

Industrial Fired Boilers for General Refinery and Petrochemical Service

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Reliable boiler operations are necessary to ensure steam production in refineries and petrochemical plants. Boilers are a critical component of U.S. commercial and industrial facilities and operations. Industrial boilers are also a major energy consumer. U.S. refineries and petrochemical plants employ approximately one-third of the total boiler heat input of all U.S. commercial and industrial facilities.

This document is based on the accumulated knowledge and experience of manufacturers and users of industrial fired boilers. This recommended practice (RP) addresses design, operating, maintenance, and troubleshooting considerations for industrial boilers that are used in refineries and chemical plants. This document directly reflects business needs by having API's Subcommittee on Heat Transfer Equipment (SCHTE) membership, vendors, manufacturers, and contractors tailor these precise requirements. Manufacturers' input from within and outside the SCHTE was sought and thus the final document reflects prevailing technical expertise. This RP could not have been developed in this manner by any other industry group. Manufacturers' and contractors' standards and requirements have individual differences that may not permit a purchaser to understand technical distinctions.

ASME codes focus on a boiler's mechanical construction and performance testing. National Fire Protection Association codes focus on a boiler's burner management safety system. API standards applicable to boilers focus on fans/drivers and post-combustion oxides of nitrogen (NOx) control. This SCHTE RP complements rather than duplicates these requirements, focusing on refinery and petrochemical boilers.

API 538 includes information on boiler types, burner management, system reliability/availability, feedwater preparation, BFW and boiler water treatment, waterside control, steam purity, combustion control, boiler burners, emissions, tube cleaning, and more. The information contained in API 538 is not covered by any other standards-writing body. By combining multiple technical subjects related to industrial fired boilers, the boiler user has the benefit of the collective industry experience that this RP provides, rather than having to rely on multiple technical documents.

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Introduction

Users of this recommended practice (RP) should be aware that further or differing requirements may be needed for individual applications. This RP is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment or engineering solutions for the individual application. This may be particularly applicable where there is innovative or developing technology. Where an alternative is offered, the vendor should identify any variations from this RP and provide details.

In API RPs, the metric (SI) system of units is used. Where practical in this RP, U.S. customary (USC) units are included in brackets for information. In Annex A, separate data sheets are provided in SI units and USC units.

A bullet (•) at the beginning of a section or subsection indicates that either a decision is required or further information is to be provided by the purchaser. This information should be indicated on data sheets (see examples in Annex B) or stated in the enquiry or purchase order.

Industrial Fired Boilers for General Refinery and Petrochemical Service

1 Scope

1.1 This recommended practice (RP) specifies requirements and gives recommendations for design, operation, maintenance, and troubleshooting considerations for industrial fired boilers used in refineries and chemical plants. It covers waterside control, combustion control, burner management systems (BMSs), feedwater preparation, steam purity, emissions, etc.

1.2 This RP does not apply to fire tube boilers, gas turbine exhaust boilers, or fluidized bed boilers.

- 1.3 This RP does not cover boiler mechanical construction. Purchaser or owner shall specify codes such as ASME, ISO, etc.

1.4 This RP does not cover forced circulation boilers.

2 Normative References

The editions of the following standards, codes and specifications that are in effect at the time of publication of this recommended practice shall, to the extent specified herein, form a part of this recommended practice. Changes in referenced standards, codes and specifications shall be mutually agreed to by the purchaser and the supplier.

API Manual of Petroleum Measurement Standards (MPMS) Chapter 14.3.3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters—Part 3: Natural Gas Applications

API Specification 6FA, Specification for Fire Test for Valves

API Recommended Practice 534, Heat Recovery Steam Generators

API Recommended Practice 535, Burners for Fired Heaters in General Refinery Services

API Recommended Practice 536, Post-combustion NO_x Control for Fired Equipment in General Refinery Services

API Standard 541, Form-wound Squirrel Cage Induction Motors—375 kW (500 Horsepower) and Larger

API Standard 547, General-purpose Form-wound Squirrel Cage Induction Motors—250 Horsepower and Larger

API Recommended Practice 551, Process Measurement Instrumentation

API Recommended Practice 553, Refinery Valves and Accessories for Control And Safety Instrumented Systems

API Recommended Practice 555, Process Analyzers

API Standard 560, Fired Heaters for General Refinery Service, 5th Ed., 2015

API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems

API Recommended Practice 574, Inspection Practices for Piping System Components

API Standard 607, Fire Test for Quarter-Turn Valves and Valves Equipped with Nonmetallic Seats

API Standard 611, General Purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Services

API Standard 612/ISO 10437 ¹, *Petroleum Petrochemical and Natural Gas Industries—Steam Turbines—Special-Purpose Applications*

API Standard 613, *Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services*

API Standard 614/ISO 10438-1, *Lubrication, Shaft-Sealing and Oil-Control Systems and Auxiliaries*

API Standard 673, *Centrifugal Fans for Petroleum, Chemical, and Gas Industry Services*

ABMA 307 ², *Combustion Control Guidelines for Single Burner Firetube and Watertube Industrial/Commercial/Institutional Boilers*

AMCA Publication 99 ³, *Standards Handbook*

AMCA Publication 201, *Fans and Systems*, 2002

ANSI ⁴/AMCA Standard 210, ANSI/ASHRAE ⁵ 51, *Laboratory Methods of Testing Fans for Certified Aerodynamic Performance Rating*, 2007

ANSI/AMCA Standard 301, *Methods for Calculating Fan Sound Ratings from Laboratory Test Data*

AMCA Publication 801, *Industrial Process/Power Generation Fans: Specification Guidelines*

ASME B31.1 ⁶, *Power Piping*

ASME B31.3, *Process Piping*

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

ASME Boiler and Pressure Vessel Code (BPVC), Section II: *Materials*

ASME Center for Research and Technology Development (CRTD) Volume 34, *Consensus on Operation Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers*

ASME Center for Research and Technology Development (CRTD) Volume 66, *Consensus for the Lay-up of Boilers, Turbines, Turbine Condensers, and Auxiliary Equipment*

ASME Center for Research and Technology Development (CRTD) Volume 81, *Sampling and Monitoring of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers*

ASME Performance Test Code (PTC) 4, *Fired Steam Generators*

ASME Performance Test Code (PTC) 19.11, *Steam and Water Sampling, Conditioning, and Analysis in the Power Cycle*

ASTM A123/123M ⁷, *Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products*

ASTM D396, *Standard Specification for Fuel Oils*

ASTM D887, *Standard Practices for Sampling Water-formed Deposits*

¹ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.

² American Boiler Manufacturers Association, 8221 Old Courthouse Road, Suite 202, Vienna, Virginia, 22015, www.abma.com

³ Air Movement and Control Association International, 30 West University Drive, Arlington Heights, Illinois 60004, www.amca.org.

⁴ American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.

⁵ American Society of Heating, Refrigeration, and Air-Conditioning Engineers, 1791 Tullie Circle, N.E. Atlanta, Georgia 30329, www.ashrae.org.

⁶ ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

⁷ ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org



ASTM D1066, *Standard Practice for Steam Sampling*

ASTM D3483, *Standard Test Methods for Accumulated Deposition in a Steam Generator Tube*

ASTM D4519, *Standard Test Method for On-Line Determination of Anions and Carbon Dioxide in High Purity Water by Cation Exchange and Degassed Cation Conductivity*

IEEE 841-2009⁸, *Petroleum and Chemical Industry—Premium-efficiency, Severe-duty, Totally Enclosed Fan-cooled (TEFC) Squirrel Cage Induction Motors—Up to and Including 370 kW (500 hp)*

ANSI/ISA⁹ 84.00.01-2004 (IEC 61511-1 Mod), *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*

NBBI NB23¹⁰, *National Board Inspection Code*, 2007

NFPA 85¹¹, *Boiler and Combustion Systems Hazards Code*

NFPA 325, *Guide to Fire Hazard Properties of Flammable Liquids, Gases, and Volatile Solids*, 1994

U.S. EPA Contract No. 68-D-98-026 Work Assignment No. 0-08¹², *Stationary Source Control Techniques Document for Fine Particulate Matter*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

adiabatic flame temperature

The highest attainable combustion temperature for the fuel and reactants at a specified inlet temperature and pressure if no energy is lost to the outside environment. Heat loss due to radiation, convection, or conduction is not included. Generally, the adiabatic flame temperature is determined for a stoichiometric fuel/air mixture.

3.1.2

air, excess

Additional air above the corrected theoretical air required to burn a fuel for stoichiometric combustion. Excess air is expressed as a percentage of the corrected theoretical air required for stoichiometric combustion.

3.1.3

air flow measurement instrument

A device for determining air flow quantity.

3.1.4

air flow permissive

A sensor that ascertains minimum air flow is present for purge and boiler operation.

3.1.5

air/fuel ratio

The ratio of the combustion air flow rate to the fuel flow rate.

⁸ Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.

⁹ The International Society of Automation, 67 T.W. Alexander Drive, Research Triangle Park, North Carolina, 22709, www.isa.org.

¹⁰ The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue Columbus, Ohio 43229, www.nationalboard.org.

¹¹ National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

¹² U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW, Washington, DC, 20460, www.epa.gov.

3.1.6**air preheater****APH**

A heat transfer apparatus through which combustion air is passed and heated by a medium of higher temperature such as combustion products, steam, or other fluid.

3.1.7**applicable code**

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

3.1.8**asphaltic cutback**

A viscous substance made of asphalt cement and petroleum solvent.

3.1.9**atomization**

The breaking of a liquid into tiny droplets to improve fuel-air mixing and improve combustion. Steam, air, and fuel gas can be used as atomizing media. Steam is the most common in the refining industry. Atomization may also be accomplished by mechanical means.

3.1.10**atomizer**

A device used to reduce a liquid fuel oil to a fine mist, using steam, air, or mechanical means.

3.1.11**attenuator**

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

3.1.12**authorized inspector****AI**

A person designated by, or acceptable to, a jurisdiction that meets the requirements of the jurisdiction, the National Board Rules for In-service and New Construction Commissioned Inspectors.

3.1.13**availability**

Calculated probability, expressed as a percentage, that a protective function will take the correct action to safe state on process demand.

3.1.14**basic process control system****BPCS**

A system that responds to input signals from the process, its associated equipment, other programmable systems, and/or an operator and generates output signals causing the process and its associated equipment to operate in the desired manner.

3.1.15**blowdown**

A sudden or routine release of the boiler contents to control solids in the boiler water. Blowdown protects boiler surfaces from severe scaling or corrosion problems that can result otherwise. Boiler blowdowns can be continuous or intermittent.

3.1.16**boiler**

A closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof by the application of heat from combusting fuels in a self-contained or attached furnace.

3.1.17**boiler bank**

The collection of tubes that connect the upper and lower (mud) steam drums or headers. Steam rises from the lower drum or headers to the upper drum and water flows from the upper drum to the lower drum or headers and out to the boiler's waterwalls.

3.1.18**boiler control system**

The group of control systems that regulates the boiler process, including the CCS, but not the BMS. The boiler control system responds to input signals from the equipment under control and/or from an operator and generates output signals, causing the equipment under control to operate in the desired manner.

3.1.19**boiler enclosure**

The physical boundary for all boiler pressure parts and for the combustion process.

3.1.20**boiler feedwater****BFW**

Water supplied to the boiler at high pressure. Typically treated to remove oxygen, precipitates, or other contaminants that can impair a boiler's performance.

3.1.21**boiler feedwater control**

The control that regulates water flow and maintains steam/water interface within an acceptable range in the steam drum for all operating conditions.

3.1.22**boiler water**

Water inside the steam drum. Boiler water solids concentration is much higher than in the boiler feedwater.

3.1.23**bundle**

Groups of tubes arranged in a way that can be extracted for maintenance and cleaning.

3.1.24**burner**

A device that introduces fuel and air into a boiler at the desired velocities, turbulence, and concentration to establish and maintain proper ignition and combustion.

NOTE Burners are classified by the type of fuel fired, such as oil, gas, or a combination of gas and oil, designated as "dual fuel" or "combination."

3.1.25**burner management system****BMS**

The system (logic, sensors, actuating devices, final elements, PLC) devoted to the starting and stopping of fuel burning equipment (fuel train and fans) in the proper sequence for safe operation, and tripping equipment when necessary to prevent damage.

3.1.26**bypass**

A passage conveying a substance from the upstream side to the downstream side of a control device or equipment item so as to be independent of the action of the control.

3.1.27**capacity**

The maximum main steam mass flow rate that the steam generator is capable of producing on a continuous basis with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam). This is frequently referred to as maximum continuous rating (MCR).

3.1.28**capacity, peak**

The maximum main steam mass flow rate that the steam generator is capable of producing with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam) for intermittent operation, i.e. for a specified period of time without affecting future operation of the unit.

3.1.29**cavitation**

The formation and violent collapse of vapor bubbles in a liquid caused by movement of something such as a pump impeller. Cavitation is potentially damaging to exposed surfaces.

3.1.30**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.

3.1.31**chemical upset**

A condition outside of normal operating conditions caused by incorrect dosing of boiler chemicals or incorrect boiler water chemistry.

