Metallic Linings

Many vessels are provided with metallic linings. The primary purpose of these linings is to protect the vessels from the effects of corrosion or erosion. The most important conditions to check for when examining linings are the following:

a. That there is no corrosion.
b. That the linings are properly installed.
c. That no holes or cracks exist.

Special attention should be given to the welds at nozzles or other attachments.

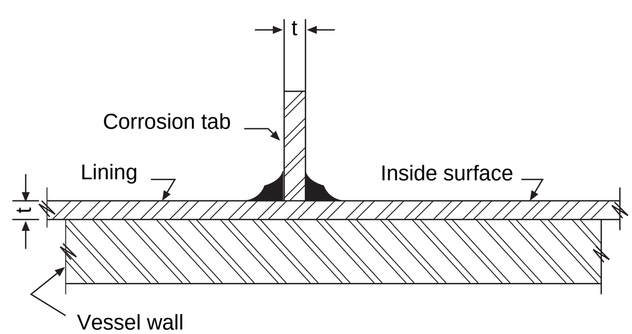
A careful visual examination is usually all that is required when checking a lining for corrosion. Light hammer taps will often disclose loose lining or heavily corroded sections. If corrosion has occurred, it may be necessary to obtain measurements of the remaining thickness. Unless the surface of the lining is relatively rough, these measurements can be made with an ultrasonic thickness instrument. Another method of checking the thickness of the lining is to remove a small section and check it with calipers. This method provides an opportunity to inspect the surface of the shell behind the lining. The application of either manual or scanning ultrasonic methods from the outside surface of the vessel can be used to detect thinning of the base material.

Small 1 x 2 in. (2.5 x 5.0 cm) tabs of lining that form a right angle with one leg extending into the vessel may be welded on the lining. The thickness of the protruding leg should be measured at each inspection. Since both sides of the tab are exposed to corrosive action, the loss in thickness would be twice that of the shell lining where only one side is exposed. This permits a fairly accurate check of any general corrosion of the lining. Figure 32 illustrates this lining inspection method.

Cracks in metallic linings can usually be located by visual inspection and light hammering. A cracked section of a liner or a loose liner gives a special tinny sound when tapped with a hammer. If cracking is expected, liquid penetrant methods may be used to supplement visual inspection. With the exception of the straight chrome steels, most of the materials used as linings are primarily nonmagnetic. Magnetic particle inspection can not be used on austenitic materials.

If cracks are found in a clad liner or weld overlayed liner, the cracks should be investigated to insure that they do not extend beyond the cladding and into the base metal or parent metal.

Bulges and buckling often occur in metallic linings and usually indicate that cracks or leaks exist in the bulged section of the lining or that pin holes exist in the adjacent welds. The bulges are formed either by the expansion or buildup of a material that seeps behind the lining during operation or by differential thermal expansion. If material seeps behind the



Note: Corrosion tab of same material and thickness as lining is installed as shown when vessel is lined.

Figure 32—Corrosion Tab Method of Determining Metal Loss on Vessel Linings

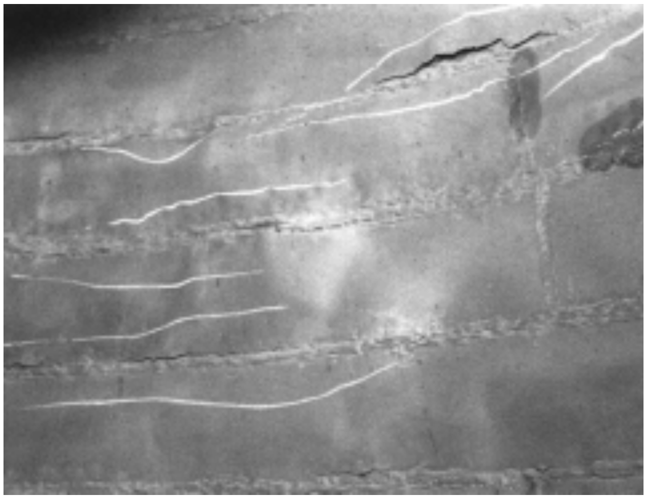


Figure 33—Strip-Liner Deterioration

lining during operation and cannot escape when the vessel pressure is reduced for a shutdown, the lining may bulge. In vacuum service the lining might bulge in service and depress when the vessel is shut down. This condition may actually wrinkle the lining. When bulges or wrinkling become excessive, it may be necessary to inspect the lining for cracks or pin holes. These cracks or pin holes may need to be repaired or the lining may need to be replaced. Figure 33 illustrates the deterioration of strip-welded linings.

Where a lining leaks, it should be determined whether or not corrosion has taken place behind the lining. In some cases, ultrasonic testing from the outside may be used. Removal of representative lining sections to permit visual examination of the vessel wall is always preferred if feasible. An automated ultrasonic examination can provide the most reliable nondestructive evaluation of defects detected in the lining or base material. Although these techniques can be applied at ambient or elevated vessel temperatures, defect sizing is most accurate at or near ambient temperatures.

Many reactors in hydrogen service, such as hydrocrackers and hydrotreaters, use complete weld overlay that uses stabilized austenitic stainless steel welding rods or wire as a liners instead of plug- or strip-welded or clad plate. Disbonding from the parent metal can be a problem with this type lining. Ultrasonic testing, visual checking for bulges, and light tapping with a hammer can reveal this problem.

10.4.6 Inspection of Nonmetallic Linings

There are various kinds of nonmetallic: glass, plastic, rubber, ceramics, concrete, refractory, and carbon block or brick linings. These materials are used most often for corrosion resistance. Some forms of refractory concrete are used as an internal insulation to keep down the shell temperatures of vessels operating at high temperatures. Refractory tile is also used for insulation.

The effectiveness of these linings in lessening corrosion is appreciably reduced by breaks in the film or coatings. For the most part, inspection will consist of a visual examination for discontinuities in the coatings. These breaks are sometimes called holidays. Bulging, blistering, or chipping are all indications that openings exist in the lining. The spark tester method of inspection for leaks in paint, glass, plastic, and rubber linings is quite thorough. A high-voltage, low-current, brush-type electrode is passed over the nonconductive lining. The other end of the circuit is attached to the shell of the vessel. An electric arc will form between the brush electrode and the vessel shell through any holes in the lining. This method cannot be used for concrete, brick, tile, or refractory linings.

CAUTION: The voltage used in this inspection method should not exceed the dielectric strength of the coating. Damage to the lining may result.

Considerable care should be exercised when working inside vessels lined with glass, rubber, plastic sheets, or paint. These coatings are highly susceptible to mechanical damage. Glass lined vessels are especially susceptible to damage and they are costly and difficult to repair.

Concrete and refractory linings may spall and crack in service. Inspection of such linings should be mostly visual. Mechanical damage, such as spalling and large cracks, can readily be seen. Figure 34 illustrates the deterioration of a refractory-tile lining. Minor cracks and areas of porosity are more difficult to find. Light scraping will sometimes reveal such conditions. Bulging can be located visually and is usually accompanied by cracking. In most cases, if corrosion occurs behind a concrete lining, the lining will lose its bond with the steel. The sound and feel of light hammer tapping will usually make such looseness evident. If corrosion behind a lining is suspected, small sections of the lining may be removed. This permits an inspection of the shell and a cross-sectional examination of the lining.

Figure 34—Deteriorated Refractory-Tile Lining

Some refractory-tile linings are hung with a blanket of ceramic fiber or other insulation between the shell and the tile. Broken or missing tiles create lanes for the channeling of any fluid that gets behind the lining. This results in the washing away of some of the insulation. Inspection of tile linings should include a visual inspection of the insulation in the vicinity of broken or missing tile. This may be done by removing enough tiles to determine the extent of the damaged areas.

In all cases where bare metal has been exposed because of lining failures, a visual inspection should be made of the exposed metal. If corrosion has taken place, the remaining wall thickness should be measured. Ultrasonic instruments are best suited for this measurement.

During operation, internally insulated vessels are sometimes subject to severe corrosion due to condensation on the shell behind the insulation. If the shell-metal temperatures are near the calculated dew point of the process stream, shell corrosion should be suspected and the shell should be checked. A frequently used corrective measure is to reduce the internal insulation or to add extra external insulation. Precautions should be taken to assure that design metal temperatures are not exceeded when these measures are used.

10.5 THICKNESS-MEASURING METHODS

There are many tools designed for measuring metal thickness. The selection of tools used will depend on several factors:

a. The accessibility to both sides of the area to be measured.
b. The desire for nondestructive methods.
c. The time available.
d. The accuracy desired.
e. The economy of the situation.

Ultrasonic instruments are now the primary means of obtaining thickness measurements on equipment. Radiography and real-time radiography may also be used in a limited way to determine thickness of vessel parts such as nozzles and connecting piping. Methods such as depth drilling (i.e. sentinel or tell-tale holes), the use of corrosion buttons, and the use of test holes may be applied at some special locations. However, these methods have generally been replaced by nondestructive methods of thickness gauging, such as ultrasonics. Ultrasonic inspection, both for thickness measurement and flaw detection, represents an important technique of nondestructive inspection.

API 510 allows a statistical treatment of ultrasonic thickness data to assess corrosion rates and current thickness. It is acceptable to average several individual thickness readings at a test point to determine the thickness at the test point. Moreover, the ensemble of test point data may be statistically analyzed to assess corrosion rates and actual minimum thickness. When using such methods, it is important that areas with distinct corrosion mechanisms be properly identified and treated in the analysis process. Alternatively, scanning techniques provide a greater data density which provides better statistical information. Magnetic flux scanning techniques are also available which provide a fast qualitative technique for the detection of corrosion losses on large surface areas.

Radiographs are taken with a step gauge of known thickness that will show on the developed film of the vessel part in question. By comparing the thickness of the step gauge on the film to the thickness of the part on the film, the part thickness may be determined.

API 510 permits an on-stream inspection to be conducted in lieu of an internal inspection under certain conditions. When this approach is used, a representative number of thickness measurements must be conducted on the vessel to satisfy the requirements for an internal inspection. A decision on the number and location of thickness measurements should consider results from previous inspections, if available, and the potential consequences of loss of containment. In general, vessels with low corrosion rates will require fewer thickness measurement locations compared to vessels with higher corrosion rates. A possible strategy for vessels with general (i.e., uniform) corrosion is to divide the vessel into its major design sections (i.e. shell, head, and nozzles) and identify at least one measurement location for each design item. The number of thickness measurement locations would progressively increase for higher corrosion rates. The inspector, in possible consultation with a pressure vessel engineer, would determine the specific measurement strategy for the vessel.

For pressure vessels susceptible to localized corrosion, additional thickness measurement locations will be required. The selection of these additional areas should be made by personnel knowledgeable in localized corrosion mechanisms.

Corrosion buttons or plugs are fabricated from materials highly resistant to corrosion and are fastened to the vessel wall in sets of two. Losses in thickness are obtained by placing a steel straightedge on the two plugs and measuring the distance from the bottom of the straightedge to the surface of the vessel.

Where the corroded surface is very rough, test holes through the vessel wall may be used to determine thickness.

Depth drilling is used in a similar way to determine corrosion rates. In this method, a hole is drilled in the vessel wall where the most corrosion is expected. The depth from the bottom of the hole to the inside surface of the vessel is measured with a depth gauge. Future readings taken at subsequent inspections will permit calculation of material loss due to corrosion. Between readings, a corrosion-resistant plug is screwed into the hole to protect the bottom of the hole from corrosion.

10.6 SPECIAL METHODS OF DETECTING MECHANICAL DEFECTS

Visual examination will reveal most mechanical defects. Magnetic particle (wet or dry) and liquid penetrant methods may be useful and have been discussed in preceding text. Other methods, such as radiography, angle beam ultrasonics, etching, and sample removal, are available and may be used when conditions warrant. Also, eddy current, alternating current, and ultrasonic methods are available for the detection of surface breaking defects. These new techniques have an advantage of increased inspection speed.

Radiography and angle beam ultrasonics are used to analyze defects, usually in welded seams, that are not visible on the surface of the metal.

Etching of small areas may sometimes be used to find small surface cracks. First, the surface must be abrasive-grit blasted clean. Then, etching solution, usually an acid, is used to wash the suspect area. Because of the nature of the resulting reaction, any cracks will stand out in contrast to the surrounding area.

Sample removal can be used to spot check welds and to investigate cracks, laminations, and other flaws. Small metal samples from the affected area are removed with a trepan or weld probe tools. The sample is then analyzed under a microscope or with an ordinary magnifying glass. If they can be adequately cleaned, the filings obtained during the cutting operation may be used in making a chemical analysis of the metal. The hole left in the vessel wall by sample removal must be carefully repaired, and the repair must be thoroughly inspected. The decision to remove samples should be made by someone who knows how to analyze the problems related to repair of the sample holes.

10.7 METALLURGICAL CHANGES AND IN-SITU ANALYSIS OF METALS

The methods used to detect mechanical changes can also be used to detect metallurgical changes. In-place metallography can be used to detect these changes with portable polishing equipment and using replica transfer techniques. Hardness, chemical spot, and magnetic tests are three other methods of detecting metallurgical changes.

Portable hardness testers can be used to detect faulty heat-treating, carburization, nitriding, decarburization, and other processes that cause changes in hardness.

Local chemical tests may be used to detect the installation of materials other than those specified. Chemicals such as nitric acid in varying concentrations are used. A spot is cleaned on the metal surface and a drop of a chemical is place on the surface. An experienced observer can observe the reactions to the acid of the metal being tested and identify the metal. Eddy-current, X-ray fluorescence, radiation, and portable light emission spectroscope instruments are also used for material identification.

Because normally nonmagnetic steel usually becomes magnetic when carburized, carburization of austenitic stainless steel can some times be detected by a magnet.

10.8 TESTING

10.8.1 Hammer Testing

In hammer testing, an inspector’s hammer is used to supplement visual inspection. The hammer is used to do the following jobs:

a. To locate thin sections in vessel walls, heads, and the like.
b. To check tightness of rivets, bolts, brackets, and the like.
c. To check for cracks in metallic linings.
d. To check for lack of bond in concrete or refractory linings.
e. To remove scale accumulations for spot inspection.

The hammer is used for these jobs by lightly striking or tapping the object being inspected and observing the sound, feel, and indentation resulting from the blow. The proper striking force to be used for the various jobs can be learned only through experience. Hammer testing is used much less today than previously. It is not recommended to hammer test objects under pressure. Also, piping upstream of a catalyst bed should not be hammered, as hammering could dislodge scale or debris and cause plugging.

10.8.2 Pressure and Vacuum Testing

When a pressure vessel is fabricated, it is tested for integrity and tightness in accordance with the standard or construction code to which it was built. (In addition to integrity and tightness, the pressure test can also result in beneficial stress redistribution at defects.) These methods of testing may also be used to subsequently inspect for leaks and to check repair work. When major repair work such as replacing a head, a large nozzle, or a section of the shell plate is performed, the vessel should be tested as if it were just installed. In certain circumstances, the applicable construction code requirements for inspection of vessels in service also require periodic pressure testing, even though no repair work has been necessary. For code rules concerning tests of vessels in service, see API 510 and NB-23. The ASME Code, although a new vessel fabrication code, may be followed in principle in many cases.

