

Inspection of Fired Boilers and Heaters

API RECOMMENDED PRACTICE 573
FOURTH EDITION, JANUARY 2021



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Inspection of Fired Boilers and Heaters

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 A297³, *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 SP0170⁴, *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During a Shutdown of Refinery Equipment*

NBBI NB 23⁵, *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**attenuator**

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.

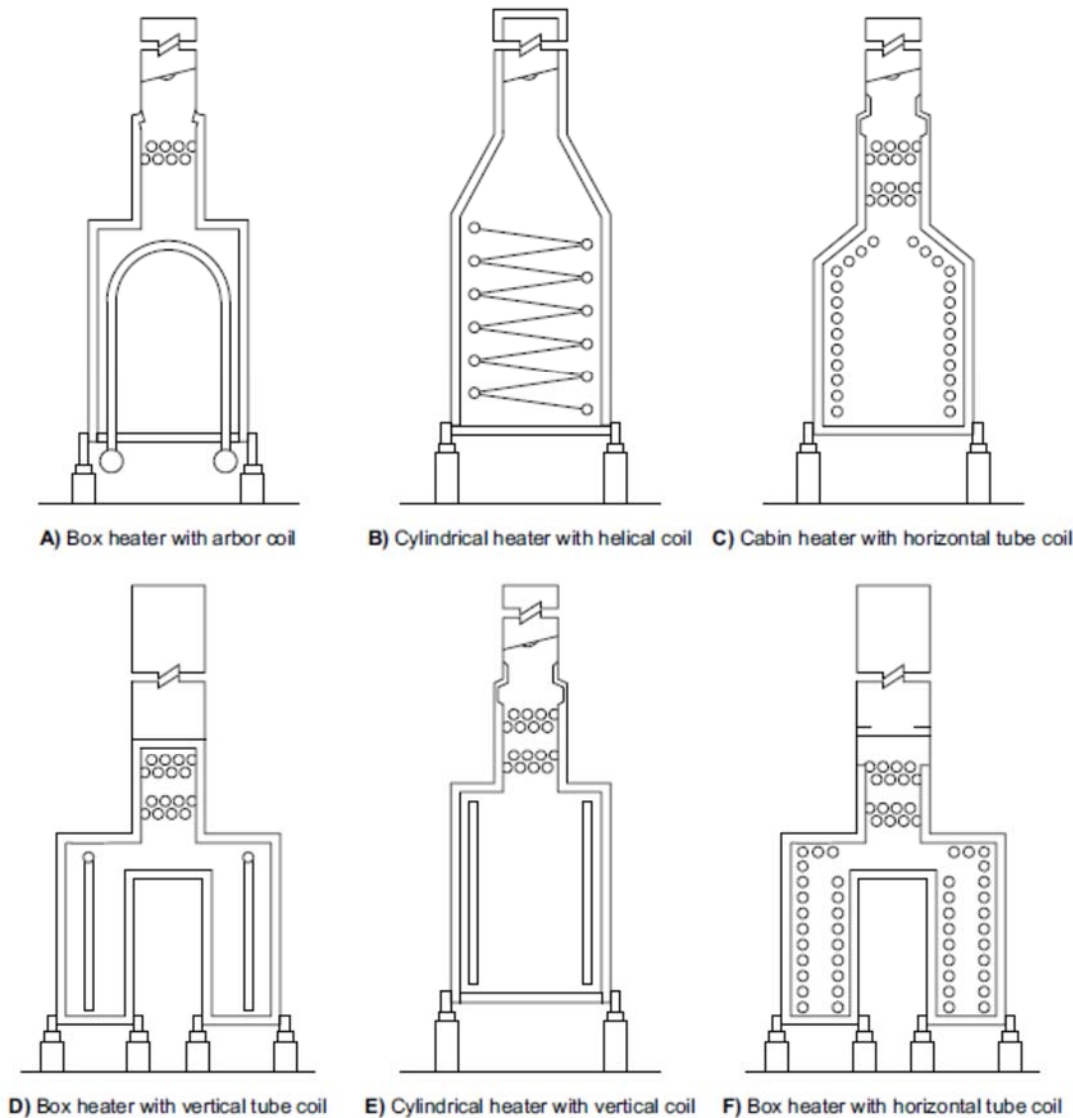


Figure 1—Typical Heater Types

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.

