Inspection of Fired Boilers and Heaters

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1 Scope

This recommended practice (RP) covers the inspection practices for fired boilers, process heaters, and furnaces used in petroleum refineries and petrochemical plants. The practices described in this document are focused to improve equipment reliability and plant safety. The intent is to provide inspection practices that accurately capture appropriate data, both onstream and off-stream, to assess current and future performance of the equipment.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Standard 530, *Calculation of Heater-tube Thickness in Petroleum Refineries*

API Recommended Practice 538, *Industrial Fired Boilers for General Refinery and Petrochemical Service*

API Standard 560, *Fired Heaters for General Refinery Services*

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 572, *Inspection Practices for Pressure Vessels*

API Recommended Practice 578, *Guidelines for a Material Verification Program (MVP) for New and Existing Assets*

API Standard 579-1/ASME [1] FFS-1, *Fitness-For-Service*

API Recommended Practice 580, *Risk-Based Inspection*

API Recommended Practice 584, *Integrity Operating Windows*

API Recommended Practice 585, *Pressure Equipment Integrity Incident Investigation*

API Recommended Practice 936, *Refractory Installation Quality Control—Inspection and Testing Monolithic Refractory Linings and Materials*

API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*

API Recommended Practice 970, *Corrosion Control Documents*

API Recommended Practice 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*

AISC M015L [2], *Manual of Steel Construction, Load and Resistance Factor Design*

[1] American Society of Mechanical Engineers International, Two Park Avenue, New York, New York 10016-5990, www.asme.org.

[2] American Institute of Steel Construction, 130 East Randolph, Suite 2000, Chicago, Illinois, 60601, www.aisc.org.

AISC M016, *Manual of Steel Construction, Allowable Stress Design*

ASME B31.1, *Power Piping*

ASME *Boiler and Pressure Vessel Code, Section I: Rules for Construction of Power Boilers*

ASME *Boiler and Pressure Vessel Code, Section IX: Welding, Brazing, and Fusing Qualifications*

ASTM A297 [3], *Steel Castings, Iron-Chromium and Iron-Chromium-Nickel, Heat Resistant, for General Application*

ASTM A530, *Standard Specification for General Requirements for Specialized Carbon and Low Alloy Steel Pipe*

NACE SP0170 [4], *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During a Shutdown of Refinery Equipment*

NBBI NB 23 [5], *National Board Inspection Code*

3 Terms, Definitions, and Acronyms

For the purposes of this document, the following terms and definitions apply.

3.1 Terms and Definitions

3.1.1
air preheater
A heat transfer apparatus through which combustion air is passed and heated by a medium of higher temperature, (i.e. combustion products, steam, or other fluid).

3.1.2
air preheater (direct exchange type)
Air preheaters that exchange heat directly between flue gas and air.

3.1.3
air preheater (external heat source type)
Air preheaters that utilize low-temperature heat from an external source (e.g. low-pressure steam) to improve heater or boiler efficiency.

3.1.4
air preheater (indirect exchange type)
Air preheaters that use water or hot oil to cool the flue gas. The heated water or oil is used to preheat incoming combustion air.

3.1.5
anchor
A metallic or refractory device that holds the refractory or insulation in place.

[3] ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania, 19428-2959, www.astm.org.

[4] NACE International, 15835 Park Ten Place, Houston, Texas 77084, www.nace.org.

[5] The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, Ohio 43229, www.nationalboard.org.

3.1.6
applicable code
The code, code section, or other recognized and generally accepted engineering standard or practice to which the system or equipment was built or that is deemed most appropriate for the situation.

3.1.7
arch
A flat or sloped portion of the heater radiant section opposite the floor.

3.1.8
attemperator
An apparatus for reducing and controlling the temperature of a superheated steam.

NOTE This is generally accomplished by injecting condensate or other, pure water stream.

3.1.9
blind
guillotine blind
A single-blade device that is used in the air or flue gas duct to isolate equipment or heaters.

3.1.10
boiler
Fired equipment that generates steam.

3.1.11
breeching
The heater section where the flue gases are collected after the last convection coil for transmission to the stack or the outlet duct work.

3.1.12
bridgewall
The transition point between the radiant section and the convection section.

3.1.13
buckstay
Horizontal structural member external to the casing, with pinned end connections, that provides structural support yet allows thermal expansion.

3.1.14
casing
The metal plate used to enclose the fired heater.

3.1.15
castable
A combination of refractory grain and suitable bonding agent that, after the addition of a proper liquid, is installed into place to form a refractory shape or structure that becomes rigid because of a chemical action.

3.1.16
ceramic fiber
A fibrous refractory insulation composed primarily of silica and alumina (and sometimes zirconia) that can come in various forms like blanket, board, module, rigidized blanket, and vacuum-formed shapes.

3.1.17
chelate
An organic compound used in boiler water treatments that bonds with free metals in solution. Chelates help prevent metals from depositing upon tube surfaces.

3.1.18
condition monitoring location
CML
Designated areas on equipment where periodic inspections and thickness measurements are conducted. Historically, they were often referred to as "thickness monitoring locations" (TMLs).

3.1.19
convection section
The portion of the heater in which the heat is transferred to the tubes primarily by convection.

3.1.20
corbel
A projection from the refractory surface generally used to prevent flue gas bypassing the convection section tubes.

3.1.21
corrosion allowance
The additional metal thickness added to allow for metal loss during the design life of the component.

3.1.22
corrosion rate
The reduction in the material thickness due to the chemical attack from the process fluid, flue gas, or both expressed in inches per year or millimeters per year.

3.1.23
crossover
The interconnecting piping between any two heater coil sections.

3.1.24
damper
A device for introducing a variable resistance for regulating volumetric flow of gas or air.

3.1.25
design metal temperature
DMT
The tube metal or skin temperature used for design.

3.1.26
downcomer
Boiler tubes or pipes where the fluid flow is away from the steam drum.

3.1.27
duct
A conduit for air or flue gas flow.

3.1.28
economizer
A section of the boiler where the incoming feedwater temperature is raised by recovery of the heat from flue gases leaving the boiler.

3.1.29
erosion
The accelerated mechanical removal of surface material as a result of relative movement between or impact from solids, liquids, vapor, or any combination thereof.

3.1.30
examiner
A person who performs specific nondestructive examination (NDE) on equipment, but does not evaluate the results of those examinations unless specifically trained and authorized to do so by the owner or user.

NOTE The examiner may be required to hold certifications as necessary to satisfy the owner or user requirements. Examples of certifications are ASNT SNT-TC-1A and CP-189, CGSB 48.9712, or ISO 9712 (replaces EN 473).

3.1.31
extended surface
Refers to the heat transfer surface in the form of fins or studs attached to the heat absorbing surface.

3.1.32
fire tube boiler
A shell and tube heat exchanger in which steam is generated on the shell side by heat transferred from hot gas or fluid flowing through the tubes.

3.1.33
flue gas
The gaseous product of combustion including the excess air.

3.1.34
furnace
Fired equipment that provides heat to process streams to create a molecular change.

3.1.35
header box
The internally insulated structural compartment separated from the flue gas stream that is used to enclose a number of headers or manifolds where access is afforded by means of hinged doors or removable panels.

3.1.36
header or return bend
The common term for a 180° cast or wrought fitting that connects two or more tubes.

3.1.37
heat recovery steam generator
HRSG
A system in which steam is generated and may be superheated or water heated by the transfer of heat from gaseous products of combustion or other hot process fluids.

3.1.38
heater
Fired equipment that provides heat to process streams.

3.1.39
integrity operating windows
IOWs
Established limits for process variables that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time.

3.1.40
jurisdiction
A legally constituted government administration that may adopt rules relating to equipment.

3.1.41
manifold
A chamber for the collection and distribution of fluid to or from multiple parallel flow paths.

3.1.42
monolithic lining
A castable lining without joints formed of material that is rammed, cast or gunned, and sintered into place.

3.1.43
mortar
A refractory material preparation used for laying and bonding refractory bricks.

3.1.44
multi-component lining
A refractory system consisting of two or more layers of different refractory types (e.g. castable and ceramic fiber).

3.1.45
onstream
Equipment in operation containing process liquids or gases such that entry is not possible.

3.1.46
pass
A continuous flow circuit consisting of one or more tubes in series, each connected by return bends or other fittings.

3.1.47
pigtail
Small-diameter piping that connects steam-methane or naphtha reformer tubes to the inlet and outlet headers to provide thermal expansion and flexibility to the connection.

3.1.48
pilot
A smaller burner that provides ignition energy to light the main burner.

3.1.49
plenum
A chamber surrounding the burners that is used to distribute air to the burners or reduce combustion noise.

3.1.50
plug header
A cast return bend provided with one or more openings for the purpose of inspection, mechanical tube cleaning, or draining.

3.1.51
radiant section
Portion of the heater in which heat is transferred to the tubes primarily by radiation.

3.1.52
repair
Work necessary to restore equipment to a condition of safe operation at the design conditions.

3.1.53
riser
Boiler tubes where the fluid flow is toward the steam drum.

3.1.54
setting
The heater casing, brickwork, refractory, and insulation, including the tiebacks or anchors.

3.1.55
shock tubes
shield tubes
The unfinned tubes at the top of the radiant section of a heater (usually 2 or 3 rows) at the entrance to the convection section that absorb the radiant heat and protect the extended surface on the convection tubes.

3.1.56
slag
Nonmetallic solid material and oxides entrapped in weld metal or between weld metal and base metal.

3.1.57
soot blower
A mechanical device for discharging steam or air to clean heat-absorbing surfaces.

3.1.58
spoilers
strakes
The metal stack attachments that prevent wind-induced vibration.

3.1.59
stack
A vertical conduit used to discharge flue gas to the atmosphere.

3.1.60
terminal
A flanged or welded projection from the coil providing for inlet or outlet of fluids.

3.1.61
tieback
See **anchor**.

3.1.62
trepan
Remove a disk or cylindrical core from metal for testing.

3.1.63
tube guide
A component that restricts the movement of vertical tubes while allowing the tube to expand axially.

3.1.64
tube support
Any device used to support tubes (i.e. hangers or tubesheets).

3.1.65
water tube boiler
A multiple tube circuit heat exchanger within a gas-containing casing in which steam is generated inside the tubes by heat transferred from radiant heat on the tubes and hot gas flowing over the tubes.

3.1.66
water tube pipe coil heat recovery steam generator (HRSG) in a pressure vessel
A tube or pipe coil circuit within a pressure vessel in which steam is generated inside the tubes by heat transferred from a high-temperature fluid or fluidized solids surrounding the tube circuits.

3.1.67
waterwall
membrane wall
A wall within a boiler enclosure that is composed of numerous closely set water-tubes.

NOTE The tubes comprising the waterwall may be either bare or covered by a mineral cement.

3.1.68
windbox
See **plenum**.

3.2 Acronyms

CCD	corrosion control document
CML	condition monitoring location
EMAT	electromagnetic acoustic transducer
FCCU	fluid catalytic cracking unit
HRSG	heat recovery steam generator
ID	inside diameter
IOWs	integrity operating windows
MT	magnetic particle examination method
NDE	nondestructive examination
OD	outside diameter
PT	liquid penetrant examination method
PTA SCC	polythionic acid stress corrosion cracking
SCC	stress corrosion cracking
TOFD	time-of-flight diffraction ultrasonic examination technique
UT	ultrasonic examination method

4 Common Heater and Boiler Designs

4.1 Types of Heaters

4.1.1 General

There are a variety of designs for tubular fired heaters. Some of the more commonly used designs are the box, cylindrical, and cabin designs. Typical heater designs are represented in Figure 1. The tubes in the radiant section of the heater are called radiant tubes. Heat pickup in these tubes is mainly through radiation from the burner flame, radiating flue gas components, and the incandescent refractory. Shock or shield tubes are located at the entrance to the convection section. Because these tubes absorb both radiant and convective heat, they usually receive the highest heat flux. These bare rows protect or shield the remaining convection-section tubes from direct radiation, excessive heat flux, and excessive fin tip temperatures. More detailed information can be found in API 560.

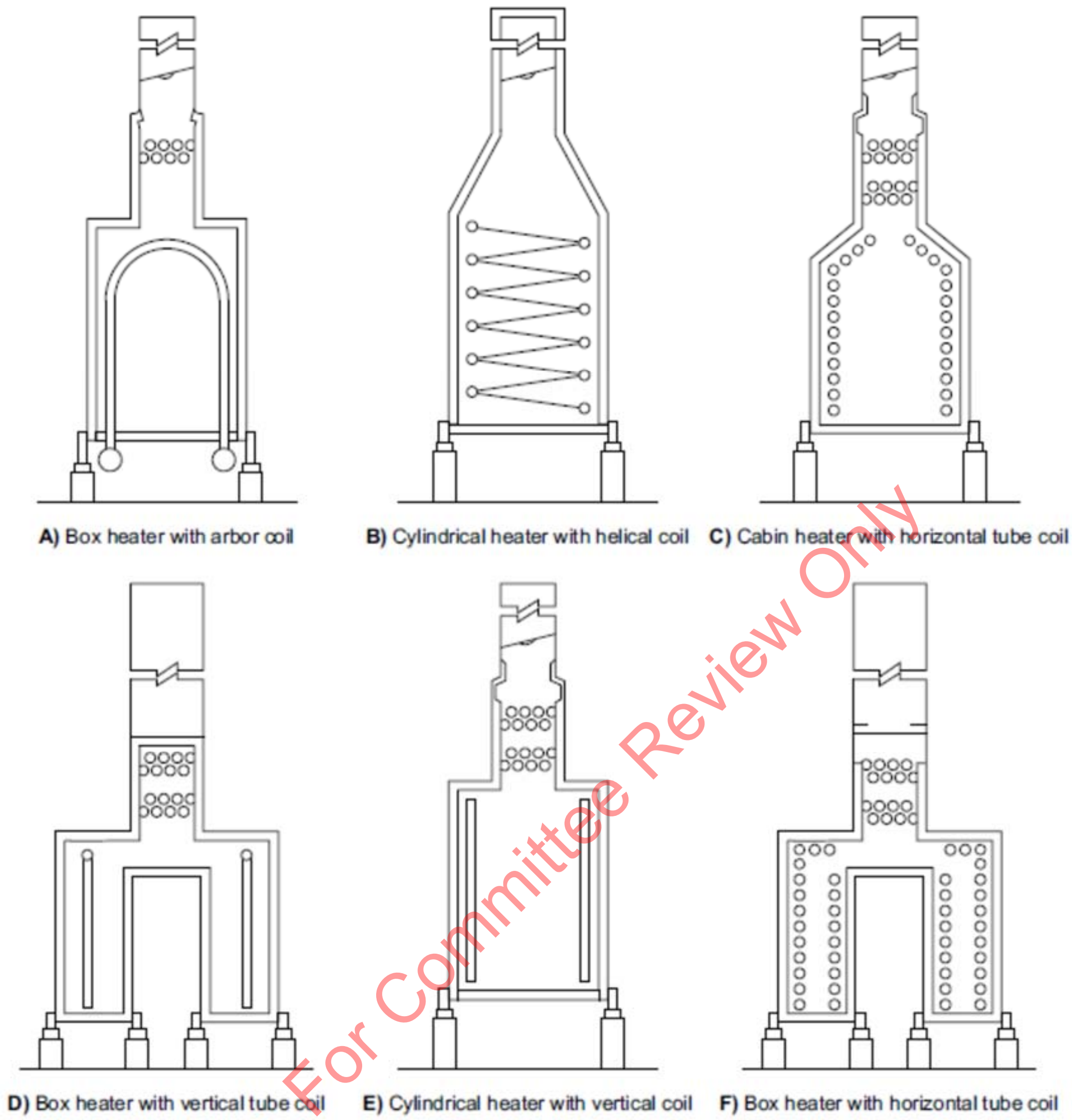


Figure 1—Typical Heater Types

Beyond the shock bank is the convection section where heat pickup comes from the combustion gases primarily through convection. Convection tubes are commonly finned or studded to increase the surface area for heat transfer. Sometimes the lowest rows of these extended surface tubes can absorb more heat per unit bare tube surface area than the radiant tubes.

4.1.2 Box-type Heaters

A box-type heater is a heater whose structural configuration forms a box. There are many different designs for box-type heaters. These designs involve a variety of tube coil configurations, including horizontal, vertical, and arbor configurations. Figure 2 shows a typical box-type heater with a horizontal coil and identifies the main heater components. This type of heater can have locations or zones of different heat densities. The size and arrangement of the tubes in a box-type heater are determined by the type of operation the heater is meant to perform (e.g. crude oil distillation or cracking, the amount of heating surface required, and the flow rate through the tubes). Box-type heaters are usually updraft with gas-fired or oil-fired burners located in the end, side wall, or floor. Alternatively, they may be downdraft with burners in the roof. After the process convection section tubes, auxiliary tubes are often added to preheat combustion air or to generate or superheat steam. In Figure 2, the convection section is centered in the upper portion of the box-type heater and the radiant tubes are on the two side walls.

4.1.3 Heaters with Vertical Coils

A vertical coil heater may be positioned in a cylindrical or a rectangular (box-type) heater. Most vertical coil heaters are bottom fired with the stack mounted directly on top of the heater. Down-fired vertical heaters may also be found in some specialized services (e.g. steam-methane reformers).

4.1.4 Heaters with Helical Coils

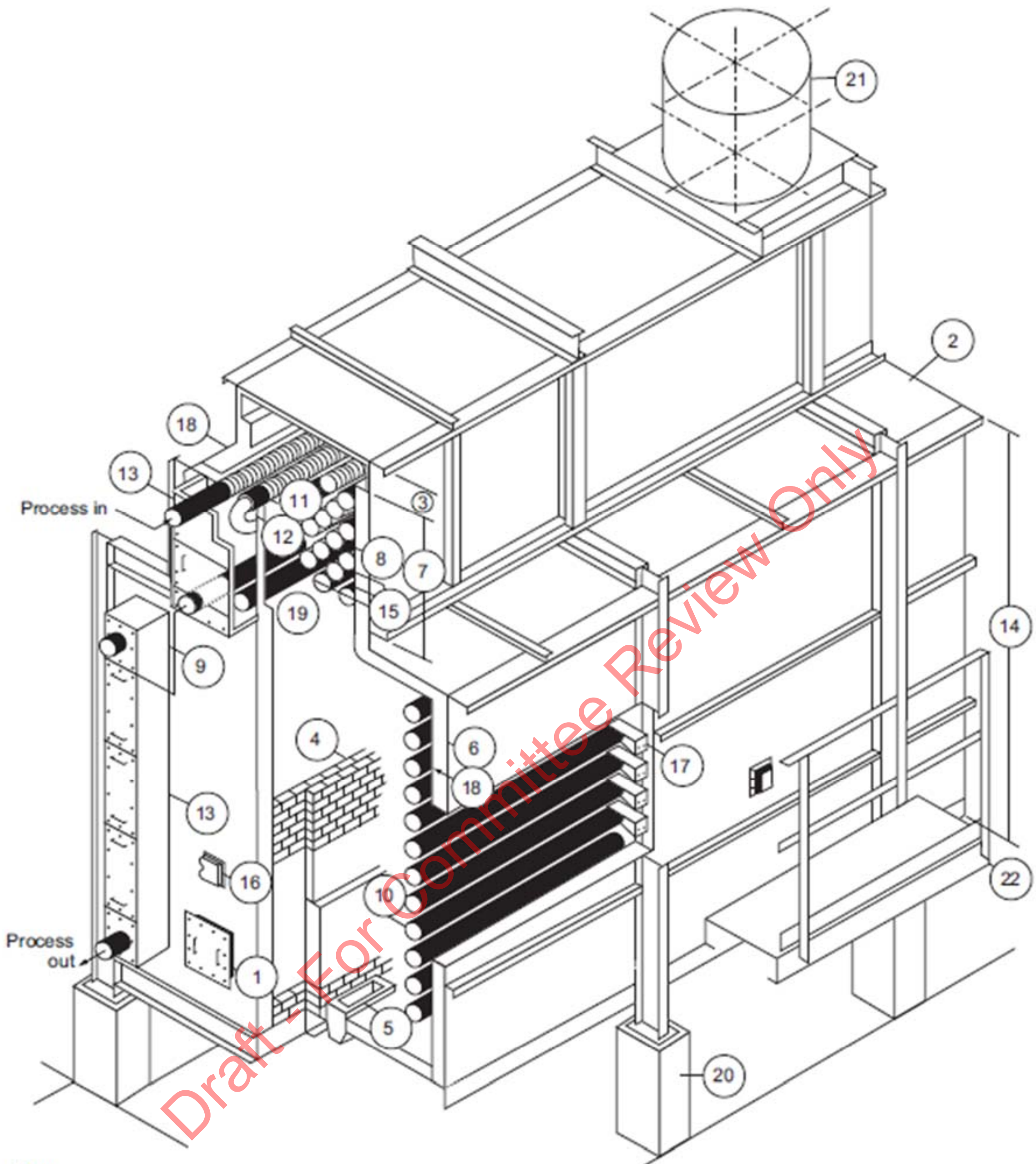
Helical coil heaters are cylindrical with the surface of the radiant section in the form of a coil that spirals up the wall of the heater. If a convection section is included, the convection surface may be in the form of a flat spiral or a bank of horizontal tubes.

4.1.5 Heaters with Arbor Coils

Heaters with arbor or wicket coils are used extensively in catalytic reforming units for preheat and reheat service and as heaters for process air or gases. These heaters have a radiant section that consists of inlet and outlet headers connected with inverted or upright L or U tubes in parallel arrangement. The convection sections consist of conventional horizontal tube coils.

4.1.6 Furnaces Used in Steam-Methane Reforming

The vaporized feed in these heaters contain a mixture of light hydrocarbons, usually flowing through multiple rows of parallel vertical tubes that operate from 1500 °F (816 °C) to 1800 °F (982 °C). These tubes contain catalyst, and the reforming reaction takes place in the tubes. Figure 3 shows one type of a steam-methane reforming furnace. These furnaces can be either down fired, side fired at several levels, or bottom fired to achieve even heat distribution across the entire length of the radiant tubes. The tubes may be made from wrought high-strength materials, including Alloy 800 and Alloy 800H, or of cast materials, including HK40, HP, and their proprietary modifications. Typically, small-diameter pipes, called pigtails, connect the tubes to the inlet and outlet headers. Most outlet pigtails are of Alloy 800H or similar wrought materials since they operate at 1400 °F (760 °C) and higher. Inlet pigtails operate at lower temperatures and can be a low Cr-Mo or austenitic stainless steel material. Heater outlet headers have various designs. Some headers and outlet lines are made from carbon steel, C-Mo steel, or low-alloy (Cr-Mo) steel and have refractory lining inside. Those that are internally uninsulated have been made from cast materials conforming to ASTM A297, Grade HT or HK, or of wrought materials, including Alloy 800H.



Key

1	access door	7	convection section	13	header box	19	tube sheet
2	arch	8	corbel	14	radiant section	20	pier
3	breeching	9	crossover	15	shield section	21	stack/duct
4	bridgewall	10	tubes	16	observation door	22	platform
5	burner	11	extended surface	17	tube support		
6	casing	12	return bend	18	refractory lighting		

Figure 2—Box-type Heater with Horizontal Tube Coil Showing Main Components

4.1.7 Pyrolysis Furnaces

Pyrolysis furnaces are used to crack various hydrocarbon feedstocks in the production of ethylene. They operate at high temperatures similar to that in steam-methane reforming furnaces. The reaction in the tubes is usually carburizing and requires that the surfaces be smooth from boring or honing and that the material be more resistant to carburization. The material used in pyrolysis furnaces is often a modification of a high-strength material that is adequate in reforming furnaces. Furnace coils typically fail due to carburization, which makes the tubes brittle and difficult to repair by welding. Failure may also be due to creep or damage sustained during steam/air decoking (local internal overheating). U-bends and Y's may experience erosion.

4.1.8 Tube Metallurgy

The selection of materials for heater tubes is based on the design temperature and pressure of the tubes and the expected damage mechanisms associated with the process. The economics associated with the materials should not be overlooked. Suitable materials are evaluated looking at the total installed cost, including availability of the material, fabrication, and heat treatment requirements.

Carbon steel, Cr-Mo steels, and austenitic stainless steels are common tube metallurgies. Carbon steel is limited to the low-temperature applications. Many companies choose to limit carbon steel to applications below 800 °F (427 °C) to limit damage due to spheroidization, graphitization, excessive oxidation, and creep. The addition of chromium and molybdenum improve high-temperature strength, resistance to spheroidization, and resistance to oxidation and some corrosion mechanisms. Austenitic stainless steels are often used for tube applications where metal temperatures exceed about 1300 °F (704 °C) or the corrosivity of the process requires its use.

Figure 3—One Type of Steam-Methane Reforming Furnace

The common tube materials and corresponding ASTM tube or pipe specification are listed in Table 1. The design metal temperature (DMT) that represents the upper limit of the reliability of the rupture strength can be found in API 530. Tube wall calculations per API 530 should be completed to determine tube life at these temperatures. Other factors (i.e. hydrogen partial pressure and resistance to oxidation) often result in lower temperature limits. See API 941.

Table 1—Common Heater Tube Metallurgies

Material	Seamless Tube Specification	Seamless Pipe Specification
Carbon Steel	A179/A192	A53/A106
$1^1/_4$ Cr-$^1/_2$ Mo	A213 T11	A335 P11
$2^1/_4$ Cr-1 Mo	A213 T22	A335 P22
3 Cr-1 Mo	A213 T21	A213 P21
5 Cr-$^1/_2$ Mo	A213 T5	A335 P5
5 Cr-$^1/_2$ Mo-Si	A213 T5b	A335 P5b
9 Cr-1 Mo	A213 T9	A335 P9
9 Cr-1 Mo-V	A213 T91	A335 P91
Type 304H	A213 TP304H	A312 TP304H
Type 316	A213 TP316	A312 TP316
Type 321	A213 TP321	A312 TP321
Type 347	A213 TP347	A312 TP347
Alloy 800H/800HT	B407 Gr 800H/800HT	B407 Gr 800H/800HT
HK	A608 Gr HK40 (see Note)	—
HP	—	A297 HP

NOTE Centrifugally cast pipe.

4.2 Types of Boilers

4.2.1 General

Fired boilers are those in which fuel is burned in a combustion chamber. The heat of combustion is absorbed by the boiler to heat the water and convert it to steam. Fired boilers that are most prevalent in industry are either fire tube boilers or water tube boilers. More detailed information may be found in API 538.

4.2.2 Fire Tube Boiler

A fire tube boiler consists of a drum with a tubesheet on each end in which the fire tubes are fastened. Water is contained within the drum surrounding the fire tubes. Fuel is burned in a combustion chamber associated with the boiler and arranged in such a manner that the heat and products of combustion (flue gases) pass through the inside of the fire tubes to heat the water surrounding them. The combustion chamber may be a refractory-lined box located against one end of the drum or a steel chamber located within the drum and surrounded on all but one side by the water in the drum. In the first instance, the boiler may be described as externally fired; in the second, as internally fired.

4.2.3 Water Tube Boiler

A water tube boiler usually has two drums: a steam drum and a water drum (or mud drum). The upper drum supplies water to the lower drum. The upper drum in the steam chest section collects the saturated steam and dries it by means of cyclonic separators and chevrons, discharging the dried steam to a header or superheater section of the boiler. The water drum supplies water to the steam generating tubes and to water distribution headers serving the boiler water walls. The fuel is burned in a combustion chamber arranged so that radiant heat and convection heat is transferred to the outside of the water tubes to heat the water within.

Water tube boilers may be either straight tube boilers or bent tube boilers. The tubes of most straight tube boilers are connected into headers, which in turn are connected to the boiler drums. Water tube boilers are usually used when large steam capacities are needed. They are also used for high pressures and temperatures. They have been built in sizes up to 5,000,000 lb (2,268,000 kg) of steam per hour at pressures up to 5000 psi gauge (34,474 kPa) and temperatures of up to approximately 1200 °F (649 °C).

Bent tube boilers are made in a variety of arrangements. They are similar to straight tube boilers, but they are almost always multi-drum, and the tubes are connected directly into the boiler drums. The tubes are bent to allow them to enter the drums radially, to facilitate installation, to allow for expansion and contraction, and to allow for flexibility in design. Figure 4 and Figure 5 illustrate typical bent tube boilers. Bent tube boilers may be either balanced draft boilers or positive pressure boilers.

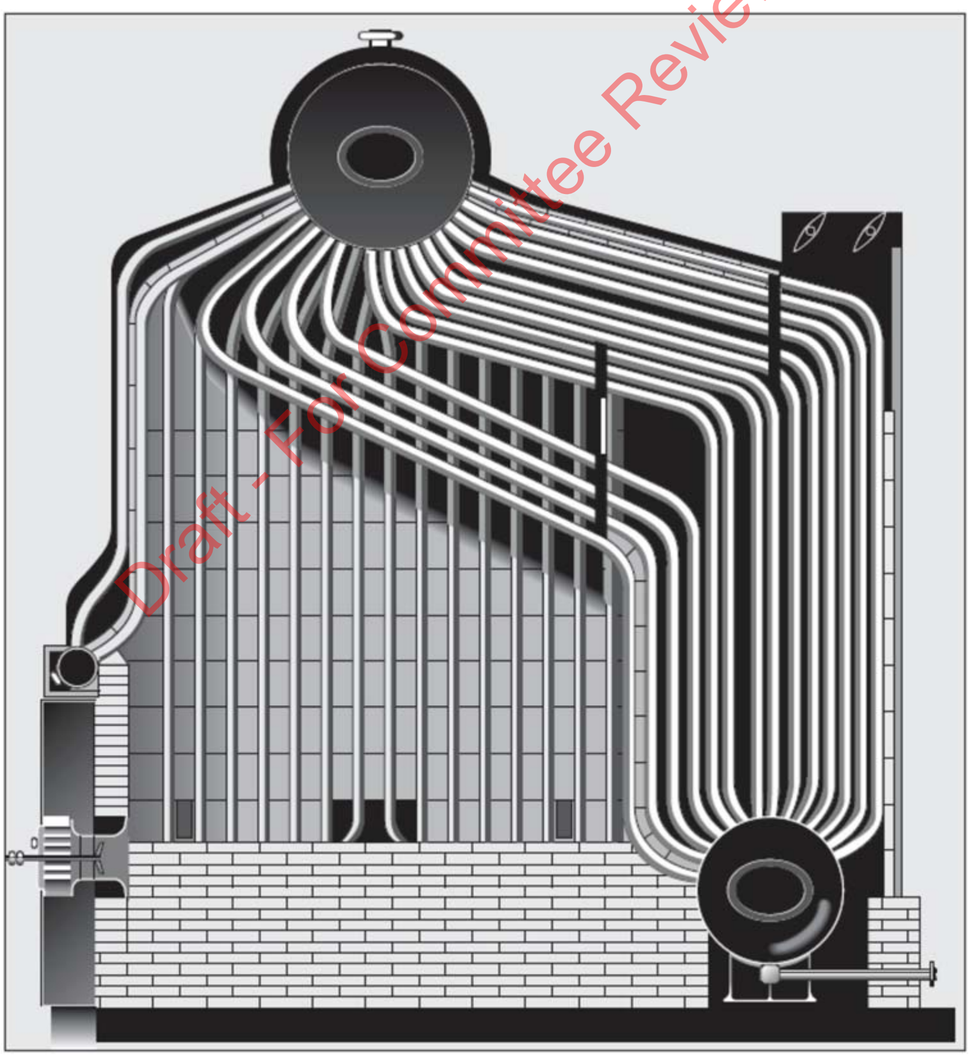


Figure 4—Typical Vertical Oil or Gas-fired Water Tube Boiler

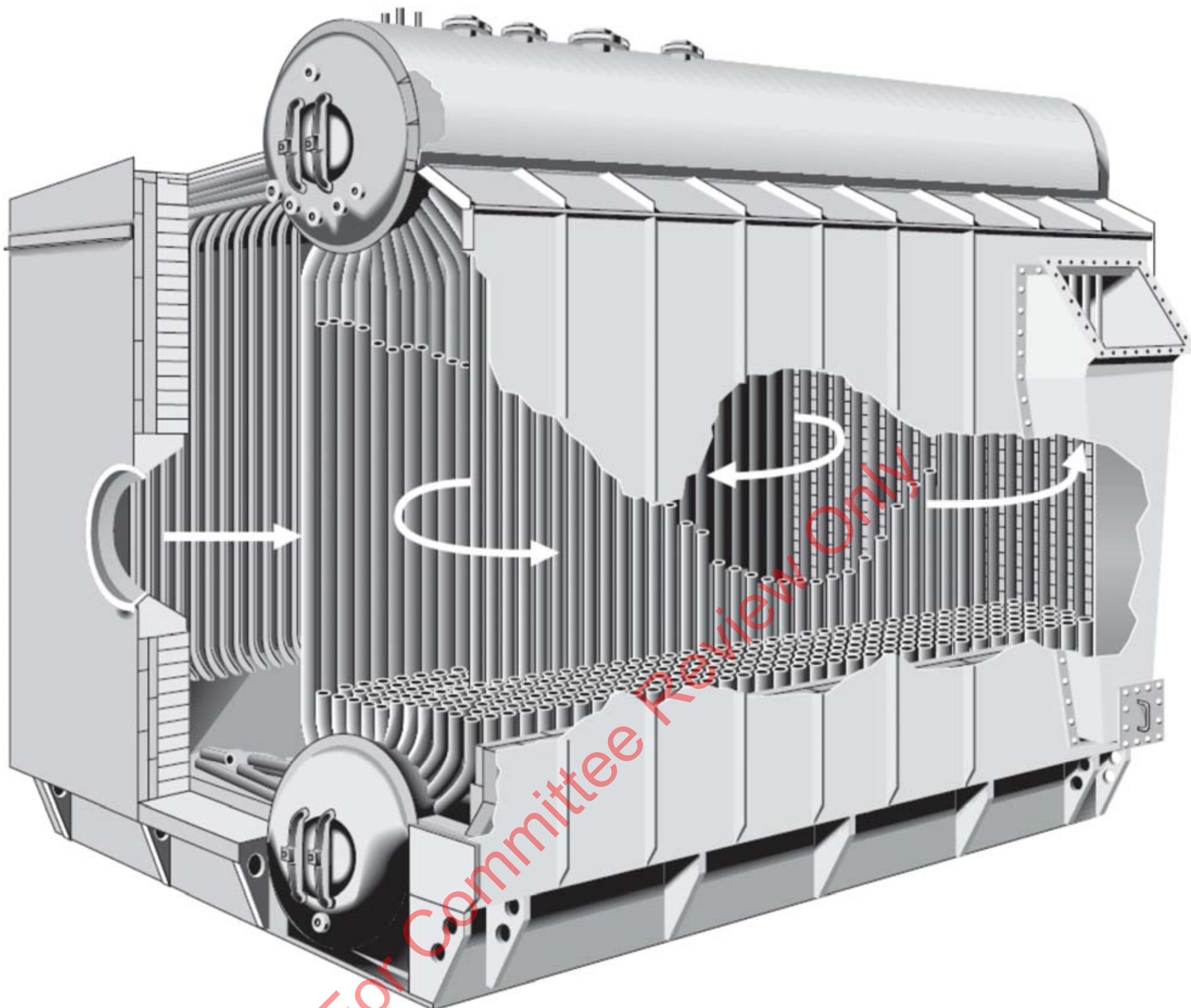


Figure 5—Another Variation of a Two-drum Bent Tube Boiler

Some boilers are fired using hot process waste gas streams, including fluid catalytic cracking unit (FCCU) regenerator flue gas as fuel to recover both sensible heat and fuel value. Carbon monoxide boilers can still be found in some refineries. Figure 6 illustrates one type of carbon monoxide boiler. Some refineries also use the combined cycle system that utilizes the hot exhaust from gas turbines as combustion air in the boilers.

4.2.4 Waste Heat Boiler (HRSGs)

Waste heat boilers can be either a fire tube or water tube design and can have nearly identical configurations to their "fired" counterparts. However, waste heat boilers generate steam by transferring heat from high-temperature gaseous products of combustion or products of chemical reaction or other hot process fluids. These boilers can often be found on units with high-temperature streams and are used to recover the heat and cool the stream. They are described here simply because the types of deterioration and inspection are similar to the fired boilers.

