Heat Recovery Steam Generators

API RECOMMENDED PRACTICE 534
SECOND EDITION, FEBRUARY 2007

REAFFIRMED, OCTOBER 2013

AMERICAN PETROLEUM INSTITUTE

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Downstream Segment

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1 General

1.1 SCOPE

This publication provides guidelines for the selection or evaluation of heat recovery steam generator (HRSG) systems. Details of related equipment designs are considered only where they interact with the HRSG system design. This publication does not provide rules for design, but indicates areas that need attention and offers information and description of HRSG types available to the designer or user to aid in the selection of the appropriate HRSG system.

The HRSG systems discussed are those currently in industry use. A general description of each HRSG system begins Sections 2 and 3. Selection of an HRSG system for description does not imply other systems are not available nor recommended. Many individual features described in these guidelines will be applicable to any type of HRSG system.

Appendices A, B, and C refer to Sections 1 through 3.

1.2 REFERENCED PUBLICATIONS

1.2.1 The editions of the following standards, codes and specifications that are in effect at the time of publication of this publication shall, to the extent specified herein, form a part of this publication.

API/ISO[1]

Std 530/ISO 13704	*Petroleum and natural gas industries—Calculation of heater-tube thickness in petroleum refineries*
RP 536	*Post Combustion NO_x Control for Fired Equipment in General Refinery Services*
Std 560/ISO 13705	*Petroleum and natural gas industries—Fired heaters for general refinery service*
Std 660/ISO 16812	*Petroleum and natural gas industries—Shell-and-tube heat exchangers for general refinery service*

ABMA[2]

Boiler 402	*Boiler Water Quality Requirements and Associated Steam Quality for Industrial/Commercial and Institutional Boilers*

ANSI[3]/ASME[4]

ANSI 14.3	*Fixed Ladders—Safety Requirements*
PTC 4.4	*Gas Turbine Heat Recovery Steam Generators Performance Test Code*

ASME

Boiler and Pressure Vessel Code, Section I: "Power Boilers" and Section VIII, Division 1, "Pressure Vessels."

Consensus Operating Practices for Control of Feedwater/Boiler Water Chemistry in Modern Industrial Boilers CRTD–Vol. 34

SA-106	*Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service*
SA-178/SA-178M	*Standard Specification for Electric-Resistance-Welded Carbon Steel and Carbon-Manganese Steel Boiler and Superheater Tubes*
SA-214/SA-214M	*Specification for Electric-Resistance-Welded Carbon Steel Heat-Exchanger and Condenser Tubes*
STS-1	*Steel Stacks*

ASTM[5]

D 1066-97(2001)	*Standard Practice for Sampling Steam*

NFPA[6]

8502	*Standard for the Prevention of Furnace Explosions/Implosions in Multiple Burner Boilers*

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[1]International Organization for Standards, 25 West 43rd Street, 4 Floor, New York, New York, 10036, www.iso.org.
[2]American Boiler Manufacturers Association, 8221 Old Courthouse Road, Suite 207, Vienna, Virginia 22182, www.abma.com.
[3]American National Standards Institute, 25 West 43rd Street, 4th floor, New York, New York, 10036, www.ansi.org.
[4]ASME International, 3 Park Avenue, New York, New York, 10016, www.asme.org.
[5]ASTM International, 100 Bar Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.
[6]National Fire Protection Association, 1 Batterymarch Park, PO Box 9101, Quincy, Massachusetts 02269-9101, www.nfpa.org.

OSHA[7]

Applicable standards of the Federal Register's Rules and Regulations

TEMA[8]

Standards of the Tubular Exchanger Manufacturers Association

1.2.2 In addition, this publication draws upon the work presented in the following publications:

1. *Steam/Its Generation and Use*, The Babcock & Wilcox Company, New Orleans, Louisiana.
2. *Combustion Engineering—A Reference Book on Fuel Burning and Steam Generation*, Combustion Engineering Co., Inc., Stamford, Connecticut.
3. A. Bar-Cohen, Z. Ruder, and P. Griffith, "Circumferential Wall Temperature Variations in Horizontal Boiler Tubes," International Journal of Multiphase Flow, Vol. 9, No. 1, pp. 1 – 12, February 1983.
4. B. Y, Taitel and A. E. Dukler, "A Model for Predicting Flow Regime Transitions in Horizontal and Near Horizontal Gas—Liquid Flow," AICHE Journal, Vol. 22, No. 1, pp. 47 – 55, January 1976.
5. *Guidelines for the Operation and Maintenance of HRSGs*, HRSG User's Group, Tetra Engineering Group, Weatogue, Connecticut.

1.3 DEFINITION OF TERMS

1.3.1 approach temperature: The difference between the saturation temperature of the steam and the temperature of the water leaving the economizer.

1.3.2 attemporator: See **desuperheater**.

1.3.3 desuperheater: A device located internal or external to the HRSG that controls the exit temperature of the steam from the superheater. The device typically injects pure water into the steam. Also called an attemporator.

1.3.4 downcomer: A heated or unheated pipe carrying water from the steam drum to an evaporator/generator section of an HRSG.

1.3.5 evaporator: The portion of the HRSG in which water is boiling to form steam. Typically a mixture of water and steam exists at the exit of this portion. Also referred to as a steam generator section.

1.3.6 firetube HRSG: A shell-and-tube heat exchanger in which steam is generated on the shell side by heat transferred from hot fluid flowing through the tubes.

1.3.7 generator: The entire water/steam heating system portion of the HRSG. Sometimes used synonymously as the evaporator section.

1.3.8 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.

1.3.9 pinch temperature: The difference between the heating medium temperature leaving the steam generator section and the steam's saturation temperature.

1.3.10 process fluid: The heating medium used to supply the heat for steam generation to the HRSG.

1.3.11 refractory design temperature: The hot face temperature for which the thickness of the lining shall be based upon. It will normally include the user defined margin above the continuous operating temperature of the process.

1.3.12 refractory rating temperature: The temperature at which the refractory material is acceptable for continuous use.

1.3.13 refractory service temperature: The temperature established by the refractory manufacturer as the highest temperature for which the material is suitable. This is normally the temperature at which the shrinkage of the material reaches its upper limit of about 1.5%.

1.3.14 riser: A heated or unheated pipe carrying water and steam from an evaporator/generator section of an HRSG to the steam drum.

[7]Occupational Safety & Health Administration, 200 Constitution Avenue, NW, Washington, D.C. 20210, www.osha.gov.
[8]Tubular Exchanger Manufacturers Association, 25 North Broadway, Tarrytown, New York 10591, www.tema.org.

1.3.15 superheater: The portion of the HRSG in which saturated steam is heated to higher temperatures.

1.3.16 vertical shell-and-tube watertube HRSG: A shell-and-tube heat exchanger in which steam is generated in the tubes by heat transferred from a hot fluid on the shell side.

1.3.17 watertube low-pressure casing HRSG: 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.

1.4 REGULATORY REQUIREMENTS

An HRSG may be subject to boiler licensing rules, which require all inspection, maintenance, and repair tasks be conducted in accordance with specific codes, as adopted by local jurisdictions. In almost all US jurisdictions, the governing codes are the ASME *Boiler and Pressure Vessel Code* (*BPVC*) and the National Board of Boiler and Pressure Vessel Inspectors Code. The appropriate portions of the *Boiler and Pressure Vessel Code* include:

- Section I “Power Boilers”
- Section II “Materials”
- Section V “Nondestructive Testing”
- Section VII “Guidelines for the Care of Power Boilers”
- Section IX “Welding and Brazing Qualifications”

Of these, Section VII most directly affects the maintenance of HRSGs because it contains specific inspection and repair guidelines.

Section VIII can be used as the design code when allowed by the local jurisdiction.

2 Firetube Heat Recovery Steam Generators

2.1 GENERAL

A firetube HRSG is a heat exchanger producing steam with boiler water present on the shell-side of the heat exchanger. The boiler water absorbs heat from a hot fluid passing through the tubes. The hot fluid is often a high-temperature gas resulting from combustion or other chemical reaction. Moderate-temperature gases, liquids, and slurries are also used.

High-temperature severe service firetube HRSGs are supplied with boiler water at a high circulation ratio. Natural (thermosiphon) or forced (pumped) circulation systems are employed. Boiler feed water is introduced to an overhead steam drum, which provides for water storage and steam-water separation in addition to the static head driving force for natural circulation systems.

Less severe, lower temperature firetube HRSGs, are often once-through (nonrecirculating) kettle (see 2.6.2) boilers. Figures 1 and 2 illustrate horizontal and vertical units involving natural circulation from an overhead drum. Figure 3 is a kettle steam generator.

This type of HRSG is typically designed in accordance with API Std 660/ISO 16812.