A large vessel and its structural supports may not necessarily be designed to support the weight of the vessel when it is filled with water. Whether it can support this weight should be determined before a hydrostatic test is made. If the vessel or its supports are inadequate for a hydrostatic test, then a pneumatic test may be considered.

Pressure testing consists of filling a vessel with liquid or gas and building up an internal pressure to a desired level. The pressure and procedures used should be in accordance with the applicable construction code requirements consistent with the existing thickness of the vessel and the appropriate joint efficiencies. (As noted in preceding text, sometimes the rules for inspection in service also require periodic pressure testing, even though no repair work has been necessary). When pressure vessels form a component part of an operating unit, the entire unit is sometimes pressure tested. Water or oil is used as a testing medium and the charge pumps of the unit are used to provide the test pressure. While the vessel or vessels are under pressure, the external surfaces are given a thorough visual examination for leaks and signs of deformation.

In recent years, acoustic emission analysis has been developed for use in conjunction with pressure testing or during equipment cooldown. When acoustic emission equipment is used on a vessel under pressure in a stressed condition, it is possible to determine the overall structural integrity of the vessel. This method can be especially useful for vessels of complex design or where the vessel contents cannot be easily removed to permit an internal inspection.

When testing pneumatically, an ultrasonic leak detector or soap solution or both should be used to aid visual inspection. The soap solution is brushed over the seams and joints of the vessel. The vessel is then examined for evidence of bubbles as an indication of leakage.

An ultrasonic leak detector may be used to pick up leaks in joints and the like that can not be reached with a soap solution without scaffolds or similar equipment. Very small leaks may be detected and located with the leak detector.

Often a vessel that operates at a vacuum may be pressure tested. When feasible, pressure testing is the preferred testing method as leaks from an internal pressure source are more easily located. When pressure testing is not feasible, a vacuum vessel can be tested for leaks with evacuators or vacuum pumps that are installed in the unit and used to create a vacuum. If the vacuum can be held for a specified time after closing off the evacuators or vacuum pumps, it is likely that the vessel is free of leaks. If the vacuum cannot be held, leaks are present. However, since this method gives no indication of the locations of leaks, a search, which may be difficult, must then be made to locate the leaks.

Consideration should be given to the temperature at which testing is done. Many of the common steels used in fabrication exhibit severe reduction in impact resistance at low temperatures. API 510 recommends that vessels constructed with these steels be tested either at temperatures not less than 30°F (15°C) above the minimum design metal temperature for vessels that are more than 2 in. (5 cm) thick, or 10°F (5°C) above for vessels that have a thickness of 2 in. or less. The test temperature should not exceed 120ºF (49ºC), unless there is information on the brittle characteristics of the vessel material to indicate the acceptability of a lower test temperature or the need for a higher test temperature (see API RP 579).

When conducting hydrostatic or pneumatic pressure tests, it is a good safety practice for all personnel not connected with the test to remain away from the area until the test is completed and the pressure is released. The number of inspection personnel in the area should be limited to the number necessary to run the test. When making pneumatic pressure tests, the recommendations set forth in the ASME Code should be followed.

10.8.3 Testing Exchangers

When an exchanger is removed from service, it is often desirable to apply a test to either the shell side or the tube side before dismantling. A leak may be detected by observation at a drain point, such as at a disconnected lower nozzle or an open bleeder. Usually, the test must be run for some time before a small leak will show up. If the exchanger leaks, it is then partially dismantled and the test reapplied. For example, when testing a floating-head exchanger with the pressure in the tubes, removal of the shell cover will reveal the source if the leak is in the gasket, stay bolts, or tube rolls at the floating head. This test will not normally distinguish between tube roll leaks at the stationary tube sheet and those at penetrated tube walls, as these parts are not visible while the tube bundle is in the shell. A shell test applied to a floating-head exchanger with the channel cover off will reveal leaking tube rolls at the stationary tube sheet, but will not clearly identify the source of leakage at floating tubesheet rolls or floating head gasket leaks. In most cases, exchangers that do not use a floating head are so constructed that a shell side test applied to the partially dismantled exchanger will enable individual detection of leaking tubes and their plugging. Also, leaking tube rolls at either end can be detected and rerolled. Exchangers with floating heads do not permit individual detection of leaking tubes or access to both ends of tube during a shell side test. A test ring is sometimes used for these exchangers. This is a device that temporarily converts the arrangement of the partially dismantled exchanger into a dual fixed tube-sheet arrangement.

In some cases, leak testing is performed at each downtime. Tube condition assessment can also be performed using scanning detection tools. The range of tools available includes eddy current, remote field eddy current, magnetic flux, laser and ultrasonic test equipment. These technologies can be used to detect erosion, corrosion, pitting and cracking in tubes. If leaking tubes are found, the tubes are located and plugged, and the bundle is put back in service. This procedure should be repeated until no new leaks are discovered: several repetitions may be required. If the number of tubes plugged interferes with the efficient use of the exchanger, the bundle should be retubed. When leakage is encountered for the first time in a given service, inspection may be performed to determine the nature of the deterioration. After historical records have been built up, inspection is performed only when the number of plugged tubes indicates that the replacement point may be approaching. When a decision is made to retube, inspection is employed to determine which parts can be salvaged and reused and which require replacement.

It is customary to test an exchanger at assembly. Where retubing has been performed, a test may be applied to the partially assembled exchanger to detect roll leaks individually. In any case, a final test on both the shell and tube sides is normally applied to the assembled exchanger.

Frequently, a bundle will be tested while it is out of the shell. In this case, the channel and floating tube-sheet covers are left in place. This method makes observation for leaks easier but necessitates a separate shell test.

When any of the parts are under test pressure, the external surfaces, rolled joints, and gasketed joints are given a thorough visual examination. Leaks and distortion of parts may be found by pressure testing.

Special equipment is available for testing exchanger tubes individually, An example of this equipment is shown in Figure 35.

The pressures to be used when testing will depend on the operating and design pressures of the unit. These pressures should be determined locally in accordance with individual practice or jurisdictional requirements. Before applying pressure to the shell side only of an exchanger, the inspector should be sure that tubes of the bundle are of sufficient wall thickness to withstand the external pressure. In addition the channel side test pressure and the shell side test pressure should be checked against one another and care should be taken that one side or the other of the exchanger is not excessively pressured when testing. Particular care should be taken with any high-pressure exchangers where the tubesheets were designed basis differential pressure.

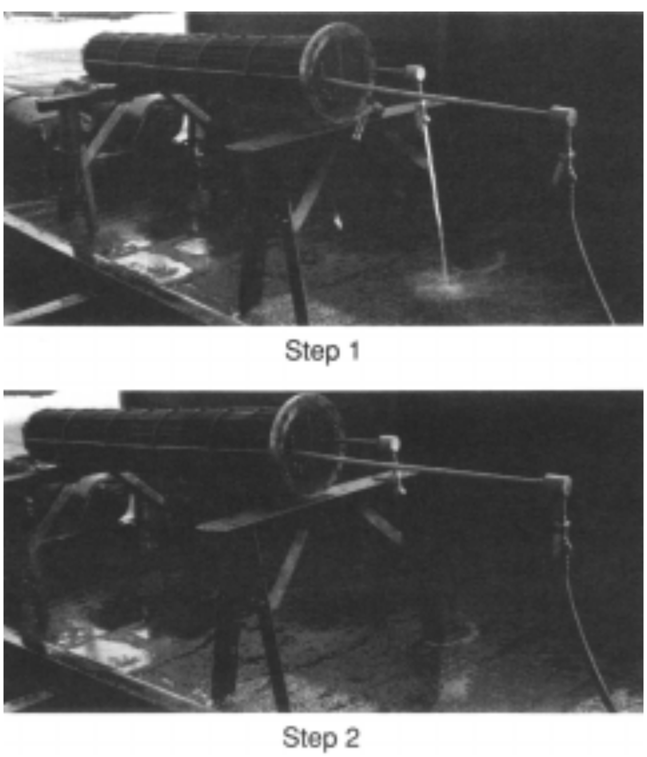


Figure 35—Steps in Using Special Equipment to Test Individual Tubes

When water is used to conduct a pressure test, care should be taken to remove all water from the equipment. When water can not be completely removed, it may be necessary to add chemical corrosion inhibitors to prevent the potential for microbiological corrosion while the equipment is out of service.

In some cases it may be preferred or desired to leak test the shell and tube exchanger while it is in service. Methods for conducting this testing include injection of a gas or liquid tracer material on the higher pressure side of the exchanger stream. If cooling water is the lower pressure stream, it may be possible to assess the hydrocarbon content of the water upstream and downstream from the exchanger.

10.9 LIMITS OF THICKNESS

The limits of wall loss, due to corrosion and other deterioration mechanisms that may be tolerated must be known, or an inspection will lose much of its value. The two most important factors of this problem are the following:

a. The retiring thickness of the part considered.
b. The rate of deterioration.

Before determining the limiting or retiring thickness of parts of any pressure vessel, the code and edition of that code that the vessel will be rated under and whether there are any regulations regarding limits and allowable repairs must be determined.

There are a great many variables, such as size, shape, material, and method of construction, that affect the minimum allowable thickness. API 510 recognizes that corrosion rate, corrosion allowances, rerating, and component assessment by ASME Section VIII, Division 2 methodology may all be used to establish retirement and next inspection criteria. For this reason it is not possible in this document to present a single set of minimum or retirement thickness. API 510 contains additional guidance on the rating of pressure vessels.

When corrosion or erosion is causing deterioration, the rate of metal loss can usually be obtained by comparing consecutive inspection records. Data and graphs showing this information should be kept with the vessel records. In many cases, computerization of inspection data has been helpful in quickly determining corrosion rates and in estimating retirement dates. The ability to predict when a vessel will reach a retiring thickness is important. Scheduling of repairs and replacements will be greatly influenced by such predictions.

When the safe limit of thickness is approached or reached, decisive action is necessary. In some cases decisions will have to be made quickly without much time for study or consideration and review by others. The minimum thickness or the methods of calculating the thickness should be known in advance for each vessel. It should be noted that different parts of a vessel may have different retirement thicknesses. A risk-based assessment of the data could be valuable.

Most vessels are built with some thickness in vessel walls and heads over that required to withstand the internal operating pressures. This thickness may result from any of the following contributions:

a. Excess thickness deliberately added in the design as corrosion allowance.

b. Excess thickness as a result of using a nominal plate thickness rather than the exact, smaller value calculated.

c. Excess thickness as a result of setting minimum plate thickness for construction purposes.

d. Excess thickness as the result of a change in vessel service: a reduction of the safety valve setting, the maximum metal temperature, or both.

When this excess thickness and the corrosion rate are known, the date when repairs or replacement will be needed for any vessel can be predicted with reasonable accuracy.

CAUTION: In some cases, the excess thickness of the shell or head plates is used by the designer as nozzle reinforcement.

Since the ASME Code is a design and construction standard for vessels, the methods for calculating the retirement thickness of many accessories of pressure vessels are not covered. Some of these parts are trays, internal tray supports, valves, grids, baffles, ladders, and platforms. For some of this equipment, there are generally accepted methods of setting the retiring thickness. Minimum thickness should be developed for all this equipment. The consequence of possible failure of equipment should be considered when setting these limits. Safety is the prime factor affecting retiring thickness. After safety, continuous and efficient operations become a factor. (API RP 574 should be consulted for inspection of some of the parts mentioned in the preceding text.)

Since they are considered as part of the pressure-retaining boundary, no minimum thickness is set for applied metallic linings. As long as the lining remains free of leaks or does not require excessive repairs, it should be satisfactory for further service.

In the case of exchangers, minimum thickness values should be developed for tubes, tube sheets, channels, covers, and other pressure retaining exchanger parts. The consequence of possible failure of such parts should be considered when setting these limits. Safety is the prime factor affecting retiring thickness for this equipment. Normally, failure of internal parts, such as the various components of the tube bundle, does not involve a hazard; hence, continuous, efficient operation is the governing factor in establishing retirement limits of internal parts. Some parts, such as baffles, may be continued in service until failure, and tubes need not be plugged or replaced until actual perforation occurs.

11 Methods of Repair

Although repair and maintenance are not parts of inspection, repairs that affect the pressure rating of a vessel and that require reinspection for safety reasons are of concern.

Before any repairs are made to a vessel, the applicable codes and standards under which it is to be rated should be studied to assure that the method of repair will not violate appropriate requirements. API 510 sets forth minimum petroleum and chemical process industry repair requirements and is recognized by several jurisdictions as the proper code for repair or alteration of petroleum or chemical pressure vessels.

Note: Some jurisdictions require that welded repairs and alterations be done by an organization with an appropriate National Board "R" stamp, usually in accordance with NB-23 and accompanied by the completion and filing National Board Form R-1 with the jurisdiction.

The defects requiring repair and the repair procedures employed should be recorded in the field notebook and later in the permanent records maintained on the vessel (see API 510 for sample repair and alteration record sheets or refer to jurisdictional requirements). Most repairs on the shell and heads of a vessel are made to maintain the strength and safety of the vessel, will therefore require reinspection, and may require radiography, stress relieving, or both. A quick visual check of all other repairs is also desirable to make sure that they have been completed.

It is important that the source of the problem requiring the repair is determined. Treating the source of the condition causing deterioration will, in many cases, prevent future problems.

Repairs made by welding to the shell and heads of a vessel should be inspected: The inspection should include a check for completion and quality. Normally, a visual examination will be sufficient for minor repairs; however, magnetic particle and liquid penetrant methods should be used on major repairs, and if required by the applicable construction code, radiographic or angle beam ultrasonic examination should also be performed.

After repairs are completed, a pressure test shall be applied if the API Authorized Pressure Vessel inspector believes that one is necessary. A pressure test is normally required after an alteration. API 510 provides additional details on pressure test requirements.

The repair of sample holes left by a trepan or weld probe tool must be closely inspected. The weld quality in such repairs is likely to be poor unless carefully controlled. Therefore, the removal of samples for weld inspection should be avoided if possible.

Sections of shell plates may be replaced to remove locally deteriorated areas. The joint efficiency of the patch should be equal to or greater than the efficiency of the original joints in the shell.

Cracks in vessel walls or heads may be repaired by chipping, by flame, arc, or mechanical gouging, or by grinding the crack from end to end and then welding. Care should be used in flame and arc gouging, as heat may cause the crack to enlarge or lengthen. If a crack extends completely through the plate, it may be expedient to cut a groove from both sides of the plate. In any event, complete removal of the crack is absolutely essential before welding is begun. Magnetic particle or liquid penetrant techniques should be employed to assure removal of the crack. If several cracks occur in any one plate, it may be wise to replace the entire plate. Repairs of weld cracks should be checked carefully. If the remaining metal, after defect removal, provides adequate strength and corrosion protection, the repair may be completed without welding by tapering and blending the edges of the cavity.

Scattered pits in pressure vessels are best repaired by welding. As a means of temporary repair, proprietary epoxy base materials are available that can be packed into pits to prevent further corrosion. This material must be capable of resisting the service conditions. In all cases, pits should be well cleaned, preferably by abrasive grit-blasting, before repairs are made.

Note: When considering the use of this method, the inspector must be satisfied that the pits are not large enough or close enough together to represent a general thinning of the vessel component. See the subsection on corrosion and minimum thickness evaluation in API 510.