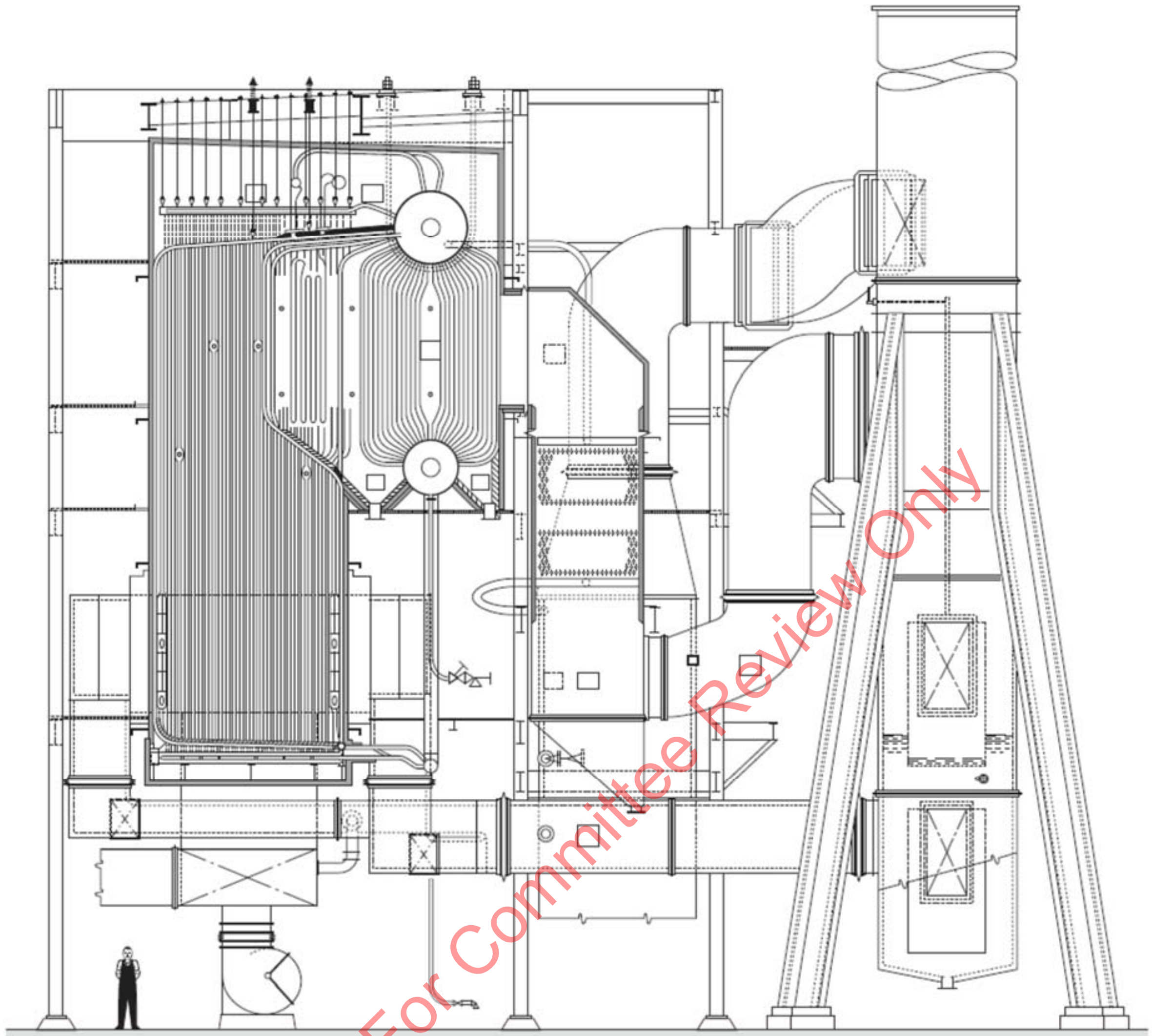


Figure 6—Typical Carbon Monoxide Boiler

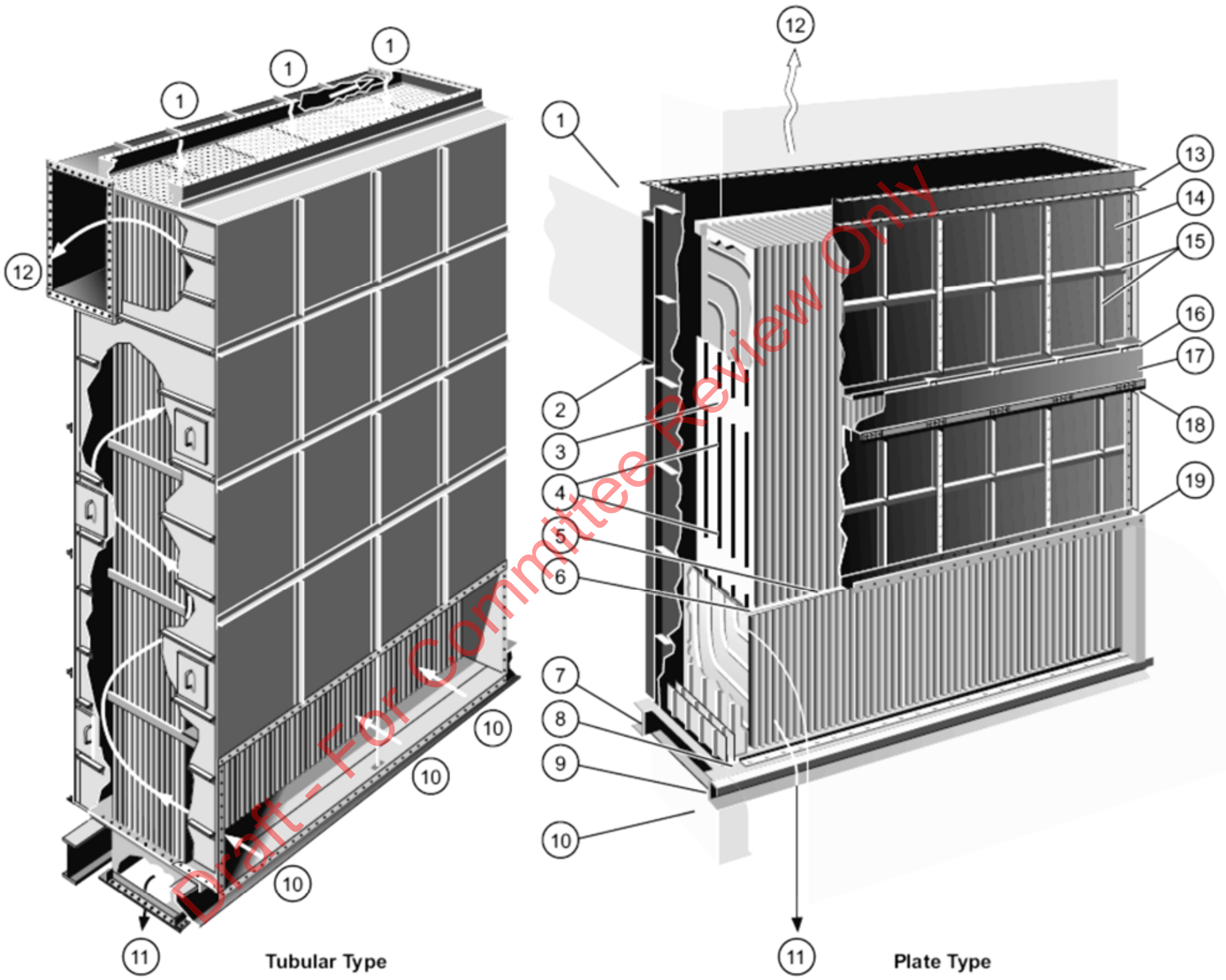
4.2.5 Economizers and Air Preheaters

Economizers and air preheaters are heat exchangers used by some boilers as auxiliaries to recover more heat from the flue gases, heat that otherwise may be lost up the stack. Air preheaters can be classified into the following types: indirect exchange, external heat source, or direct exchange. An economizer normally consists of a bank of tubes located in the path of the flue gases downstream of the steam generating surfaces in the boiler. The low-temperature boiler feedwater is pumped through the tubes in this tube bank and is heated before passing into the boiler.

Air preheaters raise the temperature of air before it enters the combustion chamber. The two basic types of air preheaters are recuperative and regenerative. The recuperative type is similar in principle to a conventional heat exchanger with the hot flue gases on one side of the heat transfer surface and the cool air on the other side. The most common recuperative type is the tubular air preheater that consists of a tube bank with the tubes rolled into a stationary tubesheet at the top of the unit and a floating tubesheet at the bottom. Flue gas flows on the outside of the tubes and air flows on the inside of the tubes. The use of a floating tubesheet accommodates the difference in expansion caused by temperature differences between the tubes and the casing. In this type, the hot gases flow through the tubes and the air passes around the tubes. Another recuperative type is made up of plates arranged with passages for the flue gas on one side of the plates and passages for air on the other side. Figure 7 illustrates two types of recuperative preheaters.

The most common regenerative type is called a rotating heat transfer wheel and is made up of many closely spaced sheets of metal. This metal absorbs heat as it rotates through the flue gas compartment of its housing and gives up heat as it rotates through the air compartment (see Figure 8). The heat transfer wheel is rotated at approximately 3 rpm by a driving motor through a reduction gear. Diaphragms and seals divide the unit lengthwise to separate the hot flue gases from the air that flows through the preheater in opposite directions.

The preheating of combustion air has high economic value. In the conventional air preheater, cold air from the forced draft fan flows through the air preheater and extracts heat from the flue gases as they flow to the stack. Economizers or air preheaters are used when fuel savings justify them.



Key

1 air inlet	7 gas inlet channel	14 heater casing
2 air inlet channel for duct connection	8 stop bar	15 stiffening angles
3 element	9 stiffening bar	16 clamps
4 space bars	10 gas inlet	17 cleanout door
5 sealing strip	11 air outlet	18 hinges
6 element lugs	12 gas outlet	19 air outlet channel for duct connection
	13 gas outlet channel	

Figure 7—Tubular and Plate Air Preheaters

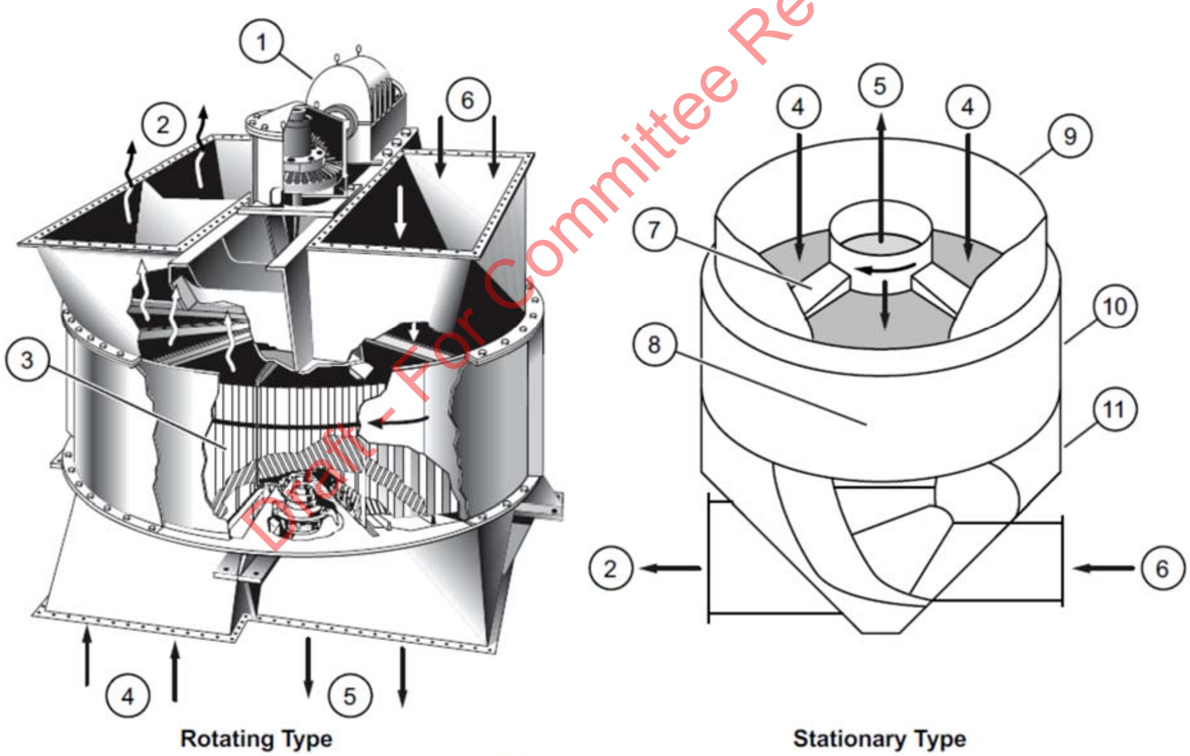
4.2.6 Superheaters

When steam is used in processing operations, superheated steam may be required to obtain the desired process temperature. Most of the large-capacity, high-pressure steam generators, especially those used for power production, are equipped with superheaters. Superheated steam is also necessary for the most efficient production of power, especially when used in high-pressure, high-speed steam turbine drives.

Superheaters consist of a bank of tubes located within the boiler setting through which saturated steam flows from the steam drum and is superheated by the same flue gas that generates steam in the boiler. They may be of the radiant design, convection design, or a combination of both, depending on the manner in which heat is transferred from the heater gases to steam.

Superheaters may have tubes in hairpin loops connected in parallel to inlet and outlet headers. They may also be of the continuous tube design in which each element has tube loops in series between inlet and outlet headers. In either case, they may be designed for drainage of condensate or may be in non-drainable pendent arrangements.

Non-drainable or pendant arrangements are susceptible to tube failure due to overheating on start-up. Water collected in the pendent is slowly vaporized to assure a flow path for the steam. If the boiler is heated too rapidly, some pendants can still contain liquid; therefore, steam does not flow and the tube will overheat and fail. Special start-up instructions should be taken into consideration with this type of arrangement. Both straight and pendent arrangement superheaters are susceptible to failure due to steam impurities.



Key

1 motor drive for rotating heat absorbing material wheel
2 cooled flue gas outlet
3 regenerative heat absorbing material
4 hot flue gas
5 heated air
6 cool air inlet
7 top rotating air ducts
8 bottom rotating air ducts
9 hood
10 stationary section (stator)
11 flue gas duct

Figure 8—Types of Regenerative Air Preheaters

4.2.7 Tube Metallurgy

Boiler tubes are generally carbon steel, $1\frac{1}{4}$ Cr-$\frac{1}{2}$ Mo and $2\frac{1}{4}$ Cr-1 Mo steel. The material selection depends on the temperature and pressure of the application. Typically, the governing criterion is the oxidation rate of the material being evaluated. Carbon steel is often used in the water-filled and steam-generating tubes where the metal temperature is below 800 °F (427 °C). Tubes used in the steam superheat section should be higher alloys for improved strength and resistance to external oxidation. Again, the selection depends on the metal temperature and operating stress of the tube.

4.2.8 Flue Gas Stacks

Flue gas stacks vent the flue gas produced as part of the combustion process of the burners to the atmosphere. They are typically located directly above the heater, furnace, or boiler or located nearby and connected to them by ductwork. Flue gas stacks are generally constructed of carbon steel and internally lined with refractory. The stack may have an organic coating to protect the steel from internal corrosion beneath the refractory lining. Stacks may be either self-supporting or guyed, and their outlets should be above the heights of nearby platforms.

5 Heater, Furnace, and Boiler Mechanical Reliability

5.1 Integrity Reliability Programs

5.1.1 General

Fired heater, furnace, and boiler mechanical reliability programs have evolved from inspection during unit maintenance outages to risk-based integrity management programs encompassing onstream process tube life monitoring and increasingly detailed and varied inspections during maintenance opportunities. In the simplest programs, reliability focuses on preventing failures of the pressure boundary. The strategy is to prevent leaks and ruptures of the tubes and, in the case of boilers, the drums too. Further refinements to these programs consider the establishment and implementation of integrity operating windows (IOWs) for the key process parameters on heaters, furnaces, boilers, and associated hardware. These parameters provide limits under which heaters, furnaces, and boilers should be operated to ensure that risk is kept as low as reasonably practicable or acceptable to the owner-user, whichever is more stringent, while maximizing reliability, availability, throughput, and fuel efficiency.

5.1.2 IOWs Program

IOWs encompass the safe operating parameters for a process unit or specific equipment. API 584 provides information and guidelines for the identification of equipment that requires IOWs and how to create and implement IOWs for each vulnerable unit and piece of equipment in a facility. The purpose of such a program is to set limits for equipment operation in an effort to prevent excessive equipment degradation and unanticipated failures.

IOWs are important for a facility; API 584 does not provide a specific list of IOW limits or the types of equipment that might require IOW (though heaters and furnaces normally require IOW). API 584 provides the readers with the information needed to identify what equipment might require an IOW and how best to create and implement IOWs.

API 584 includes information such as definitions of IOWs, the different types of IOWs, and terminology related to them. It also puts forth guidelines on creating, documenting, and implementing IOWs and presents the data and information that is most useful in their creation. It addresses how to monitor and measure variables within existing IOWs and how to communicate when a limit has been breached. Additionally, it covers reviewing and updating existing IOW programs and how to integrate these programs with other safety practices.

Informative Annexes A, B, and C contain examples of records and checklists that are useful in an IOW program. A table of example IOW parameters for heaters is shown in informative Annex D.

5.1.3 Tube Failures

Tube failures result from progressive deterioration from a variety of mechanisms. Therefore, one needs to understand the active and potential damage mechanisms in a particular heater, furnace, or boiler to develop an appropriate inspection and monitoring strategy in order to prevent them from causing a failure. For example, in elevated temperature services like boiler and heater tubes, creep and stress rupture are potential damage mechanisms. The tube operating variables that affect tube creep life and stress rupture life include: the base metal creep and stress rupture properties, tube metal temperatures, applied stress from internal operating pressure and from mechanical loading (i.e. from supports or lack of supports), and time operating at each unique combination of stress and metal temperature. Each damage mechanism should be understood; they are discussed more fully in Section 6. See API 571 for further information. Investigation of tube failures should follow the guidelines of API 585.

5.1.4 Tube Reliability

Tube reliability not only requires an understanding of the mechanisms by which the tubes can fail but also requires data on how the previous operating history has impacted tube life, predictions of deterioration rate, how the future operations can impact tube life, and monitoring of operations and deterioration to ensure the analyses and predictions are accurate and appropriate.

Historically, inspection data gathered during outages assessed the immediate condition of the tubes with varying degrees of accuracy or success. Typically, these inspections include a visual examination for bulges in tubes or changes in diameter and thickness measurements of accessible tubes. Areas where a measurable increase in tube diameter has occurred can be identified using fixed-diameter feeler gauges along the length of the tube outside diameter (OD). These areas may warrant a more detailed assessment of creep damage. Inspections can also include detailed strapping and gauging for bulges, internal ultrasonic inspection pigs to gather detailed tube wall thickness and diameter maps (including the difficulty to inspect convective tubes), onstream infrared tube temperature measurements, and destructive testing to identify specific types of deterioration or to determine actual remaining creep life (see Section 9).

Aspects of a typical tube reliability program for individual heaters, furnaces, and boilers can include:

a) list of active and potential damage mechanisms;

b) inspection techniques to identify whether the potential damage mechanisms are active;

c) review of historical heater, furnace, and boiler operations and records of maintenance repairs to identify active or previously active damage mechanisms;

d) assessment of the impact of previous operations and repairs on tube remaining life;

e) defined tasks or procedures, if practical, to minimize the likelihood of potential damaging mechanisms;

f) rate of deterioration of tubes for active damage mechanisms;

g) method or technique to assess the impact of process changes or heater, furnace, and boiler operations on rate of deterioration;

h) assessment of remaining tube life for each mechanism considering previous operations and repairs, current condition, and the rate of deterioration;

i) defined IOWs in which the tube life and rate of deterioration projections remain valid;

j) onstream monitoring tasks to ensure operating conditions remain within the IOW and procedure to address or assess the impact on tube life of out-of-bounds operations; and

k) inspection plan and monitoring and assessment of other hardware and equipment that impact the deterioration of the tubes such as burners, hangers and supports, and thermocouples.

5.1.5 Operator Rounds

An integral component of a reliability program is routine checks on the operation of the heater, furnace, or boiler. Unit personnel should routinely check and observe equipment operation and condition. These activities are generally performed by operations personnel during these periodic operator rounds and typically include:

a) routine equipment surveillance;

b) assuring air registers are functional and adjusted;

c) assuring damper is properly positioned;

d) checking for proper draft and excess oxygen;

e) checking burner flames and flame patterns;

f) checking for hot spots, bulges on the tubes;

g) checking for tubes support damage; and

h) checking for refractory damage.

Typically, the individual tasks are itemized in unit operations manuals, on itemized checklists, or are programmed into portable “intelligent” devices. The significant results of these monitoring activities are recorded in unit log books. Two examples of operator rounds checklists are shown in Annex A.

5.2 Potential Consequences of a Tube Rupture

A leak or failure in a heater, furnace, or boiler can be a significant incident depending on the temperature, pressure, process fluid, equipment location, response of operators, and other controls. The process fluid is often flammable and can result in a fire when a leak or failure occurs. The potential for personnel injury and environmental impact also exists. Fired heaters, furnaces, and boilers, especially high-pressure equipment, have the potential to cause damage and serious injury due to the significant stored energy. An inspection and reliability program for heaters, furnaces, and boilers is an important component to maintaining the integrity and operability of the equipment.

5.3 Purpose of Inspection

The purpose of inspection in an integrity and reliability program is to gather data and information on the tubes and other equipment components so that it can be analyzed and a reasonable assessment made of the equipment’s mechanical integrity for continued service. Repairs can be made if analyses of the data indicate that service life is shorter than the planned run length. In addition, repairs or replacements can be predicted for the future by analyses of appropriate data accumulated at regular internal equipment inspections and during routine onstream monitoring of actual service conditions. Planned repairs and replacements allow all necessary drawings, lists of materials, and work schedules to be prepared in the most effective manner. Necessary materials can be estimated and replacement parts either wholly or partly fabricated at the most convenient times prior to shutdown. If work schedules are properly prepared and reviewed, each craft knows exactly what has to be done and the sequence so that overall quality is improved.

5.4 Inspection of Fired Boilers

The requirements governing inspection of boilers can differ widely from one location to another since they are often regulated by jurisdictions. Under some jurisdictions, inspections are made by state, municipal, or insurance company inspectors. Other jurisdictions may allow inspections by qualified owner-user inspectors. In either case, the inspector is usually commissioned by the regulatory authority and has to submit reports of the inspection to the official responsible for enforcement of the boiler law. If the boiler is insured, inspection by the insurance company inspector also serves to satisfy his/her company that the boiler is in an insurable condition.

Normally, governmental and insurance company inspectors concern themselves only with the pressure parts of the boiler, the safety valves, level indicators, pressure gauges, and feedwater and steam piping between the boiler and the main stop valves, superheaters, and economizers. The plant inspector should also be concerned with related nonpressure parts, including the firebox, burners, flue gas ducts, stacks, and steam-drum internals since these can affect equipment reliability and performance. When inspection by an outside agency is necessary, joint inspections by the outside inspector and the plant inspector can reduce the length of boiler outages and result in shared learning. The outside inspector is primarily interested in seeing jurisdictional requirements are met. The plant inspector should be interested not only in jurisdictional requirements but also in conditions that affect reliability and efficiency. The outside inspector has an opportunity to examine many boilers that operate under widely varying conditions and often can offer valuable advice on the operation of boilers.

5.5 Inspection of Fired Heaters and Furnaces

Fired heaters and furnaces are frequently subjected to unique degradation mechanisms due to the combination of heat, internal pressure, and the various chemical characteristics of process fluids. Alloys designed to counteract specific corrosion mechanisms often exhibit other sensitivities requiring specialized inspection techniques and operating controls. Inspectors should prepare by carefully reviewing the fired heater or furnace history briefs and become familiar with the type of equipment being inspected, corrosion control measures, IOWs, past problems, and repair history.

Critical reliability and process variables associated with IOWs are monitored for abnormal trends and exceedances. These data should be monitored and tracked as an integral component of a fired equipment's history. These data in conjunction with online visual and infrared monitoring and mapping is valuable in the determination of excessive heat flux, sag/strain, localized or accelerated corrosion, coking, creep, and metal dusting associated with the various metallurgies and chemistries presented by fired process heaters. This information is essential in creating risk-based inspection plans for fired heater and furnace integrity.

Annex A contains sample checklists for inspecting heaters and boilers.

5.6 Inspector Qualifications

Inspection of heaters, furnaces, and boilers shall be performed by personnel trained and experienced with operation, damage mechanisms, and the appropriate inspection techniques to identify or monitor them. For refractory installation quality control/quality assurance (QA/QC), sites should consider the need to have API 936 certified individuals conduct the necessary refractory installation QA/QC tasks. The inspector shall have experience with or have access to an individual(s) with understanding of burners, tubes, tube hangers and supports, refractories, and overall operation. Examiners performing specific NDE procedures should be trained and qualified in the applicable procedures the examiner performs. In some cases, the examiner may be required to hold other certifications necessary to satisfy owner or user requirements. Examples of other certifications include ASNT SNT-TC-1A, CP-189, CGSB 48.9712, ISO 9712 (replaces EN 473), or AWS QC1.

Certification of boiler inspectors may be governed by jurisdictions.

5.7 Corrosion Control Documents (CCDs)

CCDs are also recommended and contain particular unit information detailing expected damage mechanisms, susceptible areas of damage, and guidance on managing material damage. CCDs are specific to the unit's operating process and special attention should be given to not only the development and implementation of CCDs but also the maintenance of CCDs when operating processes and material specifications are changed. Further guidance is provided in API 970.

6 Damage Mechanisms

6.1 Deterioration of Tubes

6.1.1 General

Tubes can experience deterioration both internally and externally. Typical mechanisms are described in the following subsections and are also discussed in API 571. Table 2 presents a summary of likely mechanisms for the typical tube alloys found in various refinery process units with references to the applicable sections of API 571.

Table 2—Tube Damage Mechanisms Common to Specific Services

Unit	Typical Tube Materials	Damage Mechanism [1]	Comments
Crude unit, atmospheric section	5Cr-1/2Mo 9Cr-1Mo	Creep, external oxidation (3.23), (3.48)	Caused by abnormal operation, low flow, or flame impingement.
	Type 316 Type 317	Sulfidic corrosion (3.35) (3.61)	Caused by alloy content inadequate to resist attack by the level of sulfur compounds.
		Naphthenic acid corrosion (3.46)	Caused by alloy content inadequate to resist attack by the level of naphthenic acid.
Crude unit, vacuum section	5Cr-1/2Mo 9Cr-1Mo	Creep, external oxidation (3.23), (3.46)	Caused by abnormal operation, low flow, or flame impingement.
	Type 316 Type 317	Sulfidic corrosion (3.35) (3.61)	Caused by alloy content inadequate to resist attack by the level of sulfur compounds.
		Naphthenic acid corrosion (3.46)	Caused by alloy content inadequate to resist attack by the level of naphthenic acid.
Delayed cokers	5Cr-1/2Mo 9Cr-1Mo	Carburization (3.13)	Common problem in this service; can be detected by chemical spot tests.
	Type 347	Creep, external oxidation (3.23), (3.48)	Excessive metal temperatures from internal coke formation, high duty, low flow, or flame impingement.
		Sulfidic corrosion (3.35), (3.61)	Caused by alloy content inadequate to resist attack by the level of sulfur compounds.
		Polythionic acid stress corrosion cracking (PTA SCC) (3.52)	Caused by polythionic acid corrosion of sensitized stainless steel.
		Erosion (3.27)	Caused by coke particles during steam-air decoking, thermal spalling, and pigging.
		Sigma phase embrittlement (3.56)	Heating some stainless steels above about 1000 °F (540 °C) can result in a loss of ductility and fracture toughness.
Catalytic hydrodesulfurizer	5Cr-1/2Mo 9Cr-1Mo	Creep, external oxidation (3.23), (3.46)	Caused by abnormal operation, low flow, or flame impingement.
	Type 321/ 347	PTA SCC (3.52)	Caused by polythionic acid corrosion of sensitized stainless steel.
		Hydrogen/hydrogen sulfide corrosion (3.35), (3.61)	Caused by alloy content inadequate to resist attack by the level of hydrogen/hydrogen sulfide.
		Sigma phase embrittlement (3.56)	Heating some stainless steels above about 1000 °F (540 °C) can result in a loss of ductility and fracture toughness.

Unit	Typical Tube Materials	Damage Mechanism [1]	Comments
Hydroprocessing, fractionation section	Carbon steel	Creep (3.23)	Damage rate is a function of stress and temperature. For carbon steels, creep can occur when tube metal temperatures are greater than 700 °F.
		External oxidation (3.46)	Damage rate is a function of tube metal temperature and excess oxygen in the firebox. Carbon steel oxidation rates increase significantly above 1000 °F.
		Internal sulfidation (3.61)	Caused by sulfur compounds entering the process flow during startup, upsets, and shutdown.
		Graphitization (3.34)	Caused by the nucleation and growth of graphite that occurs when carbon steel is exposed to temperatures hotter than 800 °F.
Catalytic reformer	$1^1/_4$Cr-$^1/_2$Mo $2^1/_4$Cr-1Mo	Creep, external oxidation (3.23), (3.48)	Caused by abnormal operation, low flow, or flame impingement.
	5Cr-$^1/_2$Mo 9Cr-1Mo	High-temperature hydrogen attack (HTHA) (3.36)	Caused by operation of tube materials above API 941 Nelson curves.
		Carburization/metal dusting (3.13), (3.44)	Caused by high carbon activity and high-temperature operation and occurs under specific conditions.
		Spheroidization	Probable in $1^1/_4$Cr-$^1/_2$Mo after long-term service.
Waste heat boiler	Carbon steel $1^1/_4$Cr-$^1/_2$Mo	Internal corrosion (3.9), (3.18)	Caused by inadequate or improper water quality.
	$2^1/_4$Cr-1Mo	Creep, external oxidation (3.23), (3.61)	Caused by abnormal operation, low flow, or flame impingement.
		External dew point corrosion [2] (3.29)	Caused by tube metal temperatures operating below the flue gas dew point.
		Erosion (3.27)	Caused by entrained catalyst in the flue gas.
Steam-Methane reformer unit [3]	HK40 HP modified	Creep (3.23) Carburization (3.13)	Caused by catalyst issues, abnormal operation, low flow, or flame impingement.
Utility-boilers	Carbon steel	Internal corrosion (3.9), (3.18)	Caused by inadequate or improper water quality.
	$1^1/_4$Cr-$^1/_2$Mo $2^1/_4$Cr-1Mo	Creep (3.23)	Caused by abnormal operation, low flow, or flame impingement.
		External oxidation (3.61)	Caused by abnormal operation, low flow, or flame impingement.

NOTE 1 API 571 summarizes more information on the degradation mechanisms shown above; number in parentheses ( ) is the applicable section of the document's Third Edition.

NOTE 2 Dew point corrosion is common to catalytic cracking waste heat boilers, air preheaters, boiler feedwater (economizer) coils, and sometimes in stacks.

NOTE 3 Reference to "Ethylene Pyrolysis" (included here in past editions) was removed as the furnace tubes are specialized high-alloy materials whose composition can vary by the application and may even be proprietary in some cases. The expected damage mechanisms will also vary depending upon the actual material used and should be determined with engineering support.

6.1.2 Internal Tube Corrosion

Internal corrosion is a function of the chemical composition of the process fluid, process and tube metal temperatures, the fluid velocity, and tube metallurgy. Some critical species include sulfur compounds and organic acids (e.g. naphthenic acid). The level of these species in the fluid influences the type and rate of corrosion on the internal surface of the tubes. Sulfur compounds in particular promote sulfidic corrosion that can manifest itself as localized and general wall thinning. Similarly, corrosion from organic acid can appear localized in turbulent regions or general thinning in areas. Typically, sulfidation rates are predicted based on industry experience or by calculations based on empirical data (e.g. modified-McConomy curves). Often the corrosion rate can be more localized in the vapor phase of horizontal convection tubes in hydrotreating unit heaters and is greater than observed in the liquid phase. The presence of hydrogen increases corrosion rates predicted by the modified-McConomy curves. Some industry data also indicate that under certain operating conditions, the modified-McConomy curves can be nonconservative. Refer to API 571, Section 3.61 and API 939-C for more information on sulfidation corrosion.

Fluid and metal temperatures influence the corrosion rate. The highest tube metal temperature predominantly occurs at the fire side front face of the radiant tube where the heat flux is greatest. The corrosion rate profile often follows the heat flux profile. Figure 9 shows an example of increased corrosion on the fire side of a tube. Differences in the corrosion rate along the length or around a cross section of a tube are often the result of temperature differences between locations. An example of temperature influence is the increase in corrosion rate with a rise in temperature to 750 °F (399 °C) for processes with sulfur compounds. Above 750 °F (399 °C), the corrosion rate decreases due to stable sulfide scale that inhibits further corrosion. Figure 10 is a convection tube that failed from internal corrosion attributed to high-temperature sulfidic attack.

High-velocity fluids, fluids containing particulate, or tubes with two-phase flow can increase the corrosion rate by stripping away protective scale and exposing fresh metal to continue the corrosion process. Corrosion from organic acids and sulfur compounds are significantly influenced by fluid velocity. Particular attention should be given to highly turbulent regions.

Figure 9—Inside Diameter (ID) of Fireside Portion of Tube Showing Severe Corrosion

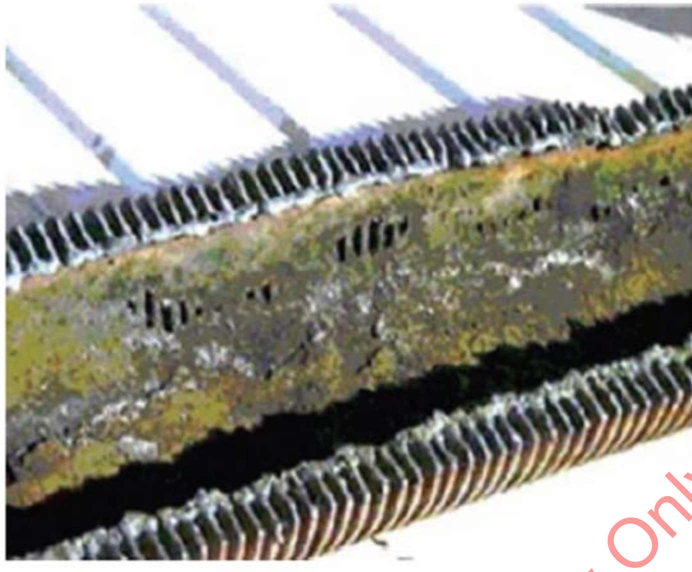


Figure 10—Convective Tube Failure from Internal, High-temperature Sulfidic Corrosion

Tube failures resulting from corrosion are generally due to local stress rupture in which the wall thickness becomes too thin and is overstressed at the metal operating temperature. These failures can appear as small leaks through pits or "fish-mouth" ruptures if the thinning is general or if it causes longitudinal grooving.

6.1.3 External Tube Corrosion

External corrosion of the tube depends on the equipment's atmosphere and temperatures. Generally, the external surface of the tube corrodes from oxidation. The atmosphere contains excess oxygen necessary for combustion of the fuel at the burners. Oxidation rates for a metal increase with increased temperature. Oxidation may either be a localized condition or extend over the entire length of the tube inside the heater, furnace, or boiler. Excessive oxidation and scaling is usually the result of operating the tubes above recommended levels. This can be the result of overfiring or internal fouling of the tubes due to the increase in the tube wall temperature. Combustion deposits may have the appearance of oxide scale, but they can be distinguished by checking them with a magnet. Oxide scales are magnetic, whereas combustion deposits are not. External oxidation is described in API 571, Section 3.48.

Other types of corrosion attack are possible. Heaters, furnaces, or boilers operating with insufficient oxygen or fuel rich can cause corrosion from the resulting reducing environment. Depending on the type and quality of the fuel, corrosion can occur from sulfidation or carburization. Acid attack can result from the combustion of fuels depending upon the sulfur content of the fuel. When the gas or fuel oil has a high sulfur content, one of the combustion products formed and deposited on the outside surfaces of the tubes is a sulfate. This sulfate is harmless during operational periods, but when the deposit is allowed to cool, it becomes highly hygroscopic and absorbs moisture from the air, hydrolyzing to produce sulfuric acid that corrodes the underlying metal. Figure 11 shows a tube exhibiting external corrosion from this type of attack.

Figure 11—General Metal Loss and Pitting of Tubes Exposed to Moisture and Corrosive Deposits During Idle Periods

When the fuel has a high vanadium content, metal at temperatures above a critical point in the range from 1200 °F (649 °C) to 1400 °F (760 °C) is subject to rapid attack from low-melting vanadium-based compounds (vanadates) and sodium-vanadium compounds (sodium vanadates). The vanadates and sodium vanadates deposit on the hot metal surface, melt, and act as a fluxing agent to remove the protective oxide scale on the tubes. The cycle repeats itself as oxide and deposit builds back up on the tube.