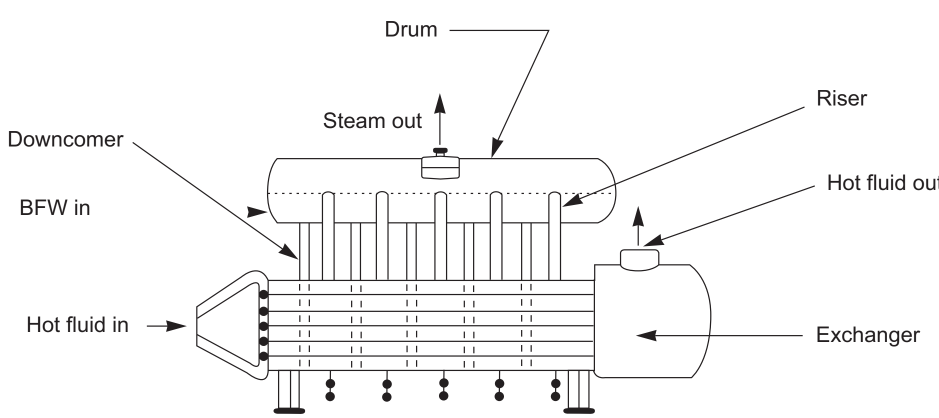


Figure 1—Horizontal Firetube with External Drum HRSG

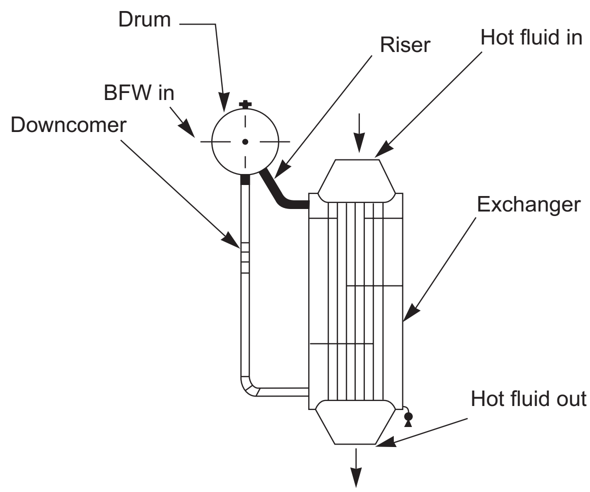


Figure 2—Vertical Firetube with External Drum HRSG

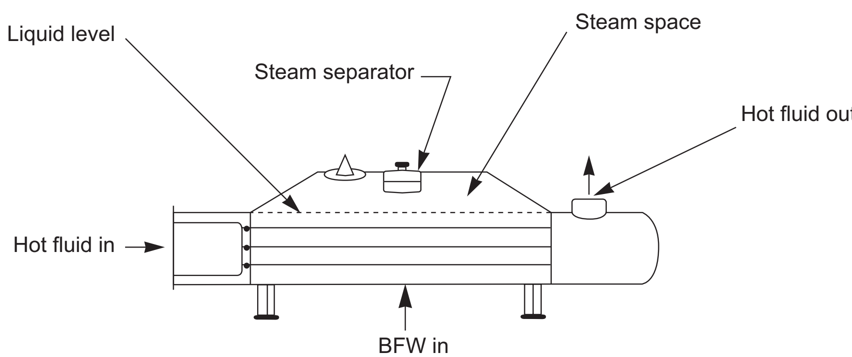


Figure 3—Firetube Kettle Type HRSG

2.2 APPLICATION

2.2.1 High-temperature/High-flux Units

Firetube HRSGs with high-temperature heating mediums (exceeding 480ºC [900ºF]) resulting in high boiling flux rates (in excess of) 94,600 W/m^2 (30,000 Btu/hr-ft^2) are considered severe service applications. Gas temperatures exceeding 1090ºC (2000ºF) and flux rates to 315,500 W/m^2 (100,000 Btu/hr-ft^2) can be accommodated in firetube HRSGs. Mechanical features as described in 2.6.1 are required for these severe services.

The following processing applications are typical of those which often make use of severe service firetube HRSGs:

a. Steam reformer effluent (hydrogen, methanol, ammonia plants).
b. Ethylene plant furnace effluent.
c. Fluid catalytic cracker flue gas.
d. Sulfur plant reaction furnace effluent.
e. Coal gasifier effluent.
f. Sulfuric and nitric acid reaction gases.

Typical steam side operating pressures range from as low as 1,050 kPa(g) (150 psig) for fluid catalytic cracker and sulfur plant applications to as high as 12,400 kPa(g) (1,800 psig) for ammonia and ethylene facilities.

2.2.2 Moderate-temperature/Low-flux Units

Firetube HRSGs which handle hot fluid temperatures not exceeding 480ºC (900ºF) with flux rates of 94,600 W/m^2 (30,000 Btu/hr-ft^2) and below have a wide range of process applications. Any hot fluid stream with a sufficient temperature above the steam saturation temperature can be utilized. Typical process applications include:

a. Fluid catalytic cracking unit slurries.
b. Miscellaneous refinery hot oil and vapor streams.
c. Sulfur recovery condensers.

Steam side operating pressures range from 350 kPa(g) (50 psig) – 4,150 kPa(g) (600 psig).

2.3 SYSTEM CONSIDERATION

2.3.1 Heating Medium

The thermal-hydraulic performance and mechanical construction of the equipment to a large degree are dependent on specific characteristics of the hot process fluid. Each fluid has its own unique aspects which must be accounted for in the firetube boiler design to assure reliable operation. For example, increased fluid hydrogen content may significantly increase the heat flux.

2.3.1.1 Fouling

Fouling of the tube inside surface in firetube HRSGs is largely a function of the specific process fluid. It is also dependent on velocity, residence time, tube size and orientation, and wall temperature.

Examples of specific concerns include:

a. Ethylene furnace effluent quench coolers are subject to coke deposition due to continuation of the cracking process at elevated temperature. Therefore, high gas velocities resulting in minimum residence time at temperature are used. Typical fouling factors are 0.00053 m^2-ºC/W (0.003ºF-hr-ft^2/Btu).
b. Hydrogen plant steam/hydrocarbon reformer effluent HRSGs are subject to silica fouling when improper refractories are used in the upstream secondary reformer (for ammonia facilities), transfer lines, or boiler inlet channels. Typical fouling factors are 0.00026 m^2-ºC/W (0.0015ºF-hr-ft^2/Btu).
c. Fluid catalytic cracking flue gas HRSGs tend to foul with catalyst deposits. Typical fouling factors are 0.00088 m^2ºC/W (0.005 ºF-hr-ft^2/Btu).
d. Sulfur recovery plant waste heat boilers/condensers. Typical fouling factors are 0.00053 m^2-ºC/W (0.003 ºF-hr-ft^2/Btu).

2.3.1.2 Velocity

The fluid velocity inside the tubes must meet certain minimum criteria for the specific processes. There are also maximum velocity limitations with respect to the erosive nature of particulate bearing streams. In most cases, however, the velocity is set by maximum pressure drop or by maximum allowable heat flux limits which must be considered in design. The range of acceptable velocities should be specified. Fluid catalytic cracking slurry steam generators are generally designed for a velocity of 1.5 m/s – 2.1 m/s (5 ft/sec – 7 ft/sec) to avoid settling out the solids constituents. For sulfur condensers, rho-v^2 should not exceed 890 kg/m-sec^2 (600 lb/ft-sec^2) to prevent “fogging” of the gas stream. Rho-v^2 is the product of the density of a fluid and the square of the velocity of the fluid. This represents the force the fluid flow is exerting on an area. It is commonly used in heat exchangers to determine if the fluid flow can exert sufficient force on the exchanger tubes to create tube vibration.

2.3.1.3 Pressure Drop

Pressure losses across the tube side of a firetube HRSG are limited by overall system considerations. For instance, the performance of an olefins plant cracking furnace is penalized by excessive backpressure imposed by downstream firetube quench coolers. The typical allowable pressure range for each application should be specified. Sulfur recovery condensers are normally designed for pressure losses of 7 kPa(g) (1 psig) or less, due to the low operating pressure level, and as a result tube diameters of 38 mm (1.5 in.) or higher are often required.

2.3.1.4 Pinch Temperature

The degree to which the heating medium is required to approach the steam saturation temperature strongly affects the HRSG. As the design pinch temperature is reduced, the log mean temperature difference (LMTD) decreases and the surface area requirement increases. HRSGs with large pinch temperatures tend to use larger diameter or shorter tubes than those with small pinch temperatures. The typical pinch temperature range is 8ºC – 14ºC (15ºF – 25ºF).

2.3.1.5 Outlet Temperature Control

Certain processing applications require close control of the heating medium outlet temperature. For instance, secondary reformer effluent in an ammonia plant enters a CO to CO_2 shift reactor after being cooled by the firetube HRSG. Overcooling by the HRSG adversely affects the shift reaction catalyst. For this reason, such firetube HRSGs incorporate a hot gas bypass system, which may be either internal or external to the HRSG. Refer to 2.6.1.13 for further construction details.

The amount of gas bypassed is a function of turndown, extent of fouling, and the design temperature approach. The equipment tends to overcool the heating medium when run at reduced throughput and when clean. HRSGs with large design approaches tend to overcool due to the large approach (serving as thermal driving force) at the outlet end. Such units require large bypass systems for temperature control.

2.3.1.6 Gas Dew Point

Process fluid gas streams which may reach the dew point of one of the gas constituents require special attention. Condensation can occur on cold surfaces such as the tubes and refractory lined walls even though the bulk gas temperature may be above the dew point. If bulk gas cooling below the dew point occurs, as in sulfur recovery boilers, provision must be made to ensure condensate removal. For acid gases, material selection is more important with respect to dew point than condensate removal.

2.3.2 Boiler Feed Water/Steam

Appendices A and B provide general information with regard to the boiler feed water/steam system. Additional considerations unique to firetube equipment are covered in 2.3.2.1 and 2.3.2.2.

2.3.2.1 Heat Flux

Maximum allowable heat flux rates for firetube HRSGs are a function of equipment construction details, steam pressure, recirculation rates, water quality, etc. Specific construction features which affect flux limits include:

a. Tube quantity, diameter and pitch; in general, flux limits are lower for increasing tube quantity or decreasing pitch to diameter ratio.
b. Quantity, size, and location of risers and downcomers.
c. Clearance between bundle and shell.

Actual flux rates for comparison with design limits are based on clean tube surface at the tube inlet where the process fluid is the hottest. Firetube HRSG design should account for increased hot process fluid heat transfer coefficients due to tube entrance effects.

2.3.2.2 Boiler Water Circulation

Critical service, high-temperature firetube HRSGs are furnished with elevated steam drums, from which boiler water is supplied with high circulation rates. Systems may be either natural or forced circulation, with the former being most common.

Low-flux HRSGs may also be furnished with an external drum. However, such HRSG equipment more commonly makes use of an expanded shell-side compartment with the tube bundle submerged in the boiler water. Liquid disengagement occurs above the established liquid level within the expanded shell. Such a unit is commonly referred to as a kelly type boiler. Natural circulation patterns occur within the kettle shell. A water-steam mixture rises through the tube bundle; the vapor rises through the steam/water interface to the steam space above; and the boiler water recirculates back down each side of the bundle to the bottom of the shell. The kettle HRSG shell serves the purposes of a steam drum in a conventional boiler system. It differs from a conventional drum in that the HRSG heating surface is self contained, connections are altered, and steam/water internal flow patterns are different. Saturated steam generated in kettle HRSGs is normally used for non-critical services so that the requirements for purity and quality (see Appendix A) may be relaxed. Therefore, separation is commonly achieved by deflector plates or dry pipes. See 2.6.2.4 for additional shell details.

The HRSG shall include a level control system to ensure that the tubes are always fully submerged and not subjected to dry conditions, as this will create excessive tube wall temperatures and high tube-to-tubesheet joint stress.

2.4 ADVANTAGES OF FIRETUBE OVER WATERTUBE HRSGS

2.4.1 Ease of Cleaning

Tubes containing fouling-prone, hot process streams such as olefins plant cracking furnace effluent, coal gasifier overhead, and fluid catalytic cracking flue gas are easier to clean in firetube HRSGs.

2.4.2 Residence Time

Firetube HRSGs have lower process fluid volume and residence time for services where time at temperature must be limited.

2.4.3 High-pressure or High-temperature Process Fluids or Special Metallurty Requirements

High-pressure process fluids contained on the tube side may minimize HRSG weight in a firetube HRSG. This is particularly beneficial when more expensive, alloy materials are used. For example, ammonia converter effluent can be at 34,500 kPa(g) (5,000 psig) and requires alloy or clad materials. For this example, a firetube HRSG may be preferred.