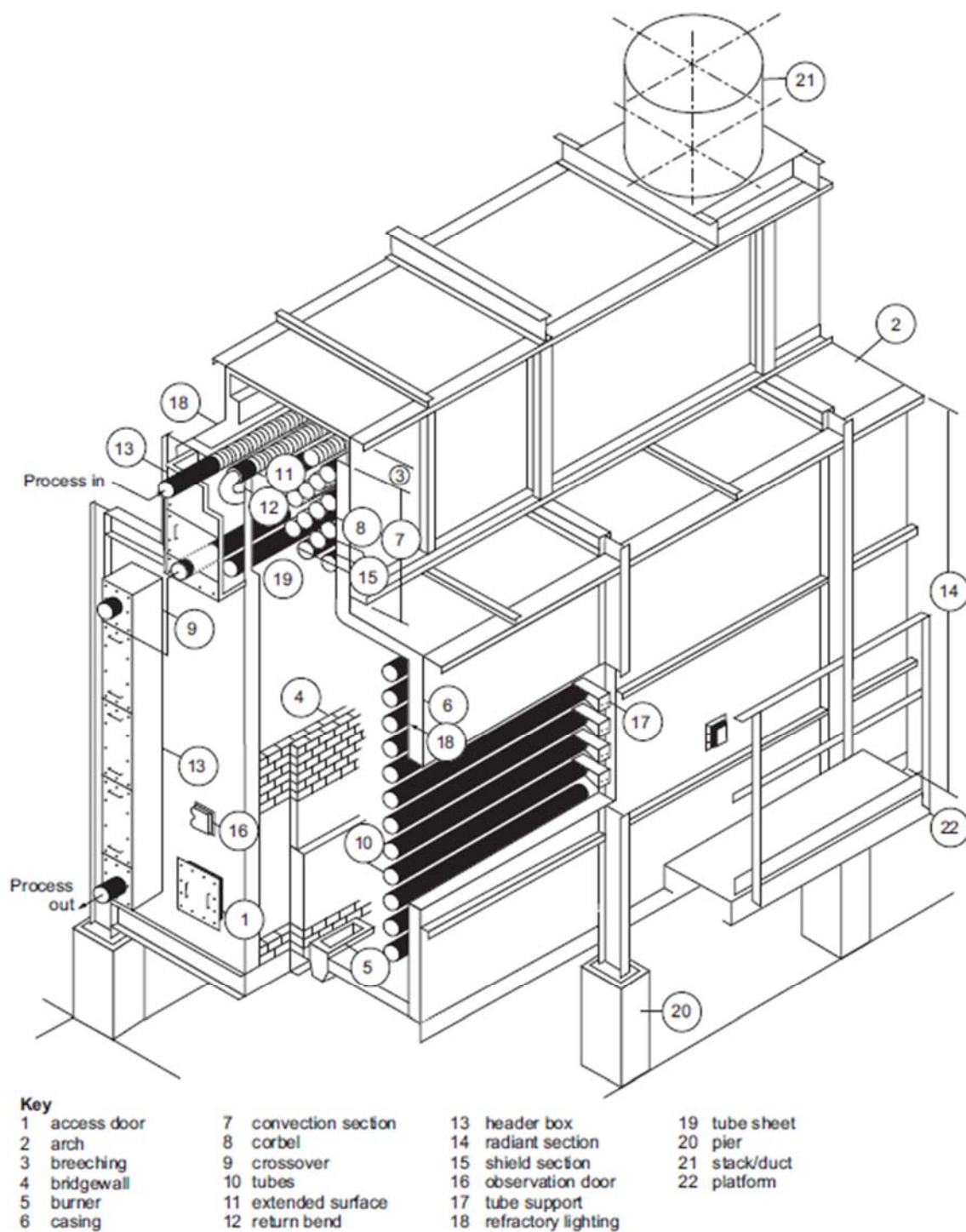


Figure 2—Box-type Heater with Horizontal Tube Coil Showing Main Components

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 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 ¹ / ₂ Mo	A213 T5	A335 P5
5 Cr-1 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.