3.1.32**circulation ratio**

Mass ratio of (steam + water)/steam.

3.1.33**combustion control system****CCS**

The control system that regulates the furnace fuel and air inputs to maintain the air-fuel ratio within the limits that are required for continuous combustion and stable flame throughout the operating range of the boiler in accordance with demand.

3.1.34**computational fluid dynamics****CFD**

Numerically modeling a system's physics using fluid dynamic equations for continuity, momentum, and energy.

3.1.35**conductivity**

A measure of the ability of a material to conduct an electric current. In this document it generally refers to water conductivity, which is a surrogate for total dissolved solids and is reported as micro S/cm or micro mho/cm. These two units are equivalent. Micro S/cm will be used throughout the document.

3.1.36**continuous blowdown**

Water continuously taken from the steam drum at a controlled rate to reduce the level of dissolved solids to specified requirements. Utilizes a calibrated valve and a blowdown tap near the boiler water surface to reduce the level of dissolved solids.

3.1.37**convection section**

Portion of the boiler in which the primary heat transfer mechanism is by convection.

3.1.38**corrosion allowance**

The additional metal thickness added to allow for metal loss during the design life of the component. It is the corrosion rate multiplied by the component design life, expressed in inches or millimeters.

3.1.39**corrosion rate**

The annual reduction in material thickness due to chemical attack from process fluid or flue gas, or both.

3.1.40**critical heat flux****CHF**

A set of operating conditions that occurs when relatively high heat transfer rates from the tube wall to the steam/water mixture flowing inside the tube, associated with nucleate or forced convective boiling, change to lower rates associated with transition or film boiling. This causes DNB.

3.1.41**damper**

A device for regulating volumetric flow of gas or air by introducing variable resistance to air entering a fan.

3.1.42**dead band**

The range through which the control input signal may be varied, upon reversal of direction, without initiating an observable change in valve position.

3.1.43**dead time****T_d**

The interval of time between initiation of an input change or stimulus and the start of the resulting observable response.

3.1.44**deaerator**

An open-type heater in which small droplets and thin films of water are brought into intimate contact with steam, thereby raising the water temperature to its boiling point at the deaerator pressure. As the water approaches the boiling point, the solubility of the "gas" in the liquid decreases significantly. The steam also serves to strip oxygen and carbon dioxide from the makeup water for removal via the vent(s) from the stripping section.

3.1.45**departure from nucleate boiling****DNB**

Occurs when the applied heat flux to a tube becomes greater than or equals the CHF value. The liquid film that was present along the tube wall at lower heat fluxes disappears, the heat transfer coefficient decreases, and the tube wall temperature increases.

3.1.46**desiccant**

A substance that absorbs water used for the removal of moisture.

3.1.47**desuperheater**

See **attenuator** definition.

3.1.48**directional blocking**

An interlock that, upon detection of a significant error in furnace pressure or HRSG process variables, acts to inhibit the movement of all appropriate final control elements in the direction that would increase the error.

3.1.49**downcomer**

Boiler tubes or pipes that take boiler water away from the steam drum and to the heat absorbing surfaces where steam is generated.

3.1.50**draft**

Negative pressure (vacuum) of flue gas or air at any point in the boiler.

3.1.51**duct**

A conduit for air or flue gas flow.

3.1.52**economizer**

A section of the boiler where incoming feedwater temperature is raised to less than saturation temperature by recovery of the heat from flue gases leaving the boiler.

3.1.53**effective projected radiant surface**

The total flat projected area of the non-refractory lined waterwalls, the floor, roof, both sides of the radiant superheater, furnace exit plane, and waterwall platens.

3.1.54**erosion**

A reduction in material thickness due to mechanical attack from a fluid, expressed in inches or millimeters.

3.1.55**evaporator**

The area of the boiler where water boils to form steam. Typically, a mixture of water and steam exits at the outlet of this area. Also referred to as the steam generator section.

3.1.56**extended surface**

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

3.1.57**fan actual flow rate**

The volume flow rate determined at the conditions of static pressure, temperature, compressibility, and gas composition, including moisture, at the fan inlet flange.

3.1.58**fan inlet velocity pressure**

The difference between fan static pressure and static pressure rise.

3.1.59**fan maximum allowable speed**

The highest speed at which the manufacturer's design permits continuous operation.

3.1.60**fan rated point (fan capacity)**

The capacity and pressure rise required by fan design to meet all specified operating points.

3.1.61**fan rated point (fan speed)**

The highest speed necessary to meet any specified operating condition.

3.1.62**fan static pressure**

Difference between the fan total pressure and the fan velocity pressure.

3.1.63**fan static pressure rise**

Static pressure at the fan outlet minus the static pressure at the fan inlet.

3.1.64**fan total pressure**

Difference between the total pressure at the fan outlet and the total pressure at the fan inlet.

3.1.65**fan trip speed**

Speed at which the independent emergency overspeed device operates to shut down a prime mover.

3.1.66**fan velocity pressure**

Pressure corresponding to the average velocity at the specified fan outlet area.

3.1.67**filter strainer****strainer/filter**

A device that removes and collects particles of iron, dirt, etc. that could otherwise cause fouling and/or failures in the system.

3.1.68**firebox**

An enclosed space provided for the combustion of fuel. Also known as the furnace or combustion chamber.

3.1.69**flame detector**

The flame-sensing element. Its output signal is the input for the flame safeguard amplifier.

3.1.70**flame envelope**

The term used to define the flame contour (width and length); usually corresponds to the boundary (not necessarily visible) at which 99.5 % of the fuel is fully converted to CO₂ and H₂O.

3.1.71**flame failure**

The loss of flame detection by any cause other than a deliberate, intended action.

3.1.72**flame safeguard**

The flame detector that detects a flame and in the event of failure to ignite, igniter failure, or main flame failure, removes the flame proving signal to the BMS to initiate a safety shutdown. The flame safeguard consists of a flame detector, an amplifier, and a safety certified output (typically discrete relay output) for signal transmission.

3.1.73**flue gas**

The gaseous product of combustion including the excess air.

3.1.74**fluid catalytic cracking****FCC**

A process whereby heavy distillates or residues are converted into higher value products.

3.1.75**flushing**

A cleaning procedure whereby the interior surfaces are rinsed to remove deposits.

3.1.76**forced draft fan****FD fan**

A device used to supply ambient combustion air to the combustion chamber burners.

3.1.77**fouling resistance**

Heat transfer resistance used to calculate the overall heat transfer coefficient.

NOTE The inside fouling resistance is used to calculate the maximum metal temperature for design. The external fouling resistance is used to compensate for the loss of performance due to deposits on the external surface of the tubes or extended surface.

3.1.78**fuel efficiency**

Total heat absorbed by the steam and water divided by the total input of heat derived from the chemical energy of the fuel combusted (HHV basis excludes sensible heat of the fuels, but includes sensible heat from air preheat).

3.1.79**fuel ignition safety time**

The period during which the main fuel SSV(s) is (are) permitted to be open before the igniter flame is extinguished and before the flame safeguard is required to supervise the main flame alone.

3.1.80**furnace**

The portion of a boiler where combustion takes place.

3.1.81**furnace (firebox) area heat release rate [Btu/(h-ft²) or W/m²]**

The total boiler heat input on HHV basis divided by the furnace effective (projected) radiant cooling surface area.

3.1.82**furnace (firebox) heat flux [Btu/(h-ft²) or W/m²]**

The net heat absorbed by the furnace portion divided by the effective (projected) furnace area.

3.1.83**heat flux density**

Heat absorbed divided by the exposed heating surface of a specific coil section.

3.1.84**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.

3.1.85**higher heating value gross heating value****HHV gross heating value**

Total heat obtained from the combustion of a specified fuel when all the products of combustion are at the original pre-combustion temperature. H₂O is a liquid byproduct.

3.1.86**igniter**

A permanently installed device that provides proven ignition energy to light-off the main burner.

3.1.87**ignition period (igniter and main burner)**

Defined time intervals that start with the opening of the fuel SSVs during light-off. Failure to detect flame at the end of these time intervals results in fuel supply shutoff.

3.1.88**ignition safety time**

The period of time that starts with the opening of the fuel supply during the start-up process and ends, in the absence of a flame, with the shutting off of the fuel supply.

3.1.89**induced draft fan****ID fan**

A device used to remove the products of combustion from the boiler.

3.1.90**infrared thermography****IR**

Detection of radiation in the infrared range of the electromagnetic spectrum using a thermal imaging camera and the production of images of that radiation, called "thermograms."

3.1.91**intermittent (manual) blowdown**

Periodically removing boiler water through taps at the bottom of the boiler. These openings allow for the removal of solids/sludges that settle at the bottom of the boiler. Intermittent blowdown is also used to keep water level control devices and cutoffs clear of any solids that would interfere with their operation.

3.1.92**intermittent igniters**

Igniters that support burner operation in certain operating modes.

3.1.93**interrupted igniters**

Igniters used for initial burner light-off only.

3.1.94**jurisdiction**

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

3.1.95**lagging**

External sheathing (typically metal) that protects insulation from atmosphere and elements.

3.1.96**layup**

A period of time during which a boiler is inoperative in order to allow for repairs or preventive maintenance.

3.1.97**leak tightness device**

A system to prove the effective closure of the main fuel SSVs and that is capable of

- a) detecting small fuel leakage rates, e.g. a pressure proving system, and
- b) venting safely small leakage rates, two SSVs in series, fitted with proof of closure switches to close the fuel line, and a third valve fitted with a switch to prove that it is open, to vent safely the space between them.

3.1.98**logic system**

The decision-making and translation elements of the BMS. A logic system provides outputs in a particular sequence in response to external inputs and internal logic. Logic systems are comprised of the following:

- a) hardwired systems—individual devices and interconnecting wiring, and microprocessor-based systems—computer hardware, power supplies, input/output (I/O) devices, and the interconnections among them; and
- b) operating system and logic software.

3.1.99**louver damper**

A damper consisting of several blades, each pivoted about its center and linked together for simultaneous operation.

3.1.100**lower flammable limit**

The lowest ignitable concentration of fuel gas or vapor in air. Below this concentration, a fuel gas/air mixture will not ignite. The lower flammability limit decreases with increasing temperature.

3.1.101**lower heating value net heating value****LHV net heating value**

Heat obtained from combustion with water vapor as a combustion product, i.e. HHV less 2442.5 kJ/kg (1050.1 Btu/lb).

3.1.102**main flame establishment period**

A period during which the main fuel SSV(s) is/are permitted to be open before the igniter flame is extinguished and before the flame safeguard is required to supervise the main flame alone.

3.1.103**manifold**

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

3.1.104**manufacturer**

The entity that constructs the boiler, boiler components, and/or associated equipment in accordance with specifications provided by purchaser and requirements of applicable standards. While the manufacturer may subcontract all or part of the construction, the manufacturer remains fully responsible for the work product. The manufacturer may or may not be the vendor.

3.1.105**master fuel trip****MFT**

An event resulting in the rapid shutoff of all fuel, including igniters, and de-energizing spark ignition.

3.1.106**material safety data sheet****MSDS**

A data sheet that catalogs chemical, chemical compound, and chemical mixture information, focusing on the hazards when the material is used in work settings.

3.1.107**maximum continuous rating****MCR**

See **capacity** definition.

3.1.108**mud drum**

The lower drum of a two-drum boiler where boiler water sediments settle out and collect.

3.1.109**nondestructive examination**

Evaluation of the properties of a material, component, or system without causing damage.

3.1.110**operator supervision**

A circumstance by which an operator has continuous control and surveillance of the plant and is located in a position where he/she can shut the plant down in the event of an emergency.

3.1.111**original equipment manufacturer****OEM**

The company that originally manufactured the equipment.

3.1.112**overshoot**

The amount by which the step response initially exceeds the final steady state value (% of step change).

3.1.113**owner**

Having legal title to the boiler, boiler components, and/or associated equipment. The owner may or may not be the purchaser and/or user.

3.1.114**pegging steam**

Steam fed to the deaerator to achieve saturation conditions inside the deaerator and to create a scrubbing action between the steam and the feedwater, by which dissolved corrosive gases (mainly O₂, CO₂, and NH₃) that become corrosive at elevated temperatures can be eliminated. The removal of these gases is necessary to protect the piping and associated equipment. The gases removed are vented from the deaerator to atmosphere.

3.1.115**penetrant testing**

Penetrant testing, or liquid penetrant inspection, is an inspection method used to locate surface-breaking defects, e.g. hairline cracks, surface porosity, and fatigue cracks, by applying a dye penetrant.

3.1.116**personal protective equipment**

A protective garment or equipment designed to protect the wearer's head (helmet), eyes (glasses, goggles), hands (gloves), ears (plugs, muffs), and body from injury.

3.1.117**pressure design code**

The recognized pressure vessel standard specified or agreed by the purchaser, e.g. ASME *Boiler and Pressure Vessel Code*.

3.1.118**programmable logic controller****PLC**

A computer that uses multiple inputs and output arrangements to control a boiler. PLCs are programmed using application software.