2.4.4 Vibration

Firetube HRSGs are less susceptible to damaging flow induced tube vibration or acoustic vibration when cooling large volumetric flow rate gas streams.

2.4.5 Refractory Lining

Elevated temperature gas which requires insulating refractory to avoid overheating pressure-containing components is often best handled in firetube equipment. This is particularly true for pressurized gas streams, which cannot be handled in rectangular duct enclosures. Refractory lining in firetube HRSGs is generally required only in the inlet channel compartment. In comparison, shell-and-tube type watertube HRSGs require more extensive refractory linings, which must be engineered to accommodate bundle insertion and removal.

2.4.6 Low Throughput Atmospheric Pressure Flue Gases

Firetube HRSGs are better suited for incinerators and other combustion systems producing relatively low flow rates of near-atmospheric pressure flue gas.

2.4.7 Compact Design

Firetube HRSGs normally require less plot space due to its compact design. Horizontal firetube HRSGs with an external steam drum may have the drum mounted on the shell. The drum is supported by the interconnecting risers and downcomers, thereby eliminating costs associated with independent support.

2.5 DISADVANTAGES OF FIRETUBE RELATIVE TO WATERTUBE HRSGS

2.5.1 High Throughput Atmospheric Pressure Flue Gases

Firetube HRSGs are not well suited for handling large volumes of near atmospheric pressure gases. Streams such as gas turbine exhaust require large cross-sectional flow area as provided by watertube coils installed in rectangular duct enclosures.

2.5.2 Lower Heat Transfer Coefficients

Heat transfer coefficients for flow inside tubes are generally lower than for flow across the tube banks. For this reason, firetube HRSGs tend to require more bare tube surface than watertube HRSGs.

The use of extended surface (fins) against a low-pressure process gas can be an effective means of reducing size. This option is often utilized in watertube HRSGs, but is generally considered impractical for firetube designs.

2.5.3 High-pressure Steam Applications

For cases involving high-pressure steam, typically 10,400 kPa(g) (1,500 psig) and above, firetube HRSGs require heavier wall shell cylinders and tubes. This is particularly true for high capacity systems. For this reason firetube HRSGs in high-pressure steam systems weigh more than their watertube counterparts.

2.5.4 Hot Tubesheet Construction

The hot tubesheet design of firetube HRSGs, particularly its attachment to the shell and the tubes may be complex. The severity of service relates to the coexistence of multiple conditions, such as:

a. High inlet gas temperature.
b. High pressure on the steam side.
c. Loading imposed by the tubes due to axial differential thermal growth relative to the shell.
d. Potential erosive effects of particulate bearing gases.
e. Potential for corrosive attack from the process and steam sides.

The tubesheet is commonly made of Cr-Mo ferritic steels which require special attention during fabrication and testing. Many firetube HRSGs require a thermal and stress analysis to prove the construction acceptable for all anticipated operating conditions.

2.6 MECHANICAL DESCRIPTION

2.6.1 High-temperature/High-flux Units

2.6.1.1 Refractory Lined Inlet Channel

Inlet channels of high-temperature units are internally refractory lined to insulate the pressure components. A number of refractory systems are available including dual and monolithic layers, cast and gunned, or with and without internal liners. Various types of refractory anchoring systems are also used. Metallic needles may be considered as a means to further reinforce the castable.

The selection of refractory materials and their application method must be compatible with the hot side service conditions. The design must account for concerns such as:

a. Insulating capability, including effect of hydrogen content on the refractory thermal conductivity. The presence of hydrogen will increase the thermal conductivity of the refractory.
b. Chemical compatibility with the process fluid.
c. Gas dew point relative to cold face temperature.
d. Erosion resistance against particulate bearing streams.
e. Potential for coking under ferrules.

2.6.1.2 Channels

Several channel construction options exist. The gas connections may be in-line axial or installed radially on a straight channel section. In-line is preferred for designs with low-pressure drop to ensure complete distribution of gas to all tubes. The channel should be designed to minimize flow turbulence and erosion of the refractory liner, if present. Access into the channel compartment is generally through a manway in large diameter units, or through a full access cover in small units.

2.6.1.3 Tubesheets

The single most distinguishing feature of high-temperature firetube HRSGs is the thin tubesheet construction. Conventional shell-and-tube exchangers operating at moderate temperatures incorporate tubesheets traditionally designed according to the requirements of TEMA, prior to 2004. However, ASME Section VIII, Division 1 Part UHX has replaced the TEMA method for tubesheet design. Typical tubesheet thicknesses in such units range from 50 mm (2 in.) – 150 mm (6 in.) or more. Use of TEMA or ASME Part UHX tubesheets in high-temperature, high-flux (severe service) firetube HRSGs is not recommended because the tubesheet metal temperature gradient would be excessive and high stresses would result.

The thin tubesheet design is based on the use of the tubes as stays to provide the necessary support for the tubesheets. Tubesheet thicknesses typically range from 16 mm ($^5/_8$ in.) – 38 mm ($1^1/_2$ in.). Flat portions of the tubesheets without tubes must be supported by supplementary stays. It is no longer possible to build an ASME *Boiler and Pressure Vessel Code*, Section VIII, Division

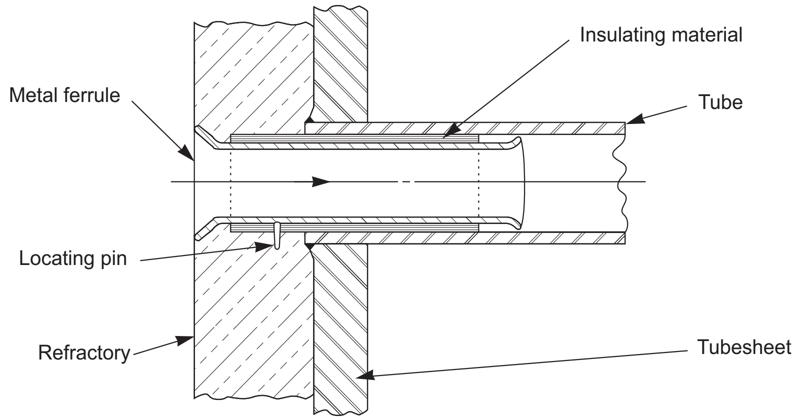


Figure 4—Insulated Metal Ferrule

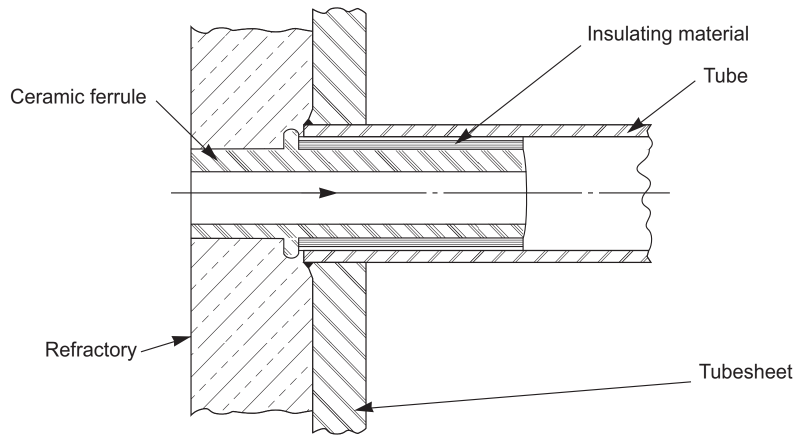


Figure 5—Insulated Ceramic Ferrule

1 HRSG with a thin, flexible tubesheet. Part UHX is now mandatory. The HRSG may have to be constructed to ASME *Boiler and Pressure Vessel Code*, Section I, or Section VIII, Division 2, in order to permit use of a thin tubesheet.

Sufficient cooling of the tubesheet depends on efficient heat transfer at the tubesheet backface by shell-side vaporization of water and high local circulation rate. This offsets the heat input from the gas through the front face and, more importantly, the area created by all the tube hole perforations. The steady state tubesheet temperature is dependent on the tube pitch to diameter ratio and the tubesheet thickness. In vertical units, design provisions should be included to avoid steam blanketing at the hot tubesheet.

Tubesheet temperature can be further minimized by limiting heat flow to the tubesheet with the use of insulated ferrules inserted in each tube inlet. The ferrules project 75 mm (3 in.) – 100 mm (4 in.) from the tubesheet face. The space between the ferrules is packed with refractory, which secures the ferrules and insulates the tubesheet face. Ferrules are either a high-temperature resistant metallic or ceramic material, wrapped with an insulating paper for a lightly snug fit in the tube bore. Overcompression of the insulation will reduce its effectiveness. Figures 4 and 5 show details of one style each of a metallic and ceramic ferrule. Other configurations have been used.

2.6.1.4 Tube-to-tubesheet Joints

The tube-to-tubesheet joints must provide a positive seal between the process fluid and the water-steam mixture under all operating conditions at their resulting pressure and thermal loads. The joints must also withstand transient and cyclic conditions. The tube hole tolerance should be as per TEMA, Table R-7.41, special close fit.

Tube-to-tubesheet joints in severe service applications are typically strength welded using one of the following configurations:

a. *Front (tubeside) face weld*: The tubesheet may be J-groove beveled (see Figure 6A) or the tube may be projected from the flat face, then welded with a multiple pass fillet (see Figure 6B). Additionally, each tube is pressure expanded through the thickness of the tubesheet except near the weld and not within 3 mm (1/8 in.) from the backside (shellside) face of the tubesheet. Such joints may be used in elevated gas temperature applications generating steam at pressures to approximately 6,900 kPa(g) (1,000 psig).

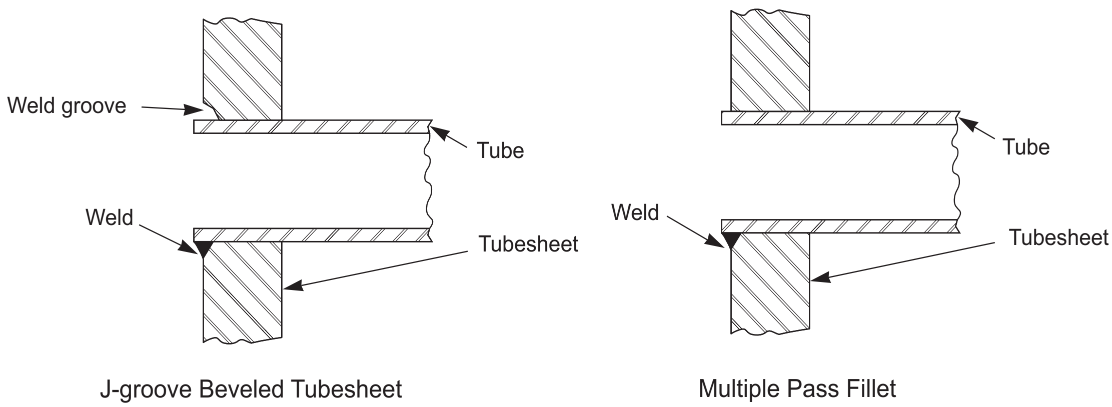


Figure 6A

Figure 6B

Figure 6—Conventional Strength Weld

b. *Full-depth weld*: A deep J-groove with minimum thickness backside land is welded out with multiple passes as per Figure 7. Provided the land is consumed and fused, the tube and tubesheet become integral through the full tubesheet thickness. Full-depth welded joints are often specified for high-temperature gases generating steam at pressures above 6,900 kPa(g) (1,000 psig).