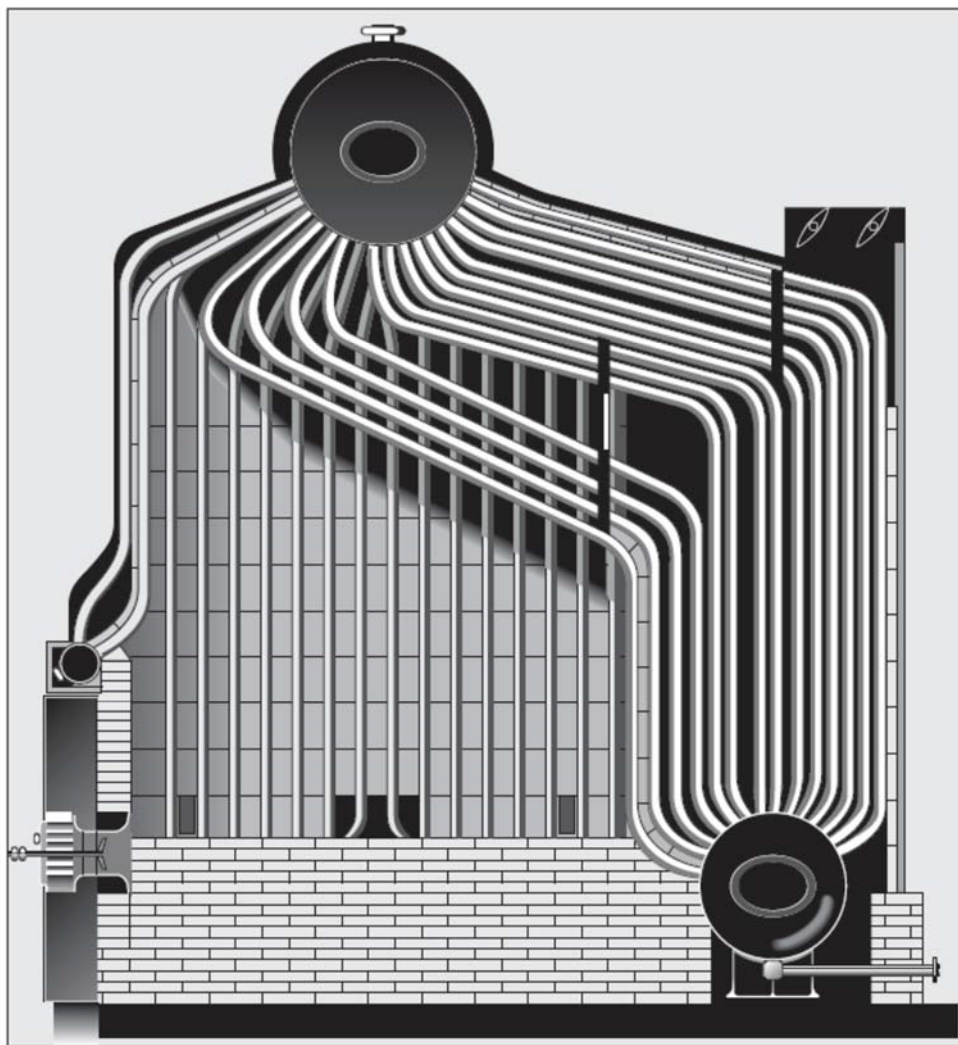


Figure 4—Typical Vertical Oil or Gas-fired Water Tube Boiler

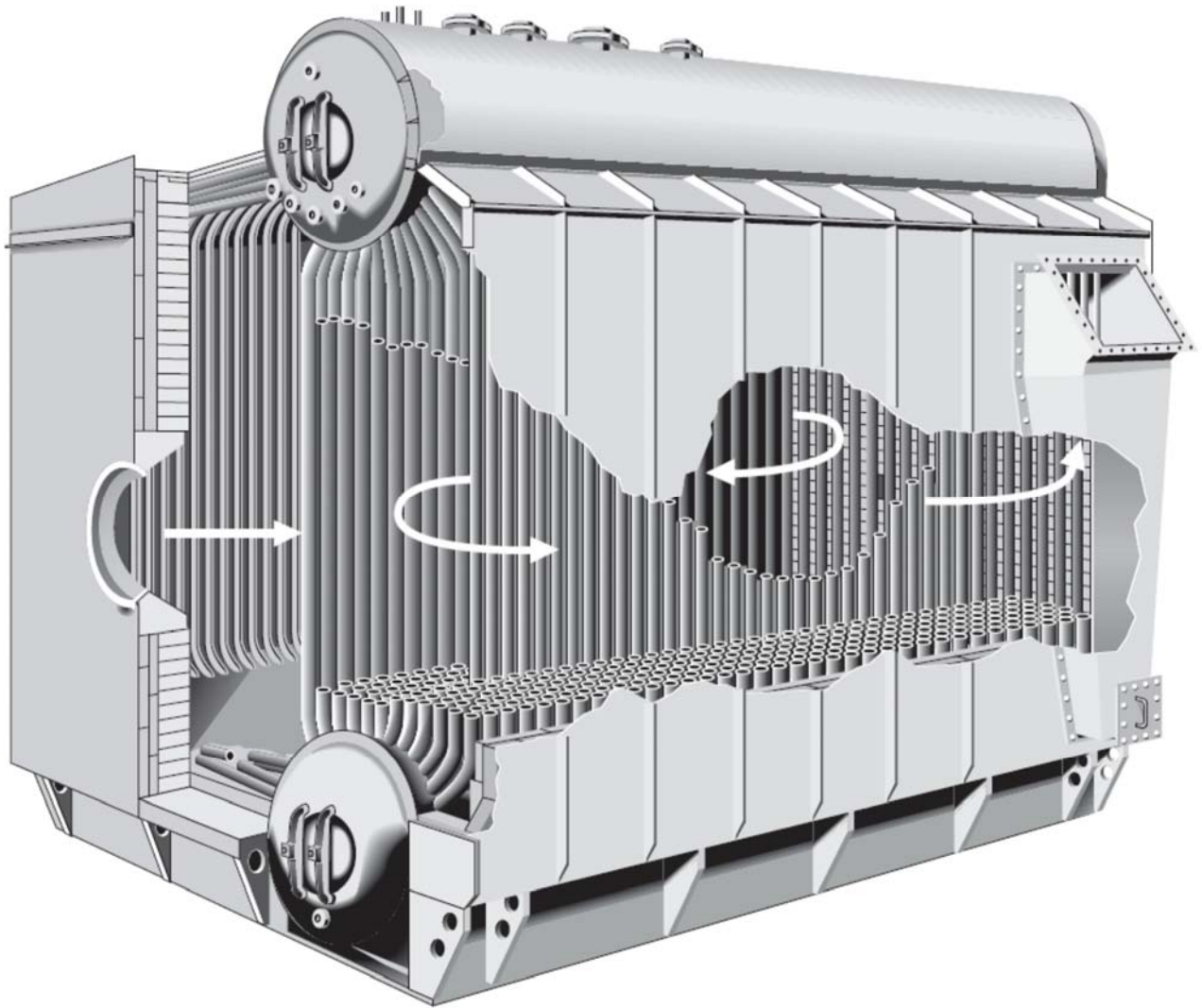


Figure 5—Another Variation of a Two-drum Bent Tube Boiler

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.