Convection sections where flue gas dew point temperatures occur during operations suffer metal loss because of acid material from the products of combustion. Metal loss on the exterior of convection tubes may be difficult to evaluate because of inaccessibility.

6.1.4 Creep and Stress Rupture

Creep and stress rupture are high-temperature mechanisms that depend on both the stress level and type of material. At high temperatures, metal components can slowly and continuously deform under load below the yield stress. Creep is defined as the time-dependent deformation of stressed components under an applied load below the yield strength at the operating temperature of the material. Stress rupture is similar to creep except that the stresses are higher and the time to failure is shorter than those used for creep. Stress rupture failures are typically short-term failures, while creep failures are typically long-term failures. Tubes that have been in service for long periods of time can fail by stress rupture if the operating severity has increased significantly during operation or the condition of the tube has deteriorated. Tubes are exposed to biaxial stresses as the result of hoop stress caused by the operating pressure and longitudinal stress caused by inadequate tube support or inappropriate design and construction that causes localized high stresses. Thick-walled tubes are exposed to triaxial stresses caused by hoop, longitudinal, and, in addition, radial stresses caused by the uneven distribution of stresses through the thickness of the tube wall. Creep and stress rupture are described in API 571, Section 3.23.

The metal temperature plays a major role in the type and severity of the deterioration of the tubes. The metal temperature of individual tubes or along the length of any specific radiant tube of a given heater, furnace, or boiler can vary considerably. The principal causes of abnormal variation in metal temperature are internal fouling of the tubes that insulates the tube wall from the process and improper or poor firing conditions in the equipment. Some potential signs of creep in tubes are as follows.

a) *Sagging*. Excessive sagging is usually because of a decrease in the structural strength of the tube caused by overheating. It may also be caused by improper spacing of hangers, uneven metal temperatures, or failure of one or more tube supports or hangers. Figure 12 shows some roof tubes exhibiting excessive sagging due to the failure of tube hangers.

b) *Bowing*. Excessive bowing is generally caused by uneven metal temperatures that may be due to flame impingement or coke accumulation inside the tube. Heating on one side of the tube causes greater thermal expansion on the hotter side and bowing toward the heat source. Bowing may also be caused by binding of the tube in the tubesheets or improper suspension of the tube so that longitudinal expansion is restricted or by the use of improper tube lengths when individual tube replacements are made.

c) *Bulging*. Bulging is generally an indication of overheating. Continuing under the same temperature and stress conditions eventually leads to creep and stress rupture. The amount of bulging varies with the specific metal and the type of damage, creep, or overstress. If the bulge is attributed to overstress (short-term overheating), and the temperature and stress have been returned to normal, typically the life of the tube has not been reduced. Creep life can be reduced if the bulge is the result of creep damage (long-term overheating). Bulging is considered more serious than sagging or bowing.

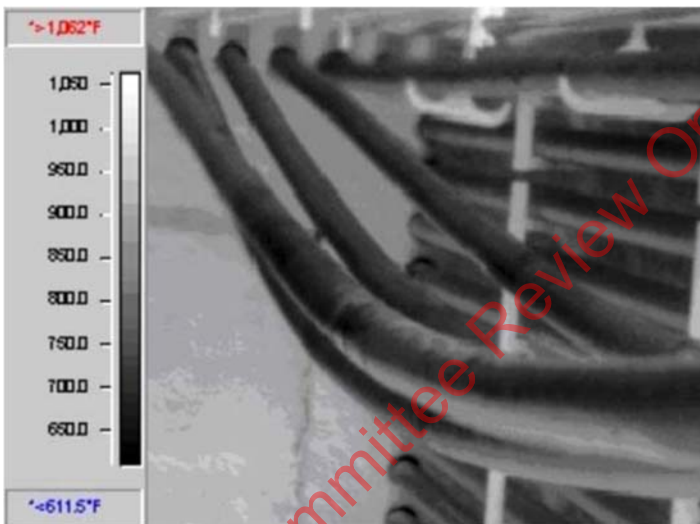


Figure 12—Roof Tubes Sagged as a Result of Failed Tube Hangers

6.1.5 Metallurgical Changes

Steels subjected to high temperatures and stress for long periods can undergo metallurgical change. This change results in various conditions, including carburization, decarburization, spheroidization, and grain growth. All of these conditions lead to a general reduction in mechanical strength or a change in ductility that may eventually result in failure of the material. Some materials, including 5 Cr-1/2 Mo, may be susceptible to precipitation hardening when concentrations of residual elements (i.e. phosphorus, tin, and antimony) are above certain threshold levels and exposed to operating temperatures for a sufficient time period. The result may be temper embrittlement with a loss of elongation and notch ductility as these elements precipitate in the grain boundaries after about a year at temperatures from 572 °F (300 °C) to 1112 °F (600 °C). Accordingly, the tube materials have ductile-to-brittle transition temperatures as high as 300 °F (149 °C) and brittle cracking has been experienced. See API 571 for a detailed description of these forms of deterioration.

Type 410 stainless steel can be susceptible to alpha-prime embrittlement or "885 °F embrittlement," depending on the trace elements present in the composition. Alpha-prime significantly reduces the toughness of the metal at temperatures below 200 °F (93 °C). Brittle fracture can result from impact loads during downtime, so extra caution during handling is prudent. At operating temperatures, the material has acceptable toughness.

6.1.6 Erosion

The velocity of flow through a heating coil may cause severe erosion in tubes and fittings if the velocity is critical or if direct impingement occurs. Often, the metal loss is aggravated by the corrosive nature of the process. Erosion in tubes is usually the result of velocity. Erosion in fittings usually results from a combination of impingement and velocity. If the charge rate on a unit is materially increased, the increased velocity may cause metal loss from erosion and corrosion.

Erosion is described in API 571, Section 3.27.

6.1.7 Thermal Fatigue

Metal that operates under cyclic temperature conditions, especially over a wide range, may develop cracks from thermal fatigue. Cracks start at the surface of the material where the stresses are normally higher, progressing slowly at first and then more rapidly with each cycle of temperature change. Thermal fatigue is often found at locations where metals that have different coefficients of expansion are joined by welding. Other common locations for thermal fatigue are in convective tubes where the tube fins can promote cyclic temperature swings, tubes with two-phase flow, and bracing and weld attachments that do not allow for thermal expansion.

Thermal fatigue described in API 571, Section 3.64.

6.1.8 Thermal Shock

Thermal shock is caused by a sudden marked change in temperature either from hot to cold or from cold to hot. The stresses resulting from the sudden unequal expansion or contraction of the different parts may cause distortion only or distortion plus cracking. Thick metals are more susceptible to cracking than are thin ones. The most likely time of temperature shock is during unit start-ups and process upsets. Heating or cooling rates should be controlled to avoid thermal shock.

Thermal shock is described in API 571, Section 3.65.

6.1.9 Liquid Metal Cracking and Embrittlement

Liquid metal cracking is a form of environmental cracking where molten metal penetrates the grain boundaries of the steel. Series 300 austenitic stainless steel tubes are particularly susceptible to this mechanism from molten aluminum, zinc, and cadmium. Fireboxes provide adequate temperatures for these metals to be molten since they have relatively low melting points. Contact of stainless steel surfaces with a low-melting-point metal should be avoided during maintenance outages in particular, including incidental contact (i.e. using marking pens containing zinc and galvanized or aluminum scaffolding poles rubbing against tubes).

Liquid metal embrittlement is described in API 571, Section 3.42.

6.1.10 PTA SCC

Heaters used in hydrodesulfurization, hydroforming, hydrocracking, and similar processes usually process reactor feed or recycled gas containing hydrogen sulfide and sulfur compounds. PTA SCC occurs when three conditions coexist. The conditions required for cracking to occur include a suitable:

1) environment—polythionic acids are formed when sulfide scales developed during service exposure are subsequently exposed to oxygen and water, primarily during outages;

2) material—sensitized Type 300 series stainless steel and higher nickel-based austenitic alloys. Sensitization can occur in these austenitic alloys after exposures to temperatures ranging from 750 °F to 1500 °F (398 °C to 816 °C) during manufacturing, fabrication, or in service. Sensitization occurs after relatively short exposure times at the high end of the temperature range, while prolonged exposure is necessary at the lower end of the temperature range;

3) stress—this can be either residual stresses from fabrication (e.g. welding) or applied stresses (e.g. hoop or axial).

Generally, the risk of cracking increases during downtime when water and air are present. Cracking can be rapid as the acid corrodes along the grain boundaries of the austenitic alloy.

Cracking can initiate from either the inside or outside of the tube. Cracking from the process side is more common because the process often contains sulfur compounds resulting in sulfide scales. However, cracking can occur from the tube OD if the firebox operates fuel rich and there is sufficient sulfur in the fuel.

Preventive measures include using materials less susceptible to sensitization, preventing acid from forming, and neutralizing the acids. Specific details are as follows.

a) Stabilized grades of stainless steel (e.g. Type 321 or Type 347) are more resistant to sensitization, but even these materials can become sensitized after a longer exposure to slightly higher temperatures. A thermal stabilization heat treatment of a stabilized grade of stainless has been shown to significantly improve resistance to sensitization and thereby minimize the potential for cracking.

b) Preventing oxygen and moisture prevents polythionic acid from forming. This can be accomplished by purging with an inert gas, like nitrogen, and keeping the tubes pressurized with it. When blinding is required, a positive flow of inert gas should be maintained while the flanges are open and a blind is being installed. If desired, a small amount of ammonia can be added to the inert gas as a neutralizing agent. Maintaining a positive flow of inert gas excludes air and moisture.

c) A wash with a soda ash solution can effectively neutralize acids and maintain a basic pH. Tubes, crossovers, headers, or other parts of the heater that have to be opened should be soda ash washed. The usual solution is a 2 wt % soda ash (Na_2CO_3) with a suitable wetting agent. The solution should be circulated so that all gas pockets are moved and all surfaces are wetted. Sodium nitrate at 0.5 wt % may also be added to the solution to inhibit chloride cracking. The solution may then be drained and reused in piping or another heater. The 2 % solution contains enough soda ash to leave a film, but a weaker solution may not. The film is alkaline and can neutralize any reaction of iron sulfide, air, and water. It is important to remember that the film, the residue from the soda ash solutions, may not be washed off during downtime. Most units are put back on stream with the film remaining. If the film has to be removed, flushing during start-up followed by inert gas may be acceptable.

d) Preventing moisture exposure by maintaining tube temperatures above the dew point prevents acid from forming. This is typically applied to external tube surfaces that are not neutralized. Depending on the dew point temperature, this may be accomplished either by keeping pilots burning during downtimes or keeping a burner at minimum fire when access is not needed and safety procedures allow. Tube temperatures should be monitored to ensure they are above the target dew point temperature. These preventive measures are described in detail in NACE SP0170.

PTA SCC is described in API 571, Section 3.52.

6.1.11 Carburization

Carburization can occur when metals are exposed to carbonaceous material or carburizing environment at elevated temperatures. Carbon from the environment combines with carbide-forming elements (i.e. Cr, Mo, Nb, W, Mo, Ti, and Fe) in the alloy to form internal carbides. These carbides precipitate at the grain boundaries of the alloy or inside the grains. As a rule, carburization problems only occur in Cr-Mo alloys at temperatures above 1100 °F (593 °C) and in austenitic alloys above 1500 °F (815 °C). In refining operations, carburization damage is sometimes found in ferritic heater tubes in catalytic reformers and coker units. The effect of carburization is to reduce the ambient temperature ductility, toughness, and weldability of the alloy. Carburization also reduces oxidation resistance by tying up chromium in the form of stable chromium-rich carbides. The creep strength of the alloy may also be adversely affected as the result of the reduced ductility of the alloy due to the carbide precipitation within in the grains and at the grain boundary.

In petrochemical operations, carburization is typically found in austenitic heater tubes in ethylene pyrolysis and steam-methane reformer furnaces. Significant carburization can occur during decoking cycles of ethylene pyrolysis furnaces. Carburization has been identified as the most frequent failure mechanism of ethylene furnace tubes. Experience has indicated that the severity of carburization damage in ethylene cracking is process dependent. Some important factors identified include the following:

a) steam dilution, which tends to decrease the rate of damage;

b) the use of lighter feeds versus heavier feeds, the former having a higher carbon potential; and

c) the frequency and nature of decoking operations (decoking is thought to be a major contributor to carburization damage).

Carburization causes the normally nonmagnetic wrought and cast heat-resistant alloys to become magnetic. As shown in Figure 13 for a cast HK40 tube alloy, the actual percentage of chromium depleted from the matrix is proportional to the magnetic permeability. The resulting magnetic permeability provides a methodology for monitoring the extent of carburization damage. Measurement devices range from simple handheld magnets to advanced multi-frequency eddy current instruments. Carburization patterns can also reveal uneven temperature distributions that might otherwise have gone undetected. Most alloys tend to have more carburization penetration with increasing temperatures.

As in the case of oxidation and sulfidation, chromium is considered to impart the greatest resistance to carburization. Aluminum and silicon alloying additions can also contribute positively to resistance to carburization. It should be noted that the addition of aluminum or silicon to the heat-resistant alloys in quantities to develop full protection involves metallurgical trade-offs in strength, ductility, and weldability. Considering fabrication requirements and mechanical properties, viable alloys are generally restricted to about 2% for each element. Other approaches to reducing the potential for carburization damage include reducing the carbon activity of the environment through lower temperatures and higher oxygen and sulfur partial pressures. Also, the addition of H_2S in the process stream inhibits carburization in steam and gas cracking in olefin and thermal hydrodealkylation units.

Carburization is described in API 571, Section 3.13.

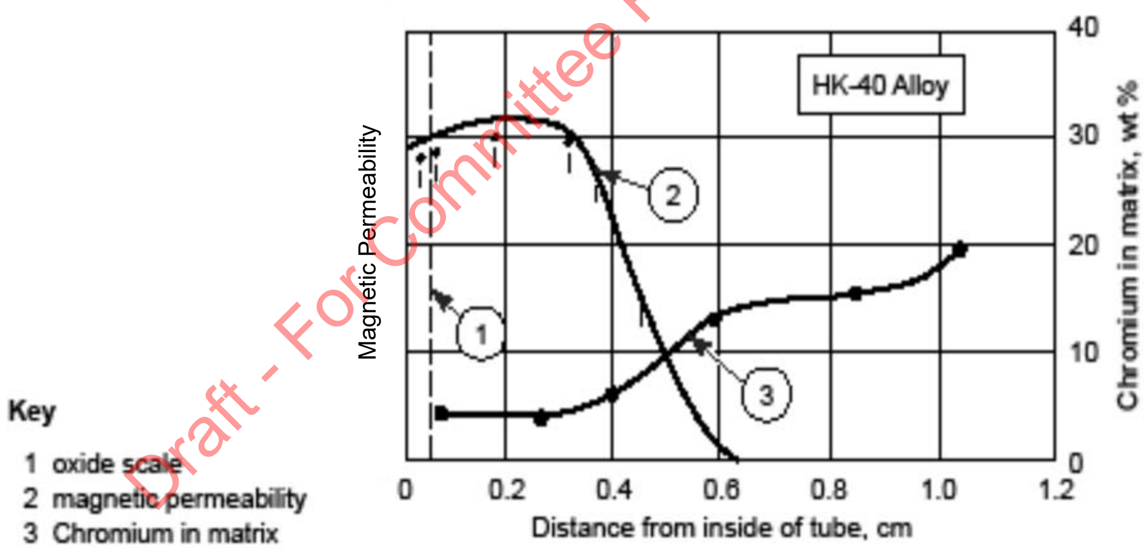


Figure 13—Changes in Magnetic Permeability Caused by Chromium Depletion

6.1.12 Metal Dusting

Metal dusting is a catastrophic form of carburization that may result in rapid metal wastage in both ferritic and austenitic alloys. This damage mechanism typically has the appearance of localized pitting or grooving along the inner walls of pipe and tubes.

Environments with high carbon activity (greater than one) and low oxygen partial pressures can be prone to this type of damage if temperatures become high enough for carbon diffusion to occur in the base metal. Depending on the type of alloy, this temperature may be as low as 800 °F (427 °C) and as high as 1400 °F (760 °C). In iron-based alloys, this mechanism initiates with the saturation of the alloy matrix with carbon, usually in a very localized manner, followed by the formation of metastable Fe_3C or cementite. The cementite decomposes as the carbon activity increases and approaches unity to form iron particles and powdery carbon. With nickel-based alloys, there is no intermediate formation of a metastable carbide. Instead, carbon diffuses into the matrix material and then decomposes into graphite and metal particles.

Common process streams where metal dusting has been known to occur include the following:

a) methanol production—where the production of a synthetic hydrogen gas results in ideal conditions for this to occur,

b) hydroforming units—where the 9 % Cr material used in many of the fired heaters have been found with this type of damage, and

c) waste heat boilers—where high metal temperatures and high activity of carbon lead to initiation of this damage.

Protection of an alloy against metal dusting requires the presence of an adherent, protective, self-healing oxidation layer on the surface of the material. In general, nickel-based alloys perform much better in a metal dusting environment than do iron-based alloys. Alloy 800H is one of the most susceptible austenitic alloys to this mechanism, with a fast initiation rate and high wastage rates. Similarly, alloys with 20 % to 40 % nickel are also strongly attacked.

Metal dusting is described in API 571, Section 3.44.

6.1.13 Mechanical Deterioration

Mechanical deterioration may materially reduce the service life of tubes and fittings. The two most common causes of this are leakage in the tube rolls—the rolled joints between tubes and fittings—and damage during mechanical cleaning. Leakage in the tube rolls may result from faulty roll procedures or workmanship when the tubes were originally installed or may be caused from thermal upsets during operation. Similarly, damage to a tube during mechanical cleaning may be caused by faulty procedures or workmanship. One of the most common causes is allowing the cleaner to operate in one position for so long that it cuts the tube metal. Machined surfaces of plug-type header fittings can be damaged by contact with cleaning tools. Cleaning by steam-air decoking can cause serious oxidation and other deterioration of tubes unless temperatures are carefully controlled.

Undue force used to close fittings may result in the development of cracks in the fitting body or at the base of fitting ears and may cause excessive wear or distortion of the plugs of U-bend seats, fitting ears, or holding sections and members-dogs or caps and screws. The use of excess force commonly occurs because of improper cleaning of ground surfaces or mismatching of plugs to return bends. Training and close supervision of personnel with regard to the proper care, use, and amount of tightening permissible are essential to prevent this damage. Casting or forging defects may also result in cracks in the fitting body or at the base of fitting ears. One common practice to aid in removing plugs and to reduce the chance of damaging the casting is to heat the fittings. Overheating with a torch may cause the fitting to crack. The depth and seriousness of cracks formed by overheating with a torch should be investigated.

Thermal expansion that has not been accommodated can cause deterioration. Tube materials expand when heated. If the expansion cannot be accommodated, it can create stresses that are high enough to cause serious weakening and deformation of the tube or fitting. For instance, tube failures have resulted from refractory repair work, which did not allow the tubes to expand, and created high enough local stresses to result in creep rupture.

6.1.14 Deterioration Specific to Steam-Methane Reformer Furnaces

6.1.14.1 Tubes and Pigtails

Steam-methane reformer heater tubes and pigtails are susceptible to creep and stress rupture due to high thermal and mechanical stresses and high operating temperatures. Failures generally occur due to stress rupture at the hottest, most highly stressed portion of the tube. The hottest areas are normally near the bottom for downflow systems or top of the tube for upflow systems, since the temperature of the gas inside the tubes rises during reaction from about 900 °F (482 °C) to about 1750 °F (954 °C) or higher. If flame from burners or from combustion products deflected off walls and impinges upon the tube, stress rupture can occur in the hottest parts of the tube.

Steam-methane reformer heater tubes can fail by creep rupture that is different from most other heater tubes. The tubes have a thick wall with a large thermal gradient across it such that there are significant thermal stresses in the region between the ID and mid-wall. These thermal stresses are high enough to promote creep initiating where the combination of stress and temperatures are above a threshold and propagating to the inner diameter. Finally, the cracks propagate to the outer diameter resulting in failure.

Minimizing mechanical stresses from thermal growth are critical to pigtail and tube reliability. Steam-methane reformer heaters have an elaborate support and hanger system designed to allow the tubes to grow in service and to reduce the stress on the pigtails and headers. If the support system is not functioning as designed, it can produce high stresses on the pigtails and tubes to the extent of promoting creep rupture. Without adequate support, tubes can bow in service, further increasing stresses. Bowed tubes have higher stress levels at their bends than do straight tubes. Bending stresses are induced on pigtails from tube bowing, tube movement, sagging of the pigtail under its own weight, and thermal expansion of a pigtail loop. The pigtails are susceptible to thermal fatigue if the movement is cyclic because of swings in operation or numerous start-ups and shutdowns.

Some cast tube materials may embrittle after exposure to high temperatures. Weld materials that embrittle during postweld cooling have high residual stresses. Weld material with a carbon-silicon ratio that does not match that of the base metal fissures easily during welding. Any microfissures not detected during fabrication can propagate during subsequent heating, thermal cycles, or continual high stresses from bowing or localized heating. Welding flux has to be removed from tube welds. Grit blasting is recommended for flux removal. Flux of lime with fluorides is corrosive if the combustion gases are reducing (because of very little excess air) and sulfur is present.

6.1.14.2 Outlet Headers

The cast alloy headers, like those fabricated from HK material, have a history of cracking near junctions because of embrittlement due to carbide precipitation and sigma formation. Other areas of concern include inlets, outlets, laterals, tees, and elbows. These headers are horizontal and do not float freely. The embrittlement that occurs does not allow any restraint of the thermal growth and results in high stresses with resultant cracking. Because of the embrittlement, welding repairs are difficult unless the surfaces are annealed or buttered with a ductile weld material before welding. Proprietary cast materials have been developed to avoid embrittlement, and their use in outlet headers has been satisfactory.

Wrought alloy headers (e.g. Alloy 800H) operating at temperatures near 1400 °F (760 °C) have also had a good service history. They maintain ductility and can yield by creep or stress relaxation to reduce localized stresses. As in any high-temperature design, stresses have to be kept low, particularly at supports and at openings in the headers.

Headers fabricated from carbon steel or low Cr-Mo require internal refractory to keep metal temperatures below allowable limits per API 941 to avoid high-temperature hydrogen attack. Because the base metal is not resistant to hydrogen at high temperatures, the refractory has to be sound to preserve its insulating properties. Refractory used in hydrogen and carbon monoxide service should have low iron and silicon content to avoid the possibility of hydrogen or carbon monoxide reacting with components of the refractory and the degradation of the refractory's essential properties. Start-up and shutdown procedures minimize wetting of the refractory, partly to avoid destroying the insulating refractory and partly to avoid carbonic acid corrosion of the steel.

6.2 Deterioration of Boiler Tubes

6.2.1 General

Boiler tubes can experience deterioration from internal and external mechanisms. The following subsections describe common damage mechanisms. Table 2 (6.1) also summarizes these common mechanisms in boiler plants.

6.2.2 Internal Corrosion

Corrosion of tubes and the drums is largely dependent on the water and water chemistry used within the boiler. Some of the more common types of waterside corrosion include caustic corrosion, dilute acid corrosion, oxygen pitting or localized corrosion, and stress corrosion cracking (SCC). A significant factor in the degree of waterside corrosion is the amount of corrosion product deposited. Deposits restrict the heat transfer and lead to local overheating, which can cause concentration of contaminants and corrosives. Depending on which contaminants are present in the feedwater during a period of chemical unbalance, different deposition locations, rates, and effects can be experienced.

Caustic corrosion or caustic gouging can occur from deposition of feedwater-corrosion products in which sodium hydroxide can concentrate to high pH levels. At high pH levels, the steel's protective oxide layer is soluble and rapid corrosion can occur. Deposits normally occur where flow is disrupted and in areas of high heat input. When the deposit thickness is great enough to locally concentrate caustic, severe corrosion resulting in irregular thinning or gouging of the tube wall can occur. Figure 14 illustrates this form of localized corrosion.

Hydrogen damage may occur if the boiler is operated with low-pH water. This may be caused by the ingress of acidic chemicals from the water treatment facility, a leak in a saline-cooling water condenser, contamination from chemical cleaning, or other factors that may lower the boiler feedwater pH to less than seven. Close control over boiler water chemistry and monitoring practices are important factors in preventing hydrogen damage.

Boiler tube failures caused by pitting or localized corrosion often result from oxygen attack on the internal side of the boiler tube. Pitting corrosion of economizer tubing normally results from inadequate oxygen control of the boiler feedwater. For full protection against oxygen pitting during shutdown, the boiler should be kept full of water treated with an oxygen scavenger and blanked or capped with nitrogen. Figure 15 illustrates a boiler tube with a through-wall oxygen pit.

Figure 14—Localized Tubing Wall Loss Caused by Caustic Gouging

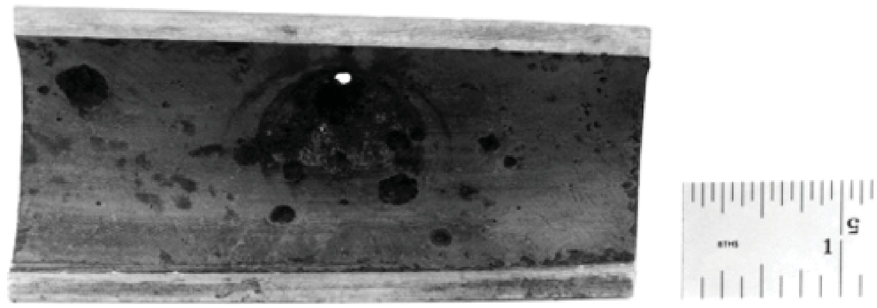


Figure 15—Boiler Tube Showing Penetration of the Tube Wall by a Localized Oxygen Pit

While SCC is usually associated with boilers in which austenitic tubes are used for superheater and reheater tubing, failures have occurred in ferritic tubes where a desuperheater or attemperator spraying station introduced high levels of caustic concentration. SCC of B-7 studs may also occur in areas where a leaking gasketed joint may allow caustic concentration.

6.2.3 External Corrosion

Fuel constituents and metal temperatures are important factors in the promotion of fireside corrosion. Fireside corrosion can be classified as either low-temperature attack or high-temperature oil-ash corrosion. Corrosion may occur on the flue gas side of economizer and air preheater tubes. The severity of this corrosion depends on the amount of sulfur oxides or acid in the fuel burned and on the temperature of the flue gas and of the media being heated. When sulfur oxides are present in the flue gases, corrosion tends to be severe if the gases cool down to the dew-point temperature. The gas temperature in economizers and preheaters should be kept above 325 °F (163 °C) to prevent condensation of corrosive liquid. Actual dew point can be calculated from the flue gas composition and should be performed for fuels with high sulfur levels. This may be best achieved by designing the tubing and the water flow in the tubing so that the gas temperatures are controlled to remain above the dew point temperature.

External corrosion of boiler parts may be expected when boilers are out of service for long periods of time. The sulfurous acid formed from the reaction of condensed moisture with the sulfur in ash deposits can cause rapid corrosion of boiler parts. Also, if a unit remains idle for an appreciable length of time, a warm humid atmosphere tends to corrode boiler parts and supports unless adequate mothballing procedures are followed.

6.2.4 Creep and Stress Rupture

Overheating is one of the most serious causes of deterioration of boilers. Overheating of the boiler tubes and other pressure parts may result in oxidation, accelerated corrosion, or failure due to stress rupture. Although overheating can occur during normal boiler operations, most often it results from abnormal conditions, including loss of coolant flow or excessive boiler gas temperatures. These abnormal conditions may be caused by inherently faulty circulation or obstructed circulation resulting from water tubes partly or wholly plugged by sludge or dislodged scale particles. Overfiring or uneven firing of boiler burners may cause flame impingement, short-term overheating, and subsequent tube failure. The results may be oxidation of the metal, deformation of the pressure parts, and rupture of the parts, allowing steam and water to escape. Figure 16 and Figure 17 show boiler tubes that have failed due to overheating.

Figure 16—Short-term Boiler Tube Failure Caused by Waterside Deposits, Subsequent Overheating, and Final Bulging of the Tube Wall

Figure 17—Longer-term Boiler Tube Failure Caused by Poor Circulation and Subsequent Overheating, Oxidation, and Final Failure by Stress Rupture

Boiler tubes may be damaged by poor circulation. Under certain conditions of load and circulation, a tube can become steam bound long enough to overheat locally and fail. If circulation is periodically reestablished, the hot portion of the tube is quenched by relatively cool water. This often causes thermal fatigue cracks that may eventually result in tube failure. This condition can also result in caustic or chelate corrosion. Steam binding may be caused by the insulating effect of slag deposits on the outside of the lower part of the tube. This demonstrates the importance of avoiding, as much as possible, nonuniform slagging of waterwalls (in coal-fired boilers). Steam superheaters can become overheated and severely damaged during start-up if cold boilers are fired at an excessive rate before a sufficient flow of steam is established to keep the superheaters cool. They can also become overheated if the steam vented from the superheater outlet is not sufficient to provide steam flow through the superheater during warm-up or low-load operations. The overheating results in warped tubes and oxidation of the tube metal leading to early tube failure.

The faulty operation of steam-separating devices may result in deposition of boiler water solids in the superheater tubes with subsequent damage to the tubes from overheating as the deposits impede heat transfer.

6.2.5 Mechanical Deterioration

Mechanical deterioration of boiler parts can result from a number of causes:

a) fatigue from repeated expansion and contraction and corrosion-fatigue from the combined action of fatigue and corrosion;

b) abnormal stresses created by rapid changes in temperature and pressure, especially in the case of thick-walled drums;

c) improper use of cleaning tools;

d) improper use of tube rollers;

e) settlement of foundations;

f) excessive external loading from connected piping, wind, earthquake, and similar sources;

g) breakage and wear of mechanical parts;

h) firebox explosion;

i) vibration due to improper design or support failure;

j) improper gaskets that allow steam leaks to score the seating surface; and

k) non-weather-tight casing that allows external tube corrosion during extended shutdowns.

If metal is cyclically stressed in operation repeatedly, it can eventually fatigue and may crack under a stress far below its normal breaking load, as discussed in API 571 (Sections 3.43 and 3.64). The metal in boiler parts may experience expansion and contraction because of temperature changes involved in taking a boiler out of service and putting it back into service. Also, expansion and contraction can be caused by the normal temperature fluctuations during operation. Tubes may also become fatigued as a result of alternate wetting by steam and water that causes fluctuating conditions. If corrosion acts concurrent with fatigue, the resistance of the metal is reduced because of the corrosion medium and the corrosion fatigue cracks that develop. When very rapid temperature changes occur in metal parts (especially thick metal parts), they may be overstressed by the expansion or contraction of the portions of the metal that have changed in temperature against the portions of the metal that have not changed in temperature. A similar situation exists when a cold glass tumbler is only partly filled with hot liquid and shatters.

Improperly employed tube cleaners allowed to operate too long in one position may cause damage by cutting grooves inside the tube. Incorrect or excessive cleaning operations especially utilizing acid-based products can lead to excessive removal of protective oxide films in boiler tubes and may lead to accelerated corrosion upon recommissioning. Improper use of tube-rolling tools by under-rolling or over-rolling may cause tube-roll leaks or damage to the tube ends or tube seats.

6.3 Damage Mechanisms of Other Components

6.3.1 General

Nonpressure parts, including refractory linings of heaters, burners, supporting structures, and casings, may also be damaged from overheating. Usually, such overheating is caused by improper operating conditions or is a result of deterioration of other protective parts. For example, if the refractory lining of a heater is permitted to deteriorate from normal wear, erosion, spalling, or mechanical damage, it no longer can protect the outer heater casing and structural supports adequately, and such parts may in turn begin to deteriorate rapidly.

6.3.2 Tube Hangers and Supports

Hangers and supports are made from heat-resistant alloys chosen for their high-temperature strength, creep properties, and resistance to corrosion. Most of this hardware is originally made from castings although wrought materials tend to be installed for replacements due to good availability of plate and bars. The form of the material, cast vs wrought, and the grade of material influence the damage mechanisms.

Tube hangers and supports deteriorate for several reasons, including stress and creep rupture, mechanical damage, corrosion, and castings of poor quality. Similar to previous discussions about stress and creep rupture of tubes, hangers and supports fail from an excessive combination of stress and temperature. Components made from a casting generally have better stress rupture and creep properties than the wrought equivalent. Therefore, extra attention should be given to those wrought components. Especially vulnerable are those fabricated for an unplanned replacement of a cast component. Corrosion of the supports and rods can reduce the cross section enough to elevate the stress level to promote failure. Corrosion can occur from high-temperature oxidation, fuel ash, and acid attack (during turndown). Oxidation can be avoided by proper alloy selection. Fuel ash and acid turndown attack from sulfur in deposits can be severe depending on the fuel quality.

Mechanical damage from vibration in service or mechanical impact during maintenance work can crack the components. Castings are particularly susceptible to mechanical impact damage since they tend to have poor resistance to impact loads. In addition, some alloys can change metallurgically from long-term exposure at elevated temperatures to become brittle at room temperature.

Poor casting quality can be the root cause for premature failures. Casting defects like voids and cracks can initiate failure from other mechanisms like stress rupture or mechanical damage. These cast components do not usually receive significant inspection after casting. Some purchasers have found it necessary to require supplemental radiographic inspection to assure themselves of acceptable components.

6.3.3 Casing and Structural Steel

Corrosive agents are produced in the combustion of fuels that contain sulfur. Deterioration from sulfur can occur on cold steelwork when it has been exposed to the gases as a result of deterioration of the refractory or insulating linings or if a heater, furnace, or boiler is operated under a positive pressure. It is imperative that the outer casing of equipment be maintained in a tight condition. When flue gases are permitted to permeate to the atmosphere at various locations, they deposit sulfurous acid on the casing and metal parts that are below the dew point. Such deposits are acidic, accelerating corrosion of the casing and the refractory supports. Figure 18 illustrates dew point corrosion of a header box. Most fired heaters, furnaces, or boilers are designed to operate at negative pressure. Operation at positive pressure results in flue gas leakage and shell corrosion.

The rate of deterioration caused by climatic conditions primarily depends on whether the atmosphere is dry, humid, or salty and on the industrial fumes that may be present. Deterioration resulting from a humid atmosphere may not be due to geographic location but may be the result of the unit’s location within the refinery. Locations near cooling ponds or towers when the prevailing winds are toward the equipment may cause deterioration.

Figure 18—Dew Point Corrosion from Flue Gas Corrosion on Radiant Section Header Box

The types of deterioration resulting from climatic conditions are rusting of exposed or unpainted steelwork, general deterioration of painted surfaces, and erosion and further deterioration of the external housing of a heater, furnace, or boiler. If the external housing is allowed to deteriorate, rain or other moisture can enter the openings and deteriorate the internal refractory, insulation, and steelwork, especially when the unit is out of service for any reason (see API 571, Sections 3.9 and 3.29).

6.3.4 Firebox and Ductwork Liners

Firing conditions and temperature are the main causes of deterioration of the materials that form the internal lining of the firebox. The severity of the deterioration varies with the temperature, which in turn is determined by the process operating conditions.

The purpose of the internal materials, including refractory or insulating linings, is to provide heat protection to the structural steel framing, roof structures, and tubesheets and to improve the thermal efficiency of the unit. At high temperatures, refractory can deteriorate after long-term exposure by spalling, failure of the binding material, melting, and loss of structural strength.

Fluxing may occur when fuel ash and refractory are in contact at a moderately high temperature, producing a slag that may be fluid. Metal oxides, including those of vanadium, molybdenum, and sodium, are fluxing agents. At least three deteriorating actions of this slag formation can be recognized, as follows.

a) *Melting*. The flux melts at a lower temperature, thereby causing the refractory to become liquid and flow, which reduces the refractory thickness.

b) *Penetration*. The flux can penetrate into the sound refractory, thereby compromising its properties.

c) *Chemical action*. The flux can react with the refractory and chemically degrade it much like metal thickness being reduced by corrosion.

The general effects of fluxing are to decrease the thickness and to reduce the insulating effect of the refractory, thereby allowing a high metal temperature on the supporting steel parts.

6.3.5 Structures

Foundation settlement may be a serious cause of deterioration in heaters, furnaces, and boilers because of the severe stress that may be set up in the complicated interconnection of parts, in the external piping, and especially in the refractory linings and baffling. Excessive loads on the equipment by the connection of large pipe lines may cause damage to the foundation and pressure parts.

Settlement of foundations may also result from heat transmission from the firebox and subsequent drying of the soil.