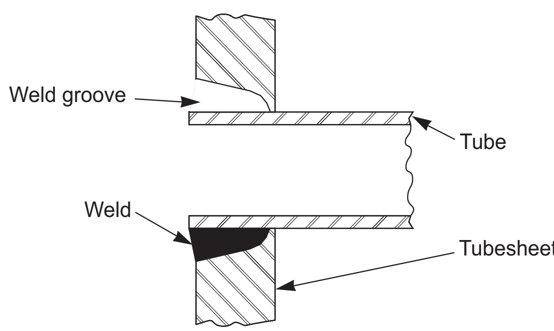


Figure 7—Full-depth Strength Weld

c. *Back (shell-side) face weld*: This type of joint is often called an internal bore weld, in that the welding is performed by reaching through the tubesheet tube hole (see Figure 8). It has been applied to a wide range of firetube HRSG operating conditions, including high-pressure steam systems. A particular characteristic of this joint is that its integrity can be verified by radiographic examination. A mock-up test is suggested for this type of weld to facilitate macro-examination and to confirm complete fusion has been achieved, with the proposed configuration and weld procedure. A tensile pull test may also be considered.

A distinct advantage of the full-depth and internal bore joints listed above is their lack of a crevice between the tubesheet and tube outer surface. A crevice, if present, is subject to accumulation of boiler water impurities. In high-temperature service, the insulating effect of a buildup of such material can result in crevice corrosion and mechanical failure of the joint.

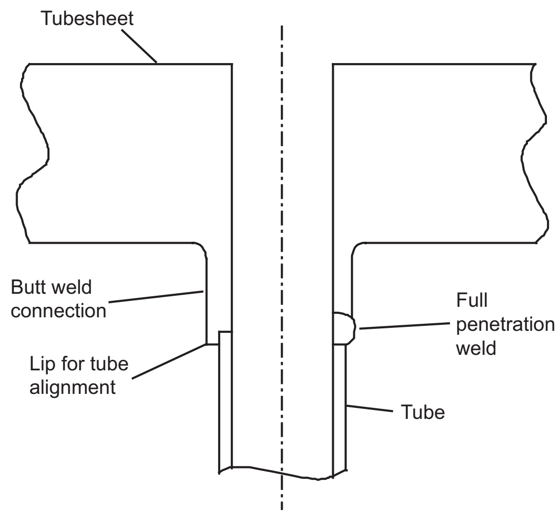


Figure 8—Back (Shell-side) Face Weld

2.6.1.5 Tubesheet Peripheral Knuckle

A thin tubesheet is generally attached to the shell with a peripheral knuckle between the flat (tubed) portion and the point of attachment to the outer shell (see Figure 9). The knuckle provides this critical joint with the necessary flexibility to absorb the axial differential movement between tubes and shell caused by operating temperatures and pressures. Proper design of the knuckle is essential for reliable operation of a firetube boiler.

The most severe cases are those involving elevated temperature gases with high-heat transfer rates and with high-steam side pressure. Such conditions impose considerable loads on the knuckles. An example of a severe service application would be reformer effluent in a hydrogen plant used to produce 10,400 kPa(g) (1,500 psig) steam. Examples of less severe services include fluid catalytic cracking flue gas and sulfur recovery plant tail gas where condensers generate steam at 4,140 kPa(g) (600 psig) and below.

2.6.1.6 Channel-tubesheet-shell Interconnection

Numerous configurations are available for the interconnection of the thin tubesheet with the HRSG shell and the gas inlet channel. Figures 9A through 9H illustrate a number of these. Selection depends on factors such as:

a. Extent of tube versus shell differential thermal growth.
b. Steam pressure.
c. Process gas pressure.
d. Materials of construction.
e. Vertical versus horizontal HRSG orientation.

Joints shown in Figures 9A and 9B are used for mild services only; due to the fillet weld attachment and accompanying crevice. Figures 9C through 9F all have a butt welded attachment to the shell. The flanged construction of Figure 9F permits channel removal. Figure 9G is used for high-pressure steam service and Figure 9H is well suited for vertically installed units.

2.6.1.7 Tubesheet without Peripheral Knuckle Configuration

A proprietary firetube HRSG design utilizes a stiffened thin tubesheet which eliminates the peripheral knuckle. Rather than relieving the tube axial loads with flexible knuckles, the loads are transmitted directly to the HRSG shell through a stiffening system which backs up the thin tubesheet. This design may permit the use of longer tubes. The differential movement absorbed by the knuckles of a conventional firetube HRSG tubesheet is proportional to the tube length. For such HRSGs a length limit exists, beyond which the knuckles would be incapable of accepting the imposed loads within stress limits of the material.

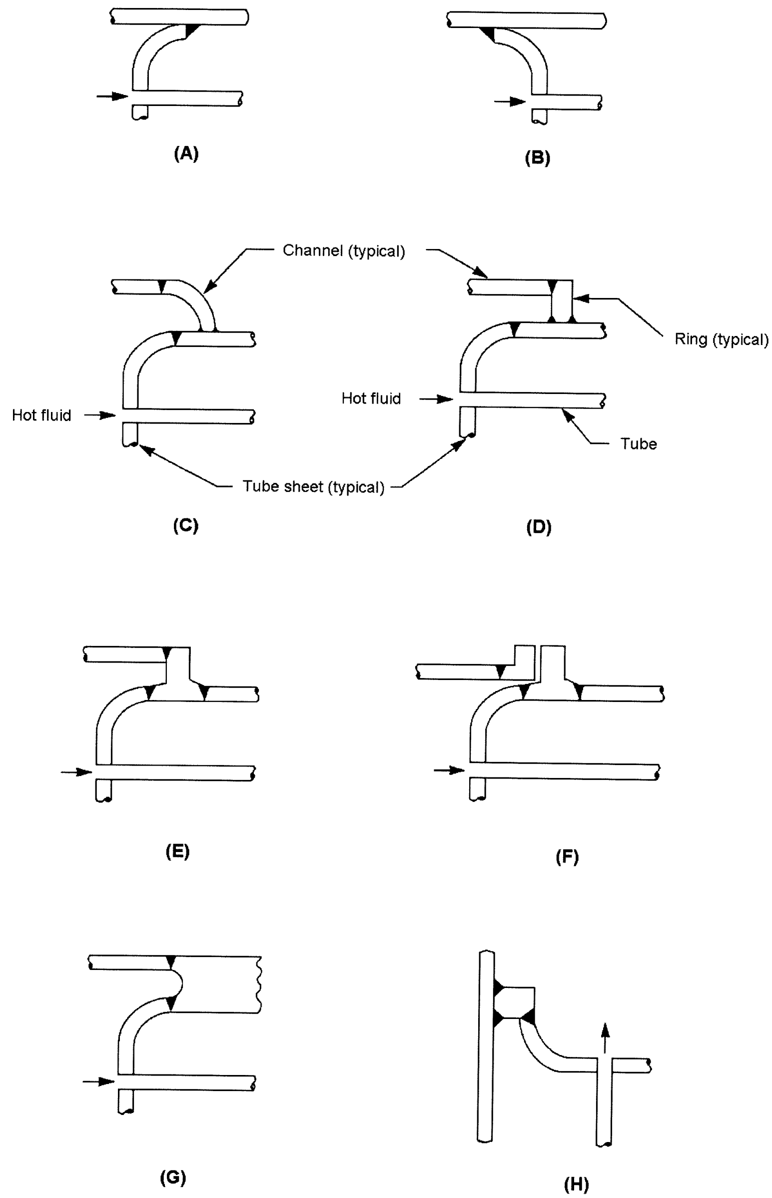


Figure 9—Channel-tubesheet-shell Interconnection

2.6.1.8 Dual Compartment Firetube HRSGs

The length limitation described in 2.6.1.7 is of significant concern primarily with high-temperature, high-flux, and high-steam pressure equipment. For such cases the option exists to use dual compartment construction. Two firetube HRSGs, each with conventional knuckled tubesheets, are installed in series, as shown by Figure 10.

The two compartments may be served by a common steam drum. Advantages of this configuration include:

a. Reduces differential growth between shell-and-tubes within each compartment.

b. Permits optimization of heat transfer surface through utilization of different tube diameters and lengths in each compartment, thereby reducing the total surface required.

c. Permits locating the internal bypass system in the second compartment, thereby subjecting the control components to less severe temperature conditions.

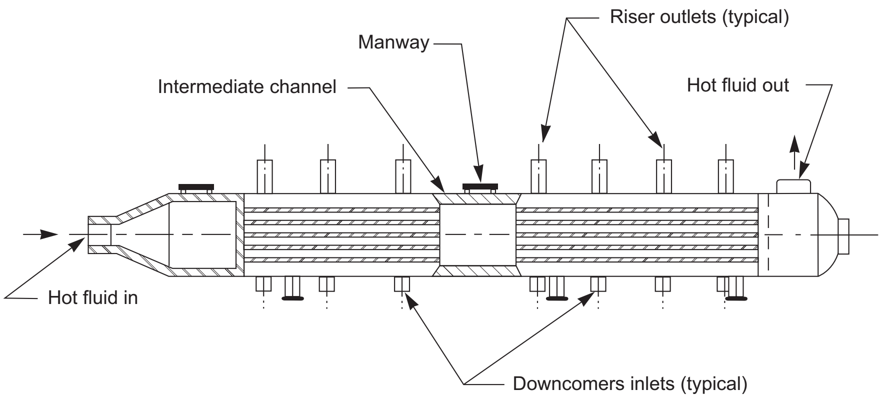


Figure 10—Dual Compartment Firetube HRSG

2.6.1.9 Tubes

Typical tube diameters in high-temperature firetube HRSGs range from 32 mm (1.25 in.) – 100 mm (4 in.). Use of relatively large tubes permits the following:

a. Low-pressure drop application typical of low-pressure process gas streams such as tail gas of sulfur recovery plants.
b. Thermal design at lower heat fluxes.
c. Installation of tube inlet ferrules without over-restricting the flow area available at each tube entrance.
d. Limit the potential for plugging of tubes in services prone to fouling.