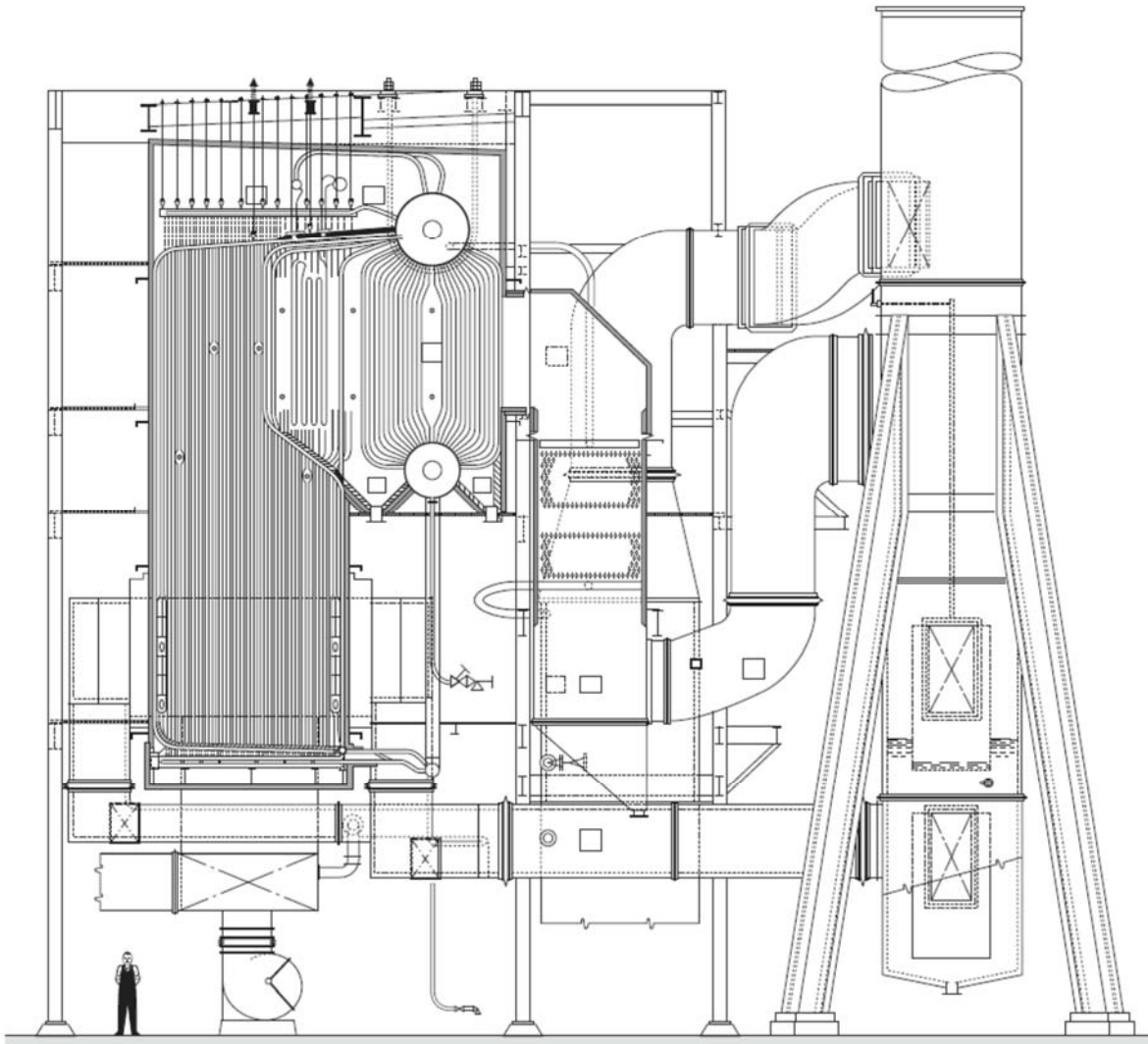


Figure 6—Typical Carbon Monoxide Boiler

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.