Repair of appurtenances such as platforms, ladders, and stairways will usually consist of replacing excessively worn parts. Stairway treads that have been worn smooth can be roughened by placing weld beads on the worn surfaces. Also, proprietary coatings containing a grit type material are available.

Linings are repaired by replacing parts that are corroded through or cracked. Repairs of metallic linings require welding. Visual inspection of welding after thorough slag removal will normally be sufficient to check weld quality, unless code requirements specify radiographic, liquid penetrant, magnetic particle, or other examination of the weld.

12 Records and Reports

12.1 RECORDS

Inspection records are required by API 510, NB-23 and jurisdictions. These records form the basis of a scheduled maintenance program, and are very important. A complete record file should contain three types of information:

a. Basic data (i.e., permanent records per API 510).

b. Field notes.

c. The data that accumulates in the "continuous file" (i.e. progressive records per API 510).

Basic data include the manufacturer's drawings, data reports and specifications, design information, and the results of any material tests and analyses.

Field notes consist of notes and measurements recorded on site either on prepared forms (see Appendix B) or in an either written or electronic field notebook. These notes should include in rough form a record of the condition of all parts inspected and the repairs required.

The continuous file includes all information on the vessel's operating history, descriptions and measurements from previous inspections, corrosion rate tables (if any), and records of repairs and replacements.

As indicated earlier, some organizations have developed software for the computerized storage, calculation, and retrieval of inspection data. When the data is kept up-to-date, these programs are very effective in establishing corrosion rates, retirement dates, and schedules. The programs permit quick and comprehensive evaluation of all accumulated inspection data.

12.2 REPORTS

Copies of reports recommending repairs should be sent to all management groups, which would normally include engineering, operating, and maintenance departments. These reports should include the location, extent, and reasons for recommended repairs.

General inspection reports (see Appendix B) may be sent to interested parties, such as the operating, maintenance, and engineering departments. Who the interested parties are will depend on the organization of the plant or company. These reports should include metal thickness measurements, corrosion rates, descriptions of the conditions found, repairs required, and allowable operating conditions, estimations of remaining life, and any recommendations. Occasionally special reports covering unusual conditions may be circulated.

APPENDIX A—EXCHANGERS

A.1 General

Exchangers are used to reduce the temperature of one fluid by transferring heat to another fluid without mixing the fluids. Exchangers are called condensers when the temperature of a vapor is reduced to the point where some or all of the vapor becomes liquid by the transfer of heat to another fluid, usually water. When a hot fluid is cooled to a lower desired temperature by the transfer of heat to another fluid, usually water, the exchanger is usually referred to as a cooler. When air is used to reduce the temperature of a hot liquid to a lower desired temperature, the exchanger is referred to as an air cooler. Figures A-10 and A-11 illustrate heat exchanger parts and types.

A.2 Shell and Tube-Bundle Exchangers

A.2.1 GENERAL

There are several types of shell and tube-bundle exchangers. Usually, the tubes are attached to the tube sheet by rolling. A properly rolled tube is shown in Figure A-1. The tubes may be rolled and welded or attached by packing glands. The physical characteristics of the fluids such as the temperature determine the type of fluid used for a particular service. A description of some of the types of exchangers commonly used and the factors influencing their selection follow.

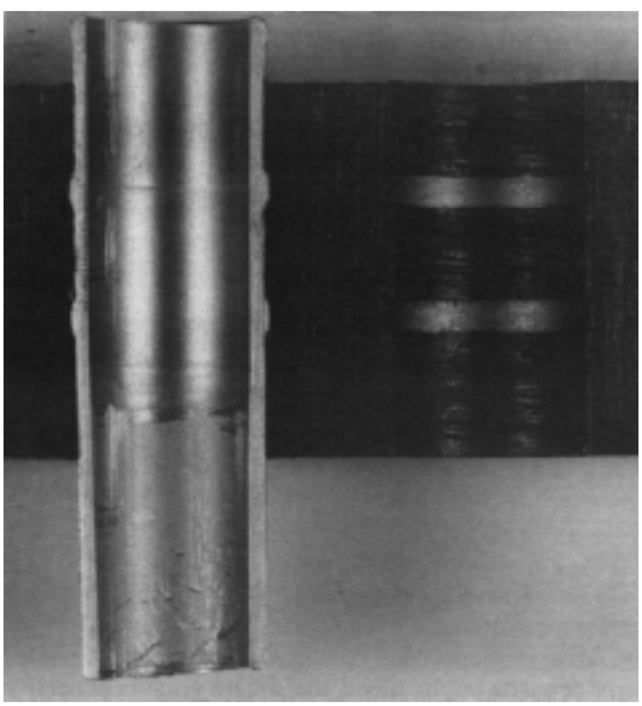


Figure A-1—Properly Rolled Tube

A.2.2 ONE FIXED TUBE SHEET WITH A FLOATING HEAD

One type of exchanger consists of a cylindrical shell flanged on both ends, a tube bundle with a tube sheet on both ends, a channel, a channel cover, a floating-head cover for one end of the tube bundle, and a shell cover. The diameter of one tube sheet of the tube bundle is small enough to pass through the cylindrical shell. The diameter of the other tube sheet is large enough to bear on a gasketed surface of one shell flange or may be an integral part of the channel. The bundle is inserted in the shell with the large tube sheet against one shell flange. The channel is bolted to the shell flange that holds the tube sheet in place. The channel and floating heads may be divided so that incoming liquid flows through some of the tubes and returns through other tubes to the channel. The number of divisions and the number of tube flow passes will vary with the design. The flow through the shell is directed by baffles as desired. Since the floating tube end is free to move in the shell, this type of construction permits free expansion and contraction with changes in temperature. This is the type of heat exchanger most commonly used.

A.2.3 TWO FIXED TUBE SHEETS

The construction details for an exchanger with two fixed tube sheets are similar to those of the floating tube-sheet type; however, both tube sheets are fixed and the tubes are installed and rolled after the tube sheets are in place. The shell side cannot be exposed for cleaning. Therefore, it is limited to either clean service or service susceptible to chemical cleaning. Because both tube sheets are fixed, the exchanger is limited to small expansion and contraction unless an expansion joint is provided in the shell.

A.2.4 ONE FIXED TUBE SHEET WITH U-TUBES

A U-tube exchanger has one fixed tube sheet with the tubes bent in the form of a long U in place of the floating head. These exchangers have the same freedom of expansion and contraction as the floating-head type. Clean service is usually limited to the tube side because of the difficulty of mechanically cleaning the inside of the U-tubes. Chemical cleaning, abrasive-grit blasting, or hydroblasting can be used successfully if care is taken not to allow the tubes to become completely plugged.

A.2.5 DOUBLE TUBE SHEET EXCHANGERS

In certain services where even minute leakage of one fluid into another can not be tolerated, double-tube-sheet construction of the exchanger is sometimes employed. As the name implies, two tube sheets are used together with only a small distance, usually 1 inch or less, between them. The tubes are rolled into both tube sheets. The outer tube sheet is attached to the channel, and the inner tube sheet is fixed to the shell. The purpose of this arrangement is to cause any leakage from the tube roll to bleed off into the space between the two sheets, thus preventing contamination of one fluid by the other. This construction is applicable only where there is no floating tube sheet. Hence, it can be used only with a U-tube exchanger.

A.2.6 REBOILERS AND EVAPORATORS

The construction details of reboilers and evaporators are the same as those of any other exchanger with one fixed tube sheet, with the exception that horizontal reboilers have a large vapor space above the tube bundle. They are used to produce vapor from liquids by passing a hot fluid through the tubes.

A.2.7 WATER HEATERS

Water heaters may be the floating-head type, U-tube type, or the fixed tube-sheet type. They are used to heat water for boiler feed or for other purposes by exchanging heat from a hot fluid.

A.2.8 CONSTRUCTION

Exchangers are equipped with baffles or support plates, the type and design of which vary with the service and heat load the exchanger is meant to handle. Pass partitions are usually installed in the channels and sometimes in the floating tube-sheet covers to provide multiple flow through the tubes. The flow through the shell may be single pass, or longitudinal baffles may be installed to provide multiple passes. The baffling used in the shell will determine the location and number of shell nozzles required. Figures A-10 and A-11 show various channel and shell baffle arrangements. Frequently, an impingement baffle plate or rod baffle is located below the shell inlet nozzle to prevent impingement of the incoming fluid on the adjacent tubes.

The tubes may be arranged in the tube sheet on either a square or a triangular pitch. When the fluid circulating around the outside of the tubes may coke or form other dirty deposits on the tubes, the square pitch is generally used. The square pitch arrangement permits better access for cleaning between the tubes.

A.3 Exposed Tube Bundles

A.3.1 GENERAL

Exposed tube bundles are used for condensing or cooling and may be located under spraying water or may be completely submerged. They also may be used as heaters, particularly in tanks where they are submerged in the liquid.

A.3.2 AN EXPOSED TUBE BUNDLE UNDER A COOLING TOWER

Exposed tubes arranged in compact bundles can be placed under a cooling tower: in this arrangement, the water from the tower flows over the tubes, and heated water is returned to the top of the tower for cooling and reuse. This placement of the tube bundles is most effective in a climate with a low relative humidity resulting in maximum evaporative effect.

A.3.3 AN EXPOSED TUBE BUNDLE UNDER SPRAY HEADS

Spray heads may be installed above an exposed tube bundle to provide an even distribution of water over the tubes (this represents a modification of the method described in A.3.2). A receiving tank is located below the tube bundle for use mainly when the water is naturally cool enough to permit recirculation without additional cooling. Where water is plentiful, this type of cooler may be used without a receiving tank, permitting the used water to drain into a treatment system.

A.3.4 SUBMERGED EXPOSED TUBE SECTIONS

When exposed tube sections are submerged, the sections are mounted either vertically or horizontally within a box. The hot fluid enters the top of the headers in vertical installations and the top section in horizontal installations. In either installation, the cooled fluid leaves at the bottom. Cool water enters near the bottom of the box, and the warmed water overflows a weir near the top of the box. This arrangement produces counter current flow resulting in maximum cooling with a minimum use of water.

Submerged sections are used primarily when a hot fluid leaving the cooler might result in a dangerous condition if the water supply should fail. The large volume of water in the cooler box would give partial cooling for an extended period and allow time for an orderly shutdown of the operation if necessary.

A.4 Storage Tank Heaters

The tube-bundle version of the tank heater is built in three general types for the following installations:

a. Installation outside the tank.
b. Installation partially within the tank.
c. Installation entirely inside the tank.

The first two are installations of suction line heaters, and the third (Figure A-2) heats the entire contents of the tank.

A.5 Air-cooled Exchangers

An air-cooled unit is similar to an exposed tube bundle unit: however, air is used as the cooling medium. A bank of tubes is located in a steel framework through which air is cir-

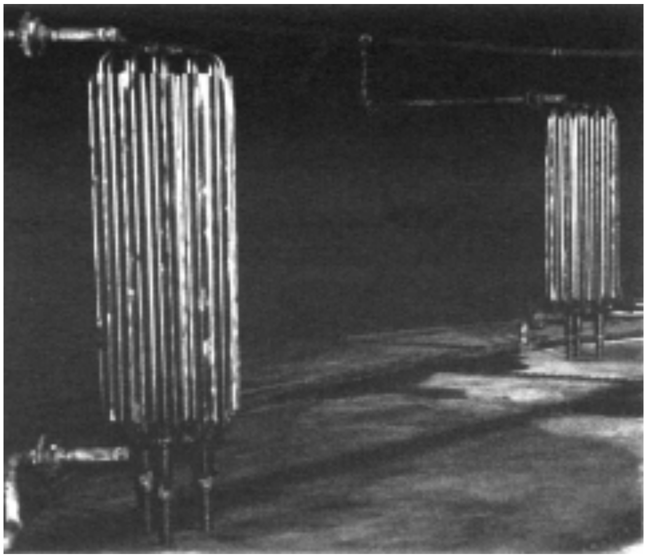


Figure A-2—Tube-Bundle Type of Tank Heater

culated by a fan placed either above or below the tube bank (a fan above the tube bank is usually referred to as an induced draft air cooler and a fan below the tube bank is usually referred to as a forced draft air cooler). These coolers may be used for the condensing or cooling of vapors and liquids and are installed where water is scarce or for other reasons. Figure A-3 illustrates air-cooled exchangers. (API Standard 661 covers the minimum requirements for design, materials, fabrication, inspection, testing, and preparation for initial delivery.)

A.6 Pipe Coils

A.6.1 GENERAL

Pipe coils are of two types:

a. Double-pipe coils.
b. Single-pipe coils.

A.6.2 DOUBLE-PIPE COILS

A.6.2.1 General

Double-pipe coils are used when the surface required is small, because they are more economical than the shell or tube type of exchanger in such service. They are also used where extremely high pressures are encountered, because their small diameter and cylindrical shape require a minimum wall thickness.

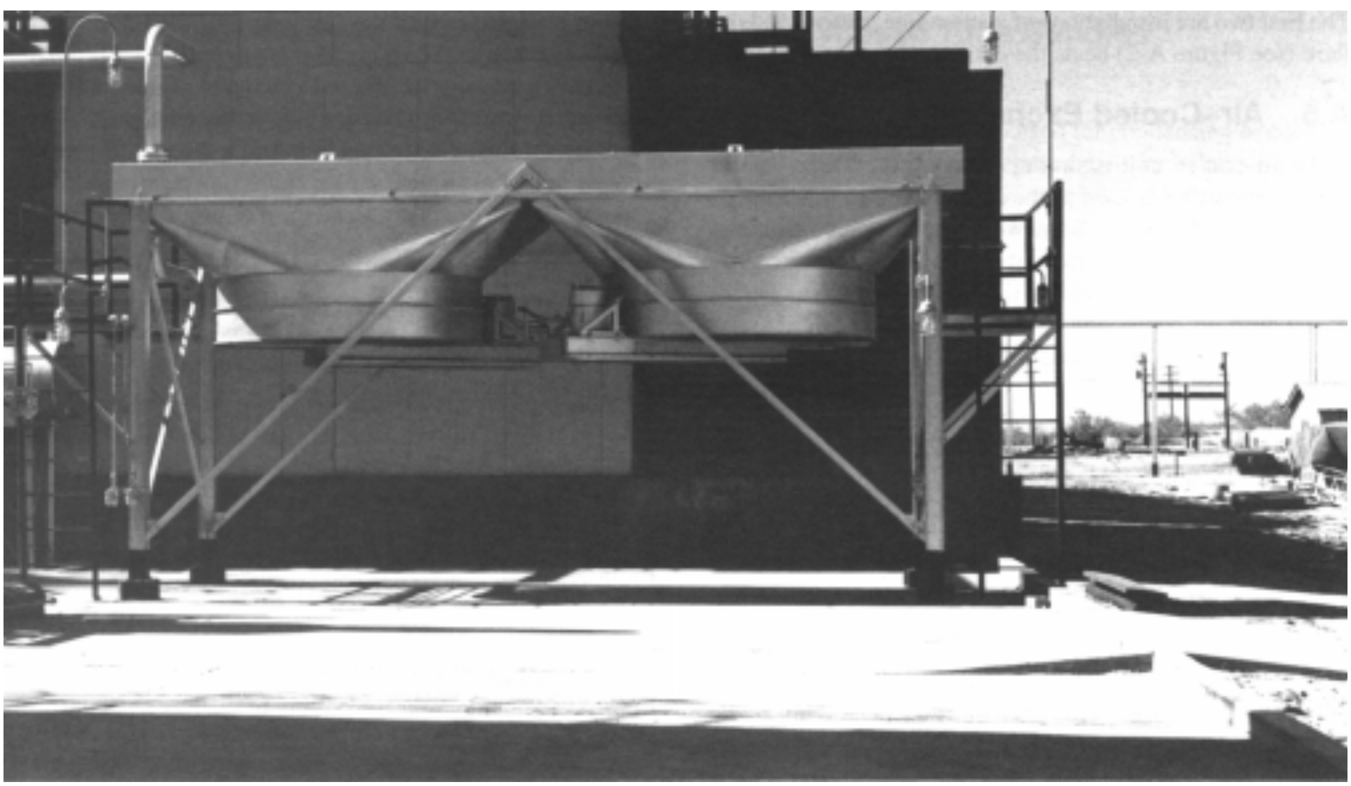


Figure A-3—Air-Cooled Exchangers

A.6.2.2 Clean-Service Double-Pipe Coils

Clean-service double-pipe coils consist of tubes within tubes (see Figure A-4). The internal tubes are connected at one end by return bends that are enclosed by return bends connecting the external tubes of the same coil unit. At the opposite end, the internal tubes project beyond the outer tube and through a tight closure that prevents leakage. Internal tubes terminate in piping or are connected to adjacent units with exposed return bends. The external tubes are connected to piping or adjoining external tubes by branch-flanged nozzles.