3.1.119**prove**

To establish by measurement or test the existence of a specified condition such as flame, flow, level, pressure, position, etc.

3.1.120**purchaser**

The one who procures the boiler, boiler components, and/or associated equipment. The purchaser may, or may not, be the owner and/or user.

3.1.121**purge**

A flow of air at a rate that will effectively remove and displace any gaseous combustibles and replace them with the purging medium.

3.1.122**quarl**

The refractory blocks surrounding the burner components. The shape of the burner tile forms the air flow path between the throat and the exit of the burner and helps stabilize the flame.

3.1.123**radiant section**

The portion of the boiler in which the primary heat transfer mechanism is by radiation.

3.1.124**register (burner air)**

A set of dampers for a burner, or an air supply system to a particular burner, used to distribute the combustion air admitted to the combustion chamber. The register frequently controls the direction and velocity of the airstream for efficient mixing with the incoming fuel.

3.1.125**reliability**

Measure of the ability of equipment/systems to operate without malfunction or failure between planned maintenance interventions.

3.1.126**residual catalytic cracking****RCC**

The residual fluid catalytic cracking process has its similarities to the fluid catalytic cracking process; however, in the RCCUs, heavy feedstocks are employed. As in FCCUs, hot flue gas developed from catalyst regeneration is used to generate steam in a waste heat boiler.

3.1.127**Ringelmann number**

A visually comparative scale used to define levels of opacity, where clear is 0, black is 5, and 1 through 4 are increasing levels of gray.

3.1.128**riser**

Boiler tubes or pipes where the two-phase fluid flow is toward the steam drum for separation.

3.1.129**safety instrumented function****SIF**

A protective function that takes corrective action to safe state when unacceptable process conditions are detected. It can be either a safety instrumented protection function or a safety instrumented control function.

3.1.130**safety instrumented system****SIS**

An instrumented system that implements one or more SIFs to maintain the boiler in a safe state when unacceptable or dangerous process conditions are detected. An SIS is composed of any combination of sensor(s), logic solver(s), and final elements.

3.1.131**safety integrity level****SIL**

A discrete level (one out of four) for specifying the safety integrity requirements of the safety instrumented functions to be allocated to the safety instrumented systems. Safety integrity increases from level 1 to level 4.

3.1.132**safety shutdown**

The process that is initiated immediately in response to a BMS signal and that causes the burner(s) to shut down.

3.1.133**Sauter mean diameter****SMD**

The diameter of a droplet whose specific surface is the same as that for the total number of droplets in the spray.

3.1.134**self-checking flame detector**

A flame detector that automatically, and at regular intervals, tests the entire sensing and signal processing system of the flame detector.

3.1.135**sootblower**

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

3.1.136**stack**

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

3.1.137**steam drum**

A pressure vessel whose primary purpose is to separate liquid and vapor phases. Steam drums also provide an operating water storage capacity.

3.1.138**steam purity**

The measurement of solid carryover in the steam.

3.1.139**steam quality**

A measure of the amount of moisture in the steam step resolution.

3.1.140**steam temperature control range**

The capacity range over which main steam temperature and/or reheat steam temperature may be maintained at the rated conditions.

3.1.141**step resolution**

The minimum step change in input signal to which the control valve system will respond while moving in the same direction.

3.1.142**step response time (T63)**

The time after an input signal step change until the output has reached 63 % of the final steady state value.

3.1.143**step response time (T86)**

The time after an input signal step change until the output has reached 86.5 % of the final steady state value.

3.1.144**stoichiometric air**

The chemically correct amount of air required for complete combustion with no unused fuel or air in the products.

3.1.145**stoichiometric fuel rate**

That fuel rate at which, if reacted completely with the combustion air flow, the fuel would just consume all the oxygen in the air.

3.1.146**stoichiometric ratio**

The ratio of fuel and air required for complete combustion such that the combustion products contain no oxygen.

3.1.147**superheater**

The portion of the boiler in which saturated steam is heated to higher temperatures.

3.1.148**sweetwater condenser**

Condenses saturated steam from the steam drum in a shell and tube exchanger utilizing feedwater as the cooling medium on the tube side. Condensed saturated steam is used to attemperate superheated steam.

3.1.149**thermal efficiency**

Total heat absorbed divided by the total input of heat derived from the combustion of fuel (hL) plus sensible credits. Credits include sensible heat from air, fuel, atomizing steam, and auxiliary power to drives.

3.1.150**unburned combustible**

The combustible portion of the fuel that is not completely oxidized.

3.1.151**upper flammable limit**

The highest ignitable concentration of fuel gas or vapor in air. Above this concentration, fuel gas/air mixture will not ignite. The upper flammability limit increases with increasing pressure.

3.1.152**user**

The organization or individual using or operating the boiler and associated equipment. The user may or may not be purchaser and/or owner.

3.1.153**valve-proving system**

The system that proves the leak tightness of the burner and igniter SSVs and prevents main burner or igniter light-off if leak tightness requirements are not satisfied.

3.1.154**vendor**

The entity that supplies the boiler, boiler components, and/or associated equipment.

3.1.155**volatile corrosion inhibitors****VCIs**

Organic compounds that prevent metal surfaces from corroding by creating an invisible barrier that emits rust blockers at a molecular level.

3.1.156**volumetric heat release**

Heat released divided by the net volume of the firebox.

3.1.157**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 a hot gas flowing over the tubes.

3.1.158**waterwalls**

Tubes forming the walls of the boiler. Water flows to these tubes from the steam drum through the downcomer piping. As the water in these tubes absorbs heat, water changes phase to a water/steam mixture that rises through these tubes due to its lower density, compared to water in the downcomer tubes.

3.2 Acronyms and Abbreviations

AHJ	authority having jurisdiction
AI	authorized inspector
APH	air preheater
BFW	boiler feedwater
BMS	burner management system
BPCS	basic process control system
CARI	combustion air requirement index
CCS	combustion control system
CEMS	continuous emission monitoring systems
CFD	computational fluid dynamics
CHF	critical heat flux
CO	carbon monoxide
DNB	departure from nucleate boiling
DWD	deposit weight density
EDTA	ethylenediaminetetraacetic acid
ERW	electric resistance welded
ESD	emergency shutdown
ESP	electrostatic precipitator
FCC	fluid catalytic cracking
FCCU	fluid catalytic cracking unit
FD	forced draft
FEGT	furnace exit gas temperature
FFRT	flame failure response time
FGR	flue gas recirculation
FST	full stroke testing
HHV	higher heating value
HRSG	heat recovery steam generator
HWCO	high water cutout
ID	induced draft
IR	infrared thermography
LEA	low excess air

LEL	lower explosion limit
LHV	lower heating value
LLCO	low level cutoff
LWA	low water alarm
LWCO	low water cutout
LWL	low water level
MAWP	maximum allowable working pressure
MCR	maximum continuous rating
MFGCV	main fuel gas control valve
MFT	master fuel trip
MSDS	material safety data sheet
NH ₃	ammonia
NO _x	oxides of nitrogen
OD	outside diameter
NRV	non-return valve
NWL	normal water level
OEM	original equipment manufacturer
PIF	protective instrumented function
PLC	programmable logic controller
POF	position on failure
PMI	positive materials identification
PST	partial stroke testing
RAGAGEP	recognized and generally accepted good engineering practice
RCC	residual catalytic cracking
RCCU	residual catalytic cracking unit
RTD	resistance temperature detector
SCR	selective catalytic reduction
SG	specific gravity
SIF	safety instrumented function
SIL	safety integrity level
SIS	safety instrumented system
SMD	Sauter mean diameter
SNCR	selective non-catalytic reduction
SO _x	oxides of sulfur
SSU	Saybolt seconds universal
SSV	safety shutoff valve
TDS	total dissolved solids
TFI	trial-for-ignition
TOC	total organic carbon
UBHC	unburned hydrocarbon

UPS	uninterruptible power supply
UV	ultraviolet
VCI	volatile corrosion inhibitor
VIV	variable inlet vane
VOC	volatile organic compound
WC	water column
WESP	wet electrostatic precipitator

4 Boilers—Equipment Overview

4.1 General Considerations

4.1.1 General

This document's scope is industrial boilers that are primarily located at refineries and petrochemical plants. The average size of these refinery boilers is 42 MW (143 MBtu/h). The majority of industrial boilers are used to manufacture chemicals, food, paper, and other products. Most of the boilers used in chemical manufacturing have a heat input of 3 MW (10 MBtu/h) or less ^[1].

Slightly more than one-fourth of these boilers have a heat input in the range of 3 MW to 15 MW (10 MBtu/h to 50 MBtu/h). Boilers are normally characterized by the steam pressure, steam temperature, and the steam flow rate.

Fired boilers are boilers in which fuel is burned in a combustion chamber (furnace) associated with the boiler. A majority of the fuel's heat of combustion is absorbed by water in the boiler and converted to steam. Fired boilers most prevalent in the refining and chemical industries are water tube boilers. Water is heated and undergoes a phase change to steam as it flows through tubes.

Section 4 is a synopsis of Section 5 through Section 17. More specific and additional details regarding subjects in 4.1 through 4.10 are contained in Section 5 to Section 17.

4.1.2 Steam Pressure

Industrial boilers contain steam at pressures below the critical pressure, which for water is 22 MPa (abs) [3206.2 psi (abs)]. Most industrial boilers operate at a steam pressure of 2.1 MPa (ga) [300 psi (ga)] or less. ^[2] Most other refinery boilers operate at steam pressures between 2.1 MPa (ga) [300 psi (ga)] and 6.9 MPa (ga) [1000 psi (ga)]. Approximately 60 % of the boilers used to manufacture chemicals operate with a steam pressure in the range of 2.1 MPa (ga) [300 psi (ga)] to 6.9 MPa (ga) [1000 psi (ga)] ^[2].

Steam pressure in a boiler is a function of generated steam flow and the flow resistance downstream of the boiler. The steam flow can be adjusted directly at the boiler steam outlet or by increasing or decreasing the amount of fuel the boiler burns. Increasing the steam flow leaving the boiler (by opening a valve) and holding the fuel flow constant will decrease the steam pressure in the boiler. Increasing the fuel flow will increase the amount of steam generated. This will increase the pressure in the steam drum. Increasing the fuel flow and keeping the non-return valve (NRV) in the same position will produce more steam, and this will increase the boiler's steam pressure. Similarly, decreasing the fuel flow rate and holding the NRV position constant will produce less steam, and this will decrease the boiler's steam pressure. Generally, steam outlet pressure is the primary process input used to control the fuel firing rate.

Decreasing the feedwater temperature and keeping the fuel flow constant will lower the steam drum pressure because less steam will be generated. Increasing the feedwater temperature will increase the steam flow and the steam drum's pressure.

4.1.3 Superheated and Saturated Steam

The type of steam produced by an industrial boiler depends on the requirements of the steam end users and distribution system. Boilers that produce saturated steam only require that either the steam pressure or steam temperature be specified (most typically pressure). Sometimes steam will be heated above its saturation temperature at a given pressure and become superheated. In this case, the saturated steam leaving the steam drum reenters the boiler and passes through more tubes, which together are called a “superheater.” The superheated steam contains a higher amount of energy than saturated steam. The higher the amount of superheat (number of degrees above the saturation temperature), the higher the amount of energy contained in the steam. Both the steam’s pressure and temperature shall be specified for superheated steam.

Control of the superheated steam temperature is commonly done by spraying clean feedwater or condensate into the superheated steam through a direct contact attenuator (desuperheater).

- Higher steam pressure and temperature result in higher tube metal temperatures and require alloys that can withstand these higher temperatures. The purchaser shall specify the boiler outlet steam pressure at the superheater NRV outlet.

4.1.4 Steam/Water Circulation

An industrial boiler’s steam and water circulation may be natural circulation or forced circulation. See Figure 1. As Figure 1 indicates, forced circulation boilers (circulation generated through use of a pump) will not be addressed in this document.