In zones with seismic activity, earthquakes may cause severe damage. The damage can be somewhat similar to that caused by foundation settlement and may be particularly severe to refractory linings. Not only can refractory linings be affected but internal, firebrick gravity walls (also known as bridgewalls or centerwalls) may also be damaged and should be inspected. Vibrations from high and moderate winds, earthquakes, burner operating instability, and high flue gas flow across tube banks can damage various parts of heaters, furnaces, and boilers as follows:

a) stacks may be so damaged that they overturn;

b) air and flue gas ductwork may be damaged, resulting in cracks at corners or connections;

c) expansion joints may crack;

d) guy lines may loosen or break;

e) piping and tubing may be overstressed and fail; and

f) anchor bolts of stacks may be overstressed and fail.

6.3.6 Burners

6.3.6.1 General

Burner tip plugging can cause multiple issues, including, but not limited to, flame and burner instability, abnormal flame patterns, firing rate limits, flame impingement, and flameout.

Burner plugging problems can often be solved if the source of the plugging can be determined. The following can cause plugging:

1) scale in the fuel gas lines,

2) liquid/aerosol carryover into the burners,

3) unsaturates (e.g. propylene) in the fuel gas,

4) amine carryover into the fuel gas system,

5) chlorides,

6) high tip/riser temperatures.

The first two items may be the most likely of the six possibilities listed above. An analysis of the obstructions may give an indication of the cause of the plugging. The cause of the problem can sometimes be readily determined. Deposits present in a burner riser may be analyzed. The potential for burner plugging can be reduced if the burners are designed to operate at lower fuel gas pressure and the size of the burner tip fuel gas ports is increased, although there may be tradeoffs with other aspects of burner performance, such as available turndown or emissions. With lower NO_x burners designed today, there is a tendency to have a larger number of small holes that need to be kept clean and clear making it necessary to include filtration or coalescing devices in the fuel gas line.

6.3.6.2 Scale

It is recommended that strainers or filters be used in all fuel lines. All fuel gas lines, gas manifolds, burner risers, and tips downstream of the filter or coalescer should be blown free of scale, cleaned, flushed, and dried. Scale in the fuel gas lines can also be removed with steam or plant air. Cleaning the lines at the unit alone may not be sufficient.

Fuel gas lines should be inspected and cleaned, if necessary, at every turnaround.

6.3.6.3 Liquid/Aerosol Carryover

Burner plugging is often caused by liquid/aerosol carryover in the fuel gas lines. The flashing of this liquid causes coke formation in the tips/risers. The presence of dark solid shapes attached to the burner tips or tiles can denote the presence of significant liquid within the fuel gas. These may form as plates, cones, or other shapes within the burner tile.

The following frequently cause liquid carryover.

1) Heavy hydrocarbons in fuel systems [butane (C4) and higher].

2) An undersized fuel gas drum knockout drum, high velocities in the drum, and/or damaged or missing coalescing mesh pad at the fuel gas outlet of the drum.

3) Insufficient steam or heat tracing in fuel delivery lines downstream of the knockout drum, whereby heavier components in the fuel gas condense before reaching the burners.

4) Cooling of a fuel gas saturated with heavier hydrocarbons due to exposed fuel lines or pressure drops across a control valve.

Coalescers are used downstream of the fuel gas drum to aid in the removal of any further liquid/aerosol entrainment. These should ideally be located as close to the burners as possible and should be downstream of the fuel gas control valve for maximum protection.

6.3.6.4 Unsaturates

The presence of greater than 10 % unsaturates, most notably propylene and butadiene, can plug burner tips/risers. When burner design has not considered these components, it may be possible to reduce the plugging by reducing the number and increasing the size of the burner firing orifices. This may not be applicable in all burners or in all equipment.

6.3.6.5 Amines

The presence of amines in the fuel system can cause plugging of burner tips and risers. Carryover from the amine treating system should be eliminated. A well-designed water-wash system can remove entrained amines from the fuel gas if the amine unit is the source. Coalescers can be used downstream of fuel gas knockout drums as another way of removing amines.

Carbon steel manifolds and risers can corrode as a result of amine carryover. This can be corrected by using stainless steel components.

6.3.6.6 Chlorides and Ammonia

Chlorides may be present when guard beds become saturated and cease removal. Chlorides and ammonia can lead to burner tip/riser plugging. Ammonia in the gas will produce ammonium salts, and sulfur in the gas will produce iron sulfides. Both of these can be removed by a coalescer, if located properly. Unreacted ammonia and sulfur will pass through the filter or coalescer and can react downstream to cause the same problems.

6.3.6.7 Gas-fired Low-NOx Burners

Burners designed to emit low NO_x levels will have operational considerations that differ from standard gas or oil burners due to the differences in burner design. Low-NO_x burners often require more fuel gas tips than other burners. The average size of the fuel gas tip holes in low-NO_x burners is typically smaller than those in standard burners. The smaller orifice sizes are more conducive to plugging. Many low-NO_x burners have burner tips containing both firing and ignition ports. The firing ports can be the same size or much larger than the ignition ports. The ignition ports being relatively small can plug more readily than the firing ports.

The flame produced from the primary tips ignite the secondary fuel gas. Failure of the primary fuel to ignite may prevent ignition of the secondary fuel.

Routine visual inspection of the burner flames is required to monitor fuel gas tip plugging.

1) Safe operation of a low-NO_x burner relies on a stable primary combustion zone, which should appear bright and hot. Conversely, a dark primary combustion zone may indicate plugged primary tips.

2) Intermittent lifting off of the staged flame is an indication of instability. This may be the result of an unstable primary combustion zone.

3) Burner tips (primary or staged) that glow brightly may indicate that the tips are plugged, because the cooling effect of fuel gas flowing through the tip is absent.

4) Staged burner tips may have firing ports that are angled in a way that the fuel gas splashes on the burner tile. This often results in a dark area on the tile where the (relatively cool) fuel gas splashes on the tile. The absence of this dark area may indicate a plugged staged tip.

Because of the complicated nature of low-NO_x burners, care needs be taken to ensure that all components are kept in good mechanical condition. Any troubleshooting efforts should first confirm that the tip orientation and positions are correct; the flame holder is undamaged and positioned correctly; the tile is undamaged; the tips are not plugged; and the tip orifices have not been eroded.

6.3.6.8 Fuel Leak in Burner Riser

A fuel leak in a burner riser can lead to combustion problems and damage to surroundings. This can occur if the burner is not positioned properly or the adjacent refractory is not properly lapped up against the burner or has deep and long cracks. The fuel from the crack can ignite overheating the refractory or the casing. This can weaken the casing around the burner causing the casing or the burner to sag and potentially fail.

6.3.6.9 Liquid in Fuel Gas Line to Burners

Failure to remove liquid from the fuel gas can cause a slug of liquid to blow out of a burner, potentially extinguishing the burner(s) or increasing the amount of heat released beyond the design of the equipment and subsequently allowing unburned fuel to enter the firebox. A slug of liquid entering a burner can also ignite and spill out of a bottom-fired burner causing danger to personnel and possibly overheating equipment outside of the heater, furnace, or boiler.

6.3.6.10 Debris in Fuel Gas Lines

Debris such as corrosion products can not only plug burner tips and risers but can also plug burner block valves and deposit within the fuel gas manifold. The latter can cause a misdistribution of fuel to the burners. Either plugging burner block valves or sediment laying down in the fuel gas manifold can change the air to fuel ratio among the multiple burners in a unit, potentially leading to afterburning or flooding.

6.3.6.11 Oil Atomization Issues

Improper atomization of a fuel oil can lead to oil dripping back through a burner causing burner fires, potentially burning personnel or igniting outside the firebox if the problem is excessive. Improper atomization can cause oil to contact tubes where the oil can ignite and elevate tube metal temperatures to unacceptable levels. Similarly, should the oil contact the refractory, the refractory could overheat and deteriorate, especially if ceramic fiber insulation is used on the casing walls.

On oil-fired burners, it is recommended to have an oil drain at the low point of the burner. Typically, this is on the burner air plenum. Routine cleaning and maintenance of the oil gun helps maintain proper atomization and helps minimize the potential for oil drips.

7 Frequency and Timing of Inspections

7.1 General

The first inspection of a heater, furnace, or boiler is necessary to confirm the anticipated rate of deterioration and to identify any unanticipated deterioration. Typically, a comparison is made with the initial inspection at the time of construction and with design records that detail considerations of corrosion, erosion, and other factors. The first inspection (baseline inspection) also helps to maintain the safety and efficiency of continued operation and forecast maintenance and replacements, based on the indicated deterioration rate. In the same way, all subsequent inspections are compared with the preceding inspection of the same specific purpose. The determination of the physical condition and the rates and causes of deterioration in the various parts makes it possible to schedule repairs or replacements prior to compromising mechanical integrity and resulting failure. Many of the parts that make up a boiler, fired heater, or furnace depend on some other part, and when deterioration and serious weakening occur in one part, some other part(s) may become unprotected or overstressed, which can shorten service life.

7.2 Boiler Inspection Frequency

The interval between boiler inspections is typically set by the jurisdiction in most U.S. states and some provinces of Canada. In jurisdictions or countries that have no such laws, the inspection interval may be set by the insurance carrier insuring the boiler. Otherwise, external and internal inspections should be scheduled periodically considering, at a minimum, the age of equipment, conditions of operation, type of equipment, kind of fuels fired, method of water treatment, previous inspection results, and deterioration rate and remaining life of boiler tubes.

7.3 Heater Inspection Frequency

Heater or furnace reliability often depends on periodic internal inspections and routine onstream monitoring and inspection. Typically, heaters are an integral section of a process unit such that internal inspection can only be accommodated during unit outages. However, the length of time between internal inspections should consider the historical and predicted deterioration rates for components (including the impact of any process change), the historical inspection findings, the results of onstream monitoring and inspection, and previous maintenance activities and their quality.

Similar information can be inputted into a risk assessment that considers the probability of failure and the consequence of failure. The inspection strategy and interval could be modified by a risk assessment. Additional information on risk-based inspection can be found in API 580. Routine onstream monitoring and inspection is a necessary component for improved reliability. Some common onstream inspections include:

a) visual inspection of the firebox and, in particular, burner flame patterns by operations personnel on a routine basis;

b) installation and monitoring of tubeskin thermocouples for tube metal temperatures;

c) periodic infrared inspection of tubes for “hot spots,” flue gas ducts, and air preheater casings to determine if refractory or insulation degradation has occurred.

8 Safety Precautions, Preparatory Work, and Cleaning

8.1 Safety

Safety precautions shall be taken before entering any heater, furnace, boiler, flue duct, or stack. In general, these precautions include, but may not be limited to, isolating energy sources, lock-out-tag-out, atmospheric gas checks, and reduction of confined space temperatures before entering. Dust and acid-containing material on internal surfaces are to be expected. The problem they present may be complicated if fuel-oil additives that leave toxic residues have been used. Protective equipment should be made available and used until it has been determined that safe conditions exist. When vanadium dust is present, protective apparatus and clothing should be used when internal inspections are performed. Consult all applicable common site-specific, OSHA, and other federal, local, and state safety rules and regulations.

8.2 General Preparatory Work

Before the inspection, the tools needed for inspection should be checked for availability, proper working condition, and accuracy. This includes tools and equipment that are needed for personnel safety. Safety signs should be provided where needed before work is started. The following tools are typically needed to inspect fired heaters, furnaces, boilers, and stacks:

a) portable lights, including a flashlight,

b) thin-bladed knife or scraper,

c) broad chisel or scraper,

d) pointed scraper,

e) inspector's hammer,

f) inside calipers,

g) outside calipers,

h) direct-reading calipers or special shapes,

i) mechanical tube caliper or micrometer for measuring the ID of tubes,

j) steel rule,

k) special D calipers,

l) pit depth cage,

m) crayon or marking device compatible with material being marked,

n) notebook,

o) magnifying glass,

p) wire brush,

q) plumb bob and line,

r) at least one type of special thickness measurement equipment (see next list),

s) small mirror,

t) magnet

u) ring gauge, and

v) 25 ft tape measure.

The following tools should be readily available in case they are needed:

1) surveyor's level,
2) carpenter's or plumber's level,
3) magnetic particle inspection equipment,
4) liquid penetrant inspection materials,
5) radiographic inspection equipment,
6) ultrasonic inspection equipment,
7) grit blasting equipment,
8) micrometer (0 in. to 1 in.),
9) electronic strain gauge caliper,
10) borescope, and
11) fiberscope.

NOTE When selecting products that can be used to mark or applied to stainless steel tubes, these products shall not contain chlorides to prevent SCC. Additionally, any equipment or paint that may contact the stainless steel tube surfaces should not be made or coated with aluminum, zinc, lead, and cadmium to prevent liquid metal embrittlement concerns.

Other related equipment that may be provided for inspection includes planking, scaffold material, a bosun's chair, and portable ladders. If external scaffolding is required, it may be possible to erect it before the unit is shut down.

Before the inspection is started, all persons working around a fired heater, furnace, boiler, flue duct, or stack should be informed that people may be working on the inside. A safety guard ("hole watch") should be stationed at the inspection door of the equipment being inspected. This person can serve as a guard and can also record data from the inspection findings.

Personnel working inside this equipment should be informed when any work is going to be done on the outside so that any unexpected noise does not cause needless alarm. Vibration of the tubes and the setting should be minimized while internal inspection work is being performed to prevent injuries due to the dislodging of loose refractory.

8.3 Precautions to Avoid PTA SCC in Stainless Steel Tubes

PTA SCC on austenitic stainless steel is a phenomenon that may also occur on the external surface of tubes during downtime under the conditions listed in 6.1.10. For heaters or furnaces with stainless steel tubes, an evaluation should be made to determine their susceptibility to internal and external PTA SCC. If deemed necessary, specific steps should be taken to prevent cracking during downtime. These procedures are detailed in 6.1.10 and in NACE SP0170. When using a soda ash wash solution to externally protect tubes, care should be taken to protect any ceramic fiber insulation from becoming wetted as the fiber can sag under the weight of the absorbed liquid.

8.4 Cleaning

Adequate cleaning is essential to inspection. There are many techniques used to clean tubes to permit inspection. Different techniques focus on the proposed inspection (e.g. coke must be removed from the inside of tubes before a smart pig can be used). This document does not cover all the methods and their application, but a summary of several common cleaning methods is included in informative Annex E.

9 Outage Inspection Programs

9.1 General

Maintenance outages provide an opportunity to gain access to the tubes and other internals to assess their present condition and to allow for data to be obtained for predicting the future reliability of the components. Inspections that can be performed during outages include, but are not limited to:

a) visual examination,

b) wall thickness measurements,

c) tube diameter or tube circumference measurements,

d) tube sagging or bowing measurements,

e) pit depth gauging,

f) intelligent pigging,

g) radiography,

h) hardness measurements,

i) borescope and video probe,

j) in situ metallography and replication,

k) dye penetrant examination,

l) magnetic particle examination,

m) tube section removal for creep testing,

n) tube section removal for metallography,

o) tube removal for detailed visual examination,

p) testing of tubeskin thermocouples.

q) refractory examination, and

r) tube support examination.

Table 3 summarizes some of the typical damage mechanisms, the associated inspection techniques, acceptance criteria, and considerations to mitigate damage mechanisms. In preparation for maintenance outages, onstream inspections should be considered in advance to facilitate defining the appropriate outage worklist (see 11.4).

Note that more information on damage mechanisms can be found in Table 3.

9.2 Visual Inspection of Heating Coils

The entire heating coil should be given a thorough visual inspection. Visual inspection is a fundamental technique to help identify the effects of deterioration, actual defects, and an indication of potential defects or weaknesses in the tubes, crossovers, fittings, and connections, including blowdown, steam, pressure gauge, vents, and thermowell connections. Conditions found by visual examination are typically followed by a more detailed inspection to assess the degree of deterioration. It provides means to focus inspection efforts.

Table 3—Recommended Inspection and Acceptance Criteria for Damage Mechanisms

Damage Mechanisms	Manifestation	Inspection Techniques	Typical Acceptance Criteria	Prevention Methods
Creep and stress rupture (3.23)	Bulge in tube	Strapping; gauging; circumference; shadows from flashlight	Maximum 1 % to 5 % growth (see 12.3)	Reduce operating metal temperature and operating stresses
Creep (3.23)	Bulge in tube	In situ metallography	No defined criteria. Assess significance and severity of creep voids and cracks.	Reduce metal operating temperature and operating stresses
Creep (or simple yielding)	Tube sagging	Measure amount of sag (e.g. with straight edges)	Generally, a maximum of 5 tube diameters over length of 35 diameters	Review metal operating temperatures, tube support systems
Metallurgical transformation of ferritic materials	High hardness	Hardness testing—TeleBrineller, Microdur, Equotip	Maximum 220 BHN for carbon steel and 280 BHN for Cr-Mo steel	Prevent temperature excursions, review burner operation and control and process flow indicators
PTA SCC of austenitic stainless steels (3.52)	Branched cracks	Liquid PT examination; UT shear wave; eddy current	No defined criteria. Can consider fitness-for-service analysis.	Use stainless steel not susceptible to PTA SCC. Use preventative measures (i.e. soda ash washing). Refer to NACE SP0170.
Thinning-external oxidation (3.48)	General metal loss	UT thickness gauging	Predicted to be above minimum required thickness at next outage	Reduce tube metal temperatures; upgrade tube material with high oxidation-resistant material
Thinning-erosion (3.27)	Localized metal loss particularly at bends	UT thickness gauging; profile radiography	Predicted to be above minimum required thickness at next outage	Review flow rates, review process fluid composition. Consider material upgrade.
Thinning-sulfidic corrosion (3.35), (3.61)	General and localized metal loss	UT thickness gauging; profile radiography	Predicted to be above minimum required thickness at next outage	Review operating conditions (i.e. concentration of sulfur compounds in process, metal temperatures). Consider material upgrade.
Thinning-H_2/H_2S (3.61)	General metal loss	UT thickness gauging	Predicted to be above minimum required thickness at next outage	Review operating conditions (i.e. metal temperature and H_2S concentration). Consider material upgrade.
Thinning-naphthenic acid (3.46)	Localized metal loss	UT thickness gauging; profile radiography	Predicted to be above minimum required thickness at next outage	Review organic acid species and concentration. Consider material upgrade.
Metal dusting and carburization (3.44), (3.13)	Localized pitting and grooving	UT thickness gauging; profile radiography	Predicted to be above minimum required thickness at next outage	Review operating temperature and process conditions. Consider material upgrade.

NOTE API 571 summarizes more information on the degradation mechanisms shown above; number in parentheses ( ) is the appropriate section of the document's Third Edition.

Tubes should be inspected externally for the following conditions:

a) sagging or bowing;

b) bulging;

c) oxidation or scaling;

d) cracking or splitting;

e) external corrosion;

f) external deposits;

g) external pitting; and

h) leaking rolls.

i) tube fittings should be inspected externally for the following conditions:

   1) damage or distortion; and

   2) corrosion.

Figure 19 and Figure 20 show examples of the bulging that may occur in tubes. Figure 21 shows an example of scaled tubes. Figure 22 shows an example of an oxidized tube. Figure 23 shows an example of a split tube. Figure 24 shows examples of the external tube corrosion that may occur during a short shutdown period on a unit that has been fired with a fuel of high sulfur content.

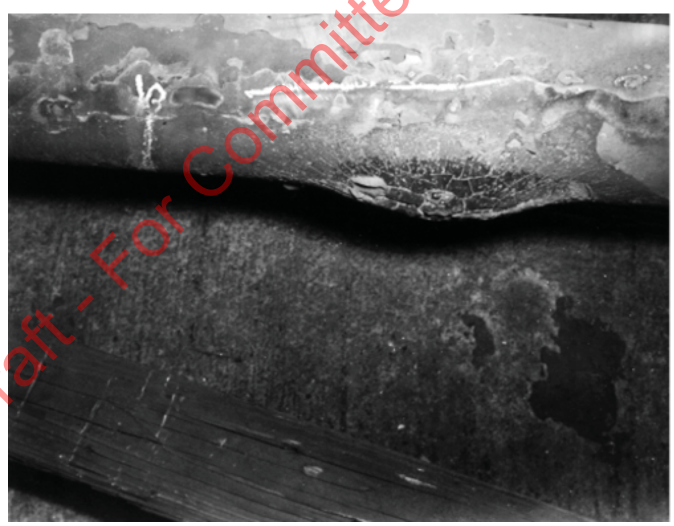


Figure 19—Bulged Tube

Because of the arrangement of the tubes and refractory walls, visual inspection of the external surfaces of the tube is usually restricted to the fireside of the radiant tubes. Special attention should be given to the following locations:

1) welds,

2) in vertical heaters or furnaces, the area from the firebox floor to approximately 20 ft (6 m) above the firebox floor,

3) entry and exit points through the tubesheets of inlet and outlet tubes, and

4) tube supports, hangers, and guides (inspect for deformation and cracking).

Figure 20—Bulged and Split Tube

All tubes rolled into fittings should be examined for leakage in the rolled joint. Leaks in tube rolls and around plugs can often be found by observing the location of coke or oily deposits around headers when the heater or furnace is removed from service. An examination should also be made when the coil is under test pressure. The inspection should be visual and should in some cases be supplemented by feeling the tube at the rear face of the fitting for indications of leakage.

Visual inspection can sometimes be facilitated by holding a small mirror between the tubesheet and the fitting to obtain a view of the juncture between the tube and the fitting. Roll leaks may not become detectable until a coil has been under pressure for 10 min to 15 min. Leakage in the tube rolls can be either a nuisance or a serious problem, depending on the process and the operating conditions. Where there is no formation of coke, the leak may be stopped by rerolling the tube. Roll leakage is serious, especially in the case of a tubes subject to coking and operate at high pressure-temperature conditions or in poisonous or highly explosive vapor service (including phenol or hydrogen service). Oil leaking between the fitting and the outside surface of the tube can result in the formation of coke. This coke formation continues with service and the force of the coke buildup can be sufficient to cause partial collapse of the tube end and to allow the tube to slip in the fitting. Under these conditions, leakage cannot be corrected by rerolling because the serration in the fitting's tube seat is full of coke and the mechanical strength of the rolled joint is not improved by the rerolling operation. Figure 25 shows an example of a fitting and a tube that have leaked in the roll.

Figure 21—Scaled Tube

Figure 22—Oxidized Tube

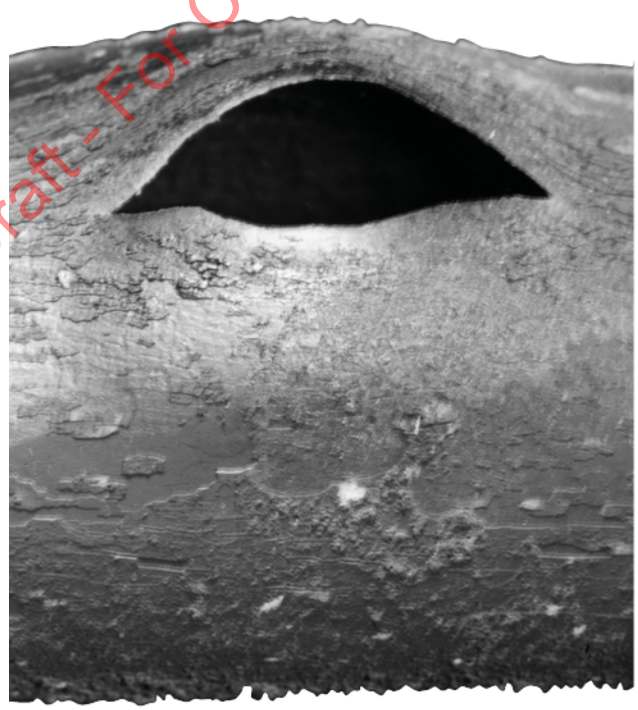


Figure 23—Split Tube

Figure 24—External Corrosion

In the case of rolled-on fittings (Figure 25), the internal surface should be inspected visually for signs of deterioration and to ascertain the fittings' general physical condition. With sectional, streamlined fittings, the housing section (the part the tube is rolled in) should be examined for undercutting, the width and condition of the U-bend seats, and excessive erosion and thinning of the housing in the annular space (the section of the housing between the end of the tube and the inside edge of the U-bend seat). The inside surfaces of the U-bend should be examined for thinning and to ascertain their general condition. With solid fittings, the body section should be examined for undercutting, the width and condition of the plug seat, and erosion and thinning of the barrel section of the body (the cylindrical section with the plug seat at one end and the tube seat at the other end) and the cross port (the connecting section between the two barrel sections).

Figure 25—Fitting and Tube that Have Leaked in the Roll

Figure 26 is a sectional view of a streamlined fitting. It shows the severe corrosion/erosion that can occur in the annular space and at the inside edge of the U-bend seat. The seating face on U-bends and plugs should be examined for corrosion, and the width of the seat should be checked against the width of the seat in the housing or body sections. If there is not a tight fit between the U-bends and the housing for the entire width of the seating surface or if the width of the seating surface is longer on one member, member erosion can be severe. This same condition should be checked on solid fittings at the closure area between the fitting body and the plug. Fittings should be examined to determine the fit and depth of seating between the U-bend or plug and the main body of the fitting. If the fitting seat has become enlarged through service, the U-bend or plug can protrude so deeply into the fitting that it is not possible to head up and get a tight joint when the fitting is under pressure. In the case of a sectional fitting, the end of the U-bend has to contact the end of the tube or the tube stop, depending on the type of tube seat used. In the case of a solid fitting, the ears on the plug have to contact the outside face of the fitting. Figure 27 shows an example of the type of corrosion experienced in U-bends.

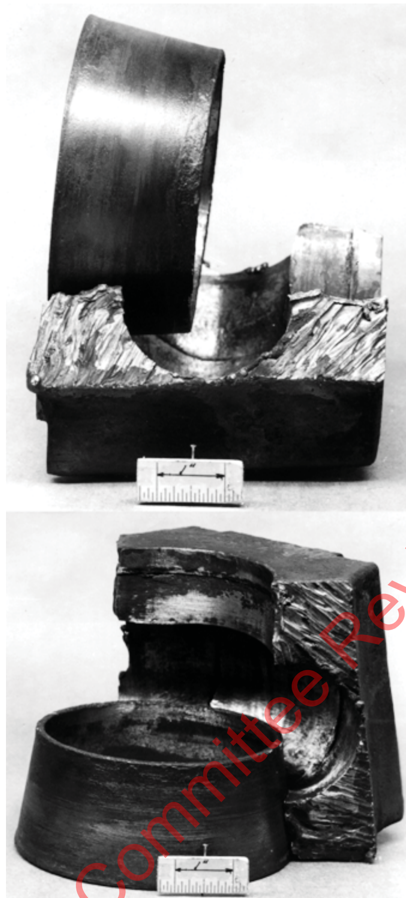


Figure 26—Corrosion/Erosion of the Annular Space in a Streamlined Fitting

In some cases, a rolled-in tube may also be welded to the fitting. The two basic reasons for welding a tube to the fitting are to stop leakage by means of a seal weld and to improve the efficiency of the rolled joint by means of a strength weld. The use of a strength weld warrants careful consideration and justification. The types of defects that are commonly found are cracking, slag, and porosity in the weld. Any welding between the tube and the fitting, regardless of its basic purpose, should be examined carefully. Review by a materials or welding engineer is recommended before any welding to the tubes.

The exterior surfaces of the fitting body and the holding members should be inspected visually. The types of deterioration commonly found on the external surface of fittings are cracking, distortion, and mechanical wear. Cracking is usually confined to the fitting body or, in the case of welded fittings, to the welded joint. Locations in the fitting body that should be examined for cracking include the area around the plug or U-bend seat, the juncture of an ear or horseshoe holding section and the main body, and the ear or horseshoe section itself. If conditions warrant, a visual inspection of cracks can be supplemented by a range of applicable surface, near-surface, or volumetric NDT techniques.

Visual inspection of the ears, the holding members, and the dogs and caps of the holding members is performed primarily to detect distortion and wear to determine whether there is a proper fit or contact and to ascertain whether the strength of the fitting has been affected. Figure 28 shows an example of poor fit between the holding section and the cap on a solid fitting. The threaded portion of the holding screw and the dog or cap should be examined for excessive wear. Distortion that is not apparent to the eye may prevent proper assembly. The plug or U-bend seat in the fitting should be examined for enlargement, deviations from roundness, change in the width of the seat, and damage to the seating surfaces. The tightness of this joint depends on these four conditions.

For welded fittings, visual inspection is limited to the external surfaces and to the weld attaching the fitting to the tube. The accessible external surfaces of the fitting should be examined closely for any indications of defects, particularly cracks in welds. The inspection of welds should cover a band of 1 in. to 2 in. (2.5 cm to 5 cm) on each side of the weld. Cracks may develop and remain entirely within the weld, or they may start in the weld and run out into the tube or fitting. The inspection of the heat-affected zone and adjacent parent metal is important, especially in the case of alloy welding. The visual inspection of a weld may be supplemented by a range of applicable surface, near-surface, or volumetric NDT techniques.

Crossover sections of tubing used to connect sections of coil may be located outside of the firebox or enclosure but should not be overlooked during inspection of a heater or furnace. Movement of the several parts of the coil and changes in temperature can cause stress and fatigue. The surfaces of the tubing, especially bend section surfaces, should be examined for cracks.

Figure 27—Corrosion of U-bends

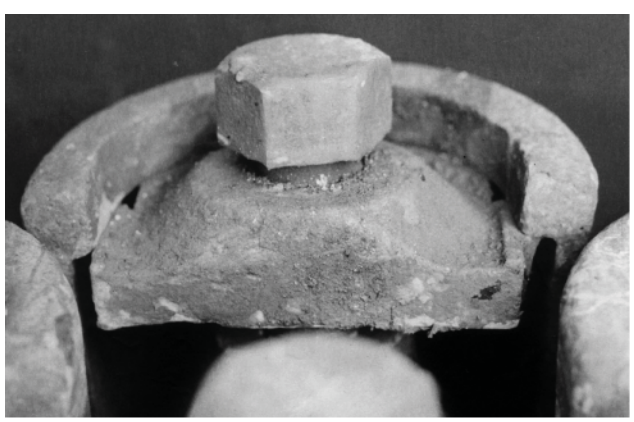


Figure 28—Spreading and Poor Fit of a Horseshoe Holding Section

9.3 Wall Thickness Measurements

9.3.1 General

The determination of the wall thickness of the tubes and fittings is an essential part of inspection. Thinning damage mechanisms can be identified and monitored through wall thickness measurements. The two basic approaches used to determine the wall thickness of piping and tubes are the following.

9.3.2 Nondestructive Methods

These include the following:

1) measurement by means of ultrasonic, laser, or electromagnetic instruments,

2) measurement of ID and OD, and

3) measurement by means of radiation-type instruments or radiography.

9.3.3 Destructive Methods

One destructive method is removal of a tube or tube section deep in convection banks and inaccessible for direct measurement of the tube wall. However, with the availability of internal ultrasonic-based intelligent pigs to measure wall thickness, the need for destructive examination is lessened.

9.3.4 Condition Monitoring Locations (CMLs)

CMLs should be selected to provide a means to determine the deterioration extent and to determine the deterioration rate. This usually involves, as a minimum, placing CMLs on all tube passes throughout the firebox. Particular attention should be made to tubes where phase changes occur and where the highest tube metal temperatures are expected. In addition, CMLs should be located on return bends to assess their deterioration. Note that the required thickness for a fitting may be different than that for the tube. For example, the inside radius of a short-radius return bend can have a higher required thickness. Typically, the number of tube thickness points is determined by criteria such as a minimum of three points per tube or readings every 5 ft to 6 ft (1.5 m to 1.8 m). Clean, corrosion-free services require fewer measurements, while high-corrosion services require more measurement points. Although spot thickness readings can identify general thinning, obtaining thickness in a circumferential band is a better approach to identify any localized conditions such as corrosion grooving. Thickness measurements should be documented and monitored where bulging, sagging, and bowing is observed.

9.3.5 Recording

Thickness measurements should be recorded and compared to historical readings in the same locations. These wall thicknesses provide a record of the amount of thickness lost, the rate of loss, the remaining corrosion allowance, the adequacy of the remaining thickness for the operating conditions, and the expected rate of loss during the next operating period.

9.3.6 Baseline

Measuring and recording the thickness of tubes and fittings when they are newly installed is considered important. If this is not done, the first inspection period may not accurately reflect actual corrosion rates. If the installed thickness of the tubes is not available at the time of the first inspection, corrosion loss is usually determined on the assumption that the wall thickness of the new tubes was exactly as specified on the purchase order. If this assumption is incorrect, an error in the calculation of corrosion rate may result.

9.3.7 Ultrasonic Thickness Examination

The ultrasonic method for obtaining tube wall thickness is the most commonly used method. For most corrosion inspections, straight-beam ultrasonic techniques are used. The sound is introduced perpendicular to the entrance surface and reflects from the back surface, which is usually parallel to the entrance surface. Proper cleaning of the external oxidation or compensating for the thickness of the oxide layer is essential to properly assess metal loss rates. In many cases, cleaning the oxide may be the only viable way to acquire ultrasonic thickness measurements from the tube's exterior surface. Application of internal ultrasonic-based intelligent pigs do not require removal of external oxide layers when measuring base metal wall thickness. These systems are described in 9.6.

9.3.8 Other Methods

9.3.8.1 General

Other methods to assess thinning of tubes include local area scanning with electromagnetic acoustic transducer (EMAT) devices and global-tube length inspection using ultrasonic guided ultrasonic wave devices. These methods are quick screening methods that highlight thinning that might be missed with spot thickness readings. Each of the methods to determine wall thickness, including measuring the ID and ODs of tubes, measuring by means of ultrasonic, laser, or electromagnetic instruments, and measuring by means of radiation-type instruments or radiography can be used to check the thickness of tubes.

Electromagnetic techniques cover a broad range of applications including eddy currents, remote testing, and magnetic flux leakage (MFL). Each technique has its own benefits and limitations. Remote field testing is commonly used on ferromagnetic tubes. It has benefits in that it can measure wall thickness and provides indications of other defect mechanisms (i.e. cracking). Most of these techniques are applied using an electromagnetic sensor device that is drawn through the ID of the tube that may require cutting the tube U-bends at the ends to gain access.

9.3.8.2 EMAT

In this method, the transducer compares a sample area of known thickness with the same material properties as the tube being examined and then either a handheld or an automated crawler head is used to scan the tube areas from the OD. If a thin area is detected, follow-up inspection using spot ultrasonic or radiographic inspection is necessary.

9.3.8.3 Guided Wave EMAT

In this method, an acoustic wave is introduced into the pipe that travels along the length of the tube. Defective areas as well as welds send back signals to a receiver that are analyzed to determine if flaws exist and at what length along the tube based on time and velocity. Then follow-up inspection using spot ultrasonic or radiographic methods is necessary to confirm whether or not flaws truly exist at the identified locations. Although guided wave ultrasonics do not provide thickness measurements of flaws detected, it is valuable in evaluating lengths of tubes where spot examination for localized corrosion may be prohibitive based on the amount of measurements that may otherwise be required.

9.4 Tube Diameter, Circumference, Sag, and Bow Measurements

9.4.1 Diameter and Circumference Growth

Tubes sustaining creep and stress rupture damage can exhibit diametral growth or sagging. Shining a flashlight along the tube length can be a quick way to identify major bulges. Frequently, the diametral growth can be localized to a small section of the tube and appear as a bulge. The bulge may be limited to the hot face of the tube and, therefore, may not be a uniform circumferential growth. Localized bulging can result from internal coke deposits causing the wall temperature to become excessive. Another potential cause is flame impingement that can elevate temperatures. It is not uncommon to find evidence of both occurrences since the elevated temperatures can promote coking in some hydrocarbon services. The amount of bulging provides an indication of the extent of damage up to the point of failure.

9.4.2 Measurement Methods

9.4.2.1 General

Measurement of tube diameter, circumference, and wall thickness can be accomplished through various methods

9.4.2.2 Ultrasonic

The use of ultrasonic in-line inspection (UT-ILI) tools, also known as ultrasonic-based intelligent pigs, can provide diametral growth measurements throughout the full coil length. These technologies are capable of accurately measuring the inner diameter of tubes for deformations such as creep, bulging, ovality, and denting with diametral measurement accuracies typically within ±0.025 in. (0.635 mm). Inspection utilizing UT-ILI can provide detection, quantification, and classification of deformations in both the radiant tubes and convection tubes of fired heaters and furnaces. These systems are further described in 9.6.

9.4.2.3 Strapping

Tube diameter or circumferential measurements provide an indication of the amount of damage. These measurements can be compared to original measurements to determine the amount of bulging and are often presented as a percentage creep growth/bulge. Measurements of the circumference can be made with a narrow and flexible tape measure (or a circumferential measuring tape that converts readings to diameter). This is referred to as "tube strapping." It is important to note that strapping measures the tube circumference. If the bulge is not uniform, the maximum tube diameter should be determined. Cleaning of the tube ODs for this method of inspection is crucial. All of the OD scale has to be removed down to sound material prior to the strapping. When cleaning the deposits, care should be taken to ensure there is no gouging of base metal.