The minimum tube wall thickness is governed by applicable code rules. Except for cases involving very high process gas pressures, the steam pressure which acts externally generally controls the minimum tube thickness. A corrosion allowance should also be considered in selection of tube wall thickness.

2.6.1.10 Tube Arrangement and Spacing

Tubes are normally arranged on a triangular pattern to provide the smallest shell diameter, although square layouts may also be used.

The selection of tube pitch should address the following concerns:

a. The maximum allowed heat flux is a function of the tube pitch to diameter ratio. Decreasing the pitch to diameter ratio reduces the allowable design flux.
b. The tubesheet metal temperature is also dependent on the tube pitch. Decreasing the pitch increases the metal temperature.
c. A minimum tubesheet ligament width between adjacent tubes is required for welded tube ends to physically accommodate the tubesheet J-groove weld preparations. This is particularly significant for full-depth welded joints.

2.6.1.11 Multiple Tube Passes

Most high-temperature process firetube HRSGs are of single tube pass construction. However, multiple pass tubes may be considered for processes involving near atmospheric pressure gases used to generate low-pressure steam. The low-heat transfer coefficients characteristically associated with such gases result in tube metal temperatures which very closely approach the steam saturation temperature. Therefore, the metal temperature difference and differential thermal growth of tubes of different passes are minimal. Hot pass tubes are typically larger diameter than subsequent passes in order to optimize heat transfer within pressure drop constraints. Figure 11 illustrates a two tube pass high-temperature firetube steam generator.

2.6.1.12 Baffles

In vertical firetube steam generators, it is important to select a type of baffle that does not block the flow of water. If the flow of water is blocked, the underside of the baffle could steam blanket and cause the tube surfaces to dry out. This could lead to overheating or corrosion of the tubes. Rod baffles, egg-crate type baffles, etc., or suitably designed conventional baffles, may minimize these issues.

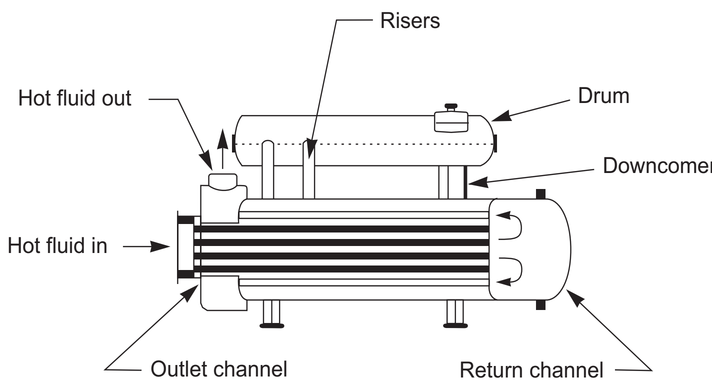


Figure 11—Two Tube Pass Firetube HRSG

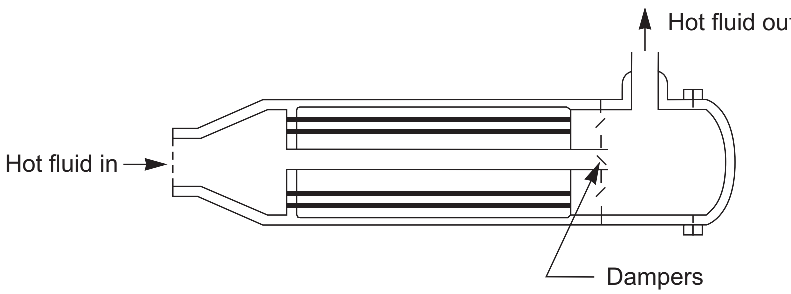


Figure 12—Internal Bypass System with Valve and Dampers

2.6.1.13 Gas Bypass Systems

Gas bypass systems for boiler outlet temperature control may be external or internal to the boiler. Internal bypasses are commonly used because they take advantage of cooling the bypass pipe with boiler water. The pipe may be internally insulated to assure that the metal temperature is maintained close to the water temperature. In high-steam pressure applications the pipe may be attached to a transition knuckle in each tubesheet to absorb axial loads. The pipe is located in the center of the tube layout to provide for axisymmetric distribution of loads.

An automatically-controlled valve is furnished at the outlet end of the gas bypass pipe. To reduce the size of the pipe and valve and to increase the flow control range, a plate with adjustable dampers may be installed in the outlet channel. By setting the dampers to a more closed position, the additional pressure drop imparted to the main gas stream encourages flow through the bypass. The outlet channel should be refractory lined or provided with internals to preclude the possibility of impingement of hot bypass gas on the channel wall. A typical internal bypass system is shown in Figure 12. Other systems are available.

2.6.1.14 Risers and Downcomers

Adequate quantity and size, and proper location of risers and downcomers are essential for reliable operation of high-temperature, high-flux firetube HRSGs. Setting the steam drum elevation, sizing the interconnecting circulation piping, and positioning the connections are an integral part of the design.

Riser and downcomer design and connection positioning depend on boiler orientation. Horizontal firetube HRSGs are usually furnished with multiple risers and downcomers. Connections are positioned to serve zones of equal steam generating capacity. For single pass boilers the connections tend to be more closely spaced at the hot end, due to the high-temperature differential and high-heat transfer rates at this location. This is where a significant portion of the steam is generated. A high circulation ratio is desired in this region to avoid “vapor locking” due to unstable two-phase flow. At least one riser and downcomer pair should be located as close as possible to the hot tubesheet, but the actual number and size of risers and downcomers should be selected in conjunction with the available pressure drop to give the correct circulation flow.

The system should be designed for the design flow rate and the specified turndown flow, normally 30%. The downcomer flow velocity should normally be restricted to a maximum of 1.5 m/s (5 ft/sec).

Vertical units have one or more downcomer connections located at the bottom of the boiler shell. Of greater significance, however, is the construction at the top which must ensure ample and continuous wetting of the entire shell side face of the tubesheet. The following construction options may be considered to help avoid vapor blanketing beneath the upper tubesheet.

a. Multiple riser connections installed around the full circumference as high on the shell as possible.
b. Reverse knuckle tubesheets to permit further elevation of the riser connections relative to the tubesheet (see Figure 9H).
c. Special baffling under the tubesheet to direct water across the back face of the tubesheet.
d. Special formed or machined upper tubesheet with a slight taper from the center upward to the periphery.
e. Installation of the entire boiler slightly canted from true vertical such that the tubesheet slopes slightly from horizontal upward toward the risers which are located on that side.

2.6.2 Kettle Steam Generators

Kettle steam generators are horizontally installed units with an enlarged shell side boiling compartment diameter relative to the tube bundle. The bundle penetrates through either a port opening in a conventional head, or the small end of an eccentric conical transition, the latter being more common.

2.6.2.1 Tube Bundle Construction

Tube bundles may be removable or fixed. Removable bundles offer certain advantages. The bundle may be removed for inspection, cleaning, repair, or replacement. Also, removable bundles avoid the differential axial thermal expansion stress which occurs in fixed tubesheet designs.

Removable bundles may be of either U-tube or floating head construction. For fluids prone to fouling or erosive process fluids that may require mechanical cleaning or inspection, the floating-head type is preferred.

2.6.2.2 Tube Size, Arrangement, and Number of Passes

Typical tube diameters are 19.05 mm ($^3/_4$ in.) and 25.4 mm (1 in.), although larger sizes are considered for process fluids prone to high fouling or viscous process fluids such as in sulfur condensers. Tubes are arranged on either a square or triangular pattern. The square arrangement is used if cleaning of the outside tube surface is anticipated, as could be the case for generating low-pressure steam from poor quality boiler water. In such cases 6 mm ($^1/_4$ in.) minimum width cleaning lanes are maintained between tubes. Otherwise, a pitch to diameter ratio of 1.25 is normally used, unless heat flux considerations require a more extended spacing.

Multiple tube passes may be used for all bundle types described under 2.6.2.1, except for cases with extremely long hot fluid cooling ranges which may experience severe thermal stress. Single pass tubes are normally limited to fixed tubesheet construction.

2.6.2.3 Channel Construction

The selection depends primarily on the anticipated frequency of opening the unit for inspection or cleaning. If frequent access is required, a channel with bolted cover plate is desirable. Channels may be according to any of the TEMA designated types.

2.6.2.4 Shell Construction for Disengagement.

A degree of disengagement of liquid is achieved in the steam space above the liquid level. The effectiveness of this volume is a strong function of the free height available. A typical minimum height is 500 mm (20 in.) in steam generating equipment. Units which produce very low-pressure steam or operate at relatively high flux tend to need additional height. Simple dry pipe devices are sometimes used to enhance separation.

A properly sized kettle shell produces steam of adequate quality and purity for most process and heating applications. Higher purity steam may be achieved by the installation of separators in the vapor space above the liquid level, within a dome welded to the top of the kettle, or in the exit vapor line. Types of separators include:

a. Wire mesh pads.
b. Chevrons.

c. Cyclones.
d. Combinations of items a, b, and c.

See Appendix A for further information.

2.6.3 Other Types of Firetube HRSGs

There are many other types of firetube HRSGs designed for a variety of services. They may be further classified as follows:

a. Proprietary designs developed for specific process applications.
b. Boilers designed with thick (TEMA type) tubesheets and external drums. The boilers may be installed in the horizontal or vertical position.
c. Partially tubed horizontally installed boilers as per Figure 13. Tubes omitted from the top portion of the tubesheets provide the steam space for internal disengagement. The channel diameter is larger and the shell diameter is smaller than those of kettle HRSGs. Tubesheets may be thick (TEMA type), or stayed thin type.

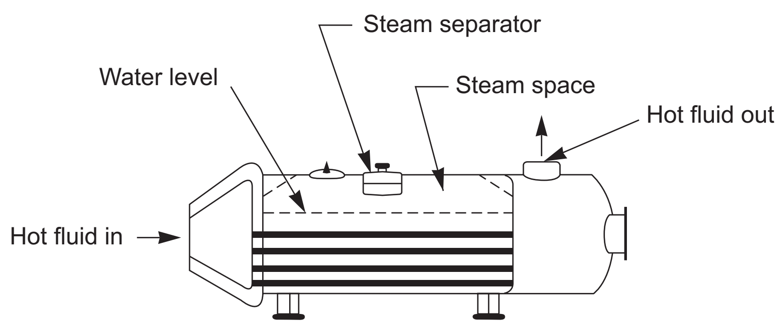


Figure 13—Partially Tubed Firetube HRSG

2.6.4 Code Considerations

Firetube HRSGs are designed in accordance with either ASME *Boiler and Pressure Vessel Code*, Section I or Section VIII, Division 1.

Heavy tubesheet firetube HRSGs were traditionally designed to TEMA requirements, however, the ASME Part UHX method is mandatory as of 2004 and replaces the TEMA method. For high-temperature firetube thin tubesheet designs, the HRSG may have to be constructed to ASME Section I, or Section VIII, Division 2, in order to permit use of a thin tubesheet.