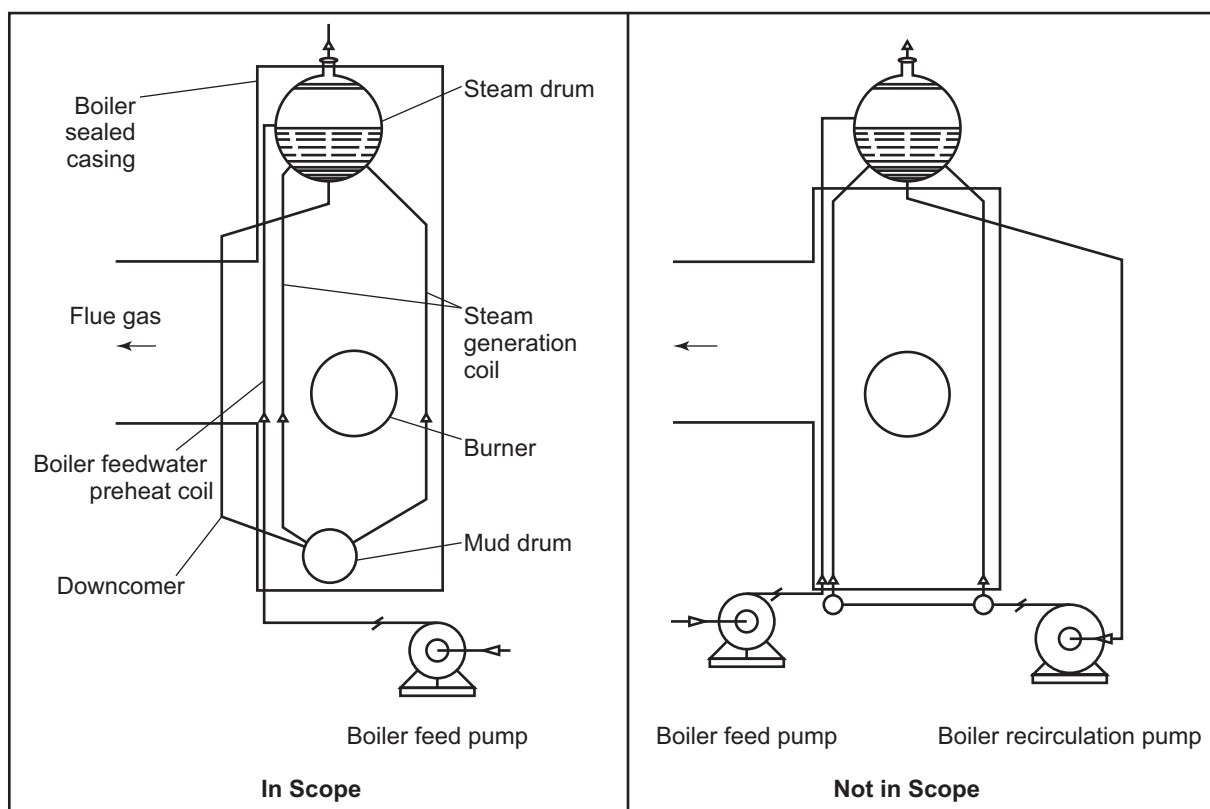


Figure 1—Boiler Steam and Water Circulation

Natural circulation of water is a simple and reliable way to generate saturated steam. In natural circulation boilers, which are the most common type, downcomers allow water to flow from the steam drum to the mud drum and/or lower waterwall headers, if so equipped. In a natural circulation boiler water can make several passes through the circulation system before it turns into steam. The downcomers may be heated or unheated. Unheated downcomers are located outside the gas stream, and therefore no heat absorption occurs in them. The water driven by gravity leaves the steam drum and flows through the downcomers to the mud drum or lower headers where it enters the riser tubes. Even if the downcomers are heated, they are designed such that the water will only reach its saturation point. In the riser tubes it absorbs heat from the flue gas and the water turns into a two-phase mixture of steam and water. Since water in the downcomers has a greater density than a two-phase mixture, the two-phase mixture generates a pressure imbalance that promotes the circulated flow. This flow pattern causes downward flow in the downcomers and upward flow in the riser tubes. The differences in density of the two-phase mixture and the water decreases as the steam drum operating pressure increases. This causes the circulation pressure force to decrease as well.

Many industrial boilers have a common component called a “boiler bank.” The purpose of this equipment is to provide additional steam to the steam drum and to cool the flue gas leaving the boiler. Industrial boilers are usually smaller than utility boilers. As a result, sometimes the circuit made of downcomers and waterwall tubes is not enough to create the required steam supply. The boiler bank consists of tubes located in the flue gas path and near the boiler exit. They connect the main steam drum with a lower drum called a mud drum. A few of these tubes are downcomers that allow water to flow from the upper drum directly to the lower drum. Most of the tubes allow the two-phase steam and water mixture to be carried from the mud drum up to the steam drum.

Much more water than steam is circulated in a boiler. The ratio of the mass flow of steam and water circulating in the boiler's circulation system to the mass flow of steam is called the “circulation ratio.” Typical circulation ratios for industrial boilers are 5:1 to 50:1 based on steaming rate. Boilers with higher drum pressures have lower circulation ratios due to the smaller difference in density between steam and water at higher pressures. It is harder to separate the steam and water at higher pressures. See Figure 11 showing typical circulation ratios for steam drum operating pressures.

4.1.5 Steam Production and Capacity

Industrial boilers used in refining and manufacturing chemicals are mainly used to generate steam for process heating and mechanical drives. As a result, their operation shall be synchronized with the plant's processes. To a much lesser extent, steam is also used for electric power generation. The approximate range of steam flow for a refinery boiler is 454 kg/h (1000 lb/h) to 453,600 kg/h (1,000,000 lb/h). The majority of the refinery boilers have a steam flow of about 113,400 kg/h (250,000 lb/h). Industrial boilers can be operated over a range of steam flows. This is typically referred to as “turndown.” A boiler's ability to follow a specified steam flow versus time is referred to as “ramp rate.”

- When specifying a boiler, the purchaser shall define the maximum continuous rate (MCR) required. If there is a need to have additional margin above the MCR, the margin shall be defined. The purchaser shall also specify the lowest steam flow requiring rated steam temperature.

4.1.6 Fuel Types

Refinery boilers burn several different types of liquid and gaseous fuels, and frequently these boilers will simultaneously burn more than one fuel. Fuels that these boilers commonly burn are natural gas, oil, and refinery gas (similar to natural gas). At many refineries a fluid catalytic cracking unit (FCCU) produces a gas called “regeneration gas,” which contains carbon monoxide (CO). The CO shall be oxidized or combusted to CO₂ so it is either sent directly to a boiler from the FCCU's regenerator or sent to a thermal oxidizer and then sent to a waste heat boiler. The boiler shall be designed to burn the maximum and minimum amount of regeneration gas from the FCCU. Since the regeneration gas has a low higher heating value (HHV), a supplementary fuel, such as refinery blended gas, shall be burned as well.

Each refinery boiler is designed specifically for the fuel(s) to be burned. Some of the common design characteristics that change based on the fuel are furnace heat release rate, flue gas velocities through tube banks, and tube spacings. Different fuel types have different adiabatic flame temperatures and air/fuel requirements that may change

the radiant/convective heat absorption ratio; each boiler's surface requirements must be tailored to the fuels proposed to be fired. Each type of fuel burned also has different combustion products. The boiler operator shall consider the emission of these combustion products to meet federal, state, local emission, and final user's requirements.

- See 6.5 for more information on fuels used in boilers. The boiler operator shall specify the fuels to be burned in the boiler.

4.1.7 Seasonal Water and Steam Balances

Seasonal water and steam demand requirements, which may fluctuate considerably, shall be considered when sizing a boiler. It is difficult to design a boiler to optimally handle wide variations in steam load. If these variations can be leveled out, it will help to ensure that the boiler is operating as efficiently as possible for all of the load variations.

4.1.8 Boiler Sparing Philosophy

Consideration should be given to having a redundant source of steam in the event a primary boiler is unavailable due to a failure, scheduled maintenance, or inspection. Redundancy should also be considered for various operating scenarios. Boiler redundancy, or sparing, can be accomplished by means of $(n + 1)$ philosophy with one boiler in cold standby mode, if a temporary loss of steam is acceptable while the standby boiler is brought online.

For boilers in critical service, the standby boiler may be in warm standby, full of water at the level prescribed by the manufacturer, and the burner igniter lit and stable. It may also be desirable to have sparging provisions incorporated into the standby boiler or insert a steam coil into the mud drum to reduce start-up time.

Redundancy may also be accomplished by having sufficient excess capacity in the refinery's fleet of boilers to allow the boiler with the highest steam capacity to be taken out of service, and making up the lost production by bringing the remaining boiler(s) to full load.

Redundancy may also be accomplished by means of temporary or rental boilers, if outages are carefully planned and provisions are in place for feedwater, steam, and fuel tie-ins.

In addition to critical service boilers, redundancy should be considered for boilers that may not be readily serviceable due to reasons of physical location, or for environmental reasons.

In refineries that have large load swings, redundancy should be considered to reduce the ramp-up rates of boilers. Once the higher steam demand has been met, boilers may be shed by increasing the firing rate of boilers in service while reducing one or more to standby mode. This allows for more controllable ramp-up rates, minimizing trips caused by drum level fluctuations.

NOTE Spare boiler parts are discussed in the maintenance sections of this document.

4.2 Operations

4.2.1 Strategies Overview

Proper operation of a boiler will maximize its availability and reliability. This requires monitoring many processes happening simultaneously. The major processes are the flow of steam, water, air, flue gas, and fuel; the combustion of fuel and air; and the transfer of heat from the flue gas to the pressure parts. Each of these processes is controlled by a separate system of equipment. A basic process control system (BPCS) allows the operator to manage and control the interaction of these systems. The operation of a boiler is described below in general terms.

In simple terms, the desired boiler output is a steam flow at a specific pressure, temperature, and steam quality, based on the steam users. To generate the desired quantity of steam at specific conditions, the temperature; pressure; and quantity of air, feedwater, and fuel are simultaneously adjusted over time.

In addition to the boiler manufacturer's instructions, refer to the most recent edition of ASME BPVC Section VII

4.2.2 Steam and Water Operating Guide

4.2.2.1 General

The following are typical guidelines for safe and reliable operation of a fired boiler. Routine monitoring of the controls and safety systems by the operator is imperative.

4.2.2.2 Boiler Water Level

The water level shall be continually checked, whether the feedwater system is operated automatically or when an operator is present. Proper water level in the steam drum shall be maintained at all times. High water level can cause a reduction in the efficiency of the steam separation equipment. This will result in water carryover and mineral deposition inside the downstream components (i.e. the superheater and turbine blades). If the water level reaches too low a point, the unit is in danger of overheating with possible catastrophic damage. Water may not enter some downcomer tubes so temperatures in those tubes may reach flue gas temperatures, thereby exceeding tube design limits and mechanical expansion capability. If the level is automatically controlled by the feedwater regulator, it should be adjusted per the manufacturer's recommendations so that the level remains stable near the centerline of the gauge glass or the normal water level (NWL), as determined by the boiler manufacturer.

The water column (when provided) and water gauge glass(s) should be drained as required. This will ensure that sludge or sediment will not accumulate in the column or gauge glass and cause an erroneous level indication. The boiler attendant, by observing drained liquid and return of liquid to glass, will be assured of proper actuation of one of the most important safety devices of the unit. Periodic testing of level alarms and low water cutoff is recommended.

4.2.2.3 Boiler Water Blowdown

Boiler water blowdown is done to remove some of the water from the pressure vessel while it is under pressure. The removed water containing suspended dissolved solids is replaced with relatively pure feedwater so that a lowering of the solid concentration occurs. Dissolved solids are brought in with the feedwater, even though this water is treated prior to use through external processes designed to remove the unwanted substances, which contribute to scale and deposit formations if not removed. Regardless of their high efficiency, none of these processes in and of themselves are capable of removing all substances, and a small amount of solids will always be present in the boiler water. The solids become less soluble in the high temperature of the boiler water, and as the water boils off as relatively pure steam, the remaining water becomes more concentrated with either suspended or dissolved solids.

Internal chemical treatment, based on water analysis, is used primarily to precipitate many of the solids and to maintain them as "sludge" in a fluid form. This sludge, along with suspended solids, shall be removed by the blowdown process. If the concentration of solids is not lowered through blowdown, but rather accumulates, foaming and priming will occur, along with scale and other harmful deposits.

Scale forming salts tend to concentrate and crystallize on heating surfaces. Scale has a low heat transfer value. It acts as insulation and retards heat transfer. This not only results in low operating efficiency, and consequently, higher fuel consumption, but also presents the possibility of overheating the boiler metal. The result can be tube failures or other pressure vessel metal damage.

There are two principal types of blowdown: intermittent and continuous. All steam boilers require intermittent blowdown, whether or not they are supplied with continuous blowdowns. Intermittent blowdown (blowoff) is done manually. Intermittent blowdown may also be used for level control. In that case, the intermittent blowdown control valve is opened automatically at levels higher than High Water Level in the steam drum. This can happen, for instance, during boiler start-up when the boiler water in the evaporator starts boiling, water is pushed out of the evaporator, and the water level rises. Continuous blowdown is a continuous removal of concentrated boiler water. If the required blowdown flow is rather small because of a good water quality, the operator may decide to use the continuous blowdown intermittent, i.e. a larger blowdown flow for a limited period (e.g. 2 h per shift).

4.2.2.4 Intermittent Blowdown

The manual blowdown valve and discharge lines are located at the bottom or low point of the boiler. This can also provide a means of draining the boiler when it is not under pressure. The intermittent blowdown should be used on an "as needed" basis with consideration given to the type of water in use and the chemical treatment program. If a boiler is operating with high-quality makeup water and there is no history of sludge accumulation, the intermittent blowdown frequency may be reduced or eliminated. If the boiler is operating on soft water with a precipitating phosphate program, the intermittent blowdown should be employed each shift. The intermittent blowdown valve may be opened fully for a very short duration at least once per shift, thus ensuring proper removal of accumulated solids that have settled in the mud drum. In cases where the feedwater is exceptionally pure, blowdown may be employed less frequently since less sludge accumulates in the pressure vessel.