A.6.2.3 Dirty-Service Double-Pipe Coils

Dirty-service double-pipe coils (scraper-type coils) are identical to clean-service double-pipe coils with the exception that a scraper is added to the inside of the inner tube. Each internal tube is equipped with scrapers mounted on a rod or shaft extending the full length of the tube. The rod projects through the return bends at each end. To prevent leakage, a bearing for the rod is capped at one end, and a bearing and a stuffing box are used at the other end. The rod extends through the stuffing box, and a sprocket is mounted on the end of the rod. The rods and scrapers are rotated by a sprocket chain driven by some form of prime mover, usually an electric motor.

A.6.3 SINGLE-PIPE COILS

A.6.3.1 General

Single-pipe coils are used in several different ways, but essentially all are continuous runs of pipe through which flows a medium to be cooled or heated.

A.6.3.2 Condenser or Cooler Coils

Condenser or cooler coils consist of a continuous pipe coil or a series of pipe coils installed in a box through which cold water flows. The pipe coil or coils rest on supports in the box and are free to move with any expansion or contraction. Water enters near the bottom of the box and overflows a weir near the top.

A.6.3.3 Chilling Coils

Chilling coils are pipe coils installed in cylindrical vessels to cool a product below atmospheric temperature. Usually a refrigerant is circulated through the coils to accomplish the cooling. The pipe may be coiled near the internal periphery of the vessel and extend from the bottom to the top or may be arranged as a flat, spiral coil near the bottom of the vessel.

A.6.3.4 Flat-Type Tank Heater Coils

The flat-type coil extends over most of the bottom of a storage tank and is a continuous coil with return bends connecting the straight runs of pipe. Steam enters one end of the coil, and condensate is drained at the other end through a steam trap. The coil rests on low supports at the bottom of the tank and slopes gently from the inlet to the outlet to facilitate drainage of the condensate. The pipe is usually made of steel, and generally all joints are welded to minimize the probability of leakage.

A.6.3.5 Box-Type Tank Heater Coils

The box-type coil is constructed in a rectangular shape, as shown in Figure A-5, and extends diametrically from the tank outlet to within a few feet of the opposite side of the tank. The

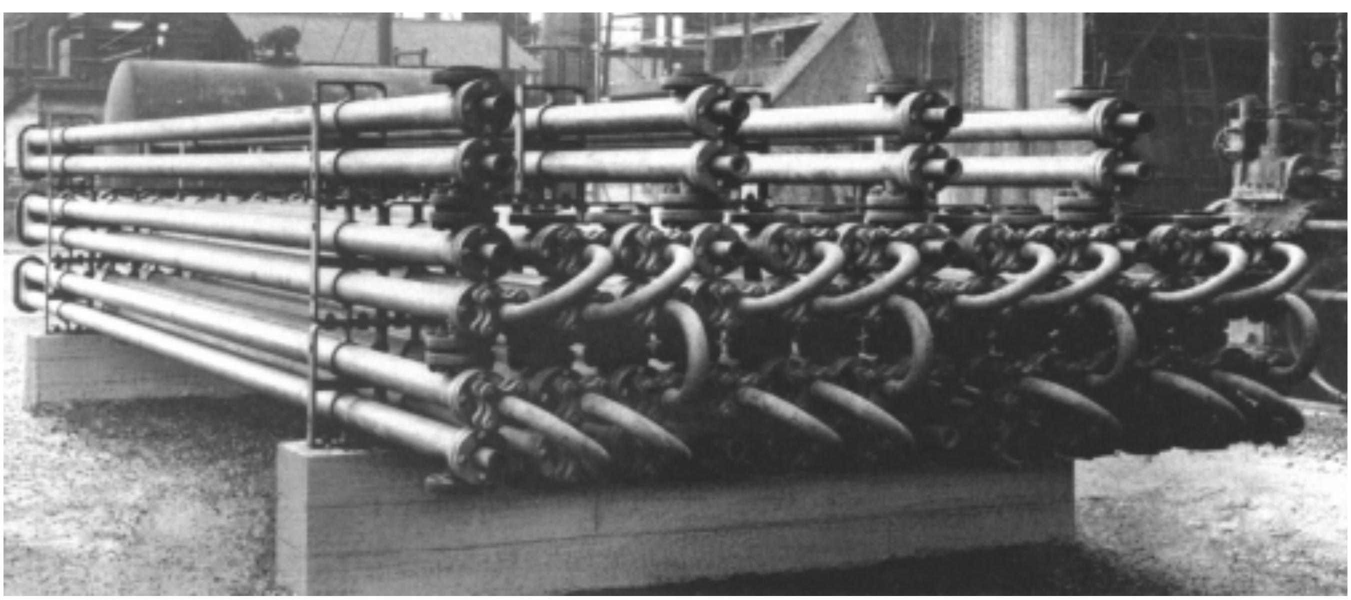


Figure A-4—Clean-Service Double-Pipe Coils

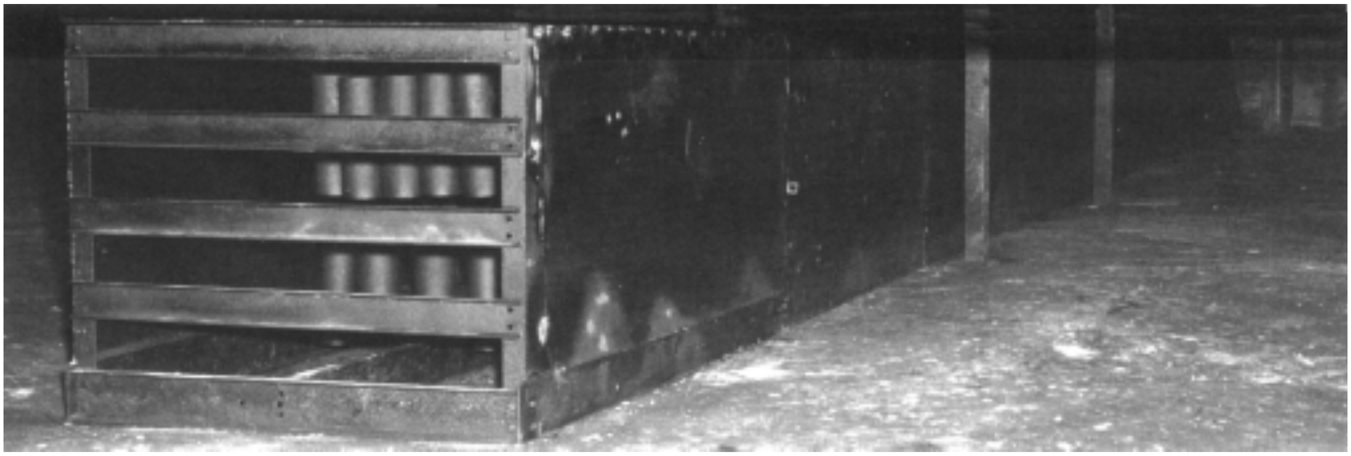


Figure A-5—Tank Suction Heater With Everything But Forward End Enclosed; Shell Suction Nozzle Enclosed in Far End

coil is enclosed in a box made of steel or wood. The end of the box opposite the tank outlet remains open to permit the entrance of oil. The oil flows through the box, around the coil, and to the tank outlet. Steam enters the top of the coil and flows downward to the outlet where condensate is drained through a steam trap. The entire coil is sloped gently from the inlet to the outlet to facilitate drainage of the condensate.

A.7 Extended Surface or Fin-Type Tubes

Extended surface or fin-type tubes are used quite extensively for more efficient heat exchange, especially when the exchange is between two fluids having widely different thermal conductivities. The addition of the extended surface requires less internal tube surface. Consequently, an exchanger smaller than would be required if plain tubes were used is necessary. The use of fin-type tubes in a double-pipe coil is shown in Figure A-6.

A.8 Plate-Type Exchangers

The plate-type exchanger is also constructed with an extended surface, making use of alternating layers of thin plates and corrugated sections. Integral channel and manifold sections enclose the open ends. The process material flows into the corrugated openings. Because the flow openings are small, they are easily clogged by dirt and products of corrosion. This is one of the reasons these units are constructed of materials that are highly resistant to corrosion. A plate-type exchanger installation for storage tank heating service is illustrated in Figure A-7.

A.9 Inspection of Exchanger Bundles

A.9.1 GENERAL

The first step in bundle inspection is a general visual inspection that may establish general corrosion patterns. If possible, bundles should be checked when they are first pulled from the shells, because the color, type, amount, and location of scales and deposits often help to pin point corrosion problems. An overall, heavy scale build up on steel tubes may indicate general tube corrosion. The lack of any scale or deposit on tubes near the shell inlet may indicate an erosion problem. A green scale or deposit on copper base tubes indicates that these tubes are corroding. As an inspector gains experience, these scales and deposits will become a useful inspection guide.

While visually inspecting a bundle, the inspector should make use of a pointed scraper to pick at suspected areas next to tube sheets and baffles. These areas may not have been cleaned completely. Picking in these areas will sometimes disclose grooving of tubes and enlargement of baffle holes. Figure A-8 shows tubes thinned at baffles.

Tapping the tubes with a light (4–8 ounce [115–225 g]) ball peen hammer or inspection hammer during the visual check will often help in locating thinned tubes. This method is especially useful when inspecting light-wall tubes of small outside diameters. The amount of rebound and the sound of the blow give an indication of the tube wall thickness. This method will become more helpful as experience is gained in the use of the hammer.

The inside of the tubes can be partially checked at the ends by use of flashlight extensions, fiber optic scopes, borescopes and special probes. The special probes are slender $^1/_8$-inch (3.2 cm) rods with pointed tips bent at 90 degrees to the axis of the rod. With these tools, it is possible to locate pitting and corrosion near the tube ends.

Obviously, only the outer tubes of a bundle can be thoroughly inspected externally, and without a borescope or fiber optic scope, only the ends of the tubes can be inspected internally. If a complete inspection of the tubes for defects is required, it can be made by using eddy-current methods or ultrasonic methods (for internal rotary, ultrasonic thickness measurements).