This method is limited only to sections of coil that are readily accessible. Other techniques include tube gauges calibrated to specified diameters to determine growth or are set to specific percentage growth and used as "pass-fail" gauges. Tube gauges can be fabricated from thin stainless steel plate [0.10 in. to 0.125 in. (2.54 mm to 3.18 mm)]. The cutout dimension is the sum of tube OD, mill out of round tolerance per ASTM A530/A530M [approximately 0.0625 in. (1.59 mm)], and creep/stress rupture growth. Typical gauges are made for 2 %, 5 %, and 10 % diametral growth. These measurement techniques may not be precise if the tube is heavily scaled. In these instances, the growth may appear more severe if the scale is not removed.

9.4.2.4 Calipers

At plugged headers where access to the tube ID is available, many types of calipers are available for measuring the IDs of tubes, including the simple 36 in. (91.4 cm) mechanical scissors and the 2-point pistol type, the cone or piston type, and the 4-12-point electric type. A caliper equipped to measure several diameters around the circumference of a tube is most likely to find the actual maximum ID. Ultrasonic-based intelligent pigging that operates with the ultrasonic transducers off of the surface (immersion method) can also be utilized to acquire ID of tubes. A large amount of data is acquired over the full coil length with this method, enabling the entire coil to be modeled in a three-dimensional color format, illustrating any damage patterns that may be present.

It is general practice to caliper the ID of a tube at two locations: in the roll and in back of the roll. Since an increase in internal diameter may not be uniform throughout the length of the tube because of erosion, erratic corrosion, bulging, or mechanical damage while cleaning, it is advisable to take several measurements to determine the worst section of each tube. On tubes where the pattern of corrosion is uniform and well established and mechanical damage is known not to exist, measurements for approximately 36 in. (91.4 cm) into the tube may suffice. The roll section of a tube in service should be calipered to locate the maximum ID at any point between the back edge of the tube flare, or the end of the tube if there is no tube flare, and the rear face of the fitting or edge of shoulder left in the tube by the rolling tool.

9.4.2.5 Profilometry

There are also laser-based profilometry systems that can measure tube ID along the tube length. These devices offer high accuracy but require clean and dry conditions to provide consistent results. These systems are described in 9.6. Thinning at the ends of rolled-in tubes is usually caused by erosion or turbulence that results from change in the flow direction. This type of thinning may also result from frequent rerolling of tubes to stop leakage. Figure 29 shows an example of a tube damaged by a cleaning head. In some cases, the OD of the tube may be increased and will have the same general appearance as a tube with a slight bulge.

9.4.2.6 Other

Specialized ultrasonic and eddy current liftoff devices on crawlers can measure the circumference and diameter of tubes. These specialized external tube crawlers are commonly used when inspecting steam-methane reformer tubes.

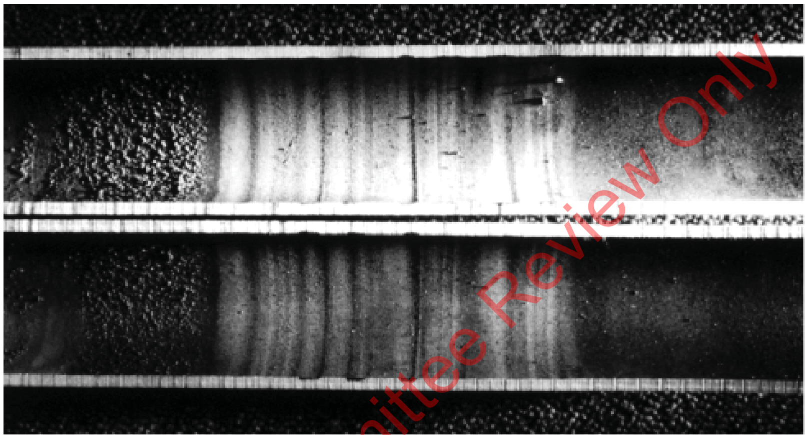


Figure 29—Tube Damage Caused by Mechanical Cleaning Equipment

9.4.3 Nonuniform Corrosion and Detection

Figure 30 shows an example of eccentric corrosion of a tube. The loss of wall thickness is not uniform around the circumference. In this type of deterioration, the most thinning usually occurs on the fireside of the tube. This type of corrosion is generally accelerated on the fireside because of the high metal temperature there. Eccentric corrosion may also be caused by external scaling. It is often difficult to determine whether tubes have become eccentric as a result of service, because the condition is not readily detectable by visual inspection of the tube ends. An indication of eccentric corrosion can sometimes be found by measuring the diameter in several directions at one location. A reliable means of detection is to measure thickness with ultrasonic-type, laser-type, or radiographic-type instruments, but these tools can only be used on accessible tubes, usually the radiant tubes. Ultrasonic-based intelligent pigging can be applied to quickly detect and quantify eccentric corrosion damage throughout the convection, crossover, and radiant tubes. Although this type of corrosion is more common on radiant tubes, it has occurred on convection tubes, usually on those tubes adjacent to the refractory.

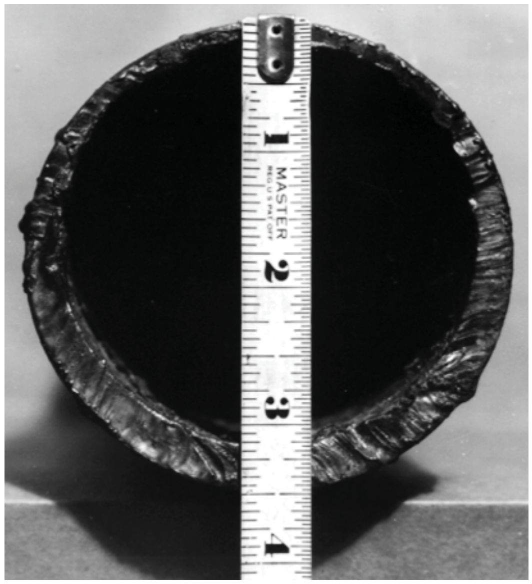


Figure 30—Eccentric Corrosion of a Tube

9.4.4 Sagging and Bowing

Shining a flashlight along the tube length can be a quick way to identify sags and bows. Tube sagging is another indication of creep damage or short-term overload. In this case, the stresses are longitudinal and usually result from inadequate support or excessive temperature. Excessive sagging is often caused by short-term overheating because of runaway decoking or loss of flow. In such cases, the tubes should be hardness checked to ensure adequate strength remains and the thickness should be measured. If sagging is caused by long-term creep, a criterion (i.e. 1 % to 5 % elongation) should be used depending on the material.

Tube sags are estimated as the distance offset from straight. In reality, the tube is flexible and can have some natural amount of sag and so the measurement may not be precise. Sag measurements can be used similar to diameter measurements to estimate the extent of creep. A significant amount of sag can be tolerated before rupture is a concern, and so this condition is not considered serious unless it prevents cleaning or causes headers to jam and wedge against other headers or against the sides of the header compartment. In convection sections, sagging of the tubes in upper rows to a point between those in lower rows can prevent the free passage of flue gas around the tubes. This condition (called nesting) may cause overheating of adjacent tubes and draft loss. If this condition is found, the offending tubes should be replaced.

9.5 Pit Depth Measurements

General pitting of the external tube surface should be evaluated with a pit depth gauge to assess the depth and to estimate a pitting rate. The gauge should be used in conjunction with an ultrasonic thickness gauge to more accurately determine remaining wall thickness. Scale on the tubes can mask pits, and so it is prudent to remove scale in selected areas to find the deterioration.

9.6 Intelligent Pigs and In-line Inspection Devices

9.6.1 General

Recent technological advances have produced “intelligent pigs” that can perform multiple inspection functions from inside of the tube. These devices utilize immersion-based ultrasonics to measure tube IDs in both ferritic and austenitic tube coils. Simultaneously, the same ultrasonic transducers measure the tube wall thickness. The instruments are outfitted with multiple ultrasonic transducers or a rotating mirror to permit high-density sampling. These inspection tools are useful in addressing creep, corrosion, erosion, or pitting-type damage mechanisms.

9.6.2 Applications

These devices are suitable for welded carbon and stainless steel convection section, radiant section, and crossover piping coils. Radiant section coils with radial insert plug headers can also be inspected using these devices. These devices are not suitable for cast materials or radiant section coils with flat insert plug headers. Though no scaffolding is required to utilize these devices, intelligent pigs operate in a bidirectional mode and require only a single point of entry to the coil's ID to launch and receive the intelligent pig.

9.6.3 Tubes of Changing Diameter

Some intelligent pig designs are capable of inspecting coils with changing diameters. Prior to inspection of multi-diameter coils, it should be verified that the working diameter range of the intelligent pig covers the range of diameters for the coil. It may be possible to inspect the coil utilizing multiple intelligent pigs when the diameter range of the coil exceeds the working range of the intelligent pig. In addition to verifying the working diameter range, the owner-user should confirm with the service provider or equipment manufacturer that the intelligent pig is capable of measuring the thickness range that exists in the coil.

9.6.4 U-bend Considerations

Intelligent pigs are self-contained units and are capable of navigating the short radius 1D × 180° U-bends (see Figure 31). This is a significant advantage for inspection of convective section tubes that cannot be accessed. Generally, convective tubes only receive a rudimentary visual inspection, and their condition is estimated from inspections performed on other components of the such as the convective tube U-bends and radiant tubes. The pigs are propelled through the tubes using a liquid medium (i.e. water, soda ash solution, diesel, glycol) to act as both couplant and hydraulic vehicle and allow a thorough, complete inspection of a tube pass. The pig also contains axial positioning capabilities that enable precise location of the damage mechanism to be identified. Users are cautioned to understand the capability of the intelligent pig to accurately measure the wall thickness and tube inside diameter of U-bends and other fittings. The complex geometry of these locations can make conventional inspection practices difficult.

Figure 31—Intelligent Pig Positioned in Short Radius 1D × 180° Return Bend

9.6.5 Other Methods

Other technological advances for in-line devices have produced various other pig or crawler technologies. One method is an internal ultrasonic pig that uses an internal rotary inspection system. The pig is designed to maneuver around bends being pushed along by motive water force. The device has a spinning ultrasonic immersion transducer (i.e. a transducer aimed at an angled-spinning tungsten mirror used for reflection or a specially designed membrane that allows transmission and protects an angled spinning centrally located transducer head). This method is accurate if there is no debris or scale on the tube ID and should accurately determine the extent of ID and OD corrosion.

9.7 Radiographic Examination

Radiographic examination is often employed to measure tube wall thickness and identify the presence and thickness of internal coke deposits. Radiography can show a variation in thickness of a minimum of 2 % of total thickness. Thickness is determined by directing the rays tangentially to the tube wall and recording the radiation on a film behind the tube. By comparing with some geometric standard projected on the film, the wall thickness can be determined. Performing radiography at various angles to the tube allows wall thickness measurements in other planes. Additionally, localized thin areas can often be identified by radiography that could be missed by other techniques (i.e. spot ultrasonic readings). For example, radiography is often employed to identify wall loss on return bends in erosive service.

9.8 Borescope and Videoprobe

The internal visual inspection of tubes is limited to coils with fittings of the removable U-bend or plug type. On tubes up to about 30 ft (9 m) in length, it is possible to view the entire interior reasonably well if a light is inserted at the end opposite the one at which the tube is being examined and the examination is made from both ends of the tube.

The inside surface of a tube can be examined with optical instruments. Considerable time is required to inspect the full length of tube. Consequently, optical instruments are generally used for the more thorough inspection of questionable areas revealed by visual inspection or to assess internal fouling/deposits and measure pit depth using stereoscopic measuring lenses. Most optical equipment today allows videotaping of the images. The videotape can serve as a record of the internal inspection and allows better comparison of conditions in the future.

The internal visual inspection of tubes can be made to locate and determine the extent of the following types of deterioration commonly experienced in tubes:

a) selective, spot-type, or pit-type corrosion;

b) thinning of tube ends;

c) cutting or other cleaning damage;

d) loosening of the tube roll and flare;

e) erosion; and

f) fouling and coke deposits.

Figure 32 shows examples of the spot-type or pit-type corrosion often found in tubes. This type of corrosion is one of the most difficult to detect. Visual inspection can be hindered if the internal surfaces of the tubes are not free from coke and any other foreign matter. Mechanical cleaning does not always reveal spot-type or pit-type corrosion. If this type of corrosion is apparent or suspected, the inside surfaces of the tube at the tube ends might be cleaned using an acetylene torch to burn coke or grit blasting material out of the pits. Grit blasting is also preferred and least likely to damage the tubes as may happen with an acetylene torch.

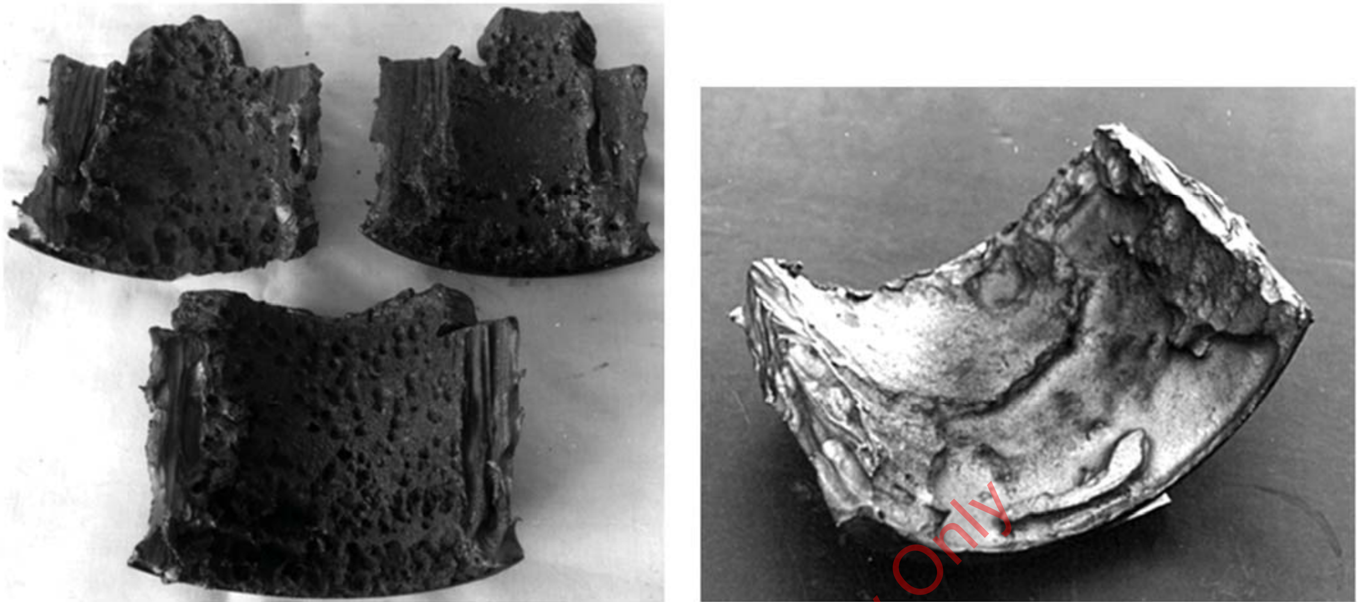


Figure 32—Spot-type and Pit-type Corrosion

9.9 Hardness Measurements

Hardness testing of ferritic tubes can indicate that the tubes experienced a severe overheat or identify some forms of embrittlement or carburization. A severe temperature excursion exceeding the lower critical transformation temperature of the metal can cause a hard microstructure to result if the cooling rate is fast enough. If the cooling rate is slow, softening may actually occur. The hard tubes can be susceptible to brittle fracture if they are mishandled or impacted. They can also be susceptible to some forms of stress cracking like sulfide stress cracking during downtime. Refer to API 530 for a listing of material transformation temperatures.

Hardness testing of ferritic tubes can also be used to qualitatively determine how evenly the tubes are fired. In Cr-Mo tubes, thermal softening can occur at elevated temperatures. Tubes in the firebox that are softest may represent the hottest tubes. Softening can indicate a reduction in tensile strength for a ferritic material.

External carburization and 885 °F embrittlement can be identified through hardness changes. With each mechanism, there will be a noticeable increase in hardness. However, if the depth of carburization is not significant, the field test instruments may not identify a change and measure the base metal hardness below the hardened layer.

Hardness measurements can be made using available sonic and impact field testing instruments. Caution should be taken when obtaining hardness measurements to assure adequate surface preparation. Surface roughness and oxide scale can dramatically affect the hardness value.

In general, tubes with hardness outside the normal range (either excessive hardness or excessive softening) should be evaluated for continued service and appropriate repairs made if necessary. This evaluation may require the review of someone with knowledge of the service and potential damage mechanisms that may result.

9.10 Dye Penetrant and Magnetic Particle Examination

Dye penetrant and magnetic particle examination often supplement a visual examination for cracking. If cracks are suspected or expected based on experience, one or more of these techniques are employed. Austenitic stainless steel components are often dye penetrant inspected, while ferritic metallurgies receive a magnetic particle inspection for cracks. Austenitic stainless steel tube welds are often penetrant examined when external PTA SCC is a concern. Other common locations where either dye penetrant or magnetic particle examination is used depending on the metallurgy include inspecting attachment welds of tubeskin thermocouple, tube hangers, and tube supports. Dye penetrant can be used on ferritic steels as well; however, it is more common to magnetic particle examine those components since magnetic particle examination is quicker.

9.11 In Situ Metallography and Replication

As indicated previously, certain types of deterioration experienced in tubes result from some change in metallurgical structure. The more common types of deterioration are carburization, decarburization, the initial stages of external SCC, creep, fatigue cracking, and some forms of hydrogen attack.

It is possible to detect most of these types of deterioration in the field by visual inspection, nondestructive testing, in situ metallography, or replication. Carburization and decarburization can be determined accurately by a chemical or physical test. Most of the testing should be done by specially trained personnel. Damage that results from some metallurgical changes can be determined by a wide range of NDT techniques designed for the characterization of material degradation (e.g. ultrasonic, magnetic particle, and liquid penetrant examination). In situ metallography and replication are rarely used alone for evaluation of these damage mechanisms. It is best used in combination with other NDE techniques.

9.12 Detailed Examination and Destructive Testing of Tube Samples

9.12.1 General

When deterioration cannot be effectively identified or monitored in service, obtaining tube samples for destructive examination may be appropriate. Metallographic examination can be performed for identification of deformation mechanisms such as decarburization, carburization, hydrogen attack, and stress cracking. Physical testing of creep life can be appropriate for severe services and for affirming any calculated remaining life. Oftentimes, calculated remaining tube life includes several assumptions of tube operating history that can lead to inaccurate results. The density of scale samples can be measured and may provide information on the tube operating history. Furthermore, physical properties of the tubes can be measured that can assist in damage assessments. Additional information is available through other technical documents.

Prior to removal of a tube section, consideration should be given to the ability to make the repair weld between the new tube section and the existing tube sections.

9.12.2 Internal Inspection

Often, tubes are not accessible for an internal visual inspection. Some companies make a practice of thoroughly inspecting all tubes that are condemned and removed from a heater, furnace, or boiler, regardless of the reason for the tubes' removal. This inspection is made by cutting a tube into short sections of 2 ft to 3 ft (60 cm to 90 cm) so that the inside surface can be examined. Measurements for metal-wall thicknesses are made at the ends of each section. In some cases, the sections are split longitudinally, thus exposing the entire inside surface for examination. The ends of the tube rolled into the fitting should be removed for examination. They may then be inspected to determine the general condition and effectiveness of the rolled joint.

9.12.3 External Inspection

When external deterioration, including that due to oxidation, scaling, cracking, and external corrosion, is suspected, especially in the case of convection tubes, representative tubes may be removed, then cleaned and examined thoroughly. The selection of the tubes to be removed may be guided by the tube locations, the length of time the tubes have been in service, and the general appearance of the tubes in the area. If the tubes chosen for inspection are found to be defective or unfit for further service, other tubes in the same area and of the same or similar age and general appearance should also be inspected.

9.13 Testing of Tubeskin Thermocouples

During outages, tubeskin thermocouples should be tested for accuracy and potential failure. Tubeskin thermocouples may be inaccurate or fail prematurely. Inspection and testing during outages is an important step to improve reliability. Thermocouple leads are often the root failure by being exposed to flame and radiation. The sheathing protecting the thermocouple leads should be inspected for any breaches and kinks. The thermocouple will also read inaccurately if it lifts off the tube surface. Attachment welds should be inspected with dye penetrant for cracks that can cause the thermocouple to read firebox temperature.

Some thermocouples can have a temperature drift due to long-term exposure or temperature cycling. Procedures can be developed to determine if the tube temperature is accurately measured by heating an area adjacent to the tube and monitoring the temperature rise. A calibrated contact pyrometer can measure temperature at that point and be used for comparison to the thermocouple.

9.14 Magnetic Test for Carburization

Austenitic tubes are essentially nonmagnetic. Carburized areas of the tubes become magnetic, and if these areas are large, they can be detected with a magnet. A magnet on a string dropped down a tube can indicate areas that are magnetic but cannot indicate the depth of carburization. There are several commercially available devices that are used for measuring the ferrite content of austenitic welds that may be suitable for identifying localized areas of magnetism in tubes (see Figure 33). Some instruments and field services can relate the degree of magnetism to the depth of carburization. Most of the instruments are proprietary and the field services are limited.

A rule of thumb states that up to 50 % carburization can be tolerated onstream before loss of strength materially affects tube life. Although this rule of thumb indicates that a tube with 50 % carburization should be replaced, it does not mean that a tube with less than 50 % carburization cannot remain in service until the next shutdown. Factors including the rate of carburization, the expected service time until the next shutdown, the amount of excess metal, and changes in pressure and temperature should be taken into account. Tubes that are heavily carburized may be difficult to field weld successfully when replacing coil components. Measuring the relative local carburization levels in a coil to find locations that are less carburized may be useful in determining the best location for repair welds.

Figure 33—Various Magnetic Measurement Devices (Clockwise from Top Left: Severn Gauge, Feritscope, and Magne Gauge)

9.15 Hammer Testing

A hammer test has been an accepted method of exploring the surface of metal objects to locate areas of substantially reduced wall thickness; however, other NDE techniques, particularly ultrasonic thickness testing, have made this technique outdated. When a hammer test is made, the variations in metal-wall thickness are indicated by the feel and rebound of the hammer and by the sound produced. One value of hammer testing is that it is a good way to determine whether the scale on the outside surface of a tube is an oxide due to overheating or a product of fuel combustion. Although combustion deposits vary in texture depending on the fuel used, the scale that results from oxidation is generally harder, requires a stronger blow to be knocked loose from the tube, and is of a flakier texture than scale from the products of combustion. A magnetic check of the material offers the most conclusive test; oxide scale is magnetic, and scale from the products of combustion is nonmagnetic.

Tubes that have been in service may become temper embrittled and have low ductility at ambient temperature. To avoid any possible damage, carbon and alloy steel tubes should have a minimum metal temperature of about 60 °F (15 °C) during hammer tests. In certain cases, the hammer testing of tubes can lead to damage. Austenitic stainless steel tubes may suffer SCC at areas that are cold worked by hammering. Cast austenitic stainless steel tubes and Cr-Mo ferritic tubes should not be hammer tested when tubes are heavily carburized.

9.16 Inspection of Steam-Methane Reformer Tubes

9.16.1 General

In addition to the methods mentioned in 9.4, there are several other effective methods for inspecting reformer tubes.

9.16.2 Laser Profilometry

Creep strain within steam-methane reforming and pyrolysis furnaces typically develops in the form of bulging or swelling. Laser profilometry has been successfully applied to inspect spun-cast high-alloy tubes. The technique can measure the diametral dimensions of the tubes from either the tube interior (if the catalyst is removed) or the tube exterior. The laser profilometry method enables modeling the tube in a color three-dimensional format, revealing both localized and general areas of concentrated creep strain. Data are presented in a quantitative format that can then be applied to generate tube remaining life assessments on the full tube length or within localized regions. By combining the produced images of each individual tube, overall damage patterns within the heater can be identified (see Figure 34).

9.16.3 Ultrasonic Refracted Longitudinal Wave and Time-of-flight Diffraction (TOFD)

Creep cracking of cast tubing used in steam-methane reforming and pyrolysis furnaces usually starts near the mid-wall of the heater tube and is normally longitudinal, resulting from hoop and thermal stresses in the tube.

Ultrasonic equipment that implements through-transmission (i.e. pitch catch) has been used to inspect tubes. With this attenuation method, a grading of percent transmission is made to draw some conclusions about the degree of fissuring that attenuates transmission of the ultrasound. Since tubes vary in the amount of equiaxed and columnar grains, the calibration standard used should reflect the tubes being inspected. Without an adequate standard, the judgment of percent transmission may be in error.

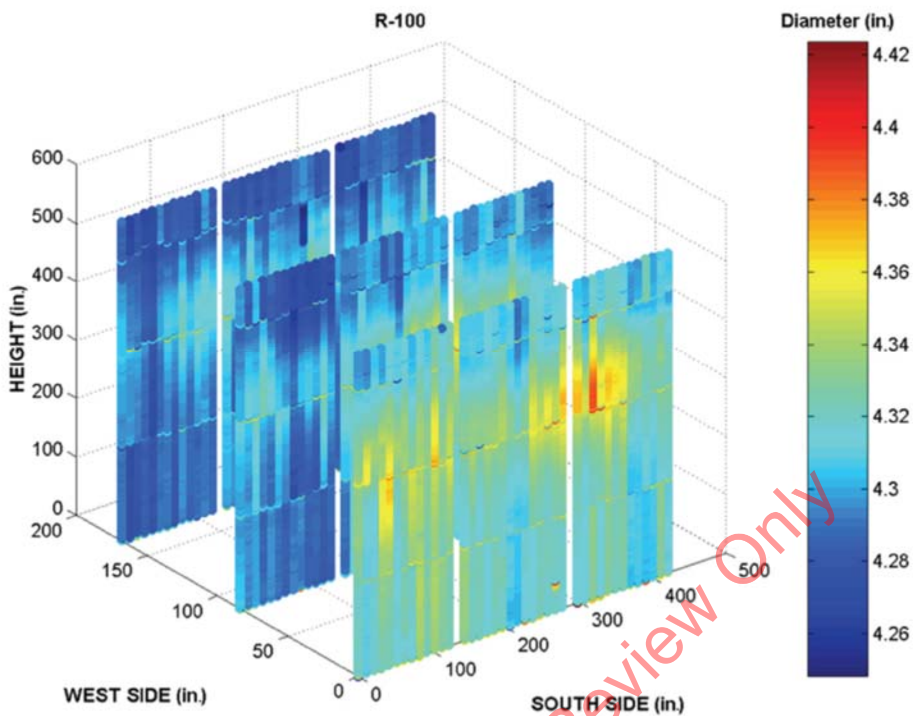


Figure 34—Laser Profilometry Results

Ultrasonic TOFD has also been used to compliment through-transmission tube inspection. TOFD is a method that detects diffracted waves coming from the tips of flaws and is best used to detect severe flaws (i.e. fissures in steam-methane reformer tubes).

Assessment of degradation using these ultrasonic techniques may be accomplished by performing a baseline examination and recording trends over a period of time. A "snapshot" inspection may not adequately assess damage because of the many variables involved.

Evaluations of tubes have indicated that the initiation of internal fissuring can eventually cause the tube to fail. Major fissuring, which is easily detected, indicates that failure may occur in up to 10,000 hours. Since such a wide range of tube life is available for evaluation, a risk analysis should be made. Tubes that are expected to fail in less than 1 year should be replaced. Tubes that may be good for several years may be allowed to remain in service until the next scheduled shutdown when they can be re-inspected or replaced. Replacement tubes can be ordered so that they are on hand when needed. All these evaluations have to be based on the assumptions that the original design and casting quality are adequate and that operation, especially with respect to tube metal temperature, is within the design limits.

9.16.4 Radiographic Inspection

Radiographic methods have been used to inspect reforming tubes. However, tight cracks cannot readily be seen unless they are normal to the film. When catalyst is in the tubes, the tight cracks may be harder to find because of the varied film densities and the catalyst edges that are present. It is desirable to remove the catalyst from the tubes, but this is not normally practical or economical when the catalyst is not scheduled for replacement.

Radiographs can show cracks regardless of whether there is catalyst in the tubes. However, radiography may not be as sensitive to initial fissuring and tight cracks as is ultrasonic inspection. If radiographs do show cracks, the cracks can be judged on the basis of how many there are and how wide they appear to be on the radiograph. Normally, dark, wide cracks on a radiograph indicate that the cracks are open to the ID of the tube and that the tube should be replaced.

9.16.5 Eddy Current

Eddy current inspection of stainless steel steam-methane reformer tubes is employed to identify crack-like defects. The principal behind eddy current inspection is that a defect changes the energy flux induced in the material through a magnetic field. Caution should be taken when applying eddy current as variations in material permeability can result in false positives. For austenitic stainless steels, the energy field penetrates up to 1 in. (25 mm) deep, which is greater than the wall thickness of most tubes. This technique can be performed externally without removal of the catalyst.

Some operators have found it useful to assess data from a combination of technologies (i.e. diametral, laser profilometry, eddy current, and ultrasonic). The advantage of using multiple technologies is a cross-comparison of results, particularly for the case where a damage mechanism may be sensitive to multiple methods.

Most commercial equipment can grade each tube in terms of relative creep damage based on characteristic signals within a particular type of material. In addition, some equipment can also measure wall thickness ultrasonically and tube diameter as it travels along the tube. Diameter changes in tubes can also be determined through laser profiling from the tube ID. These additional measurements combined with eddy current and ultrasonic test results can allow an assessment of relative creep damage. Grading of individual tubes combined with subsequent repeat examinations may enhance tube damage trending and ultimate tube replacement planning.

9.16.6 Onstream Repairs

Heaters with external pigtails have been operated to tube rupture. In such cases, pigtail nipping has been used to crimp the inlet and outlet pigtails to cut off the inlet and outlet gases. Designs for pigtail nippers are available but should be checked to ensure that the hydraulic-system pressure is enough to cut off all flow [usually over 5000 lbf/in.^{2} (34.4 MPa) gauge], that stops are on the anvils to prevent the pigtail from being cut off (the design should be based on wall thickness), and that some locking device is available to keep the crimp closed when the pigtail nipper pressure is released for removal of the hydraulic cylinders.

9.17 Inspection of Pigtails

Pigtail failures typically occur due to the combination of intergranular creep crack growth from repeated loading and high-temperature oxidation. During outages, liquid penetrant inspection can be used to identify areas of cracking along the length of the pigtail. Creep strain damage can be assessed by using digital calipers to measure the creep strain on the OD of the pigtail.

10 Boiler Outage Inspection

10.1 General

Before the boiler is cleaned, it is a good practice to perform a preliminary inspection of the inside of all equipment to the extent practicable. The location, amount, physical appearance, and analysis of mud, sludge, or scale deposited on the inside of shells and drums can provide information about the effectiveness of the feedwater treatment, blowdown operation, and methods of cleaning needed. The preliminary inspection may also be helpful in determining which parts of shells or drums require the closest inspection. Heavy internal or external scale found either on drums or tubes is an indication to inspect the area closely for metal overheating. Flow marks in fly ash or soot deposited on the baffling can help locate gas leaks in it. Any conditions that indicate that close inspection is required after cleaning should be noted.

The detailed inspection may proceed after the preliminary internal inspection and general cleanout. Inspection personnel should be familiar with the operation and design of the type boiler and inspect in a way that provides information necessary to determine the boiler's ability to operate properly for the next run length. To perform an appropriate inspection, access is necessary to all major components. All manhole covers and a sufficient number of handhole plates should be removed for inspection. Representative tubes should be made accessible for as much of their lengths as possible from inside the firebox. Steam drum internals may also need removal to allow access to tubes. Ordinarily, it is not necessary to remove insulation material, masonry, or fixed parts of the boiler, unless defects or deterioration peculiar to certain types of boilers are suspected. Where moisture or vapor shows through the covering, the covering should be removed and a complete investigation made.

In preparation for maintenance outages, onstream inspections should be performed in advance to facilitate defining the appropriate outage worklist (see 11.4).

10.2 Piping

10.2.1 Visual Inspection

A visual inspection should be made for evidence of leakage in pipe and threaded or flanged pipe joints. Water leaks may be detected by the presence of moisture or deposits at the point of leakage and steam leaks by the appearance of the adjacent metal.

10.2.2 Leaks

Leaks may sometimes be a result of strains caused by deformation or misalignment of the piping system. Deformations may be caused by lack of provision for expansion or by improper supports. If not eliminated, pronounced deformation may place strains of sufficient magnitude to cause failure in small connections. A careful inspection should determine if such defects are present.

10.2.3 Flanged Connections

When flanged connections are opened, gaskets and gasket seats should be inspected carefully. Gaskets may be damaged by leakage or by improper centering of the gasket when the joint is made up. Gasket seats may be scored by a steam leak at the joint, improper handling, or careless use of tools. Seating surfaces should be inspected for tool marks, other mechanical abuses, and evidence of the type of erosion commonly called “steam cutting” or “wire drawing.” Mechanical damage may lead to erosion if not corrected. A scored seat should be machined to provide a proper gasket face or the flange should be replaced; otherwise, leaks can reoccur. Before joints are remade, ring-joint (RTJ) gaskets should be examined to determine their fitness for reuse. Other types of gaskets should be replaced with new ones.

10.3 Drums

10.3.1 Overview

All internal surfaces and the connections to all outside attachments, including water-column connections and safety valve nozzles, should be examined for deformation, corrosion, pitting, grooving, cracking, scale deposits, and sludge accumulation. Special attention should be paid to all seams, whether welded or riveted, and to the areas adjacent to them. If seams are heavily coated, they may have to be grit blasted or wire brushed before a visual examination is possible.

10.3.2 Welded Seams and Connections

Welded seams and connections should be examined for cracks. Riveted joints should be checked for loose or broken rivets, cracking, or other evidence of distress. Rivets should be hammer tested for soundness. If there is any evidence of leakage or other distress in lap joints, it should be investigated thoroughly, and if necessary, rivets should be removed or the plate should be slotted to determine whether cracks exist in the seam.

Corrosion along or immediately adjacent to a seam may be more critical than a similar amount of corrosion away from the seams. Such points should receive a close visual examination and ultrasonic wall thickness measurements. Grooving and cracks along longitudinal seams are especially significant, as they are likely to occur when the material is highly stressed. Severe corrosion is likely to occur where the water circulation is poor. Both the internal and external surfaces of the drum need examination. The top external surface of drums should be cleaned of all deposits, and the surface should be examined for corrosion.

10.3.3 Additional Inspection

When a more thorough examination for cracks and other defects in plate and weld metal is desired than can be obtained by a visual inspection, a radiographic, magnetic particle, ultrasonic, or dye penetrant test may be used as follows:

a) radiography can identify cracks below at or near the metal surface if they are of sufficient size and oriented properly to make a discernible change in the film density;

b) dry powder magnetic particle examination can determine cracks at or near the surface;

c) wet fluorescent magnetic particle examination (WMFT) uses either a black or blue light for finding discontinuities and is more sensitive to tight cracks than dry powder;

d) ultrasonic straight beam and shear wave tests can indicate discontinuities in the metal at any depth;

e) dye penetrant test is used to locate surface cracks in large or small areas; and

f) electromagnetic inspection techniques may be used for surface and sub-surface crack detection instead of magnetic particle examination and liquid penetrant examination.

10.3.4 Other Drum Issues

Inspection of the steam drum should also include observations of the normal water level. Any bulges or uneven areas that may indicate excessive heat input from leaking fireside baffles should be noted. Evidence of poor circulation may be indicated by waterline gouging along the top half of the top one or two rows of downcomers. This is sometimes accompanied by flash marks on the drum surface at the tube openings. If a sample of the boiler drum is needed for chemical analysis or microscopic examination, a section may be trepanned from the wall. The resulting cavity should need to be evaluated for repair by a suitable method (i.e. welding). Normally, the wall thickness is measured ultrasonically and recorded to establish corrosion rates and remaining life estimates.

10.3.5 Drum Internals

Drum internals and connections to the drum should be inspected when the drum is inspected. Drum internals, including internal feed header, distribution piping, steam separators, dry pipes, blowdown piping, deflector plates, and baffle plates, should be inspected for tightness, soundness, and structural stability. The vigorous turbulence of the steam and water mixture present in the drum may vibrate such parts loose from their fasteners, attachments, or settings. When these parts are welded in place, it is not uncommon for the welds to crack from vibration. Welds or rivets attaching internals or connections to the drums should be inspected in the same manner as welds or rivets in the drum proper. Steam separators and baffles should be carefully inspected for tightness, corrosion, and deterioration, and associated welds should be checked for cracks. Any bypassing of the steam separator can allow carryover into the superheater, causing salt deposition, resultant overheating, and possible tube failure. Steam separators should be free from deposits that might impair their operation. Some boilers do not have steam separators and depend entirely on dry pipes for water separation.