Frequent short intermittent blowdowns should be preferred to infrequent lengthy ones. This is particularly true when the suspended solid content of the water is high. With the use of frequent blows, a more uniform composition of the pressure vessel water is maintained.

At higher steam pressures {higher than 1 MPa (ga) [145 psi (ga)]}, the intermittent blowdown system could include a motor-operated shutoff valve and a blowdown control valve. Both valves have to be located as close as possible to the flash vessel. Because of flashing conditions downstream, the control valve has to be mounted directly on the expansion vessel. The piping between the steam drum and the blowdown valves has to be designed such that there is no cavitation or flashing occurring in this line (i.e. pressure drop $\ll$ static head). It is recommended that the blowdown valve nearest the boiler be opened first and closed last, with blowing down being accomplished by the valve furthest from the boiler. The sequence of operation, once established, shall ensure that the valve last opened be the first closed so that the other valve is saved from throttling service to affect a tight closing. The frequency and amount of each blow shall be confirmed by actual water analysis.

The water level should be observed during periods of intermittent blowdown. The blowoff valves should never be left open and the operator should never leave until the blowdown operation is completed and the valves closed. Be sure the valves are shut tight. Repair any leaking valves as soon as possible.

4.2.2.5 Continuous Blowdown

Blowdown aims to maintain maximum acceptable chemistry levels in the steam drum. The amount of blowdown depends upon the rate of evaporation and the amount of sludge forming material in the feedwater. For further reference see Section 10.

Every fired boiler shall be equipped with an internal continuous blowdown pipe. The collector pipe should normally be located at approximately the same height as the low water level (LWL) alarm, at a point where the most concentrated water is found. Its location should not be adjacent to the chemical injection pipe. Either a manual controlled metering valve or a control valve shall be utilized to control the flow of concentrated water. Periodic adjustments are made to the valve setting to increase or decrease the amount of blowdown in accordance with a test analysis or by closed loop control from an online conductivity analyzer, with periodic laboratory validation. A qualified water treatment laboratory should be consulted when treating the boiler water and in setting the amount or frequency of blowdown and water testing. Proper monitoring and maintenance of appropriate water conditions in the boiler are mandatory to ensure long-term boiler integrity.

The amount of blowdown depends on the rate of evaporation and the amount of sludge-forming material in the feedwater, but ultimately blowdown aims to maintain maximum acceptable chemistry levels in the steam drum. For further reference see Section 10.

4.2.2.6 Saturated Steam Sampling

Saturated steam samples should be analyzed for properties and constituents that yield information of the steam purity and efficiency of the steam separation equipment installed inside the steam drum.

Saturated steam sampling is especially important in boilers equipped with superheaters. Boiler manufacturers are generally required to provide representative isokinetic sampling nozzles in the line(s) connecting the steam drum to the superheater. Nozzles shall be designed to meet the requirements of ASTM D1066.

Typical tests include comparison of the steam sample conductivity vs drum water conductivity. If the only measurement available is specific conductivity, it will provide broad indication separation efficiency. For high purity systems (e.g. those supplying steam to turbines), a sodium (Na) concentration comparison (of steam vs drum water) should be used as the most indicative method.

4.2.2.7 Boiler Feedwater Control

A properly sized boiler feedwater (BFW) regulator and control strategy shall be provided to ensure water delivery under all operating conditions. A BFW regulator will normally be an automatic control valve. Fail position of this valve shall be evaluated carefully and integrated into the overall operating philosophy of the unit (feedwater pumps, boiler and downstream equipment). It shall be noted that choosing an improper fail position can potentially have a catastrophic effect in the boiler or downstream equipment. The recommended fail position is to fail last and drift to close. If the feedwater regulator valve fails open, water will continue to fill the steam drum. This will result in unnecessary blowdowns and could result in a high steam drum water level alarm. If this valve fails closed, then the economizer tubes could overheat due to a lack of sufficient water flow. This could also result in a low steam drum water level alarm.

4.2.2.8 Attemperation and Desuperheating

Boilers having superheaters may or may not have attemperation or desuperheating of the steam exported to the header. Attemperation and desuperheating are two methods of controlling the superheater outlet steam temperature. The difference between the two depends on the application of the steam leaving the superheater. If the superheater outlet steam is being used for a process in the refinery and the superheater outlet steam is close to the saturation temperature, then the term for this temperature control is desuperheating. If the superheated outlet steam is being sent to a turbine, then the term for this temperature control is attemperation. If the temperature and pressure of the steam are both reduced, then the term steam conditioning is frequently used.

Considerations as to whether to use an attemperation or desuperheating system include the downstream equipment needs (temperature control range), piping design, and the available temperature control methods. The following list shows a few of the methods typically used.

- a) Spraying desuperheaters: These may be installed at the outlet of the superheater coil or in an interstage configuration. Spray water will, in many cases, be BFW, provided the steam purity is not adversely affected; in some cases it can be condensate or demineralized water.
- b) Steam desuperheating: Some designs can use saturated steam as the attemperating media, but these are rather uncommon.
- c) Fireside control methods: This can involve changes to burners, masking of furnace surfaces, etc.
- d) Steam condensers, also known as sweetwater condensers: In these cases a portion of the steam is drawn from the boiler prior to entering the superheater and then the steam is condensed by removing the latent heat (typically from BFW). The advantage of this system is that the re-injected condensate does not introduce foreign impurities into the superheater stream.
- e) Other methods suggested by the boiler manufacturer.

The installation of any mechanical attemperation system shall be accompanied with a proper control system that will take into account excessively high spraying conditions, high superheater temperatures, superheater metal monitoring, etc.

4.2.2.9 Superheater Start-up Vent

Boilers with superheaters shall be provided with a properly sized start-up vent. Venting has two (2) functions—air venting and protecting the superheater during start-up. This line shall be equipped with either a manual or an automatic control valve. The operating philosophy shall ensure that superheater tubes are kept below allowable tube temperatures at all times during start-up, and that they are gradually heated allowing for proper thermal expansion. Without flow, the superheaters can overheat, and the thermocouples will not register representative temperatures. The vent is closed progressively as steam is generated to raise the pressure and temperature in the boiler at a rate that is in accordance with the manufacturer's guidelines. The purpose of the vents is to purge the air.

4.2.2.10 Superheater Drains

Drain valves remove condensate from drainable superheaters during start-up and shutdown operations. Non-drainable superheaters are also available, and some vendors have more experience with non-drainable superheaters in selected boiler configurations. While drainable superheaters offer the ability to remove condensate during start-up operations, proven experience with either design should be considered when a boiler purchase is made.

4.2.2.11 Economizer

Boiler economizers shall be provided with drain valves and vent valves to facilitate filling of the unit. When economizers are provided with water bypasses, the economizer shall also be equipped with a safety relief valve sized per ASME BPVC Section I code requirements. Offline economizers should not be placed back in service when the flue gas temperature is in excess of 27 °C (50 °F) above the BFW temperature; severe water hammering could otherwise occur.

4.2.3 Air and Flue Gas

4.2.3.1 General

Following are typical guidelines for operating the air side of a fired boiler.

4.2.3.2 Air Moving Equipment

Fired boilers can be equipped with forced draft (FD) fans or a combination of FD and induced draft (ID) fans. The choice of what to use is normally a function of the fuel fired. Most gaseous and liquid fuel fired boilers will operate satisfactorily with just a FD fan. ID fans are used when it is necessary to keep balanced furnace pressure operation, e.g. if the boiler is burning fuels with a low supply pressure or if the furnace has areas open to the atmosphere.

- Fans can be designed per the owner's selected standard, i.e. an API document (API 673, API 560, or this document).

Fans shall be provided with adequate means for control, i.e. dampers, variable speed or combinations. For more information on fans and their accessories, see Section 8.

4.2.3.3 Dampers

Air control and flue gas control dampers shall be equipped with automatic actuators. These shall be either electrical or pneumatic. If pneumatic actuators are selected, they shall be sized with a safety factor of no less than 1.5 times the required torque and they also shall be sized for no more than 413 kPa (ga) [60 psi (ga)] of pressure.

Damper fail positions shall be carefully evaluated in coordination with the BMS or flame safeguard design.

4.2.3.4 Stack Dampers

In some cases, fired boilers will have stack dampers. These dampers minimize furnace pressure fluctuations during low load operation, particularly when stack height is tall enough to create excessive draft inside the firebox that is not acceptable for burner flame stability and operation.

A stack damper will typically be of the fail open position type to prevent furnace over pressurization. In some instances (e.g. burners sensitive to air momentum changes), the stack damper could be designed as fail last. The stack damper must have position indicating devices (i.e. switches or transmitters). An adjustable mechanical stop shall also be provided. Refer to Section 7 for further discussion on damper control.

4.2.3.5 Air and Flue Gas Ductwork

In general, ductwork shall be free of any operational vibration. Most fired boilers will have a certain amount of acceptable aerodynamic noise; however, any deflection or excessive movement should require further investigation. Refer to API 560, Annex F, for duct velocity sizing guidelines.

Air and flue gas ducts should be periodically inspected to verify their integrity, as well as for traces of materials that may have moved out of place and into the flue gas path.

- All ducts operating above 60 °C (140 °F) should be insulated, unless stated otherwise by the engineer specifying the boiler.

4.2.3.6 Flue Gas Recirculation Ductwork

One of the most popular techniques used to control nitrogen oxide (NO_x) emissions is flue gas recirculation (FGR). In this method a portion of the flue gas is extracted after the economizer and blended with combustion air and re-injected into the combustion zone. This promotes an overall lower adiabatic flame temperature in the furnace, thereby minimizing the formation of thermal NO_x.

FGR flow rates are typically controlled by a characterization in the combustion control system (CCS). Windbox oxygen measurements can also be used to trim the FGR damper position in systems with high FGR rates (greater than 25 %).

FGR ducts should preferably be equipped with an automatic control damper. In some instances, the burner designer may elect to use manual dampers.

FGR ducts will normally operate around 148 °C (300 °F) when the boiler is at 100 % load. FGR duct insulation should be provided once the boiler installation has been completed.

4.2.4 Fuel and Combustion

The fuel and combustion air entering the boiler shall be controlled to ensure complete combustion during operation and to ensure safe air to fuel ratios. All fuel enters the boiler through burners. For more information on typical fuels see 6.5. For more details on the operation and control of burners see Section 7.

Excess air, above the stoichiometric amount, should be limited to maximize the boiler's efficiency and maintain burner flame stability and a safe operating condition in the boiler. Oxygen in the flue gas should be measured at the outlet of the economizer or at the boiler outlet, if there is no economizer. Combustion air entering the boiler may be heated or unheated. For the control of combustion air using dampers see 6.3.

For a CO boiler, the furnace temperature is monitored to ensure that the CO will be oxidized. The pressure of the flue gas in the furnace is also measured. The temperature of the flue gas leaving the furnace is sometimes measured during start-up and this value is called the furnace exit gas temperature (FEGT). Knowing the FEGT can help protect the superheater. See 5.1.5 for more information regarding operation of the superheater.

4.2.5 Sootblowers

Sootblowers can be manual or automatic. If automatic, the controls are usually provided by the equipment vendor. They may be fixed, rotary, or retractable.

Sootblowers, if required by the characteristics of the fuel, are normally provided in the tube banks of fired steam generators to prolong on-stream time and maintain thermal efficiency by limiting buildup of soot or other foreign deposits.

Sootblower operation can be automatically sequenced to reduce operator involvement and to reduce sudden, large demands on the steam system. Also, precautions should be taken to protect other instrumentation, such as sampling systems of analyzers, during soot blowing.

The controls system shall be of the open architecture type.

The system shall be designed to allow automatic operation of the sootblowers in user-defined sequences. The program shall permit the user to selectively establish the order in which blowers are to be operated in the automatic sequence while in automatic mode. The system shall allow the user to create 20 sootblower "sequences" that have a total of 50 steps each.

For automatic sequencing, the following permissives shall be met to run the sootblowers:

- a) the header shall be warm,
- b) the header pressure transmitter signal shall be above the desired set point. This signals the header line has enough pressure.

4.3 Boiler Configurations

4.3.1 General

There are two fundamental types of boilers: fire tube and water tube. In water tube boilers, the water is on the inside of the tubes and the hot combustion gases are located on the outside the tubes. Water tube boilers cover the full range of operating pressures and are typically specified for steam capacities greater than 4536 kg/h (10,000 lb/h). In fire tube boilers, the water is located on the outside of the tubes and the hot combustion gases flow through the tubes. Fire tube boilers are normally used in lower pressure, {<1750 kPa (ga) [<250 psi (ga)]} applications and are typically found in sizes up to a maximum of 2000 hp (1491 kW) or about 29 metric ton/h (64,000 lb/h). In this document only water tube boilers are discussed in detail. Fire tube boilers are not generally used in refineries and petrochemical plants, except for facilities that contain sulfur recovery units.