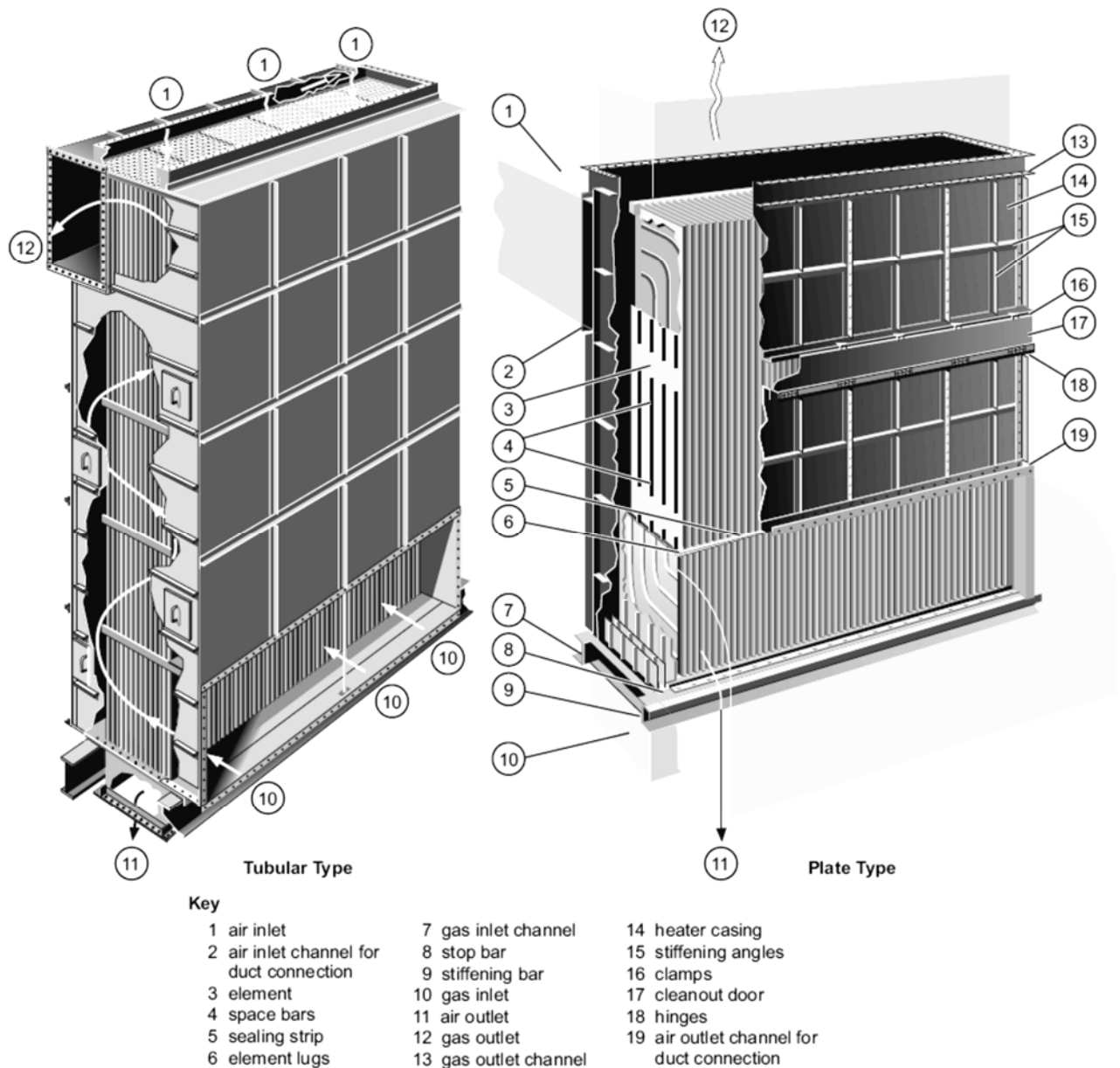


Figure 7—Tubular and Plate Air Preheaters

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.