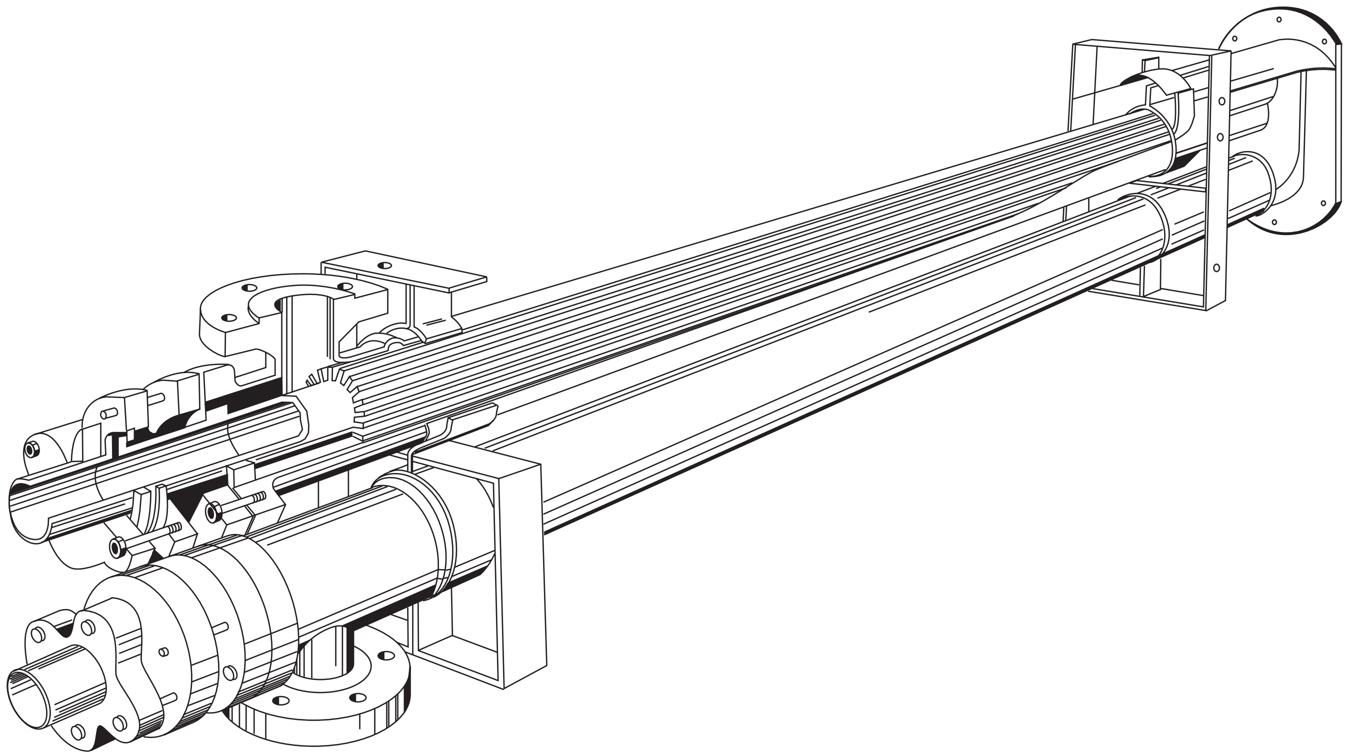


Figure A-6—Fin-Type Tubes in Double-Pipe Coil

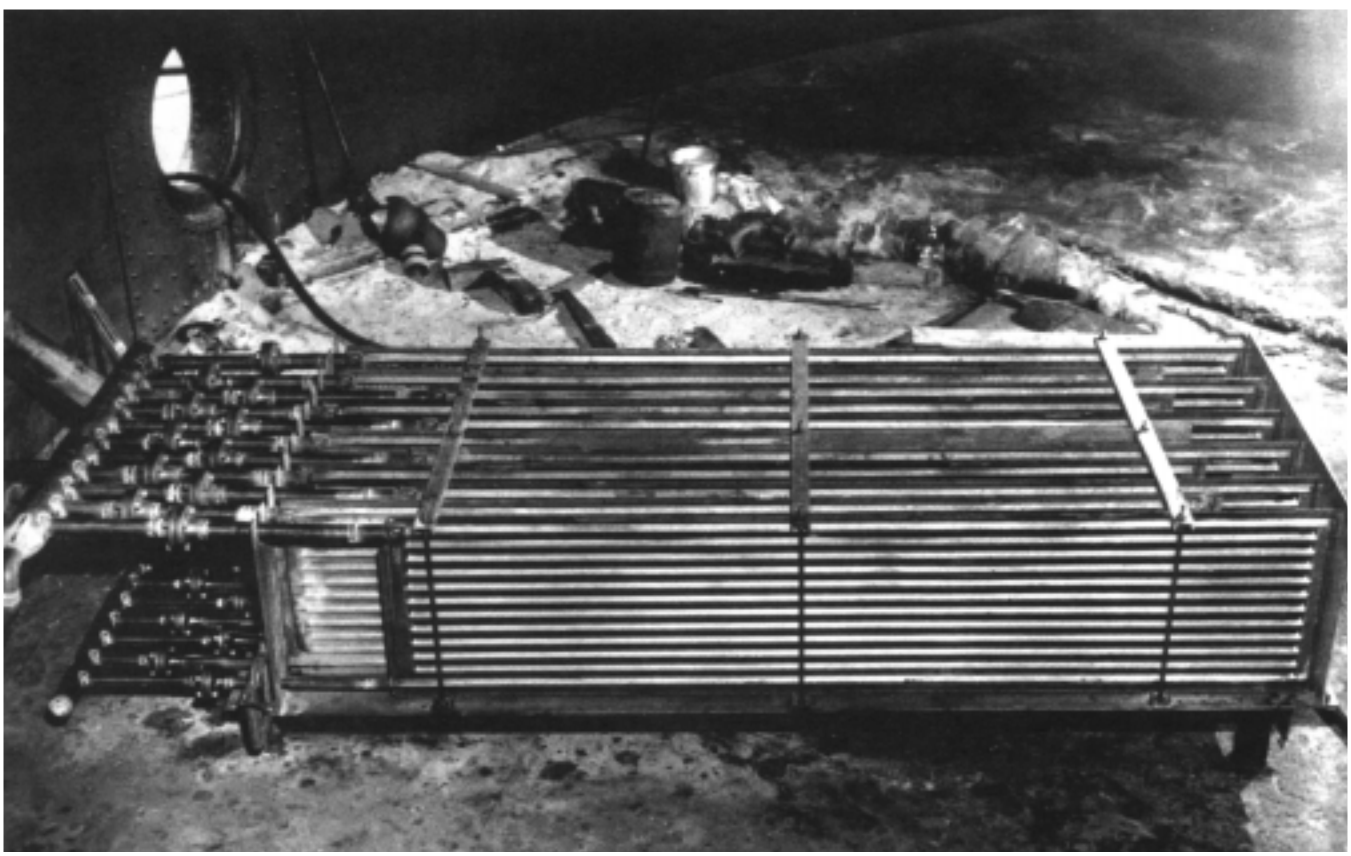


Figure A-7—Plate-Type Exchanger

Tubes may also be removed from the bundle and split for visual inspection. There are devices available for pulling a single tube from a bundle.

Removal of one or more tubes at random will permit sectioning and more thorough inspection for determining the probable service life of the remainder of the bundle. Tube removal is also employed when special examinations, such as metallurgical and chemical ones, are needed to check for dezincification of brass tubes, the depth of etching or fine cracks, or high-temperature metallurgical changes. When bundles are retubed, similar close inspection of tubes removed will help to identify the causes of failure and improve future service.

The baffles, tie rods, tube sheets, and floating-head cover should be visually inspected for corrosion and distortion. Gasket surfaces should be checked for gouge marks and corrosion. A scraper will be useful when making this inspection. Sufficient gasketed surface should remain to make a tight seal possible when the joints are completed.

Tube sheets and covers can be checked for distortion by placing a straight edge against them. Distortion of tube sheets can result from the over-rolling or improper rolling of tubes, thermal expansion, explosions, rough handling, or over-pressuring during a hydrotest.

Tube-sheet and floating-head thickness can be measured with mechanical calipers. Except in critical locations, continuous records of such readings are not usually kept. However, the original thickness readings of these parts should be recorded. Thickness readings of tie rods and baffles are not generally taken. The condition of these parts is determined by a visual inspection.

Figure A-8—Tubes Thinned at Baffles

Tube wall thickness should be measured and recorded at each inspection. It is sufficient to measure the inside and outside diameters and to thus determine the wall thickness. Eccentric corrosion or wear noted during the visual inspection should be taken into account in determining the remaining life of the tubes.

Several tools are available for the assessment of tube conditions. Long mechanical calipers can be used to detect general or localized corrosion within 12 in. (30.5 cm) of the tube ends. More detailed measurements along the entire tube length can be achieved with specialized tools such as laser optical devices, internal rotary ultrasonic tools, and electromagnetic sensors. Generally, the laser optical and ultrasonic devices require a high degree of internal tube cleanliness compared to electromagnetic methods. Laser optical devices can only detect and measure internal deterioration. Electromagnetic methods can detect and provide semi-quantitative information on both internal and external defects, but can not determine whether the defects are on the internal or external surface of the tubes. Rotary ultrasonics will generally provide the most quantitative information and can identify if defects are on the internal or external surface of the tube.

A.9.2 LIKELY LOCATIONS OF CORROSION

The locations where corrosion should be expected depend on the service of the equipment. However, there are certain locations that should be watched under most conditions of service.

The outside surface of tubes opposite shell inlet nozzles may be subject to erosion or impingement corrosion. When a mildly corrosive substance flows on the shell side of the tube bundles, the maximum corrosion often occurs at these inlet areas. The next most likely point of attack under the same conditions would be adjacent to the baffles and tube sheets. Any deterioration here is probably erosion-corrosion (see Figure A-9).

When a high temperature material flows into the tube inlet pass, the backside of the stationary tube sheets or tubes immediately adjacent to it may suffer extensive corrosion.

When process conditions allow a sludge or similar deposit to form, it will generally settle along the bottom of the shell. If the deposit contains a corrosive material, the maximum corrosion will occur along the bottom of the shell and the bottom tubes.

In water service, the maximum corrosion will occur where the water temperature is highest. Thus, when the water is in the tubes, the outlet side of the channel will be the location of maximum corrosion. Figure 27 shows pitting in a channel.

Also in water service, when exchanger parts are made of gray cast iron, they should be checked for graphitic corrosion. This type of attack is most often found in water-service channels or along the bottom of shells where sour water might collect. It can be found by scraping at suspected areas with a stiff scraper. Whether the attack is serious depends on its location and depth. Quite often, pass partitions can be almost completely corroded and still function efficiently, unless the carbon shell is broken or chipped.

In any type of exchanger, corrosion may occur where dissimilar metals are in close contact. The less noble of the two metals will corrode. Thus, carbon steel channel gasket surfaces near brass tube sheets will often corrode at a higher rate than they would otherwise.

Cracks are most likely to occur where there are sharp changes in shape or size or near welded seams, especially if a high stress is applied to the piece. Parts such as nozzles and shell flanges should be checked for cracks if excessive stresses have been applied to a unit.

When process stream velocities are high in exchangers, erosion damage can be expected at changes in the direction of flow. Damage would occur on or near such parts as tube inlets in tubular units and at return bends in double-pipe units and condenser box coils. The area of the shell adjacent to inlet impingement plates and bundle baffles is susceptible to erosion, especially when velocities are high.

Figure A-9—Erosion-Corrosion Attack at Tube Ends

A distinctive prussian blue color on bundle tubes indicates the presence of ferri-ferrocyanide. Hydrogen blistering is likely to be found on the exchanger shell near this color. A long straightedge may prove useful in determining the existence of blistering. Irregularities of the surface show up when the straightedge is placed on it. A straightedge is also useful when investigating pitting.

A.10 Inspection of Coils and Double-Pipe Exchanger Shells

Basically, coils in open condenser boxes and double-pipe exchanger shells are composed of pipe. They should be inspected according to the procedures detailed in API RP 574. (See Appendix B for a sample form for making an inspection report on a double-pipe exchanger.)

First, a thorough visual inspection should be made, including a complete hammering of the pipe. A scraper may be used to detect external pitting, a common defect found on the outside of coils in condenser boxes.

Following the visual inspection, thickness measurements should be taken. It is generally sufficient to use calipers to measure the open ends of double-pipe exchanger shells. To measure the wall thickness of coils and the middle section of double-pipe shells, ultrasonic and eddy-current devices can be used.

The enclosures of condensers or cooler boxes are made of concrete or light-gauge carbon steel. These enclosures should be visually inspected when the enclosed coil is inspected. When the container is made of carbon steel, the hammer is the most useful inspection tool available to aid the visual check. Thin spots in the container wall can be found by hitting the wall with the hammer. Calipers can be used to measure the wall thickness at the open top. If measurements below the top are required, the nondestructive instruments can be used or test-hole drilling can be applied. Concrete walls are inspected best by picking at selected points with a scraper to check for spalling, cracks, or soft spots.

A.11 Inspection of Extended Plate Exchangers

Extended plate exchangers are designed so that the flow openings between the plates are quite small. For this reason and because of the inaccessibility of the unit interior, these exchangers are usually built of alloys highly resistant to corrosion in their expected service. In most cases, the alloys used also will be highly resistant to corrosion in refinery atmospheres. Visual examination, except as discussed in 10.8.3, will not reveal much. The outer surfaces can be checked for nicks, cuts, gouges, or other forms of mechanical damage and for bulging from internal failures. Good lighting is essential for this inspection and will prove valuable when performing the soap tests discussed in 10.8.2.

These units are usually built with integral channels and distribution manifolds, the thickness of which can be accurately measured with the ultrasonic instruments and then recorded. It is not advisable to use drilling equipment on the exchangers because the equipment could be easily damaged at these points. Welding of the alloys used in the units, such as aluminum and austenitic stainless steel alloys, requires welder skills not always readily available.

Light tapping with a small (8 oz. [225 g]) hammer is useful in looking for cracked or broken parts on the exposed portions of the extended plate exchangers. The sound of the blow gives a clue to the condition. Cracked plates or manifold sections give off a tinny sound, which can be recognized more easily as more experience is with the use of a hammer is acquired.

A.12 Inspection of Air-Cooled Exchangers

Refer to API Std 661 for descriptions, minimum design criteria, and general information regarding air cooled exchangers. API 510 and the principles of API Std 661 are to be followed in any ratings, repairs, and alterations of this type of exchanger. (See Appendix B for a sample form for making an inspection report on an air-cooled exchanger.)

Tubes that are enclosed in fins cannot be inspected from the exterior. The best methods for inspecting the tubes are the internal-rotary, ultrasonic thickness-testing devices, eddy current testing., or remote field eddy current testing. These methods work from the interior of the tubes. With competent operators and clean tubes, thicknesses and defects can be found with these methods. The tubes must be thoroughly cleaned before any method is effective.

The external fins of the tubes should be checked for cleanliness. If the fins need cleaning, washing with clean water alone or clean water with soap may be sufficient. If not, care should be taken in selecting a cleaning solution. Usually the fins are aluminum and they could be harmed if the wrong cleaning medium is used.

The exterior of the tubes should be inspected between the tube sheet and the start of the fins. Exchangers in intermittent service or in service cool enough to allow moisture to collect in this area are subject to external corrosion severe enough to cause leaks in this area. Coatings applied to this area will alleviate the problem of corrosion.

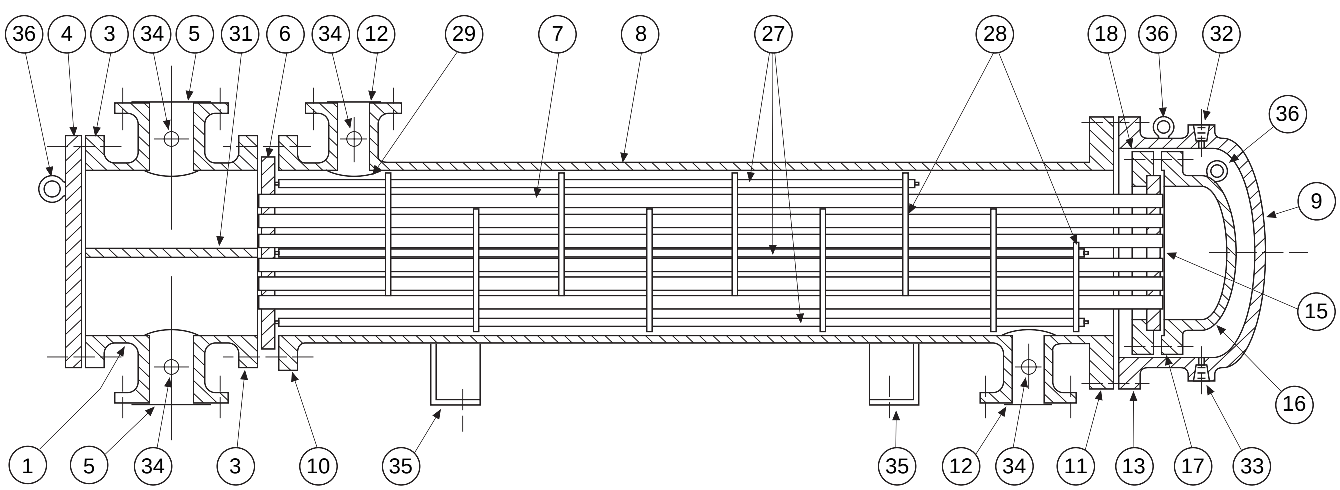
The insides of the tubes may be visually inspected near the tube-sheet ends of the air cooler. Fiber optic devices and borescopes are excellent devices for this type of inspection. A probe rod $1/8$ in. (3.2 mm) or less in diameter and approximately 36 in. (91 cm) in length with a pointed tip bent at 90 degrees to the axis of the rod also may help to locate pits or corrosion at the tube ends.

Erosion-corrosion at the tube inlets is a common problem with air-cooled heat exchangers. This damage can be found by visual inspection through the header-box plug holes, or directly if the header box has a removable cover plate. If suitable conditions exist, reflecting sunlight into the tubes with a mirror is useful in inspecting for erosion-corrosion.

The box-type header ends of the air cooler should be inspected using the same techniques as recommended for a pressure vessel. In addition, the sharp change of direction caused by its rectangular construction should be carefully checked for cracking. The header boxes with removable cover plates are obviously the easiest to inspect. A fiber optics scope may be the only way to check a header that has plug-type closures as opposed to a cover plate.