2.6.5 Construction Materials

Materials selected for use in firetube HRSGs must be compatible with the process fluid, the boiler water and steam with which they will come into contact. The materials must also exhibit mechanical properties consistent with the design requirements of the equipment.

2.6.5.1 Corrosion Resistance

Each process fluid from which heat is being recovered has its own composition and may therefore have its own unique requirements for construction materials. An important factor in materials selection is often resistance to hydrogen attack, because many high-temperature process gas streams have significant hydrogen content. The specification of materials must also account for the possibility of gas cooling below its dew point, and the corrosive acids which may be formed. Cold metal surfaces can cause local condensation, even though the bulk gas may be above the dew point.

Pressure components wetted by boiler water, including tubes and tubesheets, are normally fabricated from ferritic materials. Boiler shells are generally carbon steel. Materials subject to stress corrosion cracking, such as austenitic stainless steels, are normally avoided and are prohibited in the evaporator by ASME *Boiler and Pressure Vessel Code*, Section I.

The relative growth of the shell-and-tubes due to temperature changes is of considerable significance to firetube HRSG design. Materials with similar coefficients of thermal expansion are beneficial. This is another reason for avoiding the use of austenitic tubing.

2.7 OPERATIONAL DESCRIPTION

Safe and reliable operation of firetube HRSGs depends on the development and use of good operating procedures, specific to the process and HRSG design.

2.7.1 Process Side Operation

2.7.1.1 New refractory lining may require a special heating sequence on start-up to effect proper dryout.

2.7.1.2 Firetube HRSGs must not be subjected to hot gas flow without the tube bundle fully covered by boiler feed water.

2.7.1.3 The rate of temperature change during transients should be controlled to minimize the potential for thermal shock.

2.7.1.4 All modes of operation should be evaluated during the design phase, particularly with regard to the ability of the boiler components to withstand the primary and secondary stresses during cyclic operation.

2.7.2 Steam Side Operating Concerns

2.7.2.1 Reliability of Boiler Feed Water Supply

Of primary importance to the successful operation of firetube HRSGs is the reliable supply of boiler water to the heat transfer surface. In the event of boiler feed water supply failure, the control system must shut off the hot stream flow to the HRSG. See Appendix A for further information.

2.7.2.2 Boiler Feed Water Treatment

Boiler feed water chemical treatment must be such that boiler components are protected from waterside corrosion. Improper treatment, or upsets, may cause premature failure. Water treatment specialists are normally consulted. ABMA and/or ASME CRTD guidelines are commonly followed for boiler feed water treatment, allowable concentration of boiler water dissolved solids, blowdown, and steam purity.

2.7.2.3 Continuous Blowdown

Blowdown rates must be used in conjunction with boiler feed water treatment to assure boiler water impurities are maintained at or below recommended maximum concentrations. Continuous surface blowdown is normally accomplished through a perforated collector pipe located just below the water-steam interface or a connection at the shell bottom. Continuous blowdown from kettle HRSGs should be extracted primarily at the end opposite the feed water inlet where impurities would be most concentrated.

2.7.2.4 Intermittent Blowdown

Intermittent blowdown acts to remove settled accumulations of boiler water solids. Connections are located at low points in the shell, particularly in the most stagnant regions. Blowdown valves are operated at prescribed intervals, depending on the effectiveness of boiler water treatment.

2.7.2.5 Liquid Level in Kettles

There is no clearly defined water-steam interface inside the shell. Steam bubbles rise vigorously through the water from the heat transfer surfaces. A density difference exists between the two phase mixture in the boiler shell and the liquid in an external gage glass. To ensure submerged tubes, the water level is normally maintained at 50 mm (2 in.) to 100 mm (4 in.) above the top of the uppermost tube row.

3 Watertube Heat Recovery Steam Generators

3.1 GENERAL

3.1.1 Typical System

The watertube HRSG generates steam inside a number of tube circuits which are heated by a hot gas stream flowing through an enclosure of insulated steel casing plate.

The gas usually flows across the tubes in a single pass from inlet to outlet. In certain cases, baffles or directional vanes may be used to direct the gas across the tubes creating additional gas passes.

Steam generating tubes are connected to drums or headers. The tubes may be arranged in one continuous circuit or may be manifolded at their inlet and outlet ends to form a number of parallel flow paths.

Steam drums may be either integral to the steam generating tube circuit or mounted remotely from the tubes.

Additional tube circuits may be used for preheating feed water or superheating steam.

3.2 APPLICATION

The watertube HRSG is used to recover heat from low-pressure exhaust or flue gases. Some common applications in petroleum related facilities are:

a. Heat recovery from combustion turbine exhaust gas or use in process(es), in enhanced oil recovery and in cogeneration.
b. Heat recovery from fired heater flue gas.
c. Heat recovery from fluid catalytic cracking regenerator flue gas.

The casing should be designed with tight joints, seal welded, to prevent leakage of the gas to the atmosphere. Some minor leakage may occur at casing penetrations where thermal growth must be accommodated.

3.2.1 Horizontal Tube Evaporator

The flow within a horizontal tube evaporator normally may be forced circulation as described in Appendix B, and Figures 14 and 15. The steam drum is mounted remotely from the tubes.

It is possible to establish natural circulation through horizontal tubes by elevating the water outlet from the steam drum sufficiently above the tubes for operating pressures less than about 12,400 kPa(a) (1,800 psia). However, hydraulic resistance and vapor blanketing in the tubes are potential problems. Forced circulation flow has generally been preferred for horizontal tubes historically.

3.2.2 Vertical Tube Evaporator

The flow within a vertical tube evaporator normally is natural circulation as described in Appendix B, and Figures 16 and 17. Downcomers may be external to the gas stream connecting the upper drum and lower drum. Downcomers can also be located within the gas stream. Circulation rates must consider heat input to an internal downcomer.

3.2.3 Inclined Tube Evaporator

The flow within inclined tube evaporator arrangements is from a lower drum or header upward through parallel inclined tubes to a collector drum, header or the steam drum. Natural circulation is utilized, similar to that described for vertical tubes. The slope of the tubes and the configuration of the drums, headers, tubes and exhaust gas path is critical to proper operation of an inclined tube arrangement.

3.2.4 Preheaters, Economizers and Superheaters

In addition to the evaporator, the HRSG may include an economizer section to heat the feed water and/or a superheater section for superheating steam (see Figures 14, 15, and 17). Multiple pressure level HRSGs may have economizers or superheaters for more than one pressure level.

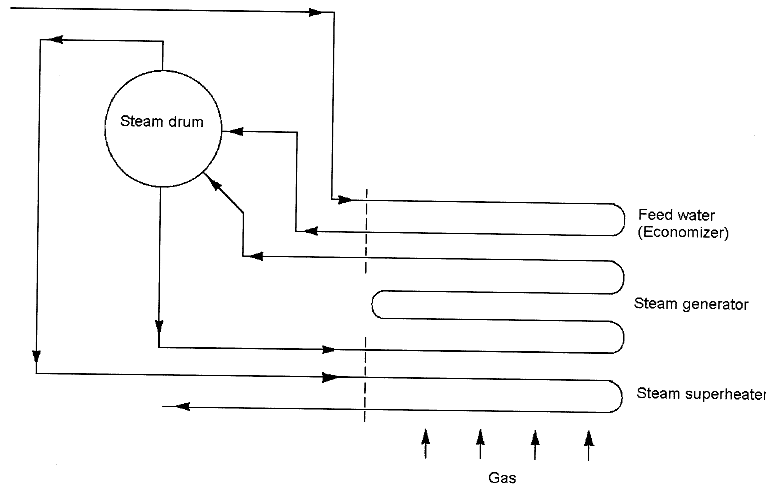


Figure 14—Basic Tubular Arrangement

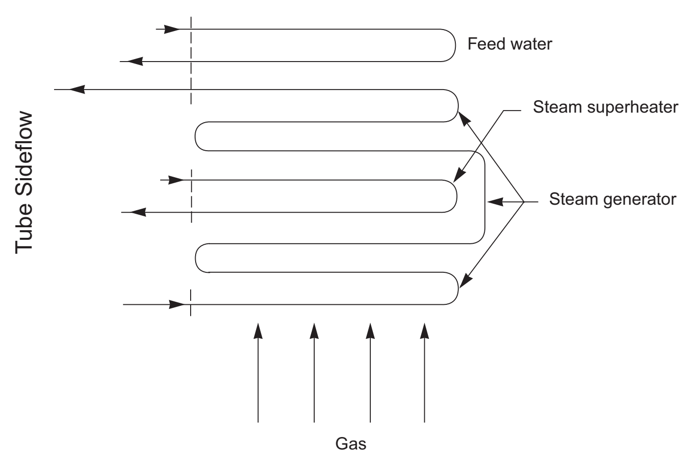


Figure 15—Interlaced Tubular Arrangement

A steam reheater, feed water preheater, or a deaerator/steam-generating coil may be included at appropriate exhaust gas temperature locations.

The exhaust gas normally passes over the superheater, steam generator and economizer (in that order) to optimize the heat transfer effectiveness of the HRSG. Alternative arrangements may be used, such as integrating economizers, evaporators and superheaters of different pressure levels to optimize heat transfer rather than locating the sections of each pressure level together. Superheater sections may be located within steam generator sections to limit superheater tube metal temperatures or the variation of superheated steam temperature with variations in gas flow or temperature.

3.3 GAS TURBINE EXHAUST HRSG

3.3.1 General

The main function of a gas turbine HRSG is to utilize the sensible heat from turbine exhaust gas to generate steam. Supplemental heat input from an internal duct burner is also routinely used to provide additional heat input.