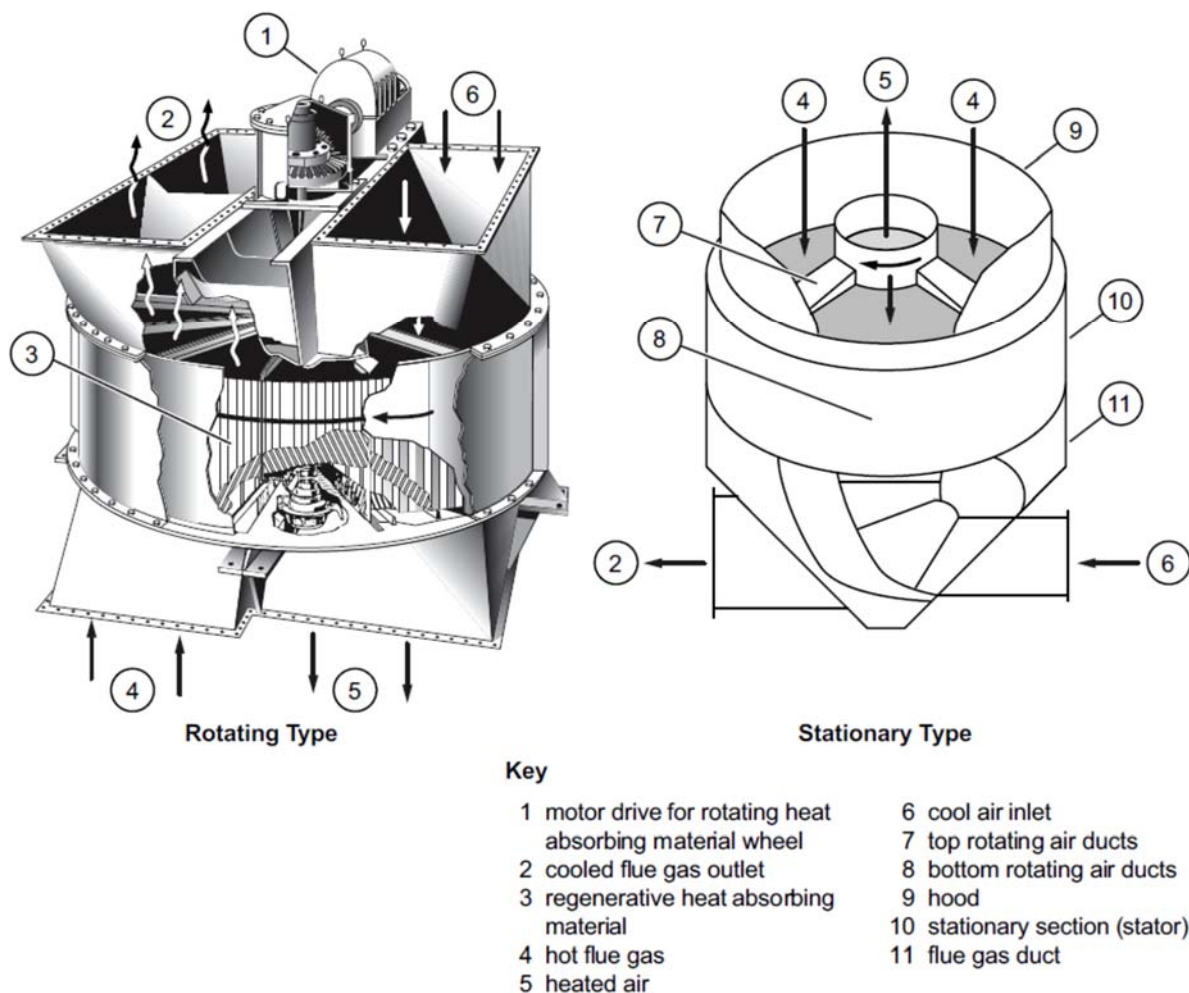


Figure 8—Types of Regenerative Air Preheaters

4.2.7 Tube Metallurgy

Boiler tubes are generally carbon steel, 1¹/₄ Cr-1¹/₂ Mo and 2¹/₄ 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	Creep, external oxidation (3.23), (3.48)	Caused by abnormal operation, low flow, or flame impingement.
	9Cr-1Mo		
	Type 316 Type 317	Sulfidic corrosion (3.35) (3.61) Naphthenic acid corrosion (3.46)	Caused by alloy content inadequate to resist attack by the level of sulfur compounds. Caused by alloy content inadequate to resist attack by the level of naphthenic acid.
Crude unit, vacuum section	5Cr-1/2Mo	Creep, external oxidation (3.23), (3.46)	Caused by abnormal operation, low flow, or flame impingement.
	9Cr-1Mo		
	Type 316 Type 317	Sulfidic corrosion (3.35) (3.61) Naphthenic acid corrosion (3.46)	Caused by alloy content inadequate to resist attack by the level of sulfur compounds. Caused by alloy content inadequate to resist attack by the level of naphthenic acid.
Delayed cokers	5Cr-1/2Mo	Carburization (3.13)	Common problem in this service; can be detected by chemical spot tests.
	9Cr-1Mo		
	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.
Catalytic hydrosulfurizer	5Cr-1/2Mo	Creep, external oxidation (3.23), (3.46)	Caused by abnormal operation, low flow, or flame impingement.
	9Cr-1Mo		
	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) External oxidation (3.46) Internal sulfidation (3.61) Graphitization (3.34)	Damage rate is a function of stress and temperature. For carbon steels, creep can occur when tube metal temperatures are greater than 700 °F. Damage rate is a function of tube metal temperature and excess oxygen in the firebox. Carbon steel oxidation rates increase significantly above 1000 °F. Caused by sulfur compounds entering the process flow during startup, upsets, and shutdown. 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 ¹ / ₂ Mo 2 ¹ / ₄ Cr-1Mo 5Cr-1 ¹ / ₂ Mo 9Cr-1Mo	Creep, external oxidation (3.23), (3.48) High-temperature hydrogen attack (HTHA) (3.36) Carburization/metal dusting (3.13), (3.44) Spheroidization	Caused by abnormal operation, low flow, or flame impingement. Caused by operation of tube materials above API 941 Nelson curves. Caused by high carbon activity and high-temperature operation and occurs under specific conditions. Probable in 1 ¹ / ₄ Cr-1 ¹ / ₂ Mo after long-term service.
Waste heat boiler	Carbon steel 1 ¹ / ₄ Cr-1 ¹ / ₂ Mo 2 ¹ / ₄ Cr-1Mo	Internal corrosion (3.9), (3.18) Creep, external oxidation (3.23), (3.61) External dew point corrosion ² (3.29) Erosion (3.27)	Caused by inadequate or improper water quality. Caused by abnormal operation, low flow, or flame impingement. Caused by tube metal temperatures operating below the flue gas dew point. 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 1 ¹ / ₄ Cr-1 ¹ / ₂ Mo 2 ¹ / ₄ Cr-1Mo	Internal corrosion (3.9), (3.18) Creep (3.23) External oxidation (3.61)	Caused by inadequate or improper water quality. Caused by abnormal operation, low flow, or flame impingement. 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