The holes in dry pipes should be free from any deposits that might restrict flow. Since dry pipe holes are in the top of the pipe near the top of the drum, it may be necessary to inspect the holes indirectly with a hand mirror. Any drain holes in the pipe should also be inspected for freedom from deposits and scale. Not all drums contain dry pipes.

The inspection methods and limitations described in API 572 are applicable to all drums forming any part of a steam boiler.

10.3.6 Appurtenances

Safety-valve nozzles and gauge-glass connections, especially the lower connections, should be examined for accumulations of sludge or debris. A flashlight should be used to visually inspect the nozzle or connection. If the inside cannot be observed directly, a small hand mirror may be used for indirect observation. Special forms of illuminating equipment, mirrors, and magnifying devices are useful for this type of inspection. When the boiler contains more than one drum, usually only one of the drums has safety valves on it.

Any manhole davits should be tested for freedom of movement and for excessive deformation. Manhole and handhole cover plates and nozzle seats should be examined for scoring in the manner described in preceding text for pipe flanges. Cover plates should be inspected for cracks.

10.4 Water Headers

10.4.1 Handholes

Each handhole and handhole plate seat should be examined for erosion, steam cutting, tool marks, and other damage that might permit leakage. If the plate has leaked previously, it should be checked for trueness and possible deformation. Seating surfaces and faces of handholes should be examined for cracks. It may be necessary to use a hand mirror to inspect the handhole seats.

10.4.2 Internal

The inside surface of the headers should be inspected for corrosion and erosion. The location and amount of scale buildup should be noted, and the tube ends should be checked for pits, scale, cutting, or other damage from tube cleaners and deposit buildup. If there is considerable scale or deposit buildup, the flow may be restricted to the point that tubes become overheated because of insufficient circulation. Deposits and scale should be removed with a scraper and the depth of coating determined. Lower waterwall headers are particularly susceptible to heavy deposit buildup.

10.4.3 Downcomers

Downcomers and risers should also be inspected for scale or deposit buildup. Thickness readings of headers should be obtained periodically by ultrasonic technique. The headers should be calipered whenever tubes are removed.

10.4.4 External

External surfaces of headers should be examined either directly or indirectly with mirrors, and particular attention should be paid to the points where tubes enter the header for indications of leakage from the tube roll. The header surfaces adjacent to tube rolls and handholes should be inspected for cracks. If external inspection of headers reveals pitting, thickness measurements should be made using ultrasonic techniques.

10.5 Superheater Header

10.5.1 Handholes

Inspections of superheater headers should be conducted in a manner similar to that for waterwall headers. Typically, not all superheater handholes are opened at every boiler shutdown or cleanout unless tubes are to be replaced or other repairs are to be made. However, a few should be removed at every shutdown as a spot check. If the unit cycles frequently, some of the ligaments between tubes should be examined for cracking with either ultrasonic or wet fluorescent magnetic particle testing, depending on access.

10.5.2 Internal

Since only dry steam passes through the superheater, there should be few or no deposits present in the headers or tubes. If deposits or scale are present in any degree, immediate steps should be taken to determine why they are present. In addition, the extent of the deposits or scale should be investigated. Superheater tubes with a moderate deposit of scale can rupture readily from the effects of overheating. Indications of scale or deposits should lead to an investigation of the steam separators, dry box, operating drum level and fluctuations, blowdown rates, and water quality.

10.6 Tubes

10.6.1 General

The inside of straight tubes should be examined as far as they are accessible with strong illumination. Straight tubes should be examined by illuminating the end away from the observer. Ultrasonic and laser profilometry test methods can provide inspection over the tube's full length.

Ultrasonic examination, laser profilometry testing, and radiography are some of the methods that may be used to inspect for tube wall loss caused by corrosion. Tube ligaments should be examined for cracks. If tubes are covered by baffle or deflector plates, a few of these plates should be removed to permit a spot check of the condition of the tubes behind them.

Internal cleanliness is required to conduct a satisfactory tube inspection. When tube cleanliness is in doubt, a turbine-type cleaner should be used to remove internal deposits. The loosened deposits should be trapped at the discharge ends. The weight of trapped deposit and the internal surface area can indicate the average thickness of the deposit removed.

Fiber optics or borescopes are of limited use on bent tubes but are satisfactory for viewing straight tubes and may also be used to inspect tube internals. Tube ends should be checked for proper projection and flaring. Calipers, micrometers, laser profilometry, and ultrasonic instruments can be used to measure tube diameters, dimensions of bulges on tubes, depth of corrosion pits, and tube wall thickness. These measurements are of great value in determining the effects of corrosion and erosion and in estimating the future lives of the parts measured. Tubes should also be checked for any cutting due to cleaning. Figure 35 is a photograph of the interior surface of a tube that has been damaged by operating a tube cleaner too long in one place.

10.6.2 Signs of Overheating

All tubes should be inspected for signs of overheating, corrosion, and erosion. Waterwall tubes and generating tubes nearest the burner are particularly susceptible to overheating and should be closely examined for bulging, blistering, quench cracking, sagging, and bowing. Inspection for blisters and local bulging is easily accomplished by shining a flashlight parallel to the length of the tube so that bulges, blisters, and other deformities cast shadows. Cleaning of a slagged tube may be necessary to find minor blisters. The tube's circumference should be measured at the blister or bulge.

Some types of waterwalls have tubes widely spaced and the area between the tubes covered by steel fins attached to the tubes. The fins may become overheated and burn or crack. The fins should be inspected for cracks that may extend into the tubes. The tubes should be inspected for signs of leakage that may result from the cracks.

Waterwall tubes should also be checked for alignment. All gas passages should be inspected for slagging or bridging from fly ash or slag buildup. The first gas pass is particularly susceptible to this condition.

10.6.3 Corrosion and Sagging

Boiler tubes should be inspected at the steam-drum connection for gouging and caustic corrosion due to steam blanketing. Roof tubes are generally designed for heat pickup on one side only. Therefore, a sagging roof tube due to burned out hangers is especially susceptible to overheating. These tubes should be straightened, and the hangers should be replaced.

10.6.4 Thickness

Waterside corrosion, generally caused by faulty water treatment, can usually be detected by ultrasonic thickness measurements of representative tubes. Measurements can also be made from inside the steam drum for a distance of 8 in. to 10 in. (20 cm to 25 cm) into the tubes. The locations measured and thicknesses found should be recorded to establish a tube corrosion rate.

Steam tubes should be examined for the type and thickness of internal scale. Ultrasonic techniques exist to nondestructively measure steam-side scale thickness from the outside surface. An assessment of tube remaining life can be made from the measured scale thickness of the tube if operating in the creep range as mentioned in 12.3.

10.6.5 External

Fireside corrosion is generally caused by moisture that accumulates in fly-ash deposits. Although fireside corrosion may occur anywhere in the tube nest, it usually occurs where the tubes enter the lower drums or headers. Moisture-causing fireside corrosion can come from leaks in tubes, drums, headers, and faulty steam soot blower shutoff valves. Other sources can come from rainwater through stacks and roofs and from condensation from the atmosphere during downtime.

Specific attention should be given to tubes near any openings (i.e. viewports) as air in-leakage can cause increased external corrosion.

Erosion of exterior surfaces is caused by the impingement of fly ash or raw fuel solids at excessive velocity or by soot blowers. Fly-ash tube erosion can be arrested by installing shields or by reducing the gas velocity. If erosion is due to soot blower medium impingement, the soot blowers should be checked for alignment, warpage, and operating wear. Wastage of exterior tube surfaces can be caused by flame impingement, which should be corrected by adjustments to the firing equipment.

10.6.6 Rupture

When a tube rupture occurs, the tube should be visually inspected. Its appearance may indicate the cause of failure. If the cause is not evident, samples of the tube in the original condition with deposits and scale intact should be taken and analyzed chemically and microscopically. The tube sample should be cut at least 1 ft (30 cm) on either side of the failure.

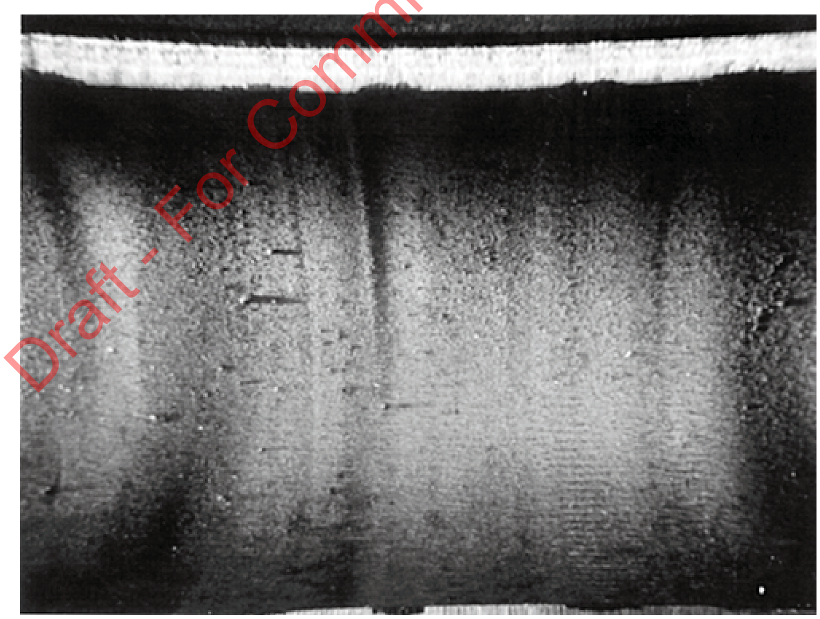


Figure 35—Interior Surface of a Tube Damaged by Operating a Tube Cleaner Too Long in One Place

Refer to Table 3 for recommended inspection and acceptance criteria for mechanisms applicable to boiler tubes.

11 Onstream Inspection Programs

11.1 General

Onstream inspection programs are a vital component to maintaining reliability. Inspection efforts often focus on the next maintenance outage since it involves significant planning and resources. However, onstream inspection is the key to monitoring the health of the equipment between major outages and allows proactive response to operating conditions that may cause premature failure. Onstream inspection programs monitor the operation of the heater, furnace, or boiler to ensure variables are operating within a satisfactory window selected for the equipment.

Ideally, this activity is a collaboration with Operations and Engineering to detect “change” in operating or physical conditions, enabling early detection and response to impending damage or failures.

11.2 Typical Inspection Activities

11.2.1 General

Typical onstream inspection programs incorporate visual examination of the firebox, external visual examination of casing and components, infrared examination of tubes, casing and stack, and monitoring of tubeskin thermocouples. Although in limited use, tell-tale holes are another practice for identifying unexpected or accelerated corrosion of tubes onstream (see 11.2.4). Other analyzers and instrumentation monitor heater, furnace, or boiler operation. These are important parts of an overall reliability program but are typically monitored for heater, furnace, or boiler performance.

11.2.2 Tubeskin Thermocouples

Tubeskin thermocouples can be an important component in a reliability program, especially for onstream inspection. Thermocouples measure the temperature of tube walls in service, and they serve a couple purposes. First, the thermocouples can alert to abnormal operation if temperatures dramatically change. Second, they provide a means to calculate and monitor remaining tube creep life. Strategic placement of the thermocouples is necessary so that the entire firebox can be reasonably monitored. Malfunctioning burners or unbalanced firing of burners can create local hot zones in the firebox and lead to premature failures. In addition, tubes that historically operate hot due to their placement in the coil may need a thermocouple, especially if it represents the most severe service of the tubes.

Tubeskin thermocouples have some limitations in reading temperatures accurately. The particular type of thermocouple should have a mid-range rating for the expected tube metal temperature for improved accuracy. Thermocouple wires can have the potential to drift with time at temperature; therefore, they require recalibration or periodic replacement. Another significant problem is the attachment of the thermocouple to the tube. If it is poorly attached, the thermocouple can separate from the tube and begin reading firebox temperatures. Hence, special attention should be taken on thermocouple attachment type and quality, and numbers and placement on tubes to prevent attachment failure during the scheduled process run to assure users that they still have adequate monitoring and control at end-of-run conditions (see 9.13).

11.2.3 Infrared Scanning

Infrared scanning provides a means to determine the surface temperature of a tube’s outermost layer of scale, ash deposits, or metal. When the heat flux, scale/ash thickness, and scale/ash thermal conductivity may be reasonably estimated, or when the tube surface may be reasonably assumed to be clean, the temperature provided by infrared scanning provides a means to determine the tube metal temperature for estimating tube remaining creep life, calculating corrosion rates, and checking the accuracy of tubeskin thermocouples. In addition, infrared thermal scanning of tubes helps identify localized hot spot temperatures and identifies tube operating temperatures in locations where there are no thermocouples. A periodic scan of heaters and furnaces should be a common practice. The inspection intervals should be shorter for those with coking tendencies (i.e. crude, vacuum, heavy oil hydroprocessing, and coker units), heaters susceptible to fouling (i.e. dry point fouling in naphtha hydrotreating units), and steam-methane reforming furnaces. Longer intervals may be used for heaters and furnaces in non-coking and non-fouling susceptible services. For furnaces or heaters that have frequent decoking activities (i.e. ethylene and olefin cracking units), a case-by-case evaluation is needed to determine how often infrared scanning should be performed to complement routine monitoring that typically uses a handheld pyrometer.

Personnel performing infrared surveillance of heaters and furnaces should be knowledgeable and appropriately trained and qualified per the owner-user's requirements for infrared scanning (e.g. ASNT SNT-TC-1A, PCN condition monitoring or owner-user standard or practice). In addition, scanning personnel should be aware of the factors that may impact infrared survey results. These factors include flame environment, distance to target, tube emissivity, stray infrared radiation, surface characteristics of different materials, infrared camera functions, and the limitations and accuracy of the method. When performing infrared scanning, inspection personnel should review prior infrared survey results, records for current operating status, temperature limits, and any new operations or maintenance issues to ensure that all areas of concern are inspected. Data analyses should include a review of previous infrared survey results.

An external infrared scan should include an assessment of casing and stack for refractory damage. Internal infrared scans of the firebox through each sight port should include an assessment of:

a) viewable (i.e. radiant or convection) tubes for overall temperatures and hot spots,

b) tubeskin thermocouples,

c) tube supports and refractory for spalled refractory or broken tube supports, and

d) burner tiles and fuel gas tips for damage or plugging.

Infrared surveys should be conducted on a scheduled interval based on IOWs, API 530, Omega DMT limits, unusual or poor operation or control, steam-air decoking, or when deemed necessary. External and internal infrared scan results that indicate significant temperature differences from previous surveys or anticipated infrared survey results should be evaluated. The owner-user should specify guidelines for acceptable temperature limits for each unit. Results outside of owner-user guidelines should be reported immediately. Inspection reports should include documentation of infrared camera settings used for the survey, drawings of heater tube locations and results, and images of all significant findings. Any exceedance of prevailing operating limits should be immediately reported.

Accuracy of infrared scanning can be influenced by the skill of the operator, the angle of incidence, the nature of the combustion products, flame patterns, and scale on the tubes. The presence of flames can mask the tubes if the operator scans through the flames. Another significant limitation is scale on the tubes. The temperature of scale on the tubes tends to be hotter than the tube since it may not be tightly bonded to the tube. During outages, it can be beneficial to remove scale in areas to allow the operator to scan a "scale-free" area and compare to other scaled areas that may allow better interpretation of results. Grit blasting stainless steel tubes has also been shown to improve the accuracy of infrared by mottling the surface enough to reduce reflectivity that artificially causes a higher temperature measurement.

The external casing can be inspected onstream both visually and using infrared. Visual examination can identify areas of distortion and holes. These inspections can indicate hot areas of lost refractory and promote continued deterioration. A periodic infrared scan of the case is more effective than visual examination in identifying "hot spots," holes, and cracks. Regular inspection of the firebox is critical for reliability. Inspection can identify poor flame pattern of improperly firing burners, fuel-rich operation as evidenced by afterburning, and changes in appearance of tubes, supports, refractory, etc. These inspections help identify changes early. Any changes or problems can be addressed or analyzed to prevent further damage and deterioration from occurring.

Header boxes should be visually examined for evidence of process leaks. These could indicate a leaking header plug for those with fittings, or a leaking instrument connection such as a thermowell. If there is evidence of process leakage, the cause should be investigated.

Figure 36 and Figure 37 are infrared thermographs of an onstream inspection that can help identify abnormal operating tube metal temperatures. In Figure 36, a section of the tube is operating at 1400 °F (760 °C), while in Figure 37 an entire coil is operating 300 °F (149 °C) above the adjacent coil. Identifying these "hot" areas early allows corrective action to reduce metal temperatures without incident. These conditions may not be identified by tubeskin thermocouples depending upon their placement.

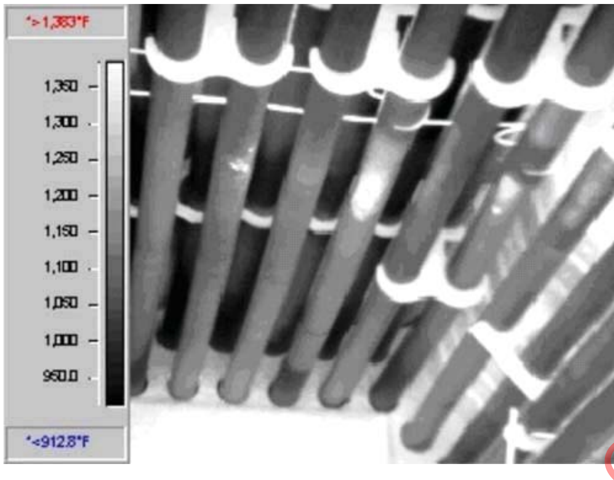


Figure 36—Infrared Thermography Identifying a Local Hot Spot on Tubes

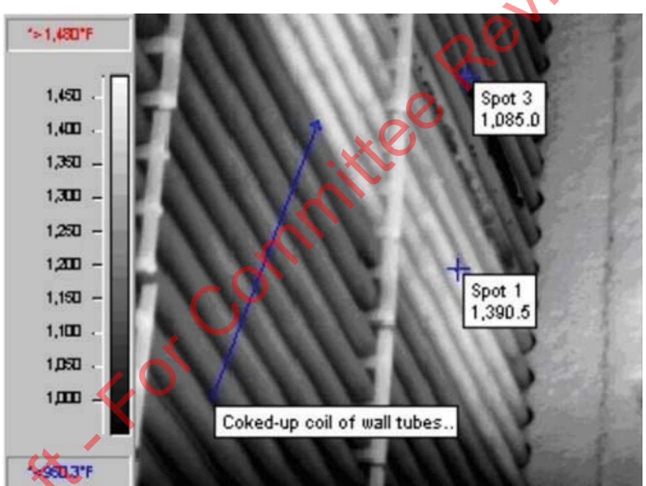


Figure 37—Infrared Thermography Identifying a Hot Coil

11.2.4 Tell-tale Holes

Although the use of tell-tale holes has fallen out of favor and is seldom used, the practice has historically provided early detection and safeguard for accelerated or unpredicted thinning of tubes. The tell-tale holes can minimize the effect of leaks associated with a tube failure. The tell-tale drilling practice has been generally regarded as a safeguarding measure in loss prevention and should not be considered a substitute for or a relaxation of good inspection and quality control practices.

Where tell-tale wholes are used, the following guidelines have been applied.

a) Tell-tale hole diameters and drilling depths:

   1) tell-tale hole drill diameters should be $^{1}/_{8}$ in. (0.32 cm);

   2) drilling depth tolerance should be +0 in. to $^{1}/_{64}$ in. (+0 cm to 0.04 cm); and

3) tube drilling depths should be calculated according to the retirement thickness in API 530.

b) Tell-tale hole locations:

4) The location of tell-tale holes should be based on the corrosion type and the tube configuration. Typical drilling patterns are located at heat-affected zones, 180° bends and areas with potential for accelerated corrosion, and random areas on straight run lengths.

5) Drilling patterns and locations in Figure 38 can be used as a guideline in most heaters and furnaces.

Figure 38—Sample Locations for Tell-tale Holes on Heater Tubes

11.3 External Tube Cleaning

Onstream cleaning of tubes to remove scale may be beneficial to improve the accuracy of infrared scan or to improve the heat transfer (i.e. heater or furnace efficiency). Some techniques used include blasting with walnut hulls, crushed dry ice, and water. Course walnut hulls have proven effective in removing loose scale; however, the user should recognize that refractory damage can occur where the hulls affect the wall. One benefit of the hulls is that they burn up in the firebox and most of the ash leaves through the stack. Another technique is to water blast the tubes, which removes scale by thermal contraction and shock. Consideration needs to be given to the water type and the spray type so that tube damage need not result. In this instance as well, refractory damage can result where the water impacts.

11.4 Pre-shutdown Inspection

Onstream inspection is also important to identify problems that cannot be seen while the equipment is out-of-service. A discussion with operations and maintenance personnel is highly recommended to identify problem areas. At this time, a review of the operating conditions may also help to indicate problems such as O_2 percentage (i.e. inability to maintain target O_2 could indicate leaks or burner problems), draft (i.e. unsteady/pulsating draft can damage heater/boiler components), drum levels, pressures, and temperatures.

An infrared scan of the casing and radiant tubes can allow a hot spot map to be created so that these areas can be investigated during the maintenance outage. Flame locations and appearance can help identify problems with burner tiles, refractory, and floors. Flames emanating from a portion of floor or wall indicate a problem that needs follow-up inspection. Complete an external inspection to determine condition of the structure such as buckstays to look for signs of expansion and buckling. Also, inspect external equipment such as blowdown valves, soot blowers, level gauges, external hangers, rods, insulation, etc. for damage that may need to be addressed at the outage.

12 Tube Reliability Assessment

12.1 General

Tube reliability can only be assessed by understanding the amount of deterioration that can be tolerated without compromising the integrity of the tube until the next outage. The assessment is often referred to as the remaining life of the tube. Determining remaining life for all deterioration mechanisms may not be possible; therefore, it may be necessary to consult with one knowledgeable in heater design, operation, and damage mechanisms (see 5.7). In addition, consulting API 579-1/ASME FFS-1, Appendix F, Section F.7 and Table F-12 on creep modeling, parameters and Omega properties and other fitness-for-service documents may provide additional guidance on assessing deterioration.

12.2 Minimum Thickness and Stress Rupture

Stress rupture is dependent on the stress the metal is exposed to and the temperature of the metal. The common approach to prevent stress rupture failures is to establish a minimum allowable thickness for the tube operating conditions (e.g. pressure, mechanical stresses, and metal temperature).

12.2.1 Tubes

12.2.1.1 Operating Conditions

Methods of establishing minimum allowable thickness range from the highly complex to the simple. With the average heater, furnace, or boiler, the operating pressure and temperature are known only for the inlet and outlet. The pressure and temperature at intermediate points is typically estimated by calculations or measured with pressure gauges and thermocouples installed at appropriate locations.

12.2.1.2 Tube Metal Temperature

The metal temperature governs the allowable working stress for tube materials. Therefore, for a given tube size and a given operating pressure, the minimum allowable thickness varies with the tube temperature. Tube temperature is an important parameter to know, especially at the highest levels of the normal operating condition.

12.2.1.3 Temperature Measurement

Many methods, including those involving tubeskin thermocouples, infrared cameras, infrared pyrometers, and optical pyrometers, are available to determine the metal temperature of a tube. A simple method is to estimate the metal temperature from the operating fluid by adjusting the temperature estimate based on the location of the tube. The skin temperatures on a tube closer to the flame or nearer the heater/furnace outlet should be hotter than one at the inlet.

12.2.1.4 Tube Wall Thickness

API 530 provides extensive information on the calculation of required wall thickness of new tubes (carbon steel and alloy tubes) for petroleum refinery heaters. The procedures supplied are appropriate for designing tubes or checking existing tubes in both corrosive and noncorrosive services.

12.2.1.5 Minimum Thickness

Under certain conditions, the methods described in the preceding text may result in a thickness that is too small for practical purposes. The minimum allowable thickness has to be great enough to give the tube sufficient structural strength to prevent sagging between supports and to withstand upset operating conditions. For this reason, it may be appropriate to add some amount based on experience to the calculated minimum allowable thickness and to use this greater thickness as the limit at which a tube should be replaced. In these cases, it is typically about 0.125 in. (0.32 cm).

12.2.2 Fittings

Similar to establishing the minimum allowable thickness for tubes, the metal temperature of the fittings has to be established so that the appropriate allowable design stress of the material can be used. Generally, if the fitting is outside the firebox, the fitting temperature is considered to be the same as the temperature of the fluid flowing through it plus 55 °F (30 °C). The metal temperature of a fitting inside the firebox is considered to be the same as that of the corresponding tubes. The allowable working stress value for fittings is determined in the same way as it is for tubes. Minimum allowable thickness can be determined from applying calculations from the appropriate ASME piping codes. Because of stresses that may be set up by closing and holding members and by thermal expansion, the calculated allowable thickness may be too small to be practical. As with tubes, it may be advisable to add some thickness based on judgment and experience when setting the minimum thickness at which a fitting should be replaced.

When plugs are used in a tube fitting like plug-type or mule-ear fittings or when a sectional L is used in a sectional fitting (see Figure 39), the width of the seating surface in the fitting has to be sufficient to prevent leakage. A width large enough to prevent leakage generally provides adequate strength against blowout, but a lesser width should never be used. The proper seating width required to prevent leakage is difficult to calculate and is often determined by experience. When there is no previous experience to be used as a guide, one way to determine these limits is to wait until evidence of slight leakage is found and then set a limit at a point that is a little greater than that at which the slight leakage was evident. Annex B (Figure B.7) shows several types of tube fittings.

Figure 39—Plug-type Tube Fittings

12.2.3 Boiler Components

Because of the great number of variables affecting the limiting thickness and the variety of types, sizes, shapes, operating methods, and constructions of boilers, it is not possible in this RP to present a set of pre-calculated minimum or retiring thickness. However, it may be quite feasible to prepare one for the boilers in a given refinery. Formulas for the thickness of drums, headers, and tubes are provided in the ASME *Boiler and Pressure Vessel Code*, Sections I and IV. ASME B31.1 also provides calculations for wall thickness of power boiler piping. These formulas can be used as guides when repairs and replacements are needed.

12.3 Creep Rupture Life

Remaining creep life for tubes is estimated or measured using various techniques ranging from the approach outlined in API 530, Annex A; API 579-1/ASME FFS-1; or destructive creep testing of tube material.

API 530, Annex A, "Estimation of Remaining Tube Life" is a common approach to assess life of in-service tubes. The calculations are based on the Larson-Miller parameter curves found in the document. API 530 provides an average and a minimum Larson-Miller curve for each metallurgy. The most conservative approach is to use the minimum curve since it represents the poorest material properties of those tested. The average curve can also be used, although the specific heat of material can exhibit properties either above or below this curve.

These life assessments usually require several assumptions about the tubes' thermal and stress history. The history needs to be established to effectively determine the amount of life expended during each operating run under different conditions. One can simplify the analysis by assuming the tubes operated under the severe conditions for their entire life. Once the life fraction has been determined, remaining life can be estimated for specific operating conditions. One can establish an operating window of temperature and pressure for which the tubes can operate where creep rupture is not expected during the next run length.

More accurate techniques to determine remaining life require destructive creep testing. One technique is the Omega methodology that uses strain rate data generated in a creep rupture test to determine remaining creep life. The creep rupture test can be performed at temperatures and stresses that closely approximate the actual operating conditions of the tube. This is unique to creep testing, since they require tests at either higher temperature or higher stress to shorten the tests to a reasonable amount of time. The results are then extrapolated back to operating conditions. This extrapolation can lead to inaccuracies in estimates. Only a few samples are necessary for this testing and samples can be prepared from only a small section of tube. The section of tube to be tested should optimally be taken from the location operating under the most severe conditions. Additionally, the samples should be tested in the most highly stressed direction in service. Typically, this is a sample oriented circumferentially in the hoop stress direction.

The remaining life determinations provide a means to manage tube life of a heater, furnace, or boiler. The operator of the equipment can understand how the operation affects tube life. For instance, tube life can be monitored throughout the run, incorporating all types of operations, including most importantly any high-temperature excursions. These remaining life calculations can be used to predict and plan tube replacements.

Tubes inside a heater, furnace, or boiler have historically been replaced if they exhibit an increase in tube diameter beyond a specified threshold value. Company practices range from 1 % to 5 % of the tubes' original diameter or circumference for wrought tubes. Creep testing can be used to determine a better relationship between growth and remaining life for particular tube metallurgy. Some metallurgies exhibit more growth than others do for a similar remaining creep life. Therefore, 5 % may be conservative for some metallurgy and not enough for others. Consider consulting with a materials engineer knowledgeable in tube metallurgy before establishing threshold criteria.

13 Method of Inspection for Foundations, Settings, and Other Appurtenances

13.1 Foundations

All foundations can be expected to settle to some extent. If the settlement is both evenly distributed and only small in extent, then little or no trouble may be experienced. If the settlement is either uneven or large in extent, then serious consequences may result. Whether even or uneven, any settlement in a foundation should be studied and, if the need is indicated, checked at frequent intervals by level measurements, which should be continued and plotted until the settlement practically ceases. When settlement is first noted, all pipe connections to the equipment should be examined carefully to determine whether they are subject to serious strain and consequent high stress. If conditions warrant corrective measures, they should be taken immediately.

One of the main causes of the deterioration of foundation concrete is high temperature. This causes calcining that is caused by the concrete's loss of water of hydration and leaves the concrete a weakened mass with very little cohesion. Calcining can easily be detected by chipping at the suspected area with a hammer. If calcining is present, the concrete can fall away as a powder with minor impact from the hammer.

Spalling is another form of concrete deterioration caused by heat or an insufficient thickness of concrete over the reinforcement. The concrete cracks and moisture can enter and attack the steel reinforcement. The products of corrosion buildup and exert sufficient pressure against the concrete covering to cause it to flake or spall, exposing the reinforcement to further attack. Only a visual inspection is necessary to detect this form of deterioration.

13.2 Structural Supports

13.2.1 Visual Inspection

A visual inspection should be made of all load-carrying structural steel members to see whether deflection is observable. If bending is present in a column, it may be caused by overloading, overheating, or lateral forces applied to the column by the expansion of elements in the heater, furnace, or boiler. These potential causes should be considered and the cause of the bending determined so proper corrective measures can be taken.

13.2.2 Overloading

If the bending is due to overloading, either the column should be reinforced by welding the necessary reinforcement to the column's web to reduce the unit stresses to a permissible value or the column should be replaced with another one of suitable size. If the bending is caused by overheating, the column should be protected by insulation or a shield. If the bending is caused by expansion of elements in the heater, furnace, or boiler, provisions should be made to accommodate the expansion without stress on the column.

13.2.3 Deflection

Beams and girders can deflect when loads are imposed on them. The deflection should be measured where it is greatest. The amount of deflection should be checked against that calculated for the load on the beam or girder. If the measured deflection is greater than the calculated deflection, overstressing is indicated. If the overstress is serious, the design should be investigated and corrective measures should be taken.

13.2.4 Determination of Stress

If corrosion in structural steel members that bear loads directly is so great that the thickness lost is enough to weaken the part, the minimum cross-sectional areas should be measured carefully after the corroded part is cleaned thoroughly to permit the determination of the remaining sound metal. When the measurement has been obtained and the remaining sectional area has been determined, the section modulus should be calculated, and the design should be checked to determine the stress. If the stress is sufficiently higher than the allowable stress, the weaker part should be reinforced or replaced. Useful design information, including information about allowable working stresses, can be found in AISC M015L and AISC M016.

13.2.5 Connections

The connections between the columns and the beams and girders should be inspected visually. These connections may be made by riveting, bolting, or welding. For riveted or bolted construction, broken or loose rivets or bolts can be detected by striking the side of the rivet or bolt and by striking the plate. A movement of the rivet or bolt can indicate that it is loose or broken. Inspection of all connections is not warranted, but inspection should be made where corrosion is severe. If the connections are welded, corroded sections should be carefully visually inspected after proper cleaning and the effect of lost metal thickness should be determined.

13.3 Setting, Exterior, and Casing

13.3.1 Exposed Parts

The exposed parts of the setting should be inspected for signs of deterioration. All metal parts can be adequately inspected with a hammer and visual examination. If the exposed parts are painted, a visual inspection should be made to see whether the coating adheres tightly to all surfaces. Areas exposed by flaking or otherwise damaged should be cleaned and repainted. The casing should be inspected for thinning or perforation due to acidic flue gas corrosion.

13.3.2 Other Attachments

Stairways, walkways, ladders, and platforms should be checked to ensure that they have not been materially weakened as a result of corrosion. Header boxes should be inspected for warpage and improper functioning. Warpage or improper functioning of doors may allow rain or other moisture to enter. Header box warpage also allows excess air into the firebox, spending additional fuel. In some operations, particularly those that process light hydrocarbons, a sudden change in temperature due to leakage of header boxes can cause enough movement in fitting closures or rolls to loosen them.

13.3.3 Access

Peepholes, access doors, and the like should be inspected visually to see that the fit is satisfactory and minimizes excess air ingress.

13.3.4 Explosion Doors

Explosion doors, if provided, should be inspected visually for corrosion of the hinges and the door itself and for warpage. Explosion doors should also be visually inspected to see whether there is proper seating contact between the door and the doorframe, ensuring a reasonably tight joint. The doors should be manually lifted to check operability. To serve effectively, the doors should open with minimum resistance.

13.4 Refractory Linings and Insulation

13.4.1 Types

Most modern settings consist of structural steel framing with refractory lining or lightweight ceramic or blanket insulation on the walls and roof of the casing. The refractory may be backed up with brick or supported on steel members with heat-resistant hangers. The supporting brickwork and reinforced concrete and the clearance in the expansion joints should be examined for deterioration due to heat, open joints, excessive distortion, or debris. The inspection of refractory should consist of a visual examination for breakage, slagging, crumbling, and open joints. Leakage of the hot gases through joints when the edges have crumbled or when the tile or insulating concrete has fallen out exposes the supporting steel to high metal temperatures, rapid oxidation, and corrosion. Leakage of hot gases outward instead of air leakage inward may indicate improper draft conditions in the firebox. The supporting steelwork should be inspected thoroughly. Beams, hangers, and supports of any type that have been damaged by heat or show excessive distortion should be replaced. Any accessible insulation used on the exterior should be inspected. Overheating of the casing can cause the casing to warp leading to further damage to the lining.

13.4.2 Cracking

Refractory linings should be inspected for excessive cracks, erosion, fluxing (melting of the refractory), bulging, and fallout. Cracks in the refractory are common and expected. Only the degree of cracking is important. No rules are established indicating what can or cannot be tolerated, and so decisions are based on good practice, experience, and, if available, consultation with one knowledgeable in refractories. If the refractory is determined to be severely cracked, repairs should be made. Metal parts and insulation behind the refractory can become overheated and damaged if these conditions persist.

13.4.3 Erosion or Fluxing

The presence and extent of refractory erosion or fluxing should be determined. Erosion is caused by flame impingement, high ash velocities, and inferior materials. Erosion may occur around burner throats, sidewalls, and back walls. In boilers with waterwalls, erosion tends to occur in the refractory material between the tubes, especially on back walls opposite burners. Fluxing is caused by inferior or improper materials, ash containing metal oxides, or flame impingement. Fluxing may occur at almost any point, but locations in the direct path of the hot gases may be most susceptible to fluxing.

The depth of erosion or fluxing and the remaining thickness of the refractory should be measured. The depth of local erosion or fluxing may be measured with a straight edge and rule. In areas around burner throats, the extent of erosion or fluxing may be difficult to determine because of the circular or conical shape. Photographs or blueprints of the original installation are helpful references in establishing the extent of erosion in these areas. The thickness of the remaining refractory may be measured by drilling or cutting out a small piece in the suspected area.

13.4.4 Repair or Replacements

Castable refractory that has fallen out or bulged to a point that it is in danger of falling out should be replaced. See API 936 for details on repair methods.

Bulging and fallout may be due to settlement of the anchor bolts, anchor brackets, or castings or of the wall setting supports themselves. When bulging or fallout is encountered, the causes should be ascertained so that corrective measures may be taken to prevent a recurrence. This often requires replacement or repair of refractory anchors as well as castable for such repairs. Bulging or fallout in waterwalls may be due to failure of the tubes to transfer the severe heat. In rare cases, this may be caused by too large a tube spacing, but it is generally caused by blocked or clogged tubes. When excessive erosion or fluxing occurs in the lower section of a wall, the upper sections may have insufficient support to the point that they can fall out.