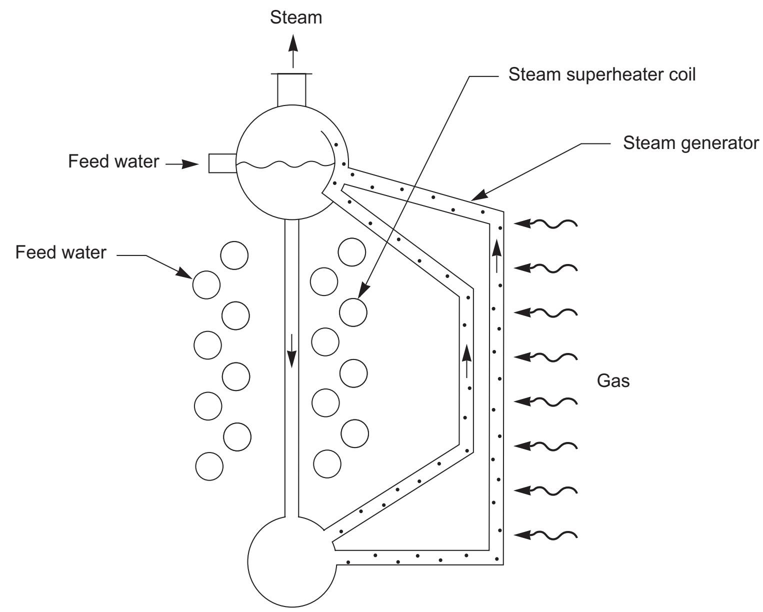


Figure 16—Natural Circulation HRSG

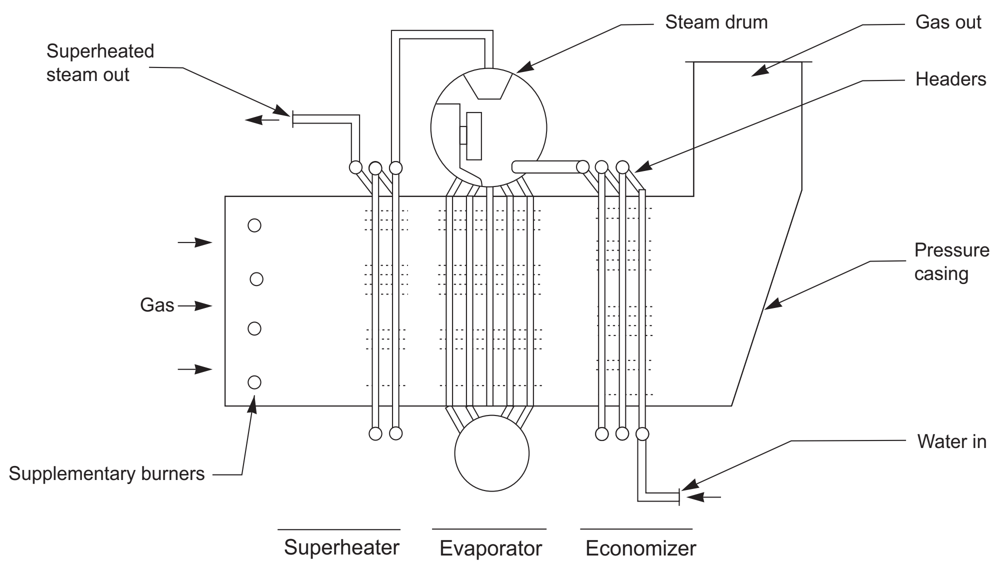


Figure 17—Typical Natural Circulation Gas Turbine Exhaust HRSG

A gas turbine HRSG, in its simplest form, consists of a casing enclosure to collect, contain, direct and conserve the heat in the hot exhaust gas; banks of tubes in which the steam is generated; a steam drum to supply water to the tubes and separate the steam from the steam/water mixture after it has passed through the tube banks; and an exhaust stack.

The two basic types of HRSGs are horizontal and vertical as defined by the direction of the flue gas flow. Single and multi-pressure steam systems are possible. Tube orientation can be in-line or staggered.

Horizontal exhaust flow units are more common than vertical exhaust flow units for larger gas turbines. Most of these incorporate natural circulation. Tubes are arranged vertically.

Vertical units generally require forced circulation. They can occupy smaller footprints than horizontal units. Tubes are arranged horizontally.

Modular design is standard. Modular sections are transported and lifted into place. Module size may be maximized as limited by transportation limits and fabrication plans. A typical HRSG system includes:

- Superheater that heats the steam above saturation temperature.
- Attemporator to control superheater steam temperature.
- Multiple pressure steam generation.
- Economizer to preheat the boiler feed water.
- Steam drum(s), headers, and blowdown system.
- Deaerator (where applicable).
- Interconnecting piping, valves, instrumentation.
- Casing, structure, expansion joints.
- Dampers (where applicable).
- Ladders and platforms.
- Supplementary firing burner and burner management system (BMS) (where applicable) used to provide supplemental heat for peaking conditions or additional steam production.
- Flow distribution grid used to evenly distribute and straighten the flue gas flow where required to:
    - tube banks,
    - supplementary firing burners, and
    - CO and/or SCR catalyst sections.
- Circulation pumps (where applicable).
- Emission reduction equipment e.g., NO_x, CO, noise (where applicable).
- Stack(s).

3.3.2 Type of Circulation

Natural and forced circulation systems each have advantages and disadvantages when compared to the other. Natural circulation systems often have vertical tubes. Forced circulation systems often have horizontal tubes. Specific applications should evaluate how these choices can meet requirements and objectives.

Vertical tubes may require more valves to vent or drain the unit. Horizontal tubes may be more prone to flow stratification.

The elevation of the steam drum is typically higher in natural circulation systems requiring more structure to support it.

3.3.3 Tubes

3.3.3.1 Materials

Tube materials are set by boiler code requirements and calculated tube metal temperatures. Tube metal temperatures are determined by theoretical heat transfer methodology and empirical design margins based upon experience.

Generally, steam generating and economizer tubes are seamless or electric resistance welded carbon steel material. Often, ASME SA-178, SA-106, SA-214 for larger tubes or other comparable carbon steel materials. ASME standards have default testing requirements plus optional tube testing requirements, e.g., flattening tests, crush tests, etc.

Once-through steam generators that produce up to 80% quality steam typically use carbon steel tubes. For generators that produce superheated steam, alloy materials (Cr-Mo alloys or higher alloys like Alloy 800) are used at the hotter end of the coil.

Alloy materials are used for coils that are designed to run dry (reach the temperature of the flue gas stream). Cr-Mo alloys may be used in supercritical steam applications.

Deaerator feed water preheat coils are carbon steel when the oxygen content of the water is less than 20 ppb. When the internal water oxygen content is equal to or greater than 20 ppb, a ferritic or duplex stainless steel should be used.

Superheater tubes may be stainless steel, low chrome alloy, or carbon steel. Material choice depends upon calculated tube metal temperature. HRSG design pressure, tube metal temperature, and the sequential layout of superheater arrangement in relation to flue gas direction and steam generation tubes affect superheater tube material choice.

Superheater tubes, steam generating tubes, and economizer tubes are manufactured with or without intermediate butt welds. Specifying no intermediate butt welds eliminates one possibility of failure. The choice whether to allow intermediate butt welds is an Owner preference decision.

3.3.3.2 Size

Tube sizes are affected by calculated tube metal temperature, pressure drop requirements, design pressure, extended tube surface used, and other factors. Tube sizes may normally vary between 25.4 mm and 76.2 mm (1 in. and 3 in.) for HRSGs that generate saturated steam with or without superheat. HRSGs that produce less than 100% quality steam may use larger tube sizes to reduce pressure drop.

3.3.3.3 Tube Damage

User experience with HRSG tubes can vary, from nearly no problems to many tube failures. It is important that the operating requirements of the particular installation be provided to the designer. This includes cycling, start-up, short-term and steady-state operations. The non steady state cases may determine the physical design of many components.

The tubes are normally finned and access to the tubes and headers is often restricted. Finned tubes make ultrasonic and eddy current testing more difficult. Tube bends and tube-to-header/drum joints are more frequently susceptible to failure.

Tubes should be designed to allow complete drainage. Not draining tubes during start-up and shutdowns may allow condensate to accumulate within the tubes, particularly in superheaters and reheaters, causing flow restrictions and increasing thermal stress on the tubes.

Corrosion fatigue, thermal fatigue, general corrosion, creep, creep fatigue, and overheating are other mechanisms of tube failures in HRSGs. Refer to the *Guidelines for the Operation and Maintenance of HRSGs* for additional information on failure mechanisms and solutions.

3.3.3.4 Tube Supports

Vertical tube HRSGs are generally constructed without intermediate tube supports. This HRSG design arrangement has the tubes hung from headers at the top of the HRSG, and the tubes grow vertically downward. However, this design arrangement using long tubes is subject to flow induced tube vibration and resonant acoustic vibration considerations. HRSG vendors have developed intermediate baffles that are used to mitigate such vibrations.

3.3.4 Superheater

Superheaters may contain both bare and extended surface tubes. Exact configuration and combinations depend upon meeting HRSG design requirements.

Superheaters should be drainable. Drains should be sufficient in capacity to prevent the passing of liquid slugs through the superheater during gas turbine start-up and during coast-down following a trip event.

Superheater headers and tubes should be designed to ensure balanced flow between passes within a specified tolerance.

Base load and cycling service affect superheater design. Variables may include gas turbine load and cycling, ambient temperatures, duct burner firing temperature, and steam pressure. Such variables affect superheater tube metal temperature design margins. A tight tolerance requirement on superheater outlet limited operating temperature may require increased heat transfer surface, additional desuperheaters, desuperheater supply source by either water or steam, heat transfer surface bypass capability, split superheater design, nesting the superheater tube surfaces within steam generator sections, etc.

Procedures for replacing any superheater tubes and for replacing the entire superheater should be determined during the design phase.

3.3.5 Evaporator Sections

Evaporator coils will normally contain extended surface tubes, except that bare tubes are often used if located upstream of the superheater. Exact configuration and combinations depend upon meeting HRSG design requirements.

Evaporator coils should be completely drainable.

Steam generator tubes, headers, downcomers and risers should be designed to a minimum circulation ratio. See Appendix B for more guidance.

Procedures for replacing any evaporator tubes and for replacing the entire steam generator should be determined during the design phase.

3.3.6 Steam Drum

The steam drum internals shall be designed to accommodate a steaming economizer when required.

See Appendix A for details on steam drums.

3.3.7 Economizer

The economizer will contain extended surface tubes. Exact configuration and combinations depend upon meeting HRSG design requirements.

Economizer coils should be completely drainable.

Procedure for replacing any economizer tubes, and for replacing the entire economizer should be determined during the design phase.

The approach temperature should be large enough to preclude economizer steaming for all on-line operating conditions, including low gas turbine loads or no-duct-firing conditions. In the event that start-up or other operating conditions result in a steaming economizer, the steaming condition must not impair required steam quality, cause vapor lock, cause HRSG damage or otherwise impair HRSG operation. Design mitigation possibilities for economizer steaming may include economizer header vent valves, bypass valves, or recirculation. Coil damage, water hammer, etc. can occur if an economizer is not properly designed for steaming. The possibility of steaming in an economizer should be evaluated for various off-design conditions including combustion turbine part load, supplemental firing variations, single vs. multiple HRSG operation (if applicable), and floating outlet pressure variations

3.3.8 Other Heat Transfer Services

In order to increase the energy recovery of an HRSG, additional types of heat transfer services are sometimes provided. These may include such things as feed water heaters, fuel gas preheaters, refinery process coils, etc.