There are several typical arrangements used in the design of natural circulation boiler systems. These are characterized by the shape of the bent tubes that form the shape of the furnace enclosure or how they are constructed. These include the "D," "O," "A," modular, and field erected configurations. Different boiler styles each have characteristics that make them more or less suitable for a given application. These characteristics affect the foundation footprint, cleanability, shipping constraints, degree of shop assembly, performance characteristics, and durability.

Once-through and/or forced circulation boilers are a subset of water tube boilers that utilize a pump to deliver sufficient water flow through the tubes to prevent overheating. These boilers can be used to generate high temperature hot water (HTHW), saturated steam, or superheated steam. These boiler types are not discussed in detail in this document.

Carbon monoxide (CO) boilers are used in some refineries. Multiple CO boiler configurations and requirements are described in 4.3.8.

4.3.2 Water Tube Package “D” Boiler

The pressure capability of package and modular boilers is limited by natural circulation ratio requirements for those boiler configurations. A maximum pressure would be 6.2 MPa (ga) [900 psi (ga)]. These boilers will be described next.

The “D” boiler is characterized by its offset furnace design. See Figure 2. This design typically provides a larger furnace, relative to the unit’s overall size, than other configurations. When designs are limited by rail shipping constraints, the width of the “D” boiler furnace typically limits the maximum rated capacity. The offset center of gravity can also require substantial shipping ballast for larger rail shipped units. Higher capacity units are typically either partially or fully field assembled. When equipped, this type of unit typically has a convective superheater located between the drums within the convection section.

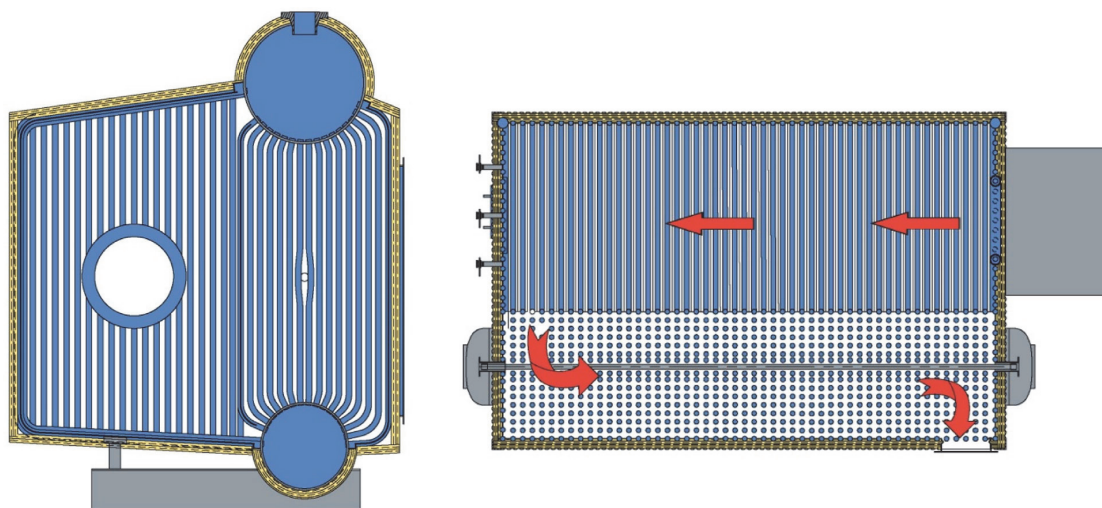


Figure 2—Water Tube Package “D” Boiler

4.3.3 Water Tube Package “O” Boiler

The “O” boiler is characterized by a furnace that is concentric with the convection tube bank. See Figure 3. When designs are limited by rail shipping constraints, the height of the “O” boiler furnace typically limits the maximum rated capacity. Higher capacity units are typically fully field assembled. When equipped, this type of unit typically has a radiant-convective superheater located in the rear of the furnace.

4.3.4 Water Tube Package “A” Boiler

The “A” boiler is characterized by its two mud drums and symmetrical design. See Figure 4. When designs are limited by rail shipping constraints, the width of the “A” boiler furnace typically limits the maximum rated capacity. Higher capacity units are typically fully field assembled. When equipped, this type of unit typically has a radiant-convective superheater located in the rear of the furnace.

4.3.5 Modular Boiler

The modular boiler is comprised of shop assembled major components that are joined in the field to produce a high capacity unit that has a minimum of field assembly. See Figure 5. Shop assembled complete major components may include a furnace module, convection zone module, and separate steam drum, although many other possible component breakdowns are possible.

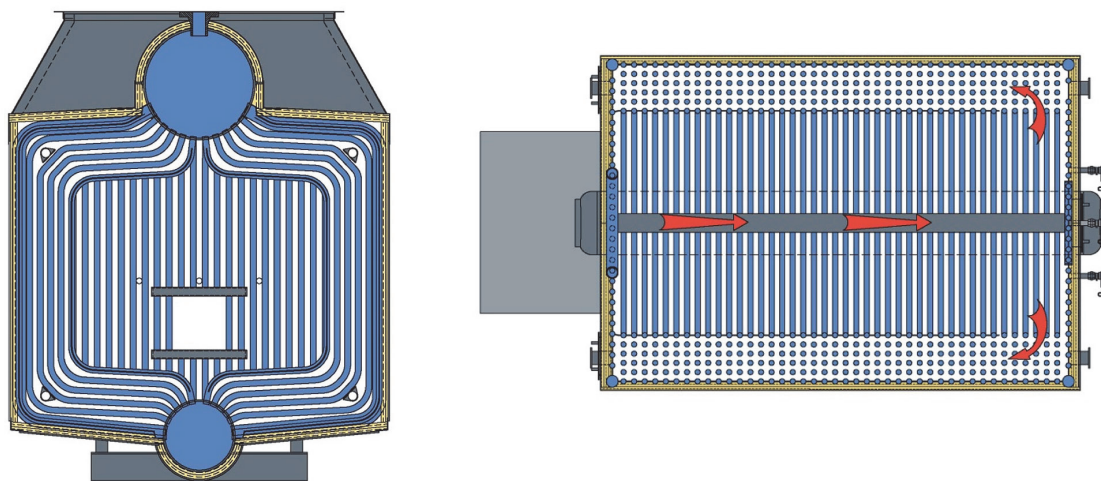


Figure 3—Water Tube Package “O” Boiler

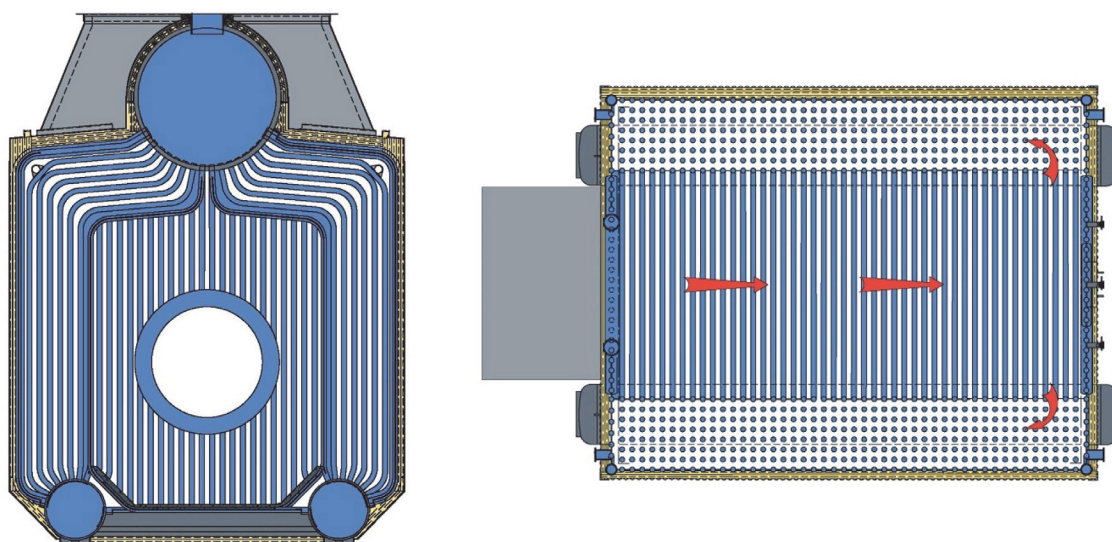


Figure 4—Water Tube Package “A” Boiler

4.3.6 Single Steam Drum Boiler

Single steam drum boilers are fully welded designs and do not have a lower (mud) steam drum as described for the two-drum boilers shown above. The connections into the steam drum are not rolled in as is common for two-drum boilers, but fully welded into the steam drum. The fully welded design allows this boiler type to operate at elevated steam pressures of typically 10 MPa (ga) [1450 psi (ga)] and higher. An example of a single steam drum type boiler is shown in Figure 6. This example shows a design with drainable superheaters. A design with non-drainable superheaters is also possible.

4.3.7 Field Erected Boiler

The field erected boiler is generally fully assembled in the field from shop built drums, headers, waterwall panels, bent tubes and pre-fabricated structural steel and casing. These units are generally over 113,399 kg/h (250,000 lb/h) or are located where shipment of large or heavy assembled components is not feasible. The boiler shown in Figure 7 has a capacity of 192,779 kg/h (425,000 lb/h) and is capable of burning CO gas, natural gas, and refinery gas.

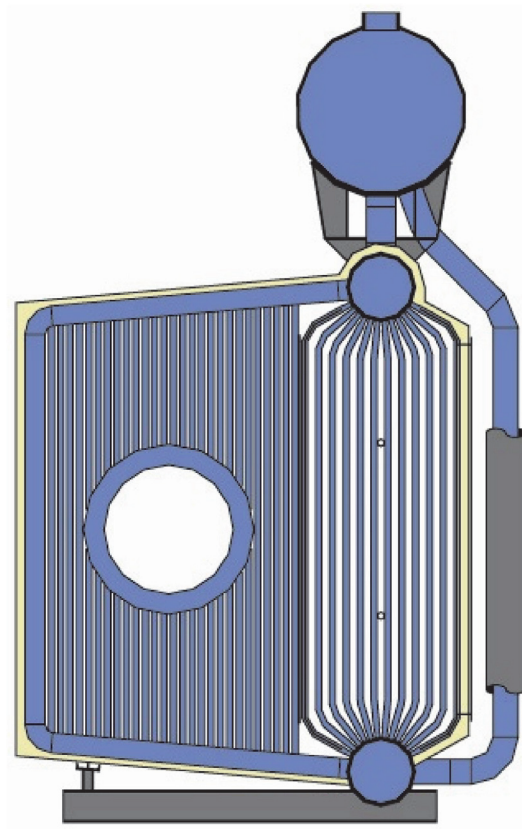


Figure 5—Modular Boiler

4.3.8 CO Boiler

4.3.8.1 General

There is another type of boiler that is uniquely designed for refineries, the professed CO boiler. A water tube CO boiler is shown in Figure 7.

A CO boiler is a steam generator located downstream of a regenerator of a FCCU or residual (fluid) catalytic cracking unit.

There are three types of FCCUs:

- a) FCC with a regenerator with full combustion,
- b) FCC with a regenerator with partial combustion,
- c) FCC with two regenerators—one with partial combustion and one with full combustion.

Steam generator types are as follows.

- a) Regenerators with full combustion: The flue gas at the regenerator outlet (regenerator flue gas) contains no combustibles. The heat recovery takes place in a flue gas cooler [heat recovery steam generator (HRSG)]. Features of a HRSG for regenerator flue gas without CO are described in API 534, Section 3.5.