Legend

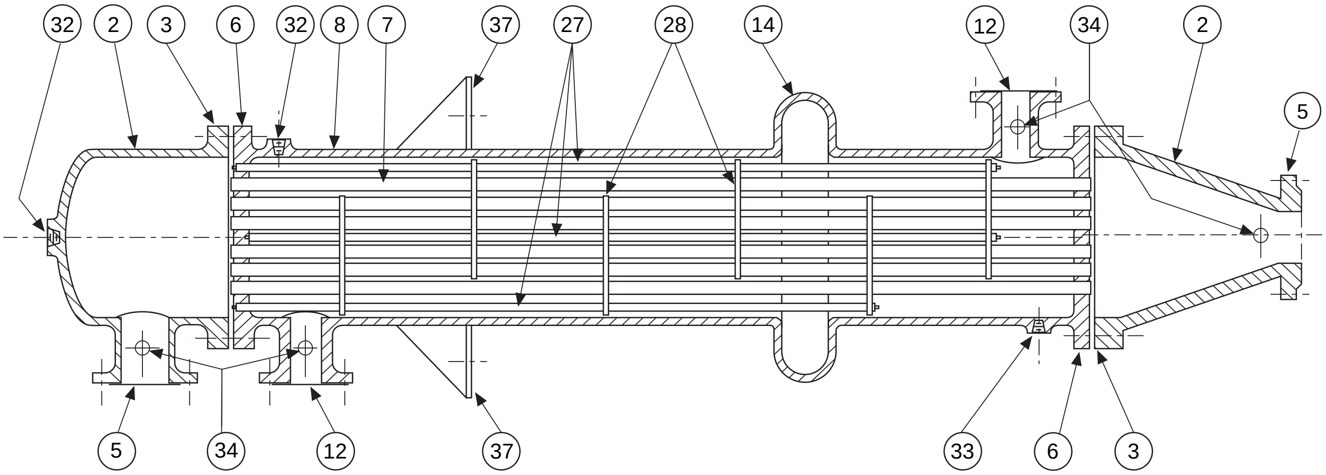
1. Stationary Head—Channel
2. Stationary Head—Bonnet
3. Stationary-Head Flange—Channel or Bonnet
4. Channel Cover
5. Stationary-Head Nozzle
6. Stationary Tube Sheet
7. Tubes
8. Shell
9. Shell Cover
10. Shell Flange—Stationary-Head End
11. Shell Flange—Rear-Head End
12. Shell Nozzle
13 Shell-Cover Flange
14. Expansion Joing
15. Floating Tube Sheet
16. Floating-Head Cover
17. Floating-Head Flange
18. Floating-Head Backing Device
19. Split Shear Ring
20. Slip-On Backing Flange
21. Floating-Head Cover—External
22. Floating Tube-Sheet Skirt
23. Packing Box
24. Packing
25. Packing Gland
26. Lantern Ring
27. Tie Rods and Spacers
28. Transverse Baffles or Support Plates
29. Impingement Plate
30. Longitudinal Baffle
31. Pass Partition
32. Vent Connection
33. Drain Connection
34. Instrument Connection
35. Support Saddle
36. Lifting Lug
37. Support Bracket
38. Weir
39. Liquid Level Connection



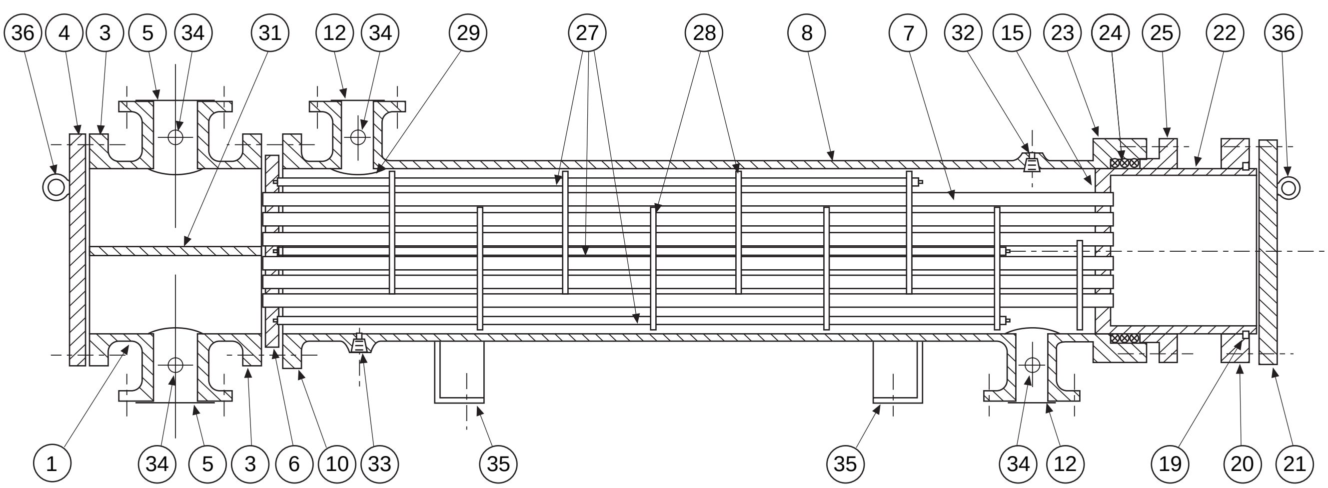
AES

Note: *AES* refers to heat exchanger type (refer to Figure A-11).

Figure A-10—Heat Exchanger Parts

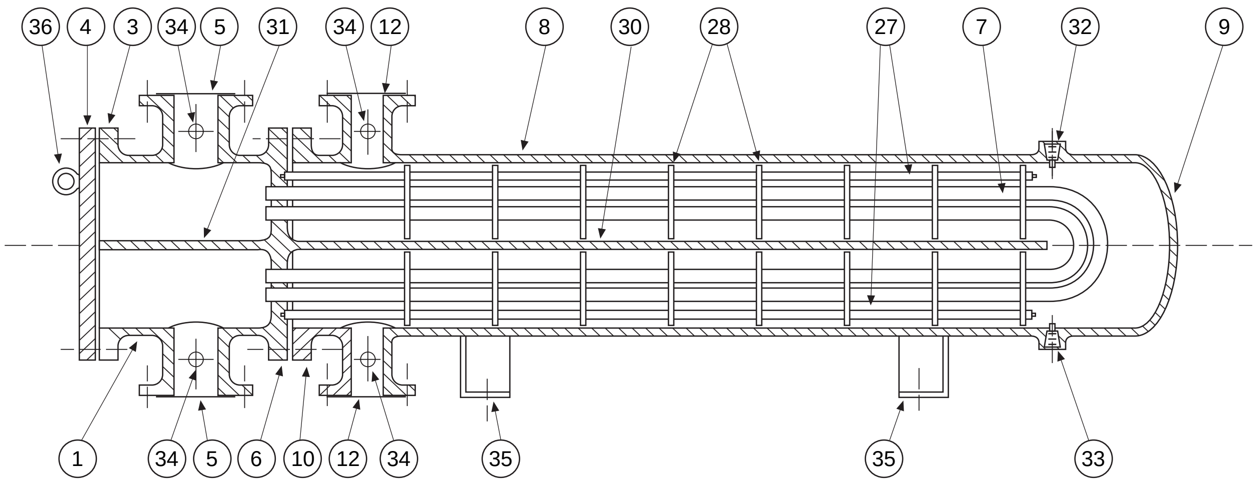


BEM

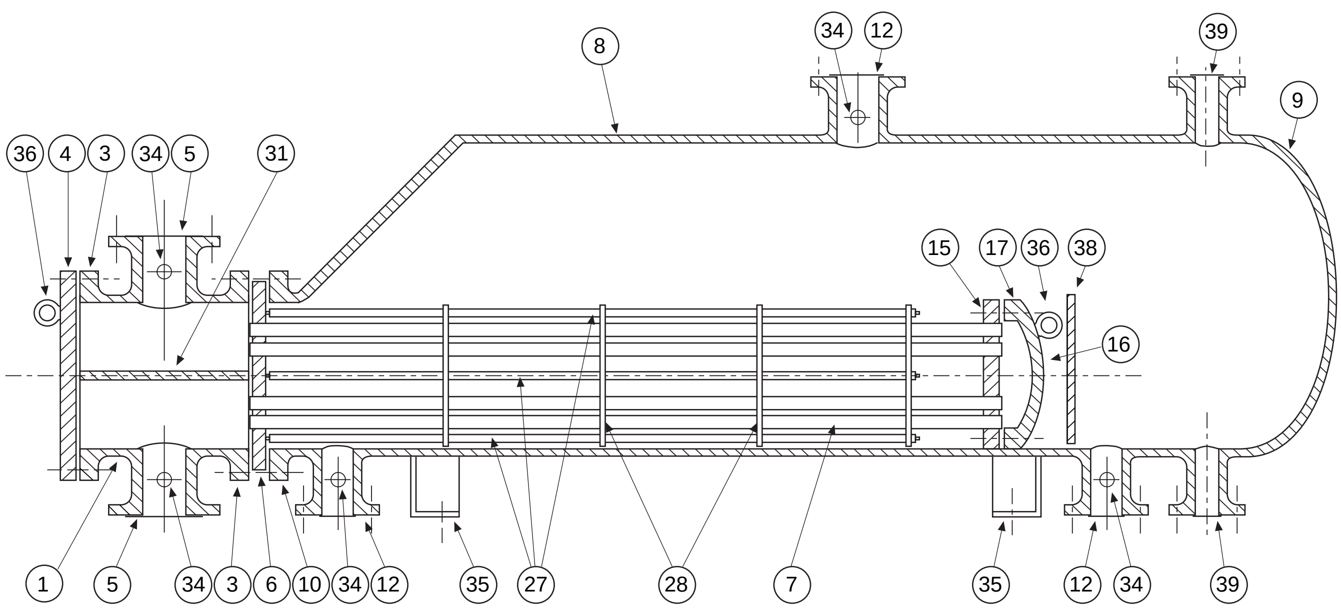


AEP

Figure A-10 (Continued)

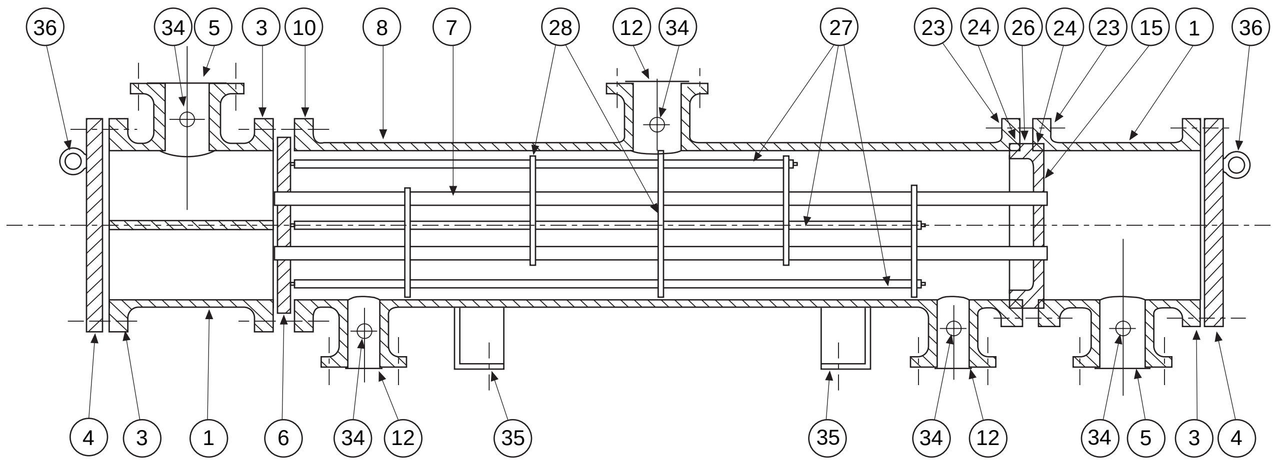


CFU



AKT

Figure A-10 (Continued)



AJW

Figure A-10 (Continued)

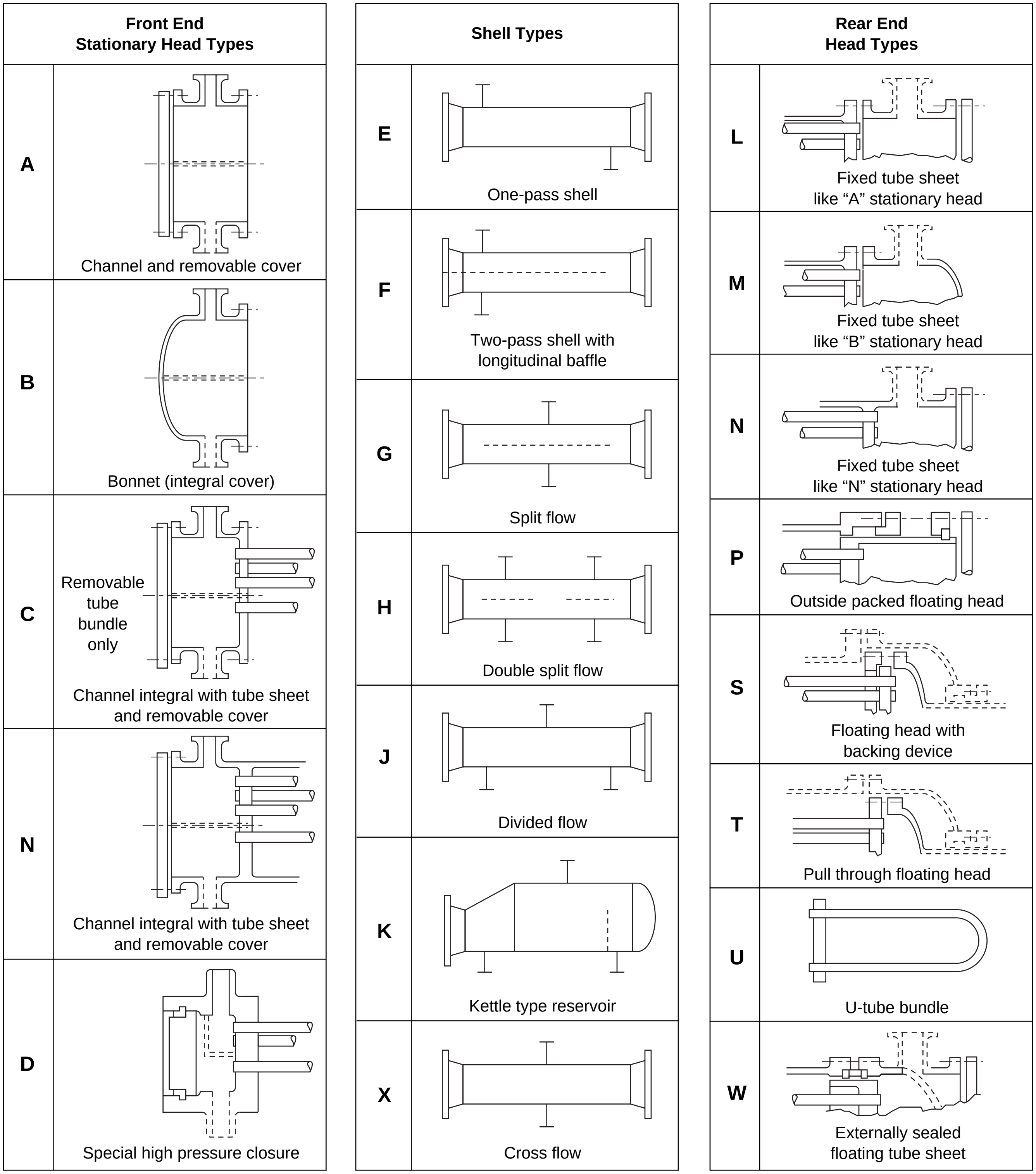


Figure A-11—Heat Exchanger Types

APPENDIX B—SAMPLE RECORD FORMS

The inspection record for pressure vessel in service illustrates a form used to store data gathered during the inspection of a pressure vessel in service. Most plants develop a more detailed set of forms that also includes other pertinent data.