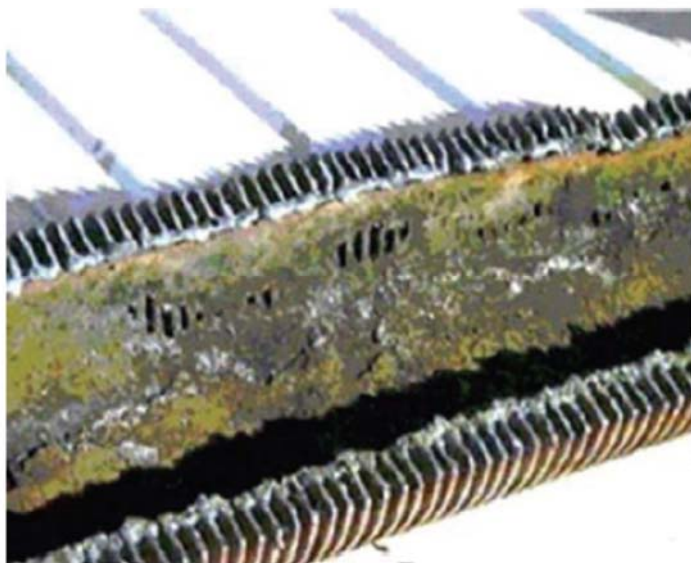


Figure 10—Convective Tube Failure from Internal, High-temperature Sulfidic Corrosion

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.

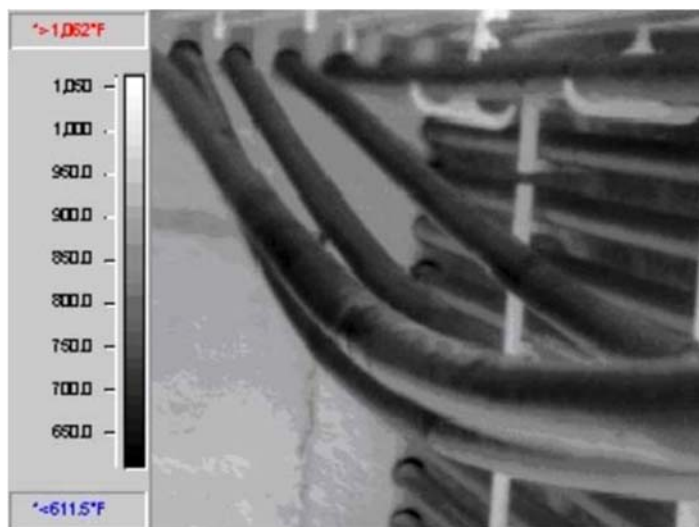


Figure 12—Roof Tubes Sagged as a Result of Failed Tube Hangers

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- $\frac{1}{2}$ 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 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;