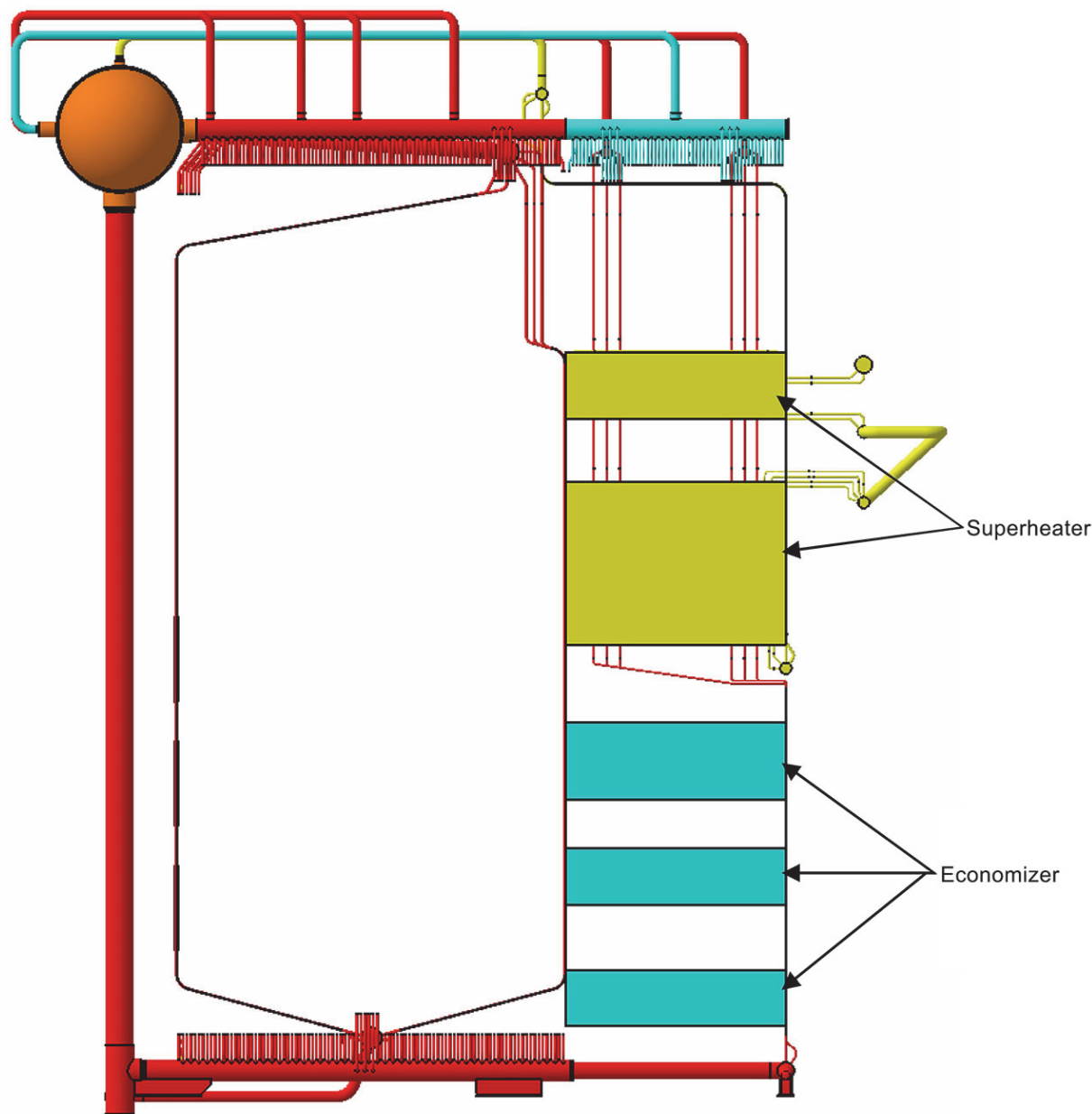


Figure 6—Single Steam Drum Boiler

- b) Regenerators with partial combustion: The flue gas at the regenerator outlet contains 3 % to 12 % CO. The CO has to be oxidized. Because of the low HHV of the regenerator flue gas entering the boiler, a supplementary fuel is used to assist in oxidizing the CO.

For burning the CO together with the supplementary fuel and for the recovery of the released heat, the following two types of boilers exist.

- 1) Waterwall CO boiler: The construction is similar to the package boilers described previously. Deviations due to the fuel characteristics are, for example, the furnace shape and the use of hoppers. Figure 7 depicts a waterwall CO boiler.

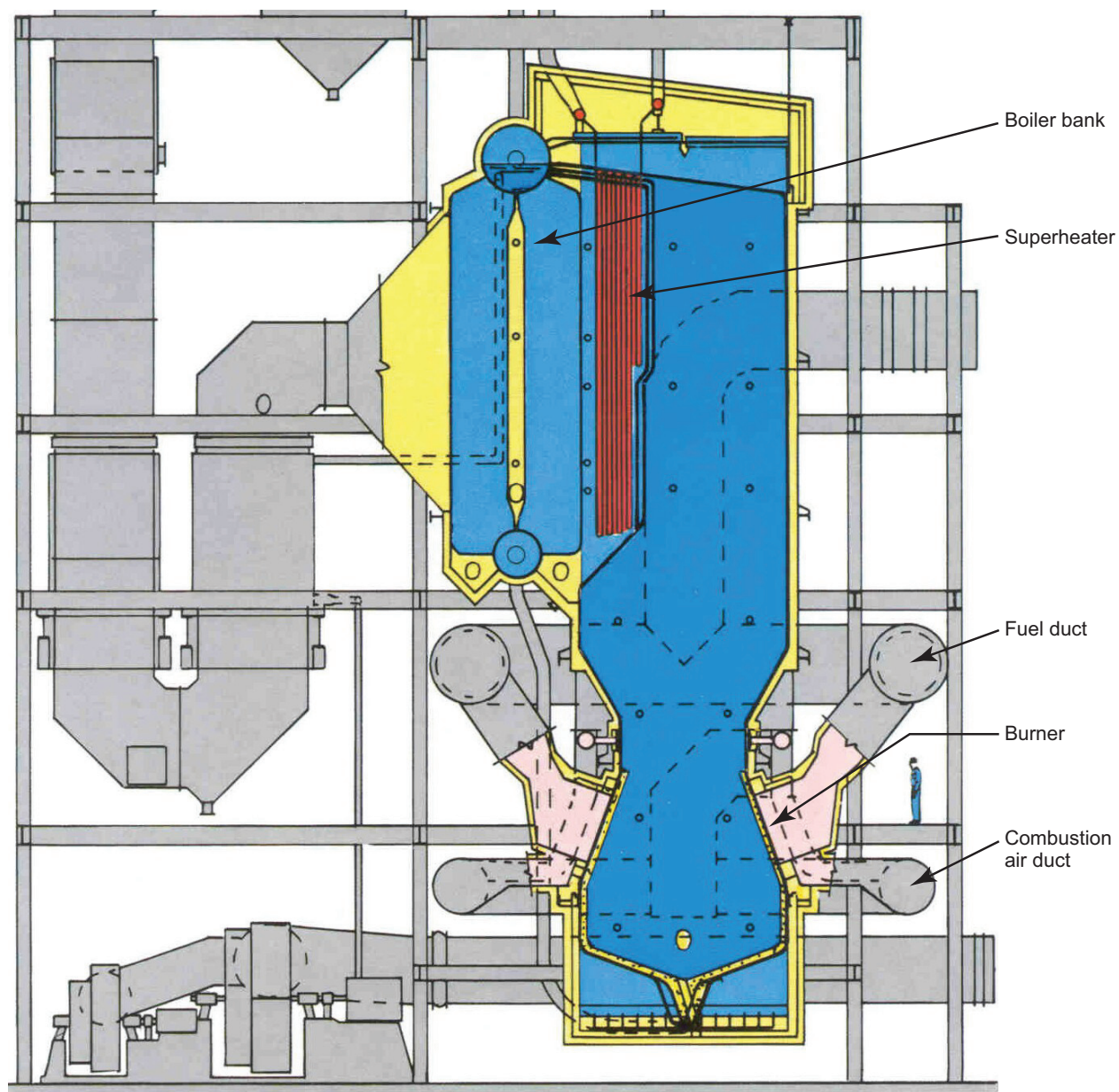


Figure 7—Field Erected Boiler

- 2) CO combustor with HRSG (waste heat boiler): The CO combustor, as well as the HRSG, is refractory lined inside. CO is oxidized by means of supplementary firing in the combustor. The adiabatic flame temperature has to be limited lower than the design temperatures of the refractory. That is realized by an additional air supply to the combustor. Primary air is used for the supplementary fuel; secondary air is used for CO burning and for quenching (if required). See 4.3.8.3 for more information on the CO combustor or thermal oxidizer. The design of the HRSG is similar to the flue gas cooler for regenerator flue gas without CO, as described above. Figure 8 details a CO combustor and a flue gas cooler (HRSG). See also 4.3.8.4 for more information on the waste heat boiler.

In the case of a FCCU with two regenerators, the first regenerator with partial combustion and the second regenerator with full combustion, the following two design options are possible.

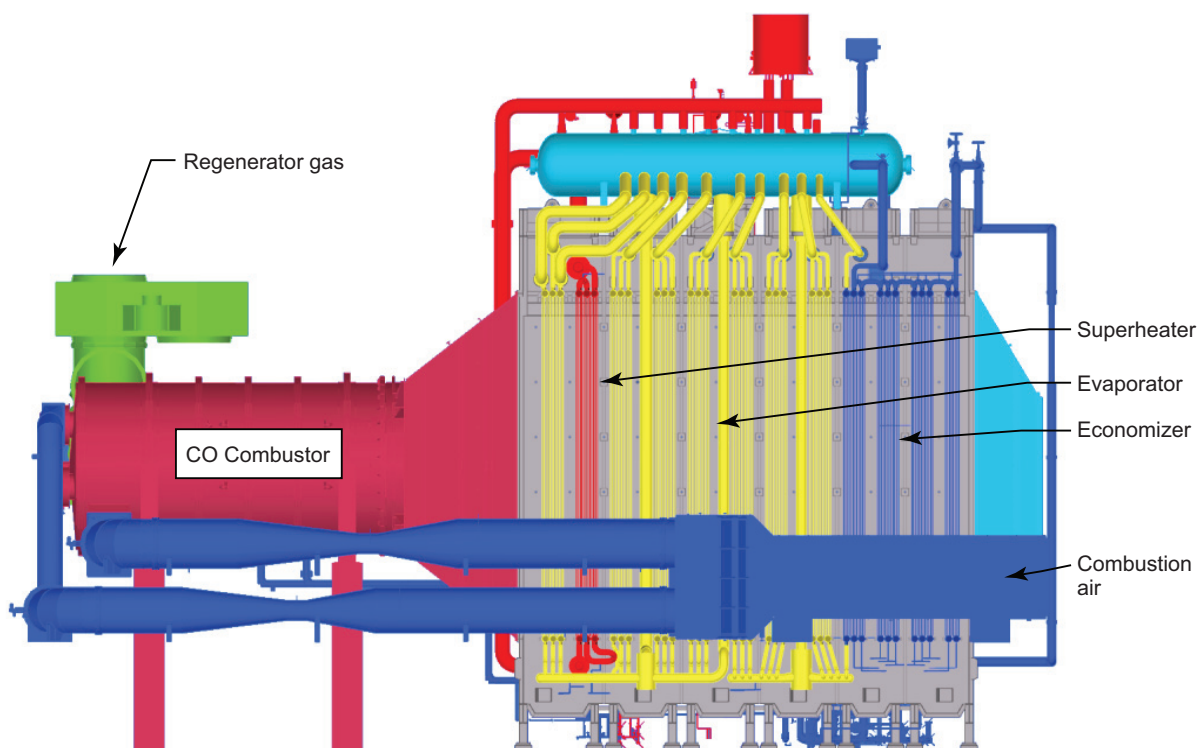


Figure 8—Carbon Monoxide Combustor and Heat Recovery Steam Generator

- 1) Two CO boilers, one as an HRSG and one a CO boiler with supplementary fuel to combust and render harmless the CO (two types possible; see above).
- 2) Only one CO boiler with supplementary firing (two types possible; see above). The flue gas from the second regenerator is mixed in the flue gas after CO combustion, upstream of the convection sections.

The second design option is preferable.

- A fired CO boiler will be started with only the supplementary firing in operation (fresh air operation). The purchaser or owner may select the boiler to deliver maximum steam production in fresh air operation, e.g. as backup for the steam grid. That may have consequences for the equipment design of the CO boiler, particularly regarding emissions during fresh air firing.

Some FCCUs produce a saturated steam flow(s) that has to be superheated in the CO boiler. Saturated steam with the pressure equal to the steam of the CO boiler is mixed with the saturated steam in the CO boiler.

Saturated steam with a lower pressure (medium pressure steam) is superheated in a separate superheater in the CO boiler. The medium pressure superheater has to also be designed for the no-flow condition.

4.3.8.2 Adiabatic CO Boiler Design

4.3.8.2.1 General

The adiabatic, or thermal oxidizer, type of CO boiler achieves very high rates of CO destruction by combusting the CO-rich residual catalytic cracking (RCCU) gas (flue gas from a regenerator) in an internally insulated chamber. As there is minimal heat loss through the internal insulation, the uniformly high temperature of the combustion chamber promotes efficient oxidation of CO to CO₂.

Such a system consists of two distinct components, the thermal oxidizer and a waste heat boiler, immediately downstream of the thermal oxidizer. The waste heat boiler cools the flue gas so the flue gas can be sent to pollution control equipment prior to discharge to atmosphere.

Supplemental fuel is usually needed to provide flame stabilization and ensure flame blowout does not occur. Additionally, extra fuel may be required to satisfy steam production requirements, although the thermal oxidizer CO boiler is typically less efficient than traditional gas and oil fired boilers due to the relatively high exit temperatures and high excess air. This results in a relatively high stack loss.

The most common style of thermal oxidizer is a refractory lined horizontal cylindrical vessel. The cylindrical shape accommodates gas side pressures of up to 34.5 kPa (ga) [5 psi (ga)] without excessive stiffening. The adiabatic CO boiler is almost always a FD design.

4.3.8.2.2 Sulfur Dew Point Corrosion

Because the RCCU gas contains significant amounts of sulfur, care shall be taken to prevent acid dew point corrosion. Acid dew points are generally in the range of 163 °C to 177 °C (325 °F to 350 °F). In CO boilers that have economizers, the BFW is usually preheated to a temperature above the acid dew point. Commonly, the BFW is heated to 177 °C (350 °F). The exit gas temperature typically is 28 °C to 56 °C (50 °F to 100 °F) higher than the feedwater temperature, or 204 °C to 232 °C (400 °F to 450 °F).