The permanent pressure vessel record illustrates a form that is used to record all the basic data of an individual pressure vessel and that becomes the permanent record for that vessel.

The vessel inspection sheet illustrates a form used as a progressive record of thicknesses, from which a corrosion rate can be calculated. Three versions of this form are included. One is blank. The other two show sketches that might be made for different types of pressure vessels. Information on only one pressure vessel should be recorded on any individual copy of this form.

Normally, an inspector would use one copy of this form to record field data, and another copy would become an office record. An inspector might use this form without a sketch when inspecting a vessel for which no basic data is available. In this case, he would make a sketch of the vessel on the form, including all pertinent dimensions and data he can secure in the field.

The record of all pressure vessels on an operating unit illustrates a form used to record and report the actual physical conditions and the allowable operating conditions of all pressure vessel on an operating unit.

The exchanger inspection field data sheet, the exchanger data record, the exchanger inspection report form, the air cooler exchanger inspection report form, and the double-pipe exchanger inspection report form illustrate other forms.

Note: Computer storage and retrieval of data in a format similar to that of the sample forms is acceptable and may be advantageous in many cases.

INSPECTION RECORD FOR PRESSURE VESSEL IN SERVICE

OWNER OR USER NO. ____________________ OWNER ____________________ DATE ____________________

JURISDICTION OR

NATIONAL BOARD NO. ____________________ OWNER ____________________ DATE ____________________

MANUFACTURER ____

MANUFACTURER'S SERIAL NO. ____

DESIGN PRESSURE ______________________________ TEMPERATURE ______________________________

MAXIMUM ALLOWABLE ORIGINAL HYDROSTATIC

WORKING PRESSURE ______________________________ TEST PRESSURE ______________________________

ORIGINAL THICKNESS A_______________ B _______________ C_______________ D_______________

CORROSION ALLOWANCE A_______________ B _______________ C_______________ D_______________

DATE OF INSPECTION	THICKNESS AT CRITICAL POINTS				MAXIMUM METAL TEMPERATURE AT CRITICAL POINTS				MINIMUM ALLOWABLE METAL THICKNESS AT CRITICAL POINTS				DATE OF NEXT INSPECTION	SIGNATURE OF INSPECTOR
	A	B	C	D	A	B	C	D	A	B	C	D		

DESCRIPTION OF LOCATION ____ DATE ______________________

DESCRIPTION OF LOCATION ____ DATE ______________________

DESCRIPTION OF LOCATION ____ DATE ______________________

DESCRIPTION OF LOCATION ____ DATE ______________________

DESCRIPTION OF LOCATION ____ DATE ______________________

NOTE: MANUFACTURER'S DRAWING CAN BE USED TO SHOW THE LOCATION OF A, B, C, AND D.

PERMANENT PRESSURE VESSEL RECORD

NAME OF UNIT ____________________

VESSEL NAME ____________________

LOCATION ____________________

ORIGINAL ITEM NO. ____________________

DATE ____________________

HISTORY

ESTIMATE NO. ____________________

ORDER NO. ____________________

MANUFACTURED BY ____________________

MANUFACTURER'S SERIAL NO. ____________________

MANUFACTURER'S INSPECTOR ____________________

MANUFACTURER'S TEST PRESSURE ____________________

DATE RECEIVED ____________________

DATE INSTALLED ____________________

COMPANY NO. ____________________

COMPANY INSPECTOR ____________________

DESCRIPTION

GENERAL

DRAWING NO. ____________________

FABRICATOR'S ____________________

CONTRACTOR'S ____________________

COMPANY ____________________

POSITION (VERTICAL OR HORIZONTAL) ____________________

CODE CONSTRUCTED ____________________

CODE ____________ YEAR ____________

CODE STAMP ____________________

MATERIAL SPECIFIED AND GRADE OR TYPE ____________________

BASE ____________________

LINING ____________________

THICKNESS ____________________

STRESS RELIEVED (ORIGINAL) ____________________

RADIOGRAPHED (ORIGINAL) ____________________

COMPLETE ____________________

WELD INTERSECTIONS ____________________

SIZE

NOMINAL INSIDE DIAMETER ____________________

LENGTH BASE LINE TO BASE LINE ____________________

DESIGN ____________________

PRESSURE, PSI ____________________

TEMPERATURE, °F ____________________

STRESS, PSI ____________________

MAXIMUM ALLOWABLE OPERATING PRESSURE, PSI ____________________

MAXIMUM ALLOWABLE TEMPERATURE, °F ____________________

LIMITED BY ____________________

SHELL

TYPE OF CONSTRUCTION ____________________

JOINT EFFICIENCY ____________________

TYPE OF SUPPORT ____________________

INTERIOR OR EXTERIOR STIFFENERS ____________________

ORIGINAL THICKNESS ____________________

CORROSION ALLOWANCE ____________________

MANWAYS

NO. ____________________

SIZE ____________________

FLANGE RATING ____________________

REINFORCEMENT

FACTORY OR FIELD ____________________

TOP HEAD TYPE

ELLIPTICAL ____________ HEMISPHERICAL ____________

DISHED

CROWN REGION ____________ KNUCKLE REGION ____________

CONICAL (ANGLE) ____________________

FLAT ____________________

JOINT EFFICIENCY ____________________

ORIGINAL THICKNESS ____________________

CORROSION ALLOWANCE ____________________

MANWAYS

NO. ____________________

SIZE ____________________

FLANGE RATING ____________________

REINFORCEMENT

FACTORY OR FIELD ____________________

BOTTOM HEAD TYPE

ELLIPTICAL ____________ HEMISPHERICAL ____________

DISHED

CROWN REGION ____________ KNUCKLE REGION ____________

CONICAL (ANGLE) ____________________

FLAT ____________________

JOINT EFFICIENCY ____________________

ORIGINAL THICKNESS ____________________

CORROSION ALLOWANCE ____________________

MANWAYS

NO. ____________________

SIZE ____________________

FLANGE RATING ____________________

REINFORCEMENT

FACTORY OR FIELD ____________________

NOZZLES

MINIMUM FLANGE RATING ____________________

TYPE FACING ____________________

OPENINGS REINFORCED ____________________

REMARKS ____________________

____

NOTE: A COPY OF THIS SHEET SHALL BE PREPARED FOR EACH INDIVIDUAL VESSEL IN A UNIT. IF NEW VESSELS ARE INSTALLED OR ANY CHANGES ARE MADE TO PRESENT VESSELS AFFECTING THE DESCRIPTION ITEMS, A NEW OR REVISED COPY OF THIS SHEET SHALL BE SUBMITTED WITH THE CURRENT INSPECTION REPORT.

VESSEL INSPECTION SHEET

UNIT ____________________

NAME OF VESSEL____________________

DIAMETER ____________________

LENGTH ____________________

VESSEL NO.____________________

DRAWINGS			
	SHELL	LINING	INTERNAL
FABRICATOR			
CONTRACTOR			
COMPANY			
SKETCH			

WALL THICKNESS MEASUREMENTS											
POINT NO.		ORIGINAL THICKNESS	MINIMUM ALLOWABLE THICKNESS	DATE							
INSPECTION INTERVALS	NO.										
	1										
	2										
	3										
	4										
	5										
	6										
	7										
	8										
	9										

VESSEL INSPECTION SHEET

UNIT ____________________

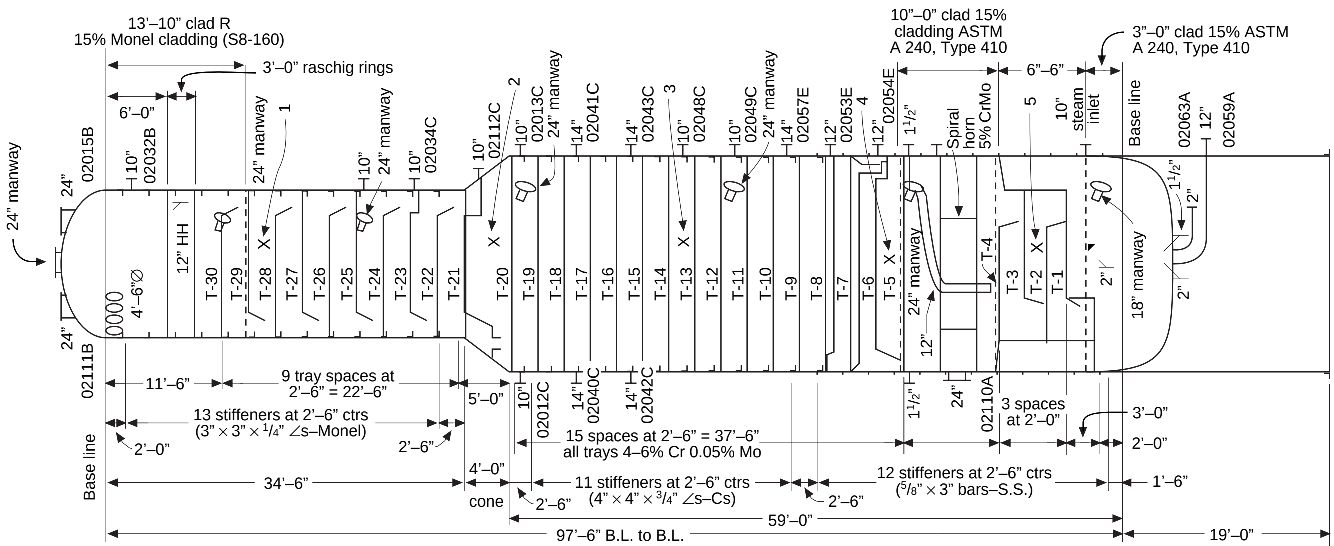
NAME OF VESSEL ____________________

DIAMETER ____________________

LENGTH ____________________

VESSEL NO. ____________________

DRAWINGS			
	SHELL	LINING	INTERNAL
FABRICATOR			
CONTRACTOR			
COMPANY			
SKETCH			



WALL THICKNESS MEASUREMENTS											
POINT NO.		ORIGINAL THICKNESS	MINIMUM ALLOWABLE THICKNESS	DATE							
INSPECTION INTERVALS	NO.										
	1										
	2										
	3										
	4										
	5										
	6										
	7										
	8										
	9										

VESSEL INSPECTION SHEET

UNIT ____________________

NAME OF VESSEL____________________

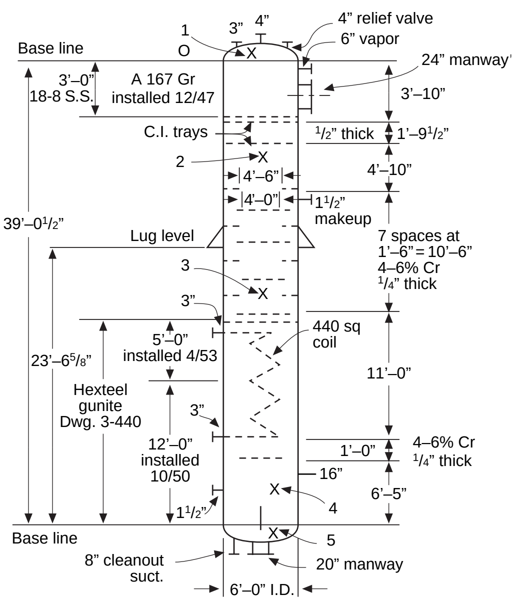
DIAMETER ____________________

LENGTH ____________________

VESSEL NO.____________________

DRAWINGS			
	SHELL	LINING	INTERNAL
FABRICATOR			
CONTRACTOR			
COMPANY			

SKETCH



WALL THICKNESS MEASUREMENTS											
POINT NO.		ORIGINAL THICKNESS	MINIMUM ALLOWABLE THICKNESS	DATE							
INSPECTION INTERVALS	NO.										
	1										
	2										
	3										
	4										
	5										
	6										
	7										
	8										
	9										

RECORD OF ALL PRESSURE VESSELS ON AN OPERATING UNIT (SHEET 1)

NAME OF UNIT ____________________

LOCATION ____________________

INSPECTION AND TEST NO. ____________________

DATE ____________________

NAME OF VESSEL				
COMPANY VESSEL AND SKETCH NO.				
OPERATING DATA				
HOURS UNDER PRESSURE TO DATE				
SERVICE DATA				
AVERAGE MAXIMUM OPERATING PRESSURE, PSI				
AVERAGE MAXIMUM OPERATING TEMPERATURE, °F				
TOP				
BOTTOM				
NO. TRAYS				
NO. BAFFLES				
NO. COILS				
INSPECTION AND TEST DATA				
INSPECTOR				
NOMINAL INSIDE DIAMETER				
MINIMUM THICKNESS				
SHELL				
LOCATION				
TOP HEAD				
BOTTOM HEAD				
JOINT EFFICIENCY				
SHELL				
HEADS				
HEAD FACTOR				
TOP				
BOTTOM				
LAST INSPECTION				
INSIDE WELDS				
OUTSIDE WELDS				
UNDER INSULATION				
EXTENT INSPECTION				

RECORD OF ALL PRESSURE VESSELS ON AN OPERATING UNIT (SHEET 2)

NAME OF UNIT ____________________

LOCATION ____________________

INSPECTION AND TEST NO. ____________________

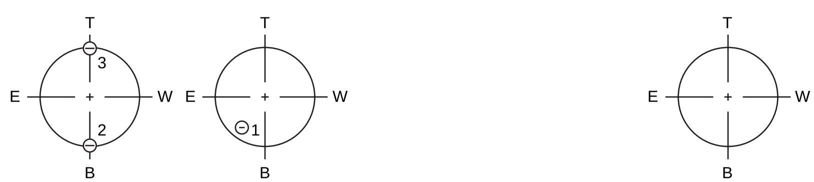
DATE ____________________

NAME OF VESSEL				
COMPANY VESSEL AND SKETCH NO.				
TEST PRESSURE				
VESSEL, PSI				
COILS, PSI				
TEST MEDIUM				
TIME PRESSURE HELD –(1) + (2)				
MAXIMUM ALLOWABLE OPERATING PRESSURE, PSI				
MAXIMUM ALLOWABLE OPERATING TEMPERATURE, °F				
LIMITED BY				
WORKING STRESS AT OPERATING TEMPERATURE, PSI				
APPROVED OPERATING PRESSURE, PSI				
APPROVED OPERATING TEMPERATURE, °F				
SAFETY VALVE SETTING, PSI				
PROTECTIVE LINING DATA				
DRAWING NO.				
DATE INSTALLED				
MATERIAL AND TYPE				
SECTION LINED				
DATE REPAIRED				
EXTENT OF REPAIRS				
DATE PREVIOUS LINING REMOVED				
CAUSE OF REMOVAL				
REMARKS				

EXCHANGER INSPECTION FIELD DATA SHEET

Mfr. ______________________ Type ______________________
Design Data:

	Tubes	Shell
Fluid thru		
Temperature		
Pressure		
Size		
Material		



Shell cover   Floating head   Channel cover

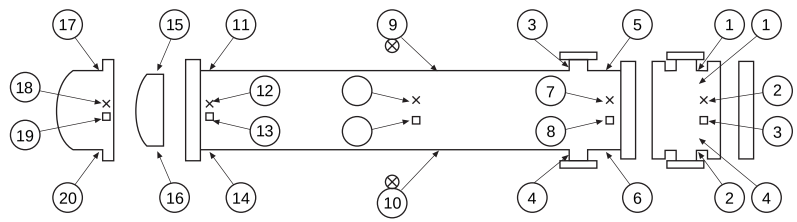
ORIGINAL THICKNESS																				
	DRILL POINT LOCATIONS WITH THICKNESS MEASURED IN 0.01 INCHES																			
DATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

ORIGINAL THICKNESS																				
	NOZZLE LOCATIONS WITH NECK THICKNESS MEASURED IN 0.01 INCHES																			
DATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

LEGEND
- ⊙ REMOVABLE TEST PLUG
- ● WELDED TEST PLUG
- ⊖ CALIPERED
- ⊝ TELL TALE HOLE

REVISIONS		

EXCHANGER DATA RECORD

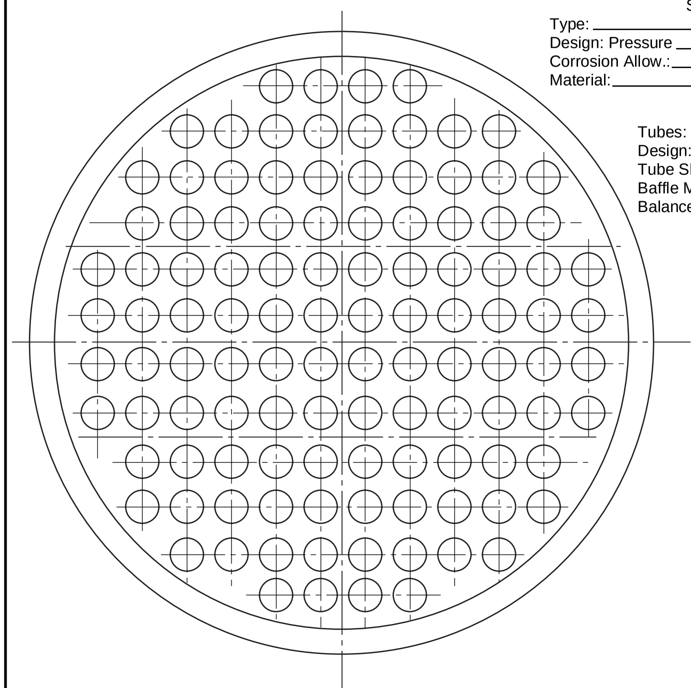


Shell

Type: ____
Design: Pressure ____ Temp. ____
Corrosion Allow.: ____
Material: ____

Bundle

Tubes: Size ____ Mat. ____
Design: Press. ____ Temp. ____
Tube Sheet Mat. ____
Baffle Mat. ____
Balance Mat. ____



ORIGINAL THICKNESS																				
	DRILL POINT LOCATIONS WITH THICKNESS MEASURED IN 0.01 INCHES																			
DATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

ORIGINAL THICKNESS																				
	NOZZLE LOCATIONS WITH NECK THICKNESS MEASURED IN 0.01 INCHES																			
DATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

LEGEND
⊙ REMOVABLE TEST PLUG
● WELDED TEST PLUG
⊖ CALIPERED
⊝ TELL TALE HOLE
□ SIDE SHOWN
× REVERSE SIDE

REVISIONS

SCALE SHOWN ____	DRAWN BY ____	DRAWING NO.
DATE ____	CHECKED BY ____	____
	APPROVED BY ____	

EXCHANGER INSPECTION REPORT FORM

TO: ____________________ DATE ____________________

____

UNIT ____________________ EQUIPMENT ____________________ SERVICE ____________________

DOWN TIME ____________________ RETURNED TO SERVICE ____________________ DATE OF LAST INSPECTION ____________________

REASON ____

____

INSPECTION COMMENTS ____

____

	MINIMUM THICKNESS			
	ORIGINAL	LAST INSPECTION	PRESENT	RETIRING THICKNESS
SHELL				
SHELL COVER				
CHANNEL				
CHANNEL COVER				
TOP NOZZLE (SHELL)				
BOTTOM NOZZLE (SHELL)				
TOP NOZZLE (CHANNEL)				
BOTTOM NOZZLE (CHANNEL)				
TUBES				

RECOMMENDATIONS ____

____

WORK REQUESTED BY ____________________ INSPECTED BY ____________________

CC: ____________________ SIGNED ____________________

CHIEF INSPECTOR

AIR COOLER EXCHANGER INSPECTION REPORT FORM

NAME OF UNIT ______________________

______________________ **PLANT**

EXCHANGER NAME ______________________

____

ORIG. ITEM NO. ______________________

PLANT NO. ______________________

PLUG TYPE—REMOVABLE HEADER

DATE ORIG. EXCH. INST. ______________________

DATE PREV. BDLE. INST. ______________________

CAUSE REMOVAL ______________________

DATE PRES. BDLE. INST. ______________________

MAT'L HANDLED ______________________

DESIGN—PRESS. PSI ______________________

TEMP. °F ______________________

OPER.—PRESS. PSI ______________________

TEMP. °F ______________________

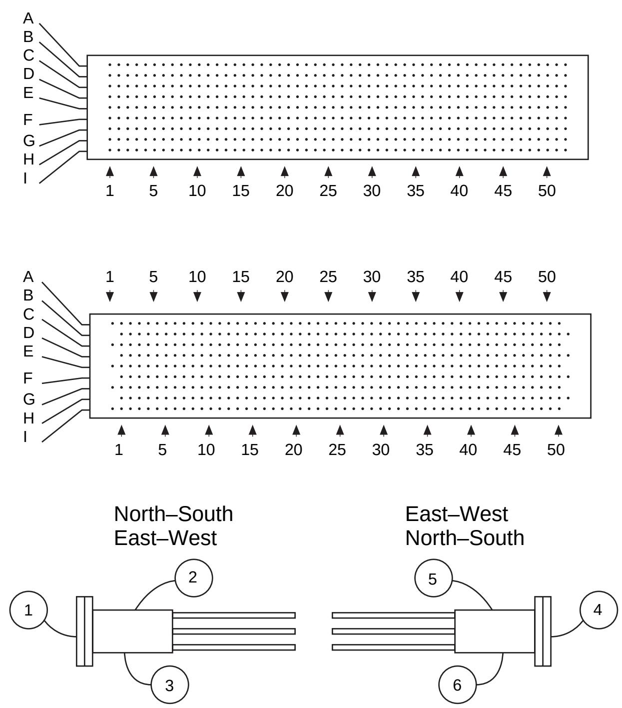
TUBE—MATERIAL ______________________

—DIAMETER ______________________

—THICK. ______________________

—LENGTH ______________________

FIN—MATERIAL ______________________



THICKNESS DATA

POINT NO.		ORIG. THK.	PREV. MIN.	DATE					
INSP. INT.	NO.								
	1								
	2								
	3								
	4								
	5								
	6								

INSP. & TEST DATA						
DATE						
GENERAL CONDITION						
CHANNEL SECTION						
TUBE SECTION						
FINS						
FAN						
FAN HOUSING						
NO. TUBES PLUGGED						
CHEMICALLY CLEANED						
MAX. ALLOW. PRESS. PSI						
TEMP. °F						
TEST PRESS. PSI						
APPROVED - PRESS. PSI						
TEMP. °F						

DOUBLE–PIPE EXCHANGER INSPECTION REPORT FORM

NAME OF UNIT ____________________

____________________ **PLANT**

EXCHANGER NAME ____________________

____

ORIG. ITEM NO. ____________________

PLANT NO. ____________________

SERVICE DATA

DATE INT. TUBE INST. ____________________

DATE PREV. INT. TUBE ____________________

INSTALLED ____________________

REMOVED ____________________

CAUSE REMOVAL ____________________

DATE EXTER. TUBE

INSTALLED ____________________

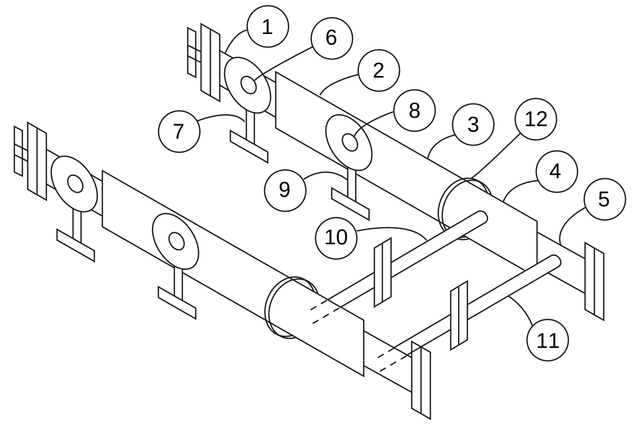
REMOVED ____________________

CAUSE REMOVAL ____________________

OPERATING DATA

TYPE OF SERVICE ____________________

	INT. PIPE	EXT. PIPE
STATE OF MEDIUM		
MED. OR MAT'L HAND.		
DESIGN—PRESS. PSI		
TEMP. °F		
OPER.—PRESS. PSI		
TEMP. °F		



THICKNESS DATA

POINT NO. INSP. INT.	NO.	ORIG. THK.	PREV. MIN.	DATE					
	1								
	2								
	3								
	4								
	5								
	6								
	7								
	8								
	9								
	10								
	11								
	12								
	13								

INSP. & TEST DATA

DATE												
INSPECTION INTERVAL												
LIMITING—INT. TUBE THK.												
LIMITING—EXT. TUBE THK.												
GENERAL CONDITION												
INT. TUBE SECTION												
EXT. TUBE SECTION												
INT. TUBE MATERIAL												
EXT. TUBE MATERIAL												
DATE LAST INSPECTED												
CHEMICALLY CLEANED												
INT. MAX. ALL.—PRESS. PSI												
TEMP. °F												
EXT. MAX. ALL.—PRESS PSI												
TEMP °F												
INT. TEST PRESS. PSI												
EXT. TEST PRESS. PSI												
	INT. TUBE	EXT. TUBE	INT. TUBE	EXT. TUBE	INT. TUBE	EXT TUBE	INT. TUBE	EXT TUBE	INT. TUBE	EXT TUBE	INT. TUBE	EXT TUBE

American Petroleum Institute — Publications Order Form - 2001

Available through Global Engineering Documents

Phone Orders: 1-800-854-7179 (Toll-free in the U.S. and Canada) • **303-397-7956** (Local and International) • **Fax Orders: 303-397-2740**

Online Orders: www.global.ihs.com

Date:

❏ **API Member** *(Check if Yes)*

Invoice To (❏ Check here if same as "Ship To")

Name:

Title:

Company:

Department:

Address:

City: State/Province:

Zip/Postal Code: Country:

Telephone:

Fax:

E-Mail:

Ship To (UPS will not deliver to a P.O. Box)

Name:

Title:

Company:

Department:

Address:

City: State/Province:

Zip/Postal Code: Country:

Telephone:

Fax:

E-Mail:

Quantity	Product Number	Title	SO*	Unit Price	Total
	C51008	API 510, *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair and Alteration*		$ 94.00	
	C57002	API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems*		$ 83.00	
	C57602	RP 576, *Inspection of Pressure Relieving Devices*		$ 83.00	
	C57901	RP 579, *Fitness-for-Service*		$ 595.00	
	C66006	Std 660, *Shell–and–Tube Heat Exchangers for General Refinery Services*		$ 70.00	
	C66104	Std 661, *Air–Cooled Heat Exchangers for General Refinery Services*		$ 105.00	
	C94105	RP 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemcal Plants*		$ 72.00	
	C94502	RP 945, *Avoiding Environmental Cracking in Amine Units*		$ 66.00	

❏ **Payment Enclosed** ❏ **P.O. No.** (Enclose Copy)

❏ **Charge My Global Account No.**

❏ **VISA** ❏ **MasterCard** ❏ **American Express** ❏ **Discover**

Credit Card No.:

Name (As It Appears on Card):

Expiration Date:

Signature:

Subtotal	
Applicable Sales Tax *(see below)*	
Rush Shipping Charge *(see below)*	
Shipping and Handling *(see below)*	
Total *(in U.S. Dollars)*	

****To be placed on Standing Order for future editions of this publication, place a check mark in the SO column and sign here:***

Pricing and availability subject to change without notice.

Mail Orders – Payment by check or money order in U.S. dollars is required except for established accounts. State and local taxes, plus 5% for shipping and handling, must be added. Send mail orders to: **API Publications, Global Engineering Documents, 15 Inverness Way East, M/S C303B, Englewood, CO 80112-5776, USA.**

Purchase Orders – Purchase orders are accepted from established accounts. Invoice will include actual freight cost, an $8.00 handling fee, plus state and local taxes.

Telephone Orders – If ordering by telephone, an $8.00 handling fee and actual freight costs will be added to the order.

Sales Tax – All U.S. purchases must include applicable state and local sales tax. Customers claiming tax-exempt status must provide Global with a copy of their exemption certificate.

Shipping (U.S. Orders) – Orders shipped within the U.S. are sent via traceable means. Most orders are shipped the same day. Subscription updates are sent by First-Class Mail. Other options, including next-day service, air service, fax transmission, and electronic delivery are available at additional cost.

Shipping (International Orders) – Standard international shipping is by air express courier service. Subscription updates are sent by World Mail. Normal delivery is 3-4 days from shipping date.

Rush Shipping Fee – In addition to the carrier charges, the following charges will be added: Next Day Delivery orders placed prior to 2:00 p.m. MST - $10.00 / Next Day Delivery orders placed after 2:00 p.m. MST - $20.00 (if time is available for order processing)

Returns – All returns must be pre-approved by calling Global's Customer Service Department at 1-800-624-3974 for information and assistance. There may be a 15% restocking fee. Special order items, electronic documents, and age-dated materials are non-returnable.

The American Petroleum Institute provides additional resources and programs to industry which are based on API Standards. For more information, contact:

• Training/Workshops	Ph:	202-682-8564
	Fax:	202-962-4797
• Inspector Certification Programs	Ph:	202-682-8161
	Fax:	202-962-4739
• American Petroleum Institute Quality Registrar	Ph:	202-682-8574
	Fax:	202-682-8070
• Monogram Licensing Program	Ph:	202-962-4791
	Fax:	202-682-8070
• Engine Oil Licensing and Certification System	Ph:	202-682-8233
	Fax:	202-962-4739

To obtain a free copy of the API Publications, Programs, and Services Catalog, call 202-682-8375 or fax your request to 202-962-4776. Or see the online interactive version of the catalog on our web site at www.api.org/cat.

American
Petroleum
Institute

Helping You
Get The Job
Done Right.[SM]

10.1.99

Additional copies are available through Global Engineering Documents at (800) 854-7179 or (303) 397-7956

Information about API Publications, Programs and Services is available on the World Wide Web at: http://www.api.org

American Petroleum Institute

1220 L Street, Northwest
Washington, D.C. 20005-4070
202-682-8000

Product No. C57202