13.4.5 Infrared Cameras

Infrared cameras can provide an indication of damaged refractory prior to shutdown. Damaged areas of insulation are observed as higher surface metal temperatures on the casing.

13.4.6 Areas of Inspection

The condition of refractory linings in the combustion chamber, stacks, flue gas ducts, observation and access doors, and around burner ports should be inspected. Special attention should be given to the lining sections intended to protect pressure parts and supports from overheating. If any of the refractory has fallen out, the supporting steel will be exposed to excessive temperatures that will damage the steel. Linings in stacks and ducts may also have areas where the refractory has fallen out. When this occurs, the outer structure is exposed to temperatures that are greater, in most cases, than the material is capable of withstanding. Outer structures composed of brick will develop cracks; outer structures composed of steel will buckle. Eventually, failures can occur unless corrective measures are taken to replace the refractory. Entrance of air into a boiler, heater, furnace, or stack (other than through the burners or related openings) may cause inefficient and potentially dangerous operating conditions.

13.4.7 Leakage Survey

A visual survey of the casing should be made for air leakage into a balanced draft unit and for leakage out of a positive pressure unit. Cracks and loose access and fire doors, peepholes, and joints permit air leakage. An artificial smoke source—titanium tetrachloride, hydrated zinc chloride, or another source of smoke—placed close to the cracks may be useful for the inspection. Use of smoke for the inspection should be done with due consideration of the hazards associated with the materials and the appropriate personnel safety equipment. The material safety data sheet for the type of smoke used should be consulted. Leakage into the casing, when such leaks are adjacent to the structural steel supports, may result in temperature gradients of sufficient intensity to cause failure of the supports. This is particularly likely to occur in areas where combustion is not complete and the concentration of carbon monoxide is high.

13.5 Tube Supports

13.5.1 General

Tubesheets and tube supports should be examined to determine their physical condition and fitness for further service. Supports should be examined carefully for cracks, oxidation, corrosion, distortion, and sagging. If the tubesheet and tube supports are found to be unsound or weak, they should be reinforced or replaced. Figure 40 shows a tube support with evidence of creep and yielding. Table 4 is a listing of common tube support material and their suggested maximum use temperature.

13.5.2 Supports in Steam-Methane Reforming Furnaces

Tube support methods vary in steam-methane reforming furnaces. Some designs require full support from the top. In these designs the pigtail may be below the tube and unable to take any load from the catalyst-filled tube. Counterweights are often used and may support two or more tubes. The lever or pulley system has to work as designed. Interference from tube flange bolts, slipping of supports off tube flanges, and other similar problems have led to pigtail failures.

Inadequate support also allows tube bending that puts a bending moment on a pigtail that exits the tube from the side, thus causing localized high stress at the fitting on the tube or the outlet headers.

Figure 40—Yielding and Creep of a Tube Support Connection

Table 4—Tube Support Materials Specifications Maximum Design Temperature

°F	°C	Material	Casting Specification	Plate Specification
800	427	Carbon steel	A216 Gr WCB	A283 Gr C
1200	649	$2^{1}/_{4}$ Cr-1 Mo 5 Cr-$^{1}/_{2}$ Mo	A217 Gr WC9 A217 Gr C5	A387 Gr 22, C1.1 A387 Gr 5, C1.1
1500	816	19 Cr-9 Ni	A297 Gr HF	A240, Type 304H
1600	871	2 5Cr -12 Ni 25 Cr-20 Ni		A240, Type 309H A240, Type 310H
1800	982	25 Cr -12Ni 50 Cr-50 Ni-Cb	A447 Type II A560 Gr 50 Cr-50 Ni-Cb	
2000	1093	25 Cr -20 Ni	A297 Gr HK	

Outlet headers grow usually from a center anchor point. Bottom tube supports on short pigtailed tubes have to allow movement of the tube bottom to minimize stress on the pigtail. If the tube is designed for bottom movement, the upper tube supports have to allow the tube to move at the bottom end. To prevent a pigtail bending moment, the heater lining should not press on the tube. Loose bricks are often used to help close openings. The bricks have to move freely if the tube presses on them.

If support springs are used, those that have been stretched should be replaced. A stretched spring cannot support a tube as designed, especially when the tube is heated up after shutdown.

13.6 Visual Inspection of Auxiliary Equipment

13.6.1 General

In addition to any external inspection of auxiliary equipment while the unit is in operation, a close inspection should be made of each piece of equipment while the unit is out of operation. Indications of malfunctions noted during external inspections should be investigated and any indicated repairs should be made. Since some parts wear out and fail without warning, manufacturers' catalogs and instructions should be reviewed so that all critical operating parts may be investigated.

13.6.2 Dampers

Power-operated or manual dampers are provided on some but not all boilers for superheater, economizer, and boiler outlet-gas control. Damper blades constructed of thin metal are susceptible to oxidation and warpage due to overheating and should be inspected for such damage. Supporting brackets, driving rods, pins, and other devices should also be examined.

The dampers should be operated and checked for binding closure, and freedom from obstructions should be ensured. Damper position should be confirmed with both control board and exterior indication devices. Personnel, other than those working on damper operation, should not be permitted in the damper section while the dampers are in operation.

13.6.3 Forced- and Induced-draft Fans

The bearing clearance and the condition of the babbit-bearing surfaces and of the antifriction bearings should be checked and the shaft diameter should be measured at the bearing surface. The condition of the oil or grease should be checked and the lubricant should be changed as required.

The general condition of the rotor and rotor blades should be checked and loose blades should be fixed. Couplings should be examined and the alignment of all parts should be inspected. If any parts are out of alignment, the cause should be determined and corrective action should be taken. Expansion joints should be examined, and all dampers should be tested for ease of operation and freedom from obstruction.

Induced-draft fans are subject to erosion and corrosive attacks from ash particles and flue gas. In addition to the inspections discussed in preceding text, inspections of the rotor blades and casings should be made for corrosion, excessive thinning, and holes in the blades and casing. The shaft should be examined for corrosion from dew-point condensation near the casing. Missing or faulty gasket seals around the shaft allows the entry of cold air and lead to condensation and subsequent corrosion. Rotor blade surfaces should be checked for cracks with magnetic particle examination or penetrant examination focusing on stress riser locations.

13.6.4 Soot Blowers

Soot blowers can be a root cause for deterioration if they are not operating properly. Therefore, soot blower parts should be inspected for proper alignment, position, and operability. If soot blowers are out of position or misaligned, the blower blast may impinge on tubes and can eventually cause tube failure due to erosion. Soot blowers can also be a source of liquid water that can promote dew point corrosion of tubes, casing, and the blowers themselves. The shut-off valve to the blowers should be checked to ensure it does not leak while in service. Condensate can form in the system when the blower is out of service and can cause dew point corrosion if it leaks into the firebox.

The blower, supporting hangers, and brackets should be examined visually for soundness and for excessive thinning from oxidation. Soot blowers for the high-temperature part of the boiler are sometimes composed of high-chromium alloys that embrittle in service and so they should be handled and inspected appropriately to avoid fracture. Connection welds of supporting elements should be inspected for cracks. If the welds look cracked, a magnetic particle inspection should be made. Packing glands and all operating parts of the rotating and retracting types of soot blowers should be examined for good working condition. Because of the potential difficulty of repacking soot blowers in service, repacking should be performed during down periods if there is any evidence that repacking might be required.

13.6.5 Air Preheaters

Air preheaters are subject to corrosion due to condensation during extended periods of downtime or in operation if dew point is reached. There are various conditions that can hinder an air preheater's ability to recover heat from intended source. Specific to mechanical attributes, these are primarily associated with surface fouling and corrosion of the transfer medium. When this occurs, system efficiency and unit capacity is adversely affected. The most common conditions are fouling and corrosion. Fouling is caused by:

a) dust and debris pulled from the environment and resting on air side surface;

b) sulfur deposits gathering on flue gas side surface due to reaching at or below dew point temperatures of the sulfur (SOx) containing flue gas; and

c) ammonium salt buildup on flue gas surface when cold block section within a selective catalytic reduction system reaches at or below dew point temperatures.

Recuperative preheaters, both the tubular type and the plate type (see Figure 7), are subject to corrosion when the element temperature is at or near the dew point. The corrosion is particularly prevalent at the cold air end. As much as possible, the recuperative-type preheaters should be inspected for corrosion. Typically, the conditions at the inlet and outlet ends provide a good indication of what can be expected in the remainder of the preheater. It is not unusual to see extensive plugging of air preheaters when boilers are being fired with heavy oil.

Poor ductwork design characteristics can be a contributing factor if cold end corrosion persists in recuperative air preheaters after the implementation of continuous flue gas exit temperature control.

Damaged tubes or plates within recuperative air preheaters can be replaced or plugged. It is sometimes necessary to remove fairly good tubes or plates to get to the bad ones. Good judgment and consideration for future replacements are important factors in selecting the most economical method for repairing tubes and plates. Some manufacturers have available replacements parts that are provided with corrosion resistance coating or higher-grade materials.

Frequently, air preheater efficiency can be calculated to determine if its surface area is fouled or damaged. A heat balance can be performed around the air preheater to determine if it is leaking from the air side into the flue gas side. The quantity of leakage can be determined by measuring the oxygen on both sides of the air preheater. Fouling or other damage could be determined by measurement of the flue gas pressure differential across the air preheater.

Regenerative preheaters (see Figure 8) require a more extensive inspection than do recuperative preheaters. Typically, rotating elements have to be removed to clean the preheater. This affords an opportunity for close inspection of all parts. In most classes of regenerative preheaters, the incoming air enters at the same end that the flue gases leave, thus cooling that layer of rotor segments first. Corrosion generally starts at this point because of condensation and proceed toward the other end of the unit. Most preheaters have two sections, and if corrosion at the flue gas exit ends is not too severe, the sections can be reversed; otherwise, new sections should be provided. Figure 41 shows examples of acidic dew point corrosion of an air preheater.

Rotor seals should be examined for corrosion. They can also be mechanically damaged by falling material, by high-pressure steam or water from soot blowers, or by being stepped on by maintenance personnel.

Soot blowers for regenerative preheaters are quite different from those used in other parts of the boiler. Manufacturers' catalogs and drawings should be examined for points that require close inspection. Soot blowers should be inspected for deposits and leaky valves. Leaky valves and buildup of ash cause corrosion of nozzle tips, and subsequent malfunction of the blowers damages rotor seals and segments. Therefore, steam inlet valves should be inspected for tight shutoff and drain valves should be inspected for correct operation.

Figure 41—Corrosion Products from Acid Condensation Plug Tubes in Air Preheater

13.6.6 Boiler Blowdown Equipment

Valves should be inspected for tight shutoff. Piping should be checked for corrosion and leakage at all joints. Ultrasonic examination and hammer sounding are good methods of pipe inspection. Elbows and sharp bends are susceptible to erosion and should be examined for indications of thin walls and holes. Coolers should be inspected in the same manner as that described for heat exchangers in API 572.

13.6.7 Fuel-handling Equipment and Piping

13.6.7.1 General

Manufacturers' instructions, sketches, and drawings should be consulted before inspecting fuel-handling equipment.

13.6.7.2 Gas

Gas system equipment is not generally subjected to severe corrosion or wear and, therefore, does not require extensive inspection. This might not be true for heaters, furnaces, and boilers firing refinery fuel gas. The seats and packing of control valves, block valves, and bypass valves should be examined, and the valves should be checked for ease of operation and tight shutoff. Burner inspection depends on the type of burner to be inspected. Typically, operating conditions indicate the condition of burners. Malfunctioning may be due to fouled or cracked burners or burned burner tips. When the system contains a dry or knockout drum, planning is advisable so that the drum can be removed from service for inspection as required.

13.6.7.3 Fuel-oil Pumps

Fuel-oil pumps should be inspected to ensure that they meet the standards called for when originally purchased (refer to applicable API standards). Fuel-oil heaters should be inspected as indicated in API 572. Valves and burners should be inspected as indicated in the preceding text for gas equipment valves and burners. When the fuel contains corrosive products, all items should be examined for evidence of corrosion.

13.6.8 Burners

Burners should be visually inspected to ensure proper operation once per shift. Conditions that need to be corrected include flame impingement on tubes and supports, abnormal flame dimensions and pattern, oil drippage, and smokey combustion. In addition, the burners should provide an even heat distribution. Poor firing from unbalanced burners can cause serious deterioration of the heating elements and setting. Defective burners that cannot be repaired in service should be replaced so that they do not lead to premature failure of other components. Prior to undertaking a repair, burner drawings from the burner vendor should be reviewed for the installation tolerances, tile diameter, and tip drilling information.

Burner plugging problems sometimes can be solved by proper sizing of the fuel drum and demister pad, heat tracing the fuel gas delivery lines, and providing filters or coalescing systems. Regardless, deposits should be analyzed to determine if the source of the plugging can be identified and eliminated.

The following guidelines are general recommendations for maintenance outage inspection. Always consult the guidelines from the burner vendor.

a) The burner tile is an air orifice. It controls the amount of air flow. Since it is extremely desirable to have even air flow to each burner, the tile dimensions are critical. Typical installation tolerance is ±$^1/_8$ in. (0.32 cm) on the diameter as shown on the burner drawing. Measure the diameter in three to four locations. Most round tiles are installed as a slight oval shape. This can result in poor fuel-air mixing and a bad flame shape. Burner tiles should not be cracked or spalled. The use of a plywood template helps set the tiles in the proper diameter and concentricity. The burner tile has to be centered on the gas tip to obtain uniform fuel air mixing. Typical installation tolerance is ±$^1/_8$ in. (0.32 cm). Poor installations result in bad flames as shown in Figure 42.

b) Check the burner drawing for the number of tip drillings and the drill bit size of the port. Use drill bits (drill blanks or shank ends are preferred) to check the holes by hand to verify proper hole size and the proper included angle of the drillings. Do not mix parts from other burners.

c) The installation tolerance on gas risers is typically ±1/8 in. (0.32 cm) on horizontal spacing and ±1/8 in. (0.32 cm) on vertical spacing. Bent gas risers can cause these dimensions to be wrong. A common problem is different lengths on the gas risers. Many burners are designed such that the gas jets intersect in the center of the burner. The tips usually have arrows or cutouts to aid in tip orientation. Welding rods can be a valuable check for alignment.

Figure 42—Improper Burner Tile Installation Leads to Poor Flame Pattern

d) Air dampers and registers should be checked for operability. Sticking air registers and dampers are a problem. Sometimes, dry graphite lubricant can improve air register operability. Penetrating oil, grease fittings, and the addition of bearings to damper shafts can improve operability.

e) Burners should be visually inspected to determine tip condition and leakage, tile condition, and proper tip alignment. This should assist in preplanning prior to shutdown.

f) If maintenance is deemed necessary and the burner is shut in, the offline inspection should include checking dimensions to match manufacturer drawings and documentation. This should include:

1) riser height,

2) tip position, and

3) tip drilling size. If port holes are greater than one drilling sizes from the original, then the tip should be replaced.

g) While servicing the burner, overall material integrity should be inspected. This should include:

1) checking tips for blockage or erosion;

2) tile damage and repair;

3) check that internal consumables are in good order, including any fiber gaskets or washer materials; and

4) confirm registers have full range of motion.

h) Prior to returning to service, tip and riser connections in heat exposed areas should be checked to verify that high-temperature anti-seize compound is used to make up connections. Silicon tape should not be used.

i) If burner tiles are replaced, new base grouting should be applied.

j) It is important to identify burners as they are removed so they may be returned to the correct location after inspection and maintenance.

k) It may be desirable to have the burner manufacturer (OEM) involved in the burner inspection and maintenance.

l) It is important to obtain detailed burner drawings for comparison during burner inspection and maintenance activities.

13.7 Stacks

13.7.1 Overall Visual

An external visual inspection should be made of brick, concrete, and steel stacks for conditions that may weaken these structures. Field glasses should be helpful in making inspections of high stacks because they can permit any defects to be observed fairly well from the ground. Brick stacks should be inspected for cracks and for the condition of mortar joints to determine the effect of weathering. Concrete stacks should be inspected for cracks and spalling that may expose the steel reinforcement. Steel stacks should be inspected externally for the condition of painted surfaces, signs of oxidation, and thinning or perforation due to corrosion by acidic flue gases. A crane and man basket may be used for inspection of the stack. The use of a crane and man basket should be reviewed by appropriate site safety personnel prior to inspection. A sample stack inspection outline can be found in Annex C.

13.7.2 Cracks

In many cases, cracks in brick and concrete stacks are a result of insufficient thickness of the internal insulation or to internal secondary combustion. These potential causes of cracks should be kept in mind when inspecting the interior of stacks.

13.7.3 Linings

The linings of all stacks should be inspected for cracks, wear, and structural soundness.

13.7.4 Thermography

While stacks are in service, an external, infrared thermographic examination can be made that shows hot spots that indicate failure of the internal liner.

13.7.5 Inspection for Soot and Removal

When liquid fuels are burned, soot accumulates in the base of the stack and should be removed occasionally. During the internal inspection, the amount of soot and ash should be noted, and whether they need to be removed should be decided. The inside of steel stacks should be inspected for corrosion or cracking due to condensation of acidic flue gases. Areas at or adjacent to welds are most susceptible to SCC.

13.7.6 Considerations for Steel Stacks

Steel stacks in heater and boiler services should be inspected and checked for wall thickness at time intervals that are warranted by experience. In addition to the thickness determination, a thorough hammer inspection should be made of the entire stack with particular attention paid to the seams, adjacent areas, and areas adjoining any stiffening rings, lugs, nozzles, and the like, which may act as cooling fins to cause condensation of gases and localized corrosion. The minimum allowable thickness at which repairs can be made should be definitely established for such structures. One practice is to establish these thicknesses on the same basis as was used in the original design for the structure (see Figure 43).

13.7.7 Bolting

Bolts at the base flange and at elevated sections should be checked periodically for loosening, breakage, and corrosion. Compromised bolting greatly reduces the stack's wind loading resistance. Elevated flanged connections that are installed for the purposes of field erection should be seal welded internally to prevent the escape of corrosive flue gases that accelerate bolt failure. Careful attention should be given to the foundations and anchor bolts.

13.7.8 Guy Wires

The guy lines to guyed steel stacks should be inspected for corrosion and wear, focusing on areas where fretting could occur. These areas should include:

1) turnbuckles,

2) jam nuts,

3) pins cotter/retaining pins,

4) clevis,

5) thimble,

6) wire rope clips,

7) guy wire anchor.

Wire rope may be inspected using magnetic flux leakage or other electronic techniques for a thorough inspection of guy wires which are difficult to access. Where the guy wires are accessible for inspection, the wire rope should be visually inspected for:

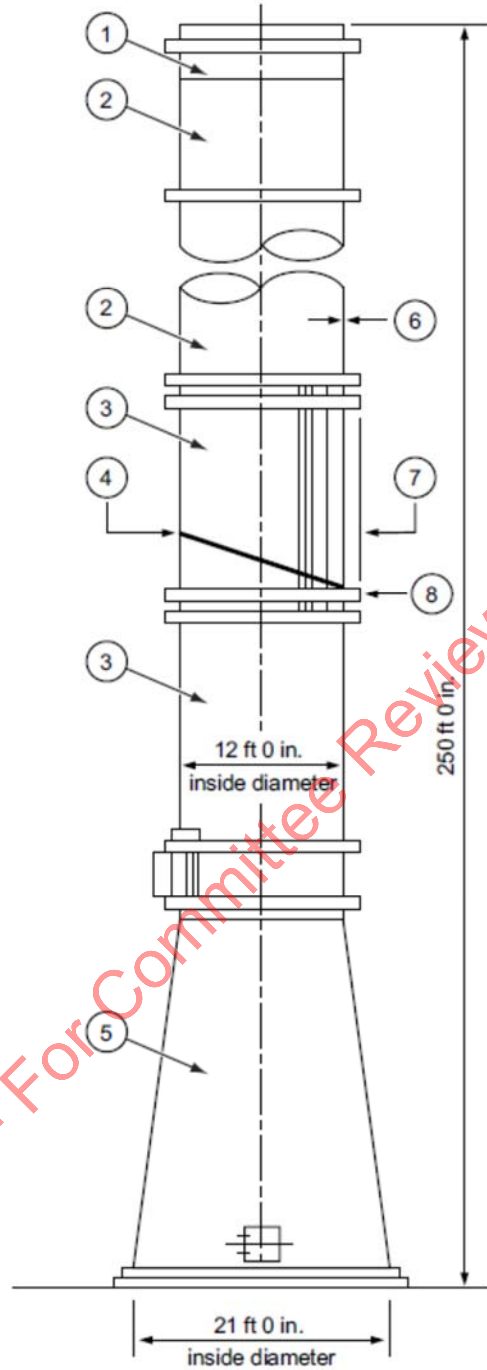
1) reduced diameter due to internal or external corrosion;

2) corroded or broken wires at end connections, especially at the deadman and the top of the stack, where moisture can be retained;

3) cracked, bent, or worn end connections;

4) worn and broken outside wires; and

5) kinks, cuts, or unstranding.



Key

1 $^{1}/_{4}$ in. plate
2 $^{3}/_{8}$ in. plate
3 $^{9}/_{16}$ in. plate
4 metal diaphragm
5 $^{15}/_{16}$ in. plate
6 lining or insulation where required
7 breaching opening
8 drain

Figure 43—Self-supporting Steel Stack

13.7.9 Inspection Techniques

Electromagnetic inspection techniques based upon flux leakage principles are available for inspecting wire rope as well. These technologies involve a crawler capable of inspecting the length of wire for localized strand defects and general thinning of the wire cross section. This allows for a quantitative assessment of the wire integrity.

13.7.10 Lightning Rods

Lightning rods on stacks and their grounding cables should be inspected visually to see that they are secured and unbroken. The ground rod should be inspected visually to see that it is firmly attached to the cable and that it extends to a ground depth sufficient to provide an electrical resistance not to exceed 25 ohms. This should be checked periodically, particularly in dry weather.

13.7.11 Ladders and Landings

The ladders on steel, concrete, and brick stacks should be inspected visually for corrosion and should be tested physically by applying test weights in excess of those that may be imposed by the personnel using them.

13.7.12 Caps

The caps on radial brick and concrete stacks sometimes become damaged, causing loose brick to fall or the reinforcing steel to be exposed. Stack caps should be inspected visually so that any necessary repairs can be made, thereby eliminating a hazard from falling bricks and preventing damage to steel reinforcement.

14 Repairs

14.1 Heaters and Furnaces

Repairs necessary to restore mechanical integrity to pressure-retaining components and modifications made to pressure-retaining components in heaters and furnaces should follow the principles of the design and fabrication codes most applicable to the work. The following issues need to be considered when developing repair and modification plans and implementing them. This is not all-inclusive as other factors may need to be considered for specific situations:

1) repairs and modifications are engineered to meet the requirements of the service including material selection;

2) weld procedures qualified to ASME *Boiler and Pressure Vessel Code*, Section IX for the material and technique appropriate for the welding that needs to be performed;

3) welders certified and qualified per ASME *Boiler and Pressure Vessel Code*, Section IX for the procedures to be used;

4) weld details are defined including any surface preparation, joint preparation, weld joint design, and preheat temperature;

5) NDE techniques to be used and the acceptance criteria, and any immediate inspection hold points need to be defined;

6) heat treatment requirements for repair welds; and

7) any required pressure testing and the acceptance criteria of the test.

The difficulty in welding old to new components and the condition of the components adjacent to the repair location should be considered. It may be prudent to replace a complete tube rather than a short section of tube or to replace a complete coil section in order to minimize field welds and extend the overall life of the repaired coil.

14.2 Boilers

Repairs and alterations made to boilers should be performed to the applicable codes and jurisdictional requirements appropriate for the locality. As indicated earlier, jurisdictions typically define which types of boilers are legislated and the appropriate repair and alteration requirements. Most often, NBBI NB 23 should be the code to which repairs and alterations are performed for legislated boilers. Where there are not any governing codes or jurisdictional requirements, the repairs and alterations should follow the principles of the design and fabrication codes most applicable to the work. Any repairs and alterations need to be considered factors similar to those defined in 14.1.

14.3 Materials Verification

Materials used in repairs should be verified that they meet the materials specified for the repair (e.g. tube materials and welding consumables). Alloy verification is critical to ensure the appropriate material is actually used and installed. Inadvertent substitution with another material can result in premature failure from corrosion, cracking, and stress rupture. Verifying materials often involves testing to show and indicate the proper chemistry. Testing can be accomplished with the use of suitable portable methods (i.e. chemical spot testing, optical spectrographic analyzers, or X-ray fluorescent analyzers). Refer to API 578 for additional information on material verification programs.

15 Records and Reports

15.1 Retention

Boiler, furnace, and heater owners and users should maintain permanent and progressive records for their equipment. Permanent records should be maintained throughout the service life of the equipment and progressive records should be regularly updated to include new information pertinent to the operation, inspection, and maintenance history of the equipment.

15.2 Contents

Records should contain at least the following types of information regarding mechanical integrity.

a) Construction and design information. This may include equipment serial number, manufacturers' data sheet, design specification data, design calculations, and construction drawings.

b) Operating and inspection history. Operating conditions, including abnormal operations, that may affect equipment reliability, inspection data reports, analysis of data, and inspection recommendations.

c) Repairs, design, and mechanical changes. Repairs should be documented as to the reason for the repair and the specific details of the repair. Similarly, any changes made to the design or mechanical components should be recorded detailing the nature of the changes. Standard report forms are often required to be filled out when any repair or design change is made. In addition, any supporting data and calculations to support the repair or design changes should be included in the record.

The importance of maintaining complete records to mechanical reliability cannot be overemphasized. Inspection records form the basis for determining reliability and establishing a preventive maintenance program. With detailed, complete records, repairs and replacements can be predicted and planned avoiding emergency shutdowns. Planned work saves time and cost by allowing personnel and materials to be scheduled prior to a shutdown. These records also provide a means to identify repetitive problems or issues that can be addressed in preparing company specifications for new equipment.

Inspection reports should be clear and complete. All unusual conditions observed should be reported fully, as what seem to be insignificant details may prove to be of importance in the future. When necessary, sketches, diagrams, and photographs should be incorporated in the report. There should be no unnecessary delay between the inspection and the submission of the report. Sample reports are shown in Annex B and Annex C.

Annex A
(informative)

Sample Inspection Checklists for Heaters and Boilers
(See Following Pages for Checklists)

These checklists are examples of the areas and type of information the inspector should focus on during an inspection. They are not intended to be all inclusive since there are a variety of heater and boiler designs that may have particular issues that need to be addressed in an inspection.

Table	Title
A.1	Fired Heater Internal and External Inspection Checklist
A.2	Water Tube Boiler Inspection Checklist
A.3	Fire Tube Boiler Inspection Checklist
A.4a	Fired Heater Operator Rounds Checklist (Checklist I)
A.4b	Fired Heater Operator Rounds Checklist (Checklist II)

Table A.1—Fired Heater Internal and External Inspection Checklist

Location:	Date of Inspection:
Equipment Number:	Reason for Inspection:
Inspector(s):	Equipment Description:
A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected	

#	Item	A	U	NA	NI	Comments
1	**TUBES—RADIANT**					
a.	External scale					
b.	External corrosion, pitting (describe location, appearance, and depth)					
c.	Bulges, blisters, sagging					
d.	Tube OD measurements					
e.	Externally cleaned					
f.	Internally cleaned					
g.	Ultrasonic measurements					
h.	Hardness measurements					
i.	Radiographic inspection					
j.	Tube supports and hardware					
k.	Weld condition					
2	**TUBES—CONVECTIVE**					
a.	External scale, debris					
b.	Tube fin condition					
c.	Ultrasonic measurements (where					
d.	Tube supports and hardware					
3	**FITTINGS**					
a.	Corrosion (scale, pits, buildup). Describe location, appearance, and depth					
b.	Distortion					
c.	Ultrasonic measurements					
d.	Condition of tube roll, plug, and threads					
e.	Weld condition					
4	**CASING AND INTERNALS**					
a.	Insulation, refractory					
b.	Insulation clips					
c.	Fire brick					
d.	Burner view port					
e.	Convection section					
f.	Thermowells					
g.	Floor hearth plate condition					

Table A.1—Fired Heater Internal and External Inspection Checklist (Continued)

Location:		Date of Inspection:				
Equipment Number:		Reason for Inspection:				
Inspector(s):		Equipment Description:				
A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected						
#	**Item**	**A**	**U**	**NA**	**NI**	**Comments**
h.	Casing condition					
i.	Condition of external coating					
5	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, buildup). Describe location, appearance, and depth					
b.	Thermocouple condition					
c.	Inlet guide shroud					
d.	Burner tile condition					
e.	Flame appearance					
f.	Burner tip condition					
g.	Pilot and/or premix primary air door movement					
6	**STACK ASSEMBLY (FLUE GAS)**					
a.	External condition					
b.	Condition of bolts					
c.	Internal Insulation, refractory, coating					
d.	Guy wire supports					
e.	Condition of damper (note freedom of movement and range of motion)					
f.	Rain cap					
g.	Condition of external coating					
7	**FOUNDATION AND SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					
8	**BLOWER**					
a.	Condition of blower motor					
b.	Condition of impeller					

Table A.2—Water Tube Boiler Inspection Checklist

Location:		Date of Inspection:				
Equipment Number:		Reason for Inspection:				
Inspector(s):		Equipment Description:				
A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected						
#	**Item**	**A**	**U**	**NA**	**NI**	**Comments**
1	**TUBES, DRUMS—WATERSIDE**					
a.	Corrosion (scale, pits, buildup) and cracking. Describe location, appearance, and depth					
b.	Excessive scale presence. Describe					
c.	Tubes free of blockage, scale					
d.	Weld condition and corrosion					
e.	Ultrasonic measurements—drums					
f.	Gasket seating surface condition					
g.	Tube borescope inspection					
h.	Internals cracked, corroded, distorted					
2	**TUBES, DRUMS—FIRESIDE**					
a.	External tube corrosion, pitting, erosion (describe location, appearance, and depth)					
b.	External drum corrosion, scale, deposits					
c.	Tube supports and hardware					
d.	Ultrasonic measurements					
e.	Tube distortion and bulges					
f.	Condition of tube fins, if any					
g.	External signs of roll leaks					
h.	Evidence of erosion from soot blowers					
3	**HEADERS**					
a.	Internal scale and corrosion					
b.	Condition of hand hole plugs					
c.	External corrosion, deposits, scale					
4	**WATER COLUMNS**					
a.	Gauge glass condition					
b.	Illuminators, reflectors, mirrors					
c.	Gauge cocks and valves operable					
d.	Condition of high water alarms					
e.	Connections to drum clean, leak free					

Table A.2—Water Tube Boiler Inspection Checklist (Continued)

Location:		Date of Inspection:				
Equipment Number:		Reason for Inspection:				
Inspector(s):		Equipment Description:				
A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected						
#	**Item**	**A**	**U**	**NA**	**NI**	**Comments**
5	**CASING**					
a.	Condition of insulation and refractory					
b.	Condition of structural steel supports					
c.	Casing distorted, cracked, corroded					
d.	Any obstruction to thermal growth					
e.	Condition of all baffle tile and caulking					
f.	Condition of access and lancing doors					
g.	Condition of external casing					
6	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, buildup) and cracking. Describe location, appearance, and depth					
b.	Thermocouple condition					
c.	Inlet guide shroud					
d.	Burner tile condition					
e.	Flame appearance					
7	**FOUNDATION AND SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					

Table A.3—Fire Tube Boiler Inspection Checklist

Location:		Date of Inspection:				
Equipment Number:		Reason for Inspection:				
Inspector(s):		Equipment Description:				
A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected						
#	**Item**	**A**	**U**	**NA**	**NI**	**Comments**
1	**TUBES—WATERSIDE**					
a.	Corrosion (scale, pits, buildup) and cracking Describe location, appearance, and depth					
b.	Excessive scale present (describe)					
c.	Ultrasonic measurements					
d.	Tube distortion					
e.	Borescope inspection					
2	**TUBES And TUBESHEET—FIRESIDE**					
a.	Corrosion, pitting, erosion (describe location, appearance, and depth)					
b.	Tubes free of blockage, scale, deposits					
c.	Tube borescope inspection					
d.	Evidence of roll leaks					
e.	Tubesheet distortion, cracks					
f.	Refractory spalling, cracking					
g.	Ferrule condition					
3	**SHELL**					
a.	Internal scale and corrosion					
b.	Ultrasonic measurements					
c.	External condition					
d.	Condition of external coating					
4	**COMBUSTION CHAMBER**					
a.	Condition of insulation, refractory					
b.	Condition of brickwork					
5	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, buildup)					
b.	Distortion from excessive heat					
c.	Flame appearance					
6	**FOUNDATION AND SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					

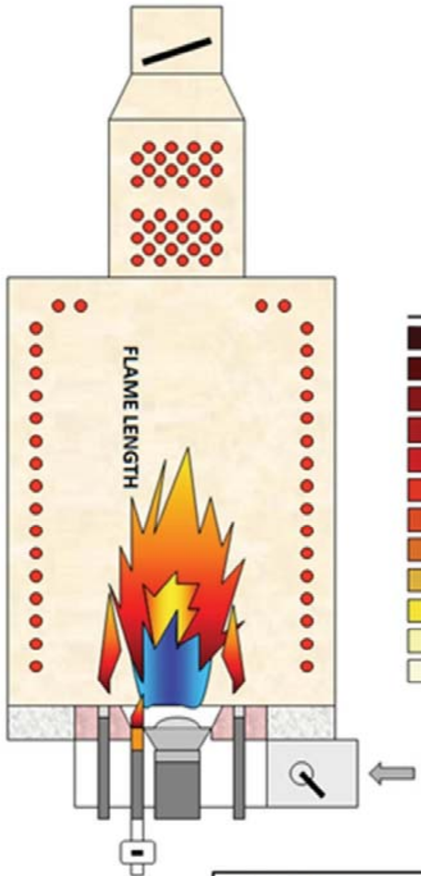
Table A.4a—Fired Heater Operator Rounds Checklist (Checklist I)

Unit:		Date:	
Heater ID:		Employee ID:	

ROUTINE SURVEILLANCE ACTIVITIES		OK	Comments	N/A
Check external condition of the heater for the following.				
1	Smoke from stack (visible plume other than water vapor).			
2	Stack vibration.			
3	Stack and draft damper positions.			
4	Hot spots of bulges on shell.			
5	Air leaks on shell or ducting.			
Check fuel system for the following.				
6	Proper fuel pressure to burners.			
7	Burner fuel valve positions.			
8	Proper fuel pressure to pilots.			
9	Burner fuel valve positions.			
10	Burner and pilot air door positions.			
11	Verify that excess oxygen combustibles and draft are within acceptable ranges by checking field devices, if applicable.			
View burner and pilot flame through sight doors on burner front plate for the following.				
12	Burner tile condition.			
13	Burner tip condition and color.			
14	Burner tip plugging.			
View internal firebox components through sight ports on heater casing for the following.				
15	Burner flame pattern (shape, length, and color).			
16	Burner flame stability (uniform).			
17	Flame impingement on tubes or tube supports.			
18	Tube condition (color, external scale, or host spots).			
19	Tube hanger/supports condition (color, tubes out of position, or hot spots).			
20	Refractory condition (damage evident by lots of refractory on floor).			
21	Flue gas haze.			