Additionally, the casing of the thermal oxidizer and the boiler itself shall be protected from corrosion. Depending on the construction, the thermal oxidizer and the boiler will be provided with external insulation, an internal corrosion barrier between refractory lining and casing, or both. The external insulation may be a dead air gap produced by lagging (or a rain shield), or a ceramic fiber insulation in the lower gas temperature zones, such as the last sections of the evaporator and the economizer, if applicable.

As an internal protection a layer of acid resistant coating, asphaltic cutback, or equivalent material, can be provided.

Infrequently, some boilers chemically neutralize sulfur dioxide when the flue gas drops below the dew point, using products such as magnesium derivatives.

4.3.8.3 Thermal Oxidizer

4.3.8.3.1 Theory for Adiabatic Combustion

The thermal oxidizer, shown in a horizontal orientation in Figure 9, is lined with refractory to maintain the temperature to approximately 982 °C (1800 °F) for at least 0.5 s.

The benefits of the adiabatic style of burning is evident when compared to the retention time required for the water cooled furnace style boiler, which is on the order of 1.5 s based on a 900 °C (1650 °F) firing temperature. The thermal oxidizer style of CO boiler is able to deal with turndowns without increasing the percentage of supplemental fuel being fired, as the temperature of the incinerator remains essentially constant, while the water cooled furnace type of boiler typically needs to increase the amount of supplemental fuel to compensate for the lower gas temperature exiting the furnace at turndown conditions.

The thermal oxidizer consists of several zones; the main ones being the RCCU waste gas inlet and distribution zone, the combustion zone, and the residence zone.

4.3.8.3.2 Mixing

Air is typically introduced in multiple locations in the thermal oxidizer. Air is needed to oxidize the CO to CO₂, combustion air is required for the supplemental fuel, and quench air is added to control the temperature in the incinerator.

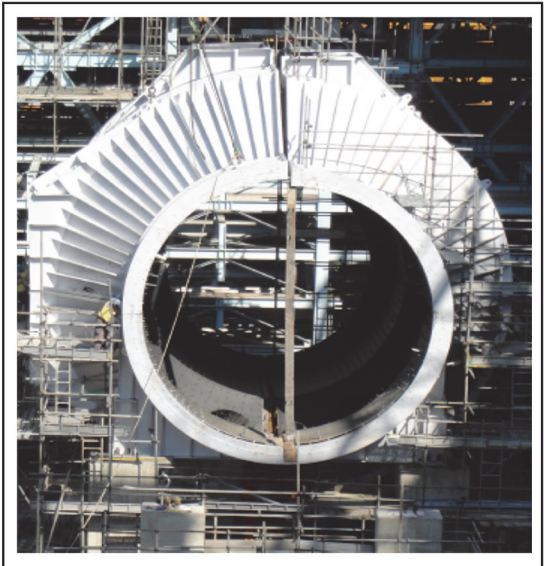
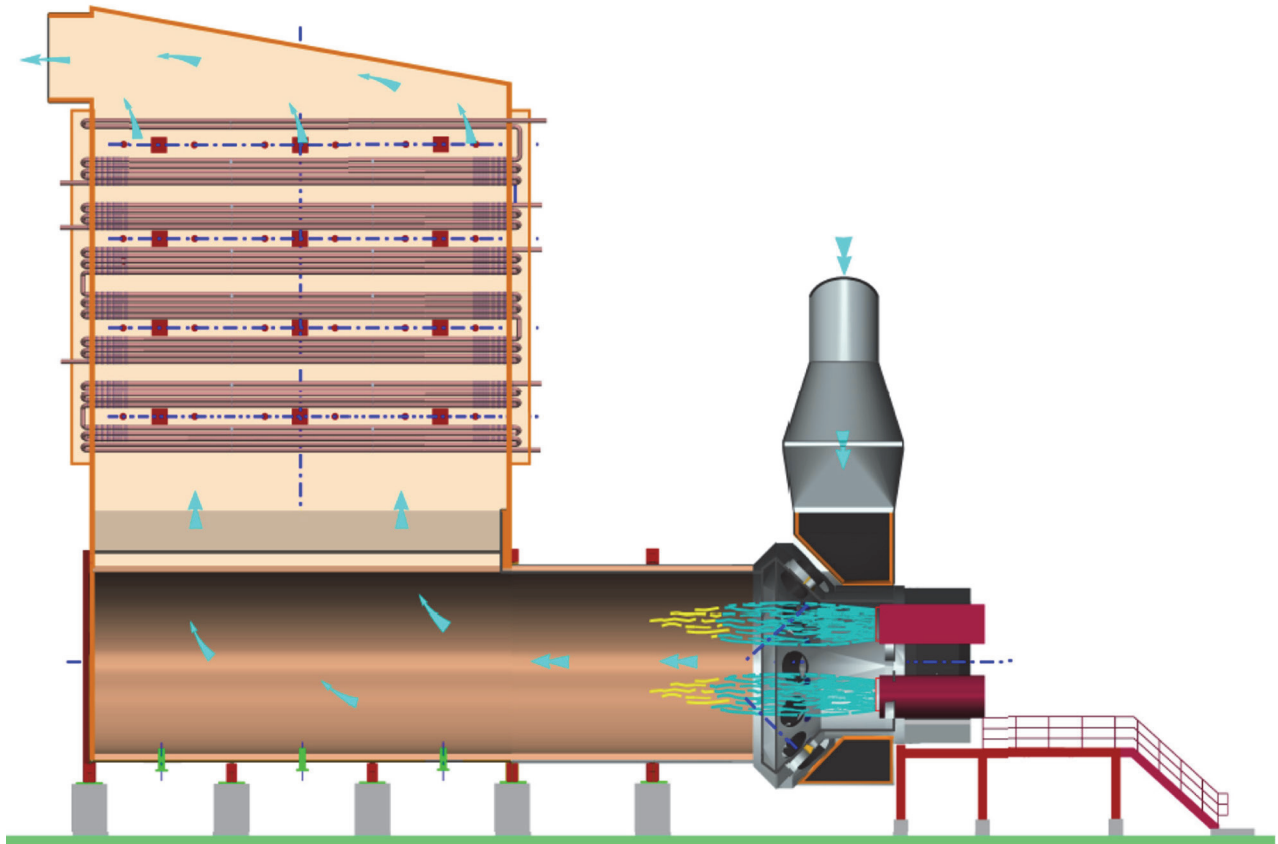


Figure 9—Thermal Oxidizer

Uniform mixing within specified tolerances is critical for efficient destruction of CO. RCCU waste gas, oxidation air, and the supplemental fuel and its combustion air shall all be considered. There are various ways of introducing the RCCU waste gas, oxidation air, and quenching air into the combustion zone, depending on the specific design of the thermal oxidizer and supplemental burner chamber.

The thermal oxidizer's combustion zone, depicted in the side view of Figure 9, has rectangular CO and air injection locations situated to achieve uniform mixing with the burners' combustion gases.

4.3.8.3 Refractory

In addition to a relatively high inlet temperature, the RCCU waste gas contains catalyst fines, which can be extremely erosive, so care shall be taken to introduce it into the thermal oxidizer without damaging the burner and flow distribution system.

- a) The design of the refractory lining of the RCCU waste gas inlet shall consider both the elevated temperatures and the erosive nature of the RCCU waste gas. Depending on the design of the RCCU waste gas inlet, a single layer refractory system or a multiple layer refractory system is utilized to protect the RCCU waste gas inlet portion of the thermal oxidizer. The hot face layer should consist of an abrasion resistant material.
- b) In the main combustion zone, which includes the entire flame length, refractory also consists of a multiple layer system. The hot face layer here shall be suitable for direct exposure to the flame and be sufficiently strong to prevent erosion. The effect of radiation from the flame should also be considered.

If the shell temperature is maintained above 177 °C (351 °F) to prevent dew point corrosion, a rain shield shall be installed on the thermal oxidizer. An internal protective coating shall be applied between the refractory and shell if the shell temperature is below 177 °C (351 °F).

4.3.8.4 Waste Heat Boiler

4.3.8.4.1 General

The waste heat boiler portion of the adiabatic CO boiler is a refractory lined design. To prevent acid dew point corrosion on the pressure-retaining casing, either outside insulation or an internal protective coating shall be applied. Figure 10 shows a modular waste heat boiler configuration. It has vertical gas flow and forced circulation. Flue gas side pressures of 34.5 kPa (ga) [5 psi (ga)] can be accommodated with a flat plate casing design properly stiffened, but is often quite lower. Casing material is carbon steel plate, typically A-36 or equivalent. Casing thickness should provide the structural integrity and some measure of corrosion allowance. Thickness can be nominally 10 mm (0.375 in.), or thinner ($\frac{3}{16}$ in. and or $\frac{1}{4}$ in. casing), with proper bracing at higher pressures. The gas side of the casing is coated with 3 mm (0.125 in.) of a corrosion-resistant material, such as asphaltic cutback, to provide corrosion protection during start-up and off design operation.

The waste heat boiler can have either horizontal or vertical gas flow, depending on site requirements, with horizontal gas flow being the most common. The boiler can have either forced circulation, as in Figure 10, or more commonly, natural circulation. The waste heat boiler can be field erected, but modular construction is generally preferred to minimize congestion on the site and to take advantage of lower shop labor rates and the higher quality control levels in a shop environment.

a) Clean and Fouled Operation

- 1) CO boilers tend to have moderately heavy fouling conditions due to FCC catalyst fines carryover, and very heavy fouling factors are often specified by end users, engineers, or process licensors. It is important to understand that at start-up, the CO boiler will have clean surfaces and significant overperformance as compared to operating for some length of time.



Figure 10—Modular Waste Heat Boiler Configurations



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- 2) The most serious result of this overperformance is high steam production from the steam generator and high steam temperature from the superheater. This can cause superheater tube metal temperatures to be higher than designed and/or may cause excessive amounts of attemperator spray water to be consumed. This may result in steam purity issues if the spray water quality is poor.
- 3) Also, the flue gas temperature exiting the economizer can be up to 28 °C (50 °F) lower than design due to evaporator and economizer overperformance, and this needs to be considered in the design of downstream equipment.

b) Flue Gas Velocities

- 1) Care shall be taken in the design of the waste heat boiler with regard to flue gas velocities. At low velocities, typically 12 m/s (40 ft/s), the catalyst fines will no longer be transported by the gas stream and they will begin to drop out and accumulate inside the waste heat boiler. In areas of low gas velocities, such as between tube banks, methods of removing accumulated catalyst should be considered. These methods may include the use of hoppers or stainless steel vacuum tubes that are normally valved off, but can be opened to suck out the fines. At velocities above 24 m/s (80 ft/s), erosion becomes a concern where the gas stream impinges on surfaces. In these areas tube shielding should be considered. For horizontal gas flow designs, the tubes are typically oriented vertically and may be either top or bottom supported. Tube ties and acoustic baffles are used to prevent whirling tube instability and vortex shedding. Vertical gas flow units can resemble the convection section of a fired heater, and there are certain similarities between the two.

4.3.8.4.2 Screen

Since there is no radiant furnace, a screen section is needed to protect the superheater elements from direct exposure to the flame and to help present a uniform temperature gradient to the superheater. The screen section tubes shall be bare tubes.

The hot face refractory in the screen section should have a temperature rating of at least 1400 °C (2552 °F). The hot face refractory needs to have good abrasion resistance. This is especially true if the flue gas flow changes direction which that can lead to direct impingement of the catalyst on the refractory. The hot face refractory should be a minimum of 75 mm (3 in.) thick, and be backed with a layer of lightweight insulation refractory.

4.3.8.5 Mechanical Design Details

This section includes the minimum requirements that are unique to CO boilers because of special considerations of this fuel. More information can be found in Section 3.5 of API 534.

The water tube boiler shall be a forced-draft or balanced-draft design. If the CO fuel pressure is not high enough, a water tube design and natural circulation type boiler shall be selected. Since this boiler is designed to burn an unusual fuel (CO and its associated gases), special care in boiler sizing and auxiliary equipment selection (mainly FD/ID fans, fuel valves skid and burner) shall be taken. See 6.5 for more details on this fuel.

The furnace design shall be gas tight. The gas side operating pressure of the furnace is 0.5 mbar to 250 mbar (ga) [0.2 in. to 100 in. (WC)]. The gaps between tubes shall be proportional to the tube outside diameter (OD), and the maximum fin (membrane) dimension should be 25.4 mm (1.0 in.) and 6.35 mm (0.25 in.) thick. A preliminary recommended minimum furnace residence time should be 1.5 s where the flue gas temperature is above 982 °C (1800 °F). This should be revised considering the specific fuel characteristics and burner supplier information.

Access doors should be located in the boiler to allow easy cleanout of catalyst. The catalyst is a white powder that enters the boiler with the CO and will build up over time. The catalyst should be cleaned out on a regular basis. Sootblowers shall be installed. For more detail, see 14.2. The requirements for sootblowers can be found in API 560.