Activity Number	Additional Comments

Table A.4b—Fired Heater Operator Rounds Checklist (Checklist II)



CHECK THESE LOCATIONS FOR AIR LEAKAGE. TAPE OR SEAL WITH HIGH TEMPERATURE CAULK OR REPAIR

- HEADER BOXES
- OBSERVATION DOORS
- AROUND BURNERS
- EXPLOSION AND ACCESS DOORS
- INSTRUMENT CONNECTIONS
- TUBE TERMINAL CONNECTIONS
- UNUSED BURNERS
- CORRODED STEEL CASING
- JOINT BETWEEN RADIANT/CONVECTION

Temperature Color Guide

BARELY RED	(900-1000 F)
DARK RED	(1000-1100 F)
DARK CHERRY	(1100-1200 F)
MEDIUM CHERRY	(1200-1300 F)
CHERRY RED	(1300-1400 F)
BRIGHT RED	(1400-1500 F)
SALMON RED	(1500-1600 F)
ORANGE	(1600-1700 F)
LIGHT ORANGE	(1700-1800 F)
YELLOW	(1800-1900 F)
LIGHT YELLOW	(1900-2050 F)
WHITE	(> 2050 F)

HEATER PERFORMANCE:

TARGET	ACTUAL	
		DRAFT
		STACK DAMPER POSITION
		O2
		CO, NOX
		BRIDGEWALL TEMPERATURE
		STACK TEMPERATURE
		FUEL PRESSURE
		PILOT FUEL PRESSURE
		PREHEAT AIR TEMPERATURE

BURNER INSPECTION:

- ____ UNSTABLE FLAME (Lift Off)
- ____ BAD FLAME PATTERN (Flame Impingement, Bushy, Yellow, etc.)
- ____ PLUGGED TIPS
- ____ COOL BURNER TILE
- ____ PILOT TIP NOT GLOWING
- ____ PILOT AIR NOT WORKING
- ____ AIR REGISTER STUCK OR NOT WORKING
- ____ AIR REGISTER OPEN WHILE BURNER OFF
- ____ FUEL VALVE PINCHED

RADIANT SECTION:

- ☐ TUBE BULGING, BOWING, SAGGING
- ☐ TUBE COLOR
- ☐ TUBE EXTERNAL SCALING
- ☐ TUBE HANGER COLOR UNIFORMITY
- ☐ TUBE HANGER DISTORTION
- ☐ FLOOR REFRACTORY COLOR
- ☐ WALL REFRAVTORY COLOR
- ☐ FLOOR REFRACTORY DAMAGE
- ☐ ROOF REFRACTORY DAMAGE

EXTERNAL:

- ☐ HOT SPOTS ON HEATER SKIN
- ☐ SIGHT PORTS FUNCTIONAL (SEAL)
- ☐ EXPLOSION DOORS, FLANGES, HOLES, LEAKING AIR IN BOX

CONVECTION SHIELD TUBES:

- ☐ BULGING, BOWING, SAGGING
- ☐ TUBE COLOR
- ☐ TUBE SCALING
- ☐ NOTICEABLE AFTERBURNING

Annex B
(informative)

Sample Heater Inspection Records

Annex B reproduces samples of the records maintained by a company on the tubes and fittings of its heater. All of these records are used as field records, office records, and completed forms included in the report covering the inspection of the heater.

The *tube layout drawing* shows the actual arrangement of tubes and fittings in the heater. The flow through the heater is also noted. Tubes removed from the heater during the inspection and tubes approaching the minimum allowable thickness for service can be noted by a special color scheme.

The *tube inspection record* shows the history of all tubes in a heater on the date the current inspection is completed and the heater is ready to return to operation.

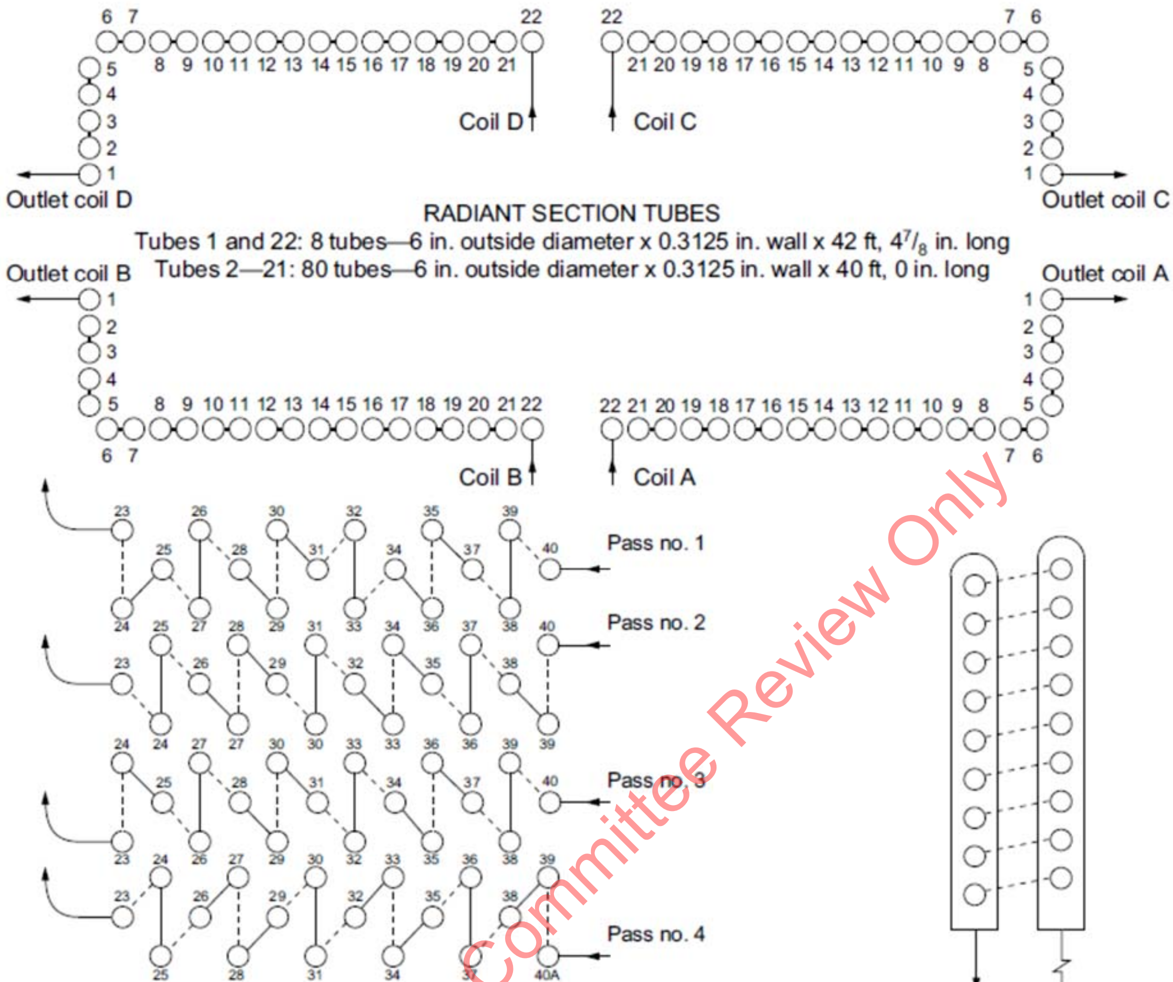
The *tube inspection record (record of tubes calipered)* is used to record the tube-calipering measurements taken during the current inspection. The figures set in roman type on the top half of each block are the measurements taken during the previous inspection. The figures set in italic type on the bottom half are the measurements taken during the current inspection. The two-digit figures to the right of the ID measurements denote the change in ID from the previous inspection and equal twice the corrosion rate for the interval between the two inspections. Once the report has been prepared, an extra copy should be made of this record and used as a field work sheet during the next inspection.

The *tube inspection record (instrument caliperings)* is used to record tube thickness measurements taken by radiography or with ultrasonic or radiation-type instruments.

The *tube renewal record* is used to record information on all of the tubes renewed during the interval between the completion of the previous inspection and the completion of the current inspection. It quickly shows the location of the tubes renewed, why the tubes were renewed, and how long the tubes had been in service. This record is especially valuable when tube life and what tube material is best suited for the particular service are considered.

The *field work and record sheet (tube rolling data)* is used to record data necessary for the tube rolling operation.

The *record of heater fitting inspection and replacement* is primarily a reference record for heater fittings and shows where the various types of fittings should be checked for thickness. It contains a table for recording the actual ODs of a fitting at the various sections. Each point number on a sketch corresponds to a section of a fitting and not to a particular point on the fitting.



CONVECTION SECTION TUBES

Tubes 23: 4 tubes—5 in. outside diameter x 0.3125 in. wall x 42 ft, 9$^1/_8$ in. long
Tubes 40: 3 tubes—5 in. outside diameter x 0.3125 in. wall x 40 ft, 0 in. long
Tubes 40A: 1 tubes—5 in. outside diameter x 0.3125 in. wall x 40 ft, 7$^1/_2$ in. long
Tubes 24—39: 64 tubes—5 in. outside diameter x 0.3125 in. wall x 40 ft, 6$^7/_8$ in. long

SUPERHEATER

18 tubes—3 in. outside diameter x 0.250 in. wall x 1$^5/_8$ in. long

Notes:
1. A copy of this diagram is to be sent in with the tube inspection record after each periodic inspection and test.
2. Color in red all the tubes that are approaching minimum thickness at the time of inspection.
3. A copy of this diagram is to be sent in with the tube renewal record only when the arrangement of the tubes in the heater has been changed.
4. Tubes that are shown in this diagram but are not in the heater or in service are to be crossed out.
5. Tubes that are in the heater but are not shown in the diagram are to be shown in their relative locations and given the same number as adjacent tubes with the suffix "A."
6. The field is to indicate the actual flow when it differs from the flow shown on the diagram.

Figure B.1—Sample of Tube Layout Drawing

Tube No.	Date Installed	Tube	
		Material	Original OD and ID (in.)
Economizer			
1 to 126	2/24/67	1	3.5 × 2.7
Preheater			
1	12/16/70	2	4.5 × 3.5
2	2/29/72	1	4.5 × 3.5
3 to 8	4/17/70	2	4.5 × 3.5
9	9/19/70	2	4.5 × 3.5
23	9/19/70	2	4.5 × 3.5
24 to 82	4/17/70	2	4.5 × 3.5
83	4/17/70	1	3.5 × 2.7
84 to 92	10/26/72	1	3.5 × 2.7
93 to 94	4/24/72	1	3.5 × 2.7
95 to 102	10/26/72	1	3.5 × 2.7
103 to104	4/17/70	1	3.5 × 2.7
105 to 106	10/26/72	1	3.5 × 2.7
107 to 114	2/24/67	1	3.5 × 2.7
Side wall			
1	7/8/71	1	4.5 × 3.5
2	1/15/72	1	4.5 × 3.5
3	12/17/71	1	4.5 × 3.5
4	7/23/72	2	4.5 × 3.5
5	1/4/72	1	4.5 × 3.5
6	7/31/72	2	4.5 × 3.5
7	1/4/72	1	4.5 × 3.5
8	7/23/72	2	4.5 × 3.5
9	4/24/72	2	4.5 × 3.5
10	7/17/71	1	4.5 × 3.5
11	4/24/72	2	4.5 × 3.5
12	1/10/69	1	4.5 × 3.5
13	4/27/72	2	4.5 × 3.5
14 to 15	1/10/60	1	4.5 × 3.5
16 to 25	4/24/72	2	4.5 × 3.5

Figure B.2—Sample of Tube Inspection History

Tube No.	Date Installed	Tube	
		Material	Original OD and ID (in.)
26	1/22/72	2	4.5 × 3.5
27	1/29/72	2	4.5 × 3.5
28	1/10/69	1	4.5 × 3.5
29	7/23/72	2	4.5 × 3.5
30	1/15/72	1	4.5 × 3.5
31	7/16/72	2	4.5 × 3.5
32	1/15/82	1	4.5 × 3.5
33	4/27/73	2	4.5 × 3.5
34	12/26/72	2	4.5 × 3.5

NOTES

1) Group tubes under headings (i.e. preheater, side wall, vertical, roof, and economizer). Consecutive tubes may be grouped.

2) Kind of steel:

1: Plain C	5: 9 Cr-1.5 Mo	9:
2: 4 Cr-6 Cr	6: 14 Cr	10:
3: 2 Cr-0.5 Mo	7: 18 Cr-8 Ni	11:
4: 4 Cr-6 Cr-0.5 Mo	8:	12:

3) Method for reporting welded tubes:
   1-1 for welded C steel,
   2-2 for welded 4 Cr-6 Cr steel, and
   7-2 for 18 Cr-8 Ni steel welded to 4 Cr-6 Cr steel.

4) Method for reporting upset-end tubes:
   The symbol denoting the kind of steel precedes U as follows: 1 U, 5 U, and 7 U.

5) Method for reporting tubes with tube-end liners:
   The symbol denoting the kind of steel precedes L as follows: 2 L and 4 L.

Figure B.2—Sample of Tube Inspection History (Continued)

Plant:				Date:				
Unit:				Sheet No.:				
Tube No.	**ID in Roll** (in.)				**ID in Back of Roll** (in.)			
	Top or Front		**Bottom or Rear**		**Top or Front**		**Bottom or Rear**	
Economizer								
1	3.69		3.70		3.50		3.51	
	3.72	**0.03**	**3.72**	**0.02**	**3.51**	**0.01**	**3.51**	**0.00**
6	4.02	0.03	4.08	0.02	3.96	0.02	3.95	0.03
	4.06	**0.04**	**4.11**	**0.03**	**4.00**	**0.04**	**4.00**	**0.05**
20	4.10	0.05	4.11	0.04	4.01	0.03	4.00	0.02
	4.14	**0.04**	**4.16**	**0.05**	**4.03**	**0.02**	**4.02**	**0.02**
80	3.98	0.06	4.00	0.05	3.91	0.04	3.98	0.03
	4.05	**0.07**	**4.04**	**0.04**	**3.97**	**0.06**	**3.95**	**0.06**
Vertical								
1	4.48	0.04	4.50	0.03	4.32	0.02	4.36	0.04
	4.54	**0.06**	**4.54**	**0.04**	**4.35**	**0.03**	**4.41**	**0.05**
12	3.79		3.76		3.50		3.50	
	3.81	**0.02**	**3.80**	**0.04**	**3.52**	**0.02**	**3.53**	**0.03**
18	3.98	0.05	4.00	0.04	3.75	0.03	3.70	0.02
	4.06	**0.08**	**4.06**	**0.06**	**3.79**	**0.04**	**3.74**	**0.04**
49	3.87	0.04	3.90	0.05	3.61	0.02	3.59	0.04
	3.92	**0.05**	**3.94**	**0.04**	**3.62**	**0.01**	**3.63**	**0.04**

NOTE Figures set in non-bold type refer to the previous ID and change. Figures set in bold type refer to the current ID and change. When an inspection report is made, a copy of this form is to be saved for use as a field work sheet at the next inspection.

Figure B.3—Sample of Tube Inspection Record (Tubes Calipered)

Plant:	Section:
Unit:	Date:
	Sheet No.:

Tube No.	Thickness Measurements (in.)					
	Top or Front		Middle		Bottom or Rear	

Figure B.4—Sample of Tube Inspection Record (Instrument Calipered)

Plant:	Section:
Unit:	Date:
	Sheet No.:

Tube No.	Thickness Measurements (in.)					
	Top or Front		Middle		Bottom or Rear	

Figure B.4—Sample of Tube Inspection Record (Instrument Calipered) (Continued)

Plant:						Tube Layout Drawing:					
Battery:						Date:					
Economizer											
33	11/4/70	1	4.5 × 3.5	3.70	3.75	4.06	3.98	D	6/15/73	1	4.5 × 3.5
34	11/4/70	1	4.5 × 3.5	3.72	3.78	4.00	4.08	D	6/15/73	1	4.5 × 3.5
Vertical Section											
8	3/31/70	2	4.5 × 3.5	3.70	3.72	3.65	3.68	A	6/20/73	2	4.5 × 3.5
9	3/31/70	2	4.5 × 3.5	3.70	3.75	3.62	3.65	B	6/20/73	2	4.5 × 3.5

NOTES

1) Group tubes under headings (i.e. preheater, side wall, vertical, roof, and economizer). Consecutive tubes may be grouped.

2) Kind of steel:

1: Plain C	5: 9 Cr-1.5 Mo	9:
2: 4 Cr-6 Cr	6: 14 Cr	10:
3: 2 Cr-0.5 Mo	7: 18 Cr-8 Ni	11:
4: 4 Cr-6Cr-0.5 Mo	8:	12:

3) Method for reporting welded tubes:
   1-1 for welded C steel,
   2-2 for welded 4 Cr-6 Cr steel, and
   7-2 for 18 Cr-8 Ni steel welded to 4 Cr-6 Cr steel.

4) Method for reporting upset-end tubes:
   The symbol denoting the kind of steel precedes U as follows: 1 U, 5 U, and 7 U.

5) Method for reporting tubes with tube-end liners:
   The symbol denoting the kind of steel precedes L as follows: 2 L and 4 L.

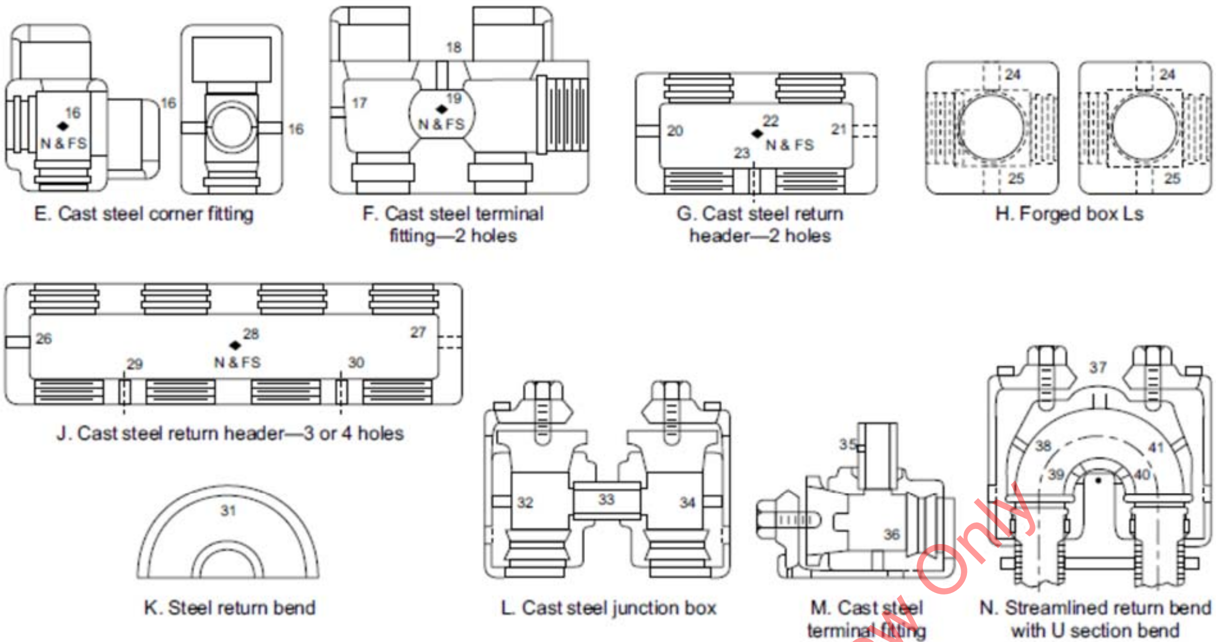
6) Cause of removal:

A: split tube,	D: thin tube,
B: burned due to split tube,	E: other causes, and
C: bulged in operation,	F: burned in operation.

Figure B.5—Sample of Tube Renewal Record

Type of Unit:							Plant:						
Unit No.:							Date:						
Tube No.	**Material**	**Front or Top Dimensions** (in.)						**Rear or Bottom Dimensions** (in.)					
		ID of Tube Hole	**Tube End**			**ID of Roll**		**ID of Tube Hole**	**Tube End**			**ID in Roll**	
			OD	**Inside Diameter**					**OD**	**Inside Diameter**			
				In Roll	**In Back of Roll**	**Required**	**Actual**			**In Roll**	**In Back of Roll**	**Required**	**Actual**
Sidewall													
8	1	4.54	4.50	3.50	3.50	3.70	3.69	4.53	4.51	3.51	3.51	3.69	3.69
10	3	4.58	4.51	3.51	3.50	3.74	3.74	4.57	4.50	3.50	3.50	3.73	3.75
19	2	4.56	4.48	3.52	3.52	3.76	3.77	4.55	4.48	3.48	3.49	3.71	3.72
26	4U	4.53	4.50	3.34	3.49	3.55	3.56	4.53	4.50	3.35	3.50	3.56	3.55
Preheater													
2	1U	4.53	4.50	3.34	3.49	3.55	3.56	4.54	4.50	3.33	3.50	3.55	3.54
8	3U	4.54	4.51	3.35	3.48	3.56	3.56	4.56	4.49	3.34	3.48	3.60	3.61
9	4U	4.56	4.50	3.32	3.50	3.56	3.57	4.55	4.51	3.33	3.51	3.55	3.56
10	4	4.53	4.48	3.36	3.50	3.62	3.63	4.53	4.49	3.35	3.50	3.57	3.57
85	1-1	3.54	3.50	2.70	2.85	2.88	2.88	3.55	3.49	2.69	2.86	2.89	2.90
87	1U	3.55	3.48	2.56	2.69	2.78	2.79	3.56	3.50	2.54	2.68	2.76	2.77
88	2-2	3.56	3.51	2.69	2.75	2.88	2.89	3.54	3.50	2.70	2.79	2.88	2.89
90	4-2	3.54	3.50	2.70	2.84	2.88	2.87	3.54	3.51	2.71	2.80	2.88	2.87

Figure B.6—Sample of Field Work and Record Sheet (Tube Rolling)



NOTE 1 The numbers shown on these sketches represent the sections of a fitting, not individual points.

NOTE 2 The fitting number shall correspond to the tube number.

NOTE 3 The symbols used to denote fitting material shall be the same as those used for tubes.

NOTE 4 The average actual outside diameter at various sections of all sizes and types of fittings on the heater shall be recorded in the table at the right.

Fitting Size	Point Number and Outside Diameter									
	PT	OD	PT	OD	PT	OD	PT	OD	PT	OD

Figure B.7—Sample Record of Heater Fitting Inspection and Replacement

Annex C
(informative)

Sample Stack Inspection Record

The condition of a number of stacks can be tabulated on a form such as in the sample contained in this annex.

SEMIANNUAL STACK INSPECTION REPORT

PLANT______________________________ REPORT BY ______________________________

CHECKED BY______________________________ APPROVED BY ______________________________

DATE ______________________________

Complete description of all defects and repairs since last inspection: <u>Inspected for condition and found OK except as noted below</u>.

Stack No.	Location and Description	Foundation	Shaft	Lining	Guys and Connection	Lightning, Rods, Points, Conductors, and Grounds	Ladders	Vertical Alignment	Remarks and Recommendations
30	Boiler No. 8 BH No. 2 6 × 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
31	Boiler No. 2 BH No. 2 6 × 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
32	Boiler No. 3 BH No. 2 6 × 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
33	Boiler No. 9 BH No. 2 6 × 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
34	Boiler No. 10 BH No. 2 6 × 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
35	FCCU 11 × 120 ft RBS	Concrete to rock	OK	Firebrick OK	None	5 Points 2 Grounds OK	OK	Outside ladder irons	General condition good
36	FCCU $4^{1}/_{2}$ × 108 ft SS	Platform	OK	None	None	None	None	$2^{1}/_{2}$ in. south 10 in. west	General condition good
37	FCCU gas flare stack 1 ft, 8 in. OD × 250 ft high × $^{9}/_{32}$ in.	Concrete to rock	OK	None	OK	None	None	3 ft east 20 in. south	Recently reconditioned—condition good: frozen concrete crumbling south side on pedestal
38	Badger pipe stills	Concrete	OK	OK	None	OK	None	OK	General condition good

NOTE Stack numbers do not appear on any stack. Abbreviations are as follows: BH = blower housing; BS = brick stack; CS = concrete stack; SS = steel stack; RBS = radial brick stack; RTS = radial tile stack; and FCCU = fluid catalytic cracking stack.

Annex D
(informative)

Parameters for Integrity Operating Windows in Fired Heaters

The table below provides example parameters for IOWs in fired heaters, furnaces, and boilers. In no way should this be taken as comprehensive or all-inclusive.

Equipment and/or Process Stream	Parameter to be Monitored or Controlled	Rationale
PROCESS OIL		
Process inlet	Flow rate	To maintain a sufficiently high inside film coefficient to control tube wall temperature, to prevent fouling, to permit a stable flow regime for two-phase flow conditions, to ensure pass flow distribution, and to control vaporization rate (when combined with absorbed duty)
Process inlet	Flow rate	To minimize excessive corrosion, especially if combined with other damage mechanisms
Process inlet	Characteristics (total acid number/sulfur/others)	To minimize excessive corrosion due to corrosion damage mechanisms
Process inlet	Temperature	To ensure dry feed and to prevent internal fouling due to operating below the dry point of a vapor process
Process inlet	Pressure	To prevent lifting pressure safety valve (PSV)
Process inlet	Pressure	To prevent heater tube damage if indication is downstream of the coil
Process steam injection inlet	Flow rate	To prevent fouling and overheating
Process outlet	Temperature	To prevent accelerated internal fouling and minimize excessive corrosion, especially if considered with other high-temperature damage mechanisms
Process outlet	Temperature	To prevent exceeding design limits of downstream piping and equipment
PROCESS STEAM		
Utility steam inlet	Flow rate	To control pass distribution and boiling/flow regime to minimize internal fouling, corrosion, and vibration
Utility steam inlet	Flow rate	To prevent exceeding relief valve or other equipment design capacity for once through systems
Equipment and/or process stream	Parameter to be monitored or controlled	Rationale
Steam drum	Flow rate	To prevent lifting PSV or other equipment design capacity
Steam drum	Conductivity (steam quality)	To prevent damage to downstream equipment
Steam drum	Pressure	To prevent lifting PSV
Boiler feed water inlet	Flow rate	To control pass distribution and boiling/flow regime to minimize internal fouling, corrosion, and vibration and to prevent exceedance of tube temperature limit
Boiler feed water inlet	Temperature	To prevent external corrosion of economizer coil by operating below flue gas dew point

Equipment and/or Process Stream	Parameter to be Monitored or Controlled	Rationale
Boiler feed water inlet	Temperature	To control boiling/flow regime to minimize internal fouling, corrosion, and vibration
Superheated steam inlet	Conductivity (steam quality)	To prevent internal fouling and damage to downstream equipment
Superheated steam outlet	Temperature	To prevent exceeding superheater coil and downstream equipment temperature limits
Superheated steam outlet	Temperature	To infer potential for internal tube fouling
COMBUSTION		
Burner fuel inlet	Pressure	To prevent exceeding burner maximum capabilities
Burner fuel inlet	Characteristics (liquid/H_2S/others)	To prevent damage to burner tips causing performance issues and to control environmental emissions
Firebox flue gas	Temperature	In conjunction with excess oxygen limit, to ensure stable ultralow NO_x burner operation
Oxygen	Content	To ensure acceptable burner performance and flame patterns
Equipment and/or process stream	Parameter to be monitored or controlled	Rationale
CO/combustibles	Content	To ensure acceptable burner performance and flame patterns
Burner emissions	Content (NO_x/CO/SO_x/others)	To ensure acceptable burner environmental performance
EQUIPMENT		
Radiant/ convection coil	Temperature	To prevent tube failure (see API 530, Annex A)
Equipment and/or process stream	Parameter to be monitored or controlled	Rationale
Firebox	Pressure	To ensure personnel are not exposed and to prevent equipment damage
Firebox flue gas	Temperature	To prevent equipment damage leading to tube integrity issues
Stack flue gas	Temperature	To prevent corrosion by staying above the flue gas dew point
Stack flue gas	Temperature	To prevent equipment damage
Air preheat flue gas outlet	Temperature	To prevent acid corrosion caused by flue gas being below dew point
Air preheat flue gas outlet	Temperature	To prevent damage to downstream equipment
Preheated combustion air to burner	Temperature	To prevent damage to downstream equipment
CALCULATIONS		
Process inlet	Vaporization	To prevent accelerated internal fouling, corrosion, erosion, and vibration
Process convection and radiant	Heat flux	To prevent accelerated internal fouling, corrosion, erosion, and vibration
Fired duty	Duty	May be used instead of or as well as heat flux. This may also be an environmental limit.

Annex E
(informative)

Cleaning Methods

E.1 External Cleaning—Tubes

Tubes may be externally cleaned by various methods. The specific method is usually determined by the accessibility of the tubes and the purpose for which they are to be cleaned. Readily accessible tubes may be cleaned by wire brushing or grit blasting. Grit blasting is preferred if defects are suspected and a close inspection is required, since all deposits can be removed and the bare metal exposed. Refractory should be protected from grit blasting.

All radiant surfaces should be cleaned. Cleaning only a portion of the radiant surfaces may promote overheating of the cleaned surfaces. Scaled or fouled surfaces may obstruct heat transfer and cause the clean surfaces to absorb more heat. Usually, it is physically impossible to clean the economizer or convection tubes by wire brushing or grit blasting because of tube arrangement. Other methods (i.e. the use of a steam lance or a stream from a water hose or high-pressure water equipment) may be used. In such instances, cleaning is performed primarily to remove external deposits and improve the heat transfer. Before resorting to steam or water cleaning of the tubes, careful consideration should be given to possible damage to the refractory insulation and brickwork, particularly in a service where a fuel with a high sulfur content is used. In addition, for stainless steel tubes, consider using a soda ash solution as detailed in 6.1.10 and maintaining the chloride content of the water at less than 50 ppm. These should minimize potential SCC of the tubes from cleaning operations.

E.2 Internal Cleaning—Tubes

E.2.1 General

Tubes may require periodic cleaning to remove internal fouling and coking deposits. These deposits can be detrimental to unit performance and reliability. Tubes and fittings usually require cleaning when deposits cause an increase in coil pressure drop, an increase in firing rate to maintain the desired coil outlet temperature, a decrease in coil outlet temperature, or tube hot spots.

E.2.2 Methods of Cleaning

Internal cleaning of tubes may be accomplished by several methods (i.e. gas oil circulation, chemical cleaning, steam-air decoking, thermal spalling, mechanical pigging, hydroblasting, and abrasive grit). These methods are typically performed off-line, although some tube arrangements can allow online thermal or steam spalling. The effectiveness of each method to remove deposits varies with the deposit type. For instance, circulating gas oil prior to steaming and water wash can be an effective cleaner for soft deposits dissolved by gas oil. However, it may not be effective in removing heavy coke deposits. Therefore, when selecting a cleaning method, the nature of the deposit in addition to safety, potential risk of damage, allotted time, and cost should be considered. In addition to potential damage from the particular technique, cleaning can cause leaks in the tube rolls or header plugs of removable headers from thermal forces or the removal of coke. Chemical cleaning consists of circulating an inhibited acid or other proprietary chemical cleaner through the coil until all deposits have been softened and removed. Water washing to flush all deposits from the coil usually follows this method. When the tubes are made of austenitic stainless steel, the chloride content of the water used for flushing should be maintained at less than 50 ppm. Consider using a soda ash solution as detailed in 6.1.10 for cleaning stainless steel tubes. Care should be used in chemical cleaning to avoid corrosion damage to the tubes.

High-pressure water jet blasting is another option for cleaning tubing with plug-type fittings. Other cleaning options for welded coils include mechanical decoking pigs (see Figure E.1) and abrasive blasting (shot blasting or sand jet blasting) with metal shot or an abrasive medium.

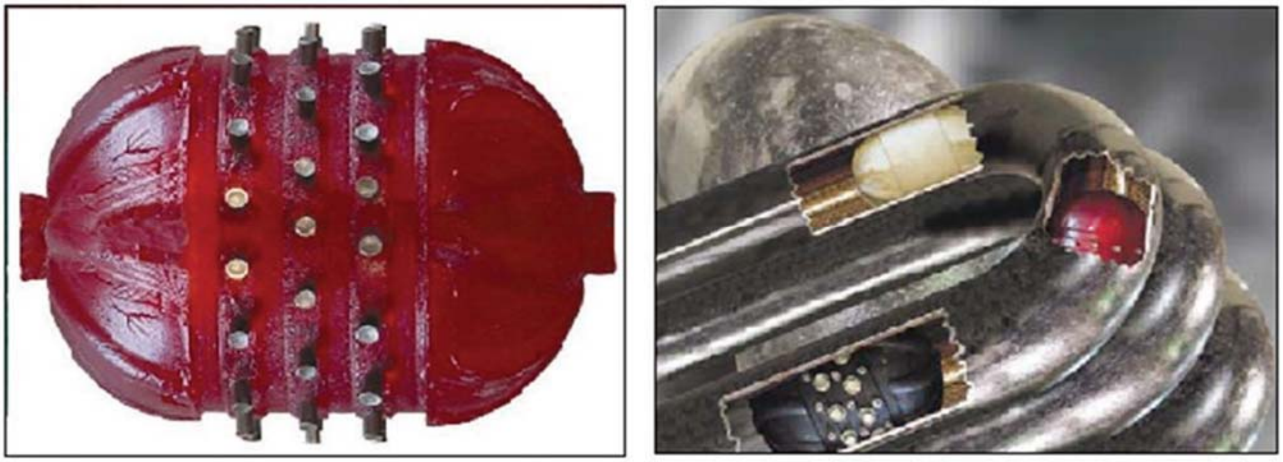


Figure E.1—Mechanical Decoking Pig

E.2.3 Steam-air Decoking

Steam-air decoking consists of the use of steam, air, and heat to burn the coke out of the tube. Only trained, experienced personnel should use this cleaning method, because improper procedures or control could result in overheating the tubes and support causing serious, costly damage to the tubes. Steam-air decoking may not always remove the coke from a tube fitting. If this is the case, it may be necessary to use mechanical cutters on the U-bends and remove them for cleaning; however, this is an expensive and destructive method of cleaning.

E.2.4 Thermal Spalling

Thermal spalling is a technique that uses alternating heating and cooling to spall coke off the tube wall. Steam is often used as the process medium to control heating and cooling. Care should be exercised with this technique as the coke particles removed from the could cause localized erosion damage of return bends.

E.2.5 Abrasive Pigs

Abrasive pigs can be used to clean tubes mechanically. The technique involves propelling a pig equipped with metal appendices through the tubes with water. The pig is sent back and forth through the tubes and deposits are removed much like using a wire brush to clean a surface. This technique often involves some modifications to piping to create a location to launch and receive the pigs. An advantage of abrasive pigs is that they are less likely to damage the tubes than other techniques (e.g. steam-air decoking and acid cleaning). Care should be taken to assure the abrasive pig does not gouge tube walls. The presence of plug fitting style tube return bends (e.g. “mule-ears” or “plug headers”) have historically challenged the cleaning effectiveness of abrasive pigs. Also, pigs are generally unable to navigate without damage through most plug fitting style return bends.

E.2.6 Tube Knockers and Cutters

Various types of tube knockers and cutters are available for the mechanical cleaning of tubes. Selection of the type of cleaning head is a matter of preference. An air motor usually drives the cutting head. In cold weather, steam is often used for motive power to warm the tube and reduce the effect of shock on the tube. Mechanical cleaning cannot be used to clean the U-bends of sectional fittings. When mechanical cleaners are used, care has to be exercised to avoid damage to the tubes or fittings.

E.3 Internal Cleaning—Boilers

E.3.1 General

Steam-drum internals and the ID surface of the drum should be inspected before washing to determine any problems, including poor circulation, poor water quality, and low steam purity.

E.3.2 Washing

The inside of shells, drums, and tubes should then be washed down thoroughly to remove mud, loose scale, or similar deposits before they dry and become more difficult to remove. The washing operation should be carried out from above if possible, to carry the material downward to the blow-off or handholes. A hose with sufficient water pressure or hand tools should be used to remove soft scale and sludge. The blow-off line should be disconnected prior to the washing procedure to keep mud and scale out of the blowdown drum. The tubes of horizontal-return-tube boilers should be washed from below and above. It is especially important to ensure that all tubes and headers are clear of sludge after the wash is completed. Water should be passed down each individual tube and observed to exit from below. Each header should be opened sufficiently to give a clear view so that it can be ascertained that all sludge has been removed. Precautions should be taken to ensure that the water does not come into contact with the brickwork of the combustion chamber. If contact cannot be avoided, the brickwork should be dried out carefully when the boiler is fired up.

E.3.3 Acid Cleaning

The use of an inhibited acid solution on the inside of the boiler is a common method of cleaning the interior surfaces. Prior to cleaning, samples of sludge and deposits should be analyzed to ensure the cleaning solution can adequately remove the material. During the cleaning operation, corrosion probes and coupons are often used to monitor the corrosivity of the circulating solution. After acid cleaning, the interior of the boiler should be neutralized, washed down, and refilled with water. If a nitrogen purge is used after acid cleaning, drums should be checked for oxygen content before entry. Acid cleaning should not be used on superheaters or other equipment that contains pockets that cannot be thoroughly flushed out. Precautions should be taken to make sure that all sludge is removed after an acid wash.

It is normal practice to fill pendent-type superheaters with condensate or demineralized water and to keep the superheater full of this water while the remainder of the boiler is acid cleaned. During chemical cleaning, all phases of the operation should be closely supervised by experienced, responsible individuals. During chemical cleaning, all electric power and other ignition sources in the near boiler have to be turned off to prevent explosion of the hydrogen and other hazardous gases that are normally given off during the cleaning.

E.3.4 Chelates

Another common method of cleaning uses chelates. The chelates are added to the boiler water, and the boiler is fired to create circulation that facilitates cleaning of the internal surfaces. Insufficient removal of chelates after cleaning is a common cause of boiler tube cracking and subsequent failure.

See the ASME *Boiler and Pressure Vessel Code*, Sections VI and VII, for more information on the care and cleaning of boilers.

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