3.3.9 Cleaning Provisions

3.3.9.1 Methods of Cleaning

- *On-line mechanical cleaning*. This form of cleaning is performed with the generator in steam production and is typically used for outside tube cleaning. On-line mechanical cleaning typically includes methods such as sootblowing and acoustics.
- *Off-line mechanical cleaning*. This form of cleaning is performed with the generator idle and is typically used for outside tube cleaning. Off-line mechanical cleaning typically includes methods such as scraping or power blasting.
- *Chemical cleaning*. Typically, this form of cleaning is performed with the generator idle or in limited production and targets the inside of the tubes.
    - *Fill and drain method*. The coils are filled and vented with a reactive chemical. After a reaction period, the solution is drained. Additional fill and drain cycles are used until the tubes are acceptably clean.
    - *Circulation method*. Circulation is started after the coils are filled with a reactive chemical. The strength of the solution is monitored and augmented and/or drained to maintain reactivity until the tubes are acceptably clean.

3.3.9.2 Reasons for Cleaning

- *Initial tube cleaning*. Tube mill scale, oil and dirt should be removed from the inside of the tubes prior to placing a new unit in service to avoid local overheating of the tubes.
- *Loss of performance*. Deposits will reduce the heat transfer rate, lower the unit capacity increase static pressure loss, and can result in tube corrosion in economizers due to reduced tube temperature.
- *Inside tube deposition*. Poor water chemistry will speed the rate of deposits left on the tube wall. Water deposits will cause increased tubewall temperatures and can increase under deposit corrosion.
- *Outside tube deposition*. Ash and inorganic material in the fuel and ammonia salts can deposit on the tubes.
- *Preventative maintenance*.

3.3.9.3 Facilities Required for Cleaning

Chemical cleaning requires nozzles for adequate filling, draining, and circulation rate.

- Vents and drains should be provided on all high points and low points such as headers and crossovers.
- Circulation nozzles should be provided on both ends of each section. Evaporators may need to be cleaned separately from other sections.
- Circulation nozzle should be sized to provide some circulation to all tubes despite uneven tube deposition thickness.
- Chemical cleaning nozzles should be accessible without shutting down the generator.
- Dew point corrosion, freeze protection, and thermal expansion should be considered in chemical cleaning nozzle design.

Sootblowers should be considered for HRSGs used with ash producing fuels and fuels containing inorganic particles. See Appendix C for additional information on sootblowers.

Manways should be provided for all sections of the HRSG to allow external tube inspection and cleaning.

Inspection (or access) doors should be considered for cleaning access to tight tube banks.

3.3.10 Process Design Considerations

3.3.10.1 Circulation of Water and Steam

Water circulation within the steam generator section(s) of an HRSG can be by natural or forced type circulation. See Appendix B.3.

3.3.10.2 Flue Gas Pressure Drop

Flue gas side pressure drop is an important design criteria as the addition of about 100 mm (4 in.) of water column pressure drop will cause about a 1% decline in the power output of the gas turbine. A cycle designer determines gas side pressure drop allowance for the HRSG based on an acceptable combustion turbine-generator power loss. The HRSG supplier provides the design to satisfy the specified pressure drop allowance. Flue gas pressure drop requirement defines the HRSG size and cost. Identical steam production can be met with an HRSG designed for 200 mm (8 in.) H_2O pressure drop or 300 mm (12 in.) H_2O pressure drop. Flue gas pressure drop will also increase with the presence of a duct burner and diverter. If the allowable exhaust gas pressure drop is low, the HRSG will be taller and/or wider with a more open cross section area, which means more surface for the same steam production and higher cost.

3.3.10.3 Flue Gas Cold End Temperatures

Consideration of the flue gas dew point temperature should be given in determining the amount of heat removal in the HRSG and boiler feed water inlet temperature to avoid dewpoint corrosion.

3.3.10.4 Pinch and Approach Temperatures

As the pinch temperature decreases and the flue gas temperature nears the saturation temperature, significant additional surface area is required with diminishing heat recovery and increasing flue gas pressure drop. As the approach temperature decreases, the potential for generating steam in the economizer coil increases. Arbitrary selection of pinch and approach temperature is generally not a good idea. It should be done with a detailed evaluation of the HRSG. This should include fuel costs, price of heat transfer surface, size of the equipment, use of the steam, etc. Some typical values are found in Table 1 for a single pressure HRSG within a petrochemical facility. A non-steaming economizer is assumed.

Table 1—Typical Pinch and Approach Temperatures

Item	Pinch Temperature, °F (°C)		Approach Temperature, °F (°C)
Evaporator Type	Bare Tubes	Finned Tubes	
Flue gas in: 1200°F – 1800°F (650°C – 980°C)	130 – 150 (70 – 85)	30 – 60 (17 – 33)	40 – 70 (22 – 40)
Flue gas in: 750°F – 1200°F (400°C – 650°C)	80 – 130 (45 – 70)	10 – 30 (6 – 17)	20 – 40 (11 – 22)

3.3.10.5 Multiple Pressure Levels

The efficiency of the HRSG can be improved by generating steam at multiple pressure levels. Reduction of exhaust temperature is limited by the saturation temperature in a single pressure level system. The remaining exhaust energy is available at a lower temperature to generate steam at a lower saturation temperature in a multiple pressure system. High-pressure steam can be generated for steam turbine generator consumption or plant steam production. Lower pressure steam may be used directly by the plant. In some situations, lower pressure steam is used for NO_x reduction by injecting it into the gas turbine. Low-pressure steam is commonly used for deaeration. One to three pressure levels of steam generation have been used. Multiple stages of superheaters, evaporators and economizers are placed in-series or parallel to each other at various exhaust gas temperature locations for optimum performance and heat recovery.

3.3.11 Internal Lining/Insulation/Refractory System

3.3.11.1 General

Refractory and insulation systems should be designed for a maximum outside casing temperature of 82°C (180°F) in still air at an ambient temperature of 27°C (80°F). Personnel protection should be provided in appropriate locations.

Refractory and insulation systems should be designed for proper expansion of all parts.

All refractory or insulation components directly exposed to the flue gas should have a refractory design temperature of at least 111°C (200°F) above the maximum flue gas temperature in contact with the surface. The inner liners shall be designed for a temperature at least 111°C (200°F) above the maximum flue gas temperature in contact with the surface.

Refractory and insulation anchor materials may be carbon steel up to 427°C (800°F), 304 SS up to 760°C (1400°F) and 310 SS up to 927°C (1700°F) anchor design temperature. The anchor design temperature may consider the temperature profile within the lining. Purchaser should approve use of other materials.

3.3.11.2 Cold Casing Fibrous Insulation Construction

Fibrous insulation may be used in all HRSG areas, except stacks. This type of construction is typically provided with an inner liner installed over the fibrous insulation.

Fibrous insulation blanket shall be a minimum of 100 kg/m^3 (6 lb/ft^3) density, needled material. Fibrous insulation may be provided in layered or in module type construction. The minimum blanket thickness of each layer should be 25 mm (1 in.). Multiple layers should have staggered seams.

Fibrous insulation should have a refractory service temperature at least 170°C (300°F) above its refractory design temperature.

Inner liner should be fabricated from overlapping plates of 3 mm ($^1/_8$ in.) minimum thickness material. Liner support studs should be designed to allow expansion of liner and prevent buckling. Liner design on the floor should consider maintenance loads. Studs should be a minimum of 13 mm ($^1/_2$ in.). Shoulder studs should be a minimum of 19 mm ($^3/_4$ in.) diameter below the shoulder and should have a 13 mm ($^1/_2$ in.) diameter tip for the liner washers. Studs should be spaced at not less than 300 mm (12 in.) centers near the gas turbine discharge and not less than 600 mm (24 in.) centers in other areas. In addition, there are many other critical design parameters such as liner overlap, edge stud spacing, fix points and guide points, etc. that must be incorporated into a good liner design.

Liner plate and pins may be carbon steel up to 425°C (800°F), 409 SS up to 650°C (1200°F), 304 SS up to 760°C (1400°F) and 310 SS up to 930°C (1700°F) design temperature. Purchaser should approve use of other materials.

Fibrous insulation blankets should be anchored separately from liner studs to prevent, vibration induced, settling of fiber within the walls. The insulation pin spacing should not exceed a square pattern of 200 mm (8 in.).

When fibrous insulation construction is used with fuels having a sulfur content exceeding 10 parts per million (ppm), the inner casing should have an internal protective coating to prevent corrosion. The protective coating should be rated for 175°C (350°F) service temperature. Anchors shall be installed before applying protective coating to the casing.

When the fuel sulfur content exceeds 500 ppm, an externally insulated “hot casing” design should be used or the inner liner must be seal welded to prevent flue gas contact with insulation. Special consideration for expansion must be used with seal welded inner liners.

3.3.11.3 Castable Construction

Hydraulic-setting castables may be used as lining for HRSGs when approved by purchaser. Minimum castable construction is a 1:2:4 volumetric mix of lumnite-haydite-vermiculite limited to a maximum service temperature rating of 1040°C (1900°F) and clean fuel applications. This castable should be limited to 200 mm (8 in.) maximum thickness on arches and walls.

For dual layer castable construction, the hot face layer should be a minimum of 75 mm (3 in.) thick. The anchoring systems should provide independent support for each layer when in arch or other overhead position.

Anchoring penetration should not be less than 70% of the individual layer being anchored for castable thickness greater than 50 mm (2 in.). The anchor should not be closer than 13 mm ($^1/_2$ in.) from the hot face.

The anchor spacing should be a maximum of three times the total lining thickness but should not exceed 300 mm (12 in.) on a square pattern for walls and 225 mm (9 in.) on a square pattern for arches. The anchor orientation should be varied to avoid creating continuous shear planes.

Anchors for total castable thickness up to 150 mm (6 in.) should be a minimum of 5 mm ($^3/_{16}$ in.) diameter. Greater thickness requires a minimum of 6 mm ($^1/_4$ in.) diameter anchors.

Castable linings in header boxes, breechings, and lined flue gas ducts and stacks should not be less than 50 mm (2 in.) thick.

Anchors in 50 mm (2 in.) thick castable lining should beheld in place by 10 gauge minimum, bare carbon steel chain-link fencing, wire mesh, or linear anchors welded to the steel.

When metallic fiber is added for reinforcement it should only be used in castables of 969 kg/m^3 (55 lb/ft^3) or greater density. Metallic fibers should be limited to no more than 3% by weight of the dry mixture.

Low iron content materials should be used when total heavy metals content within fuels exceeds 100 ppm.

Castable refractory should have a refractory service temperature at least 170°C (300°F) above its refractory design temperature.

3.3.11.4 Hot Casing Construction

Another lining system is a hot-casing type construction. In this system, a high-temperature material is used for the pressure casing and insulation and lagging is installed externally to the hot casing.

This has the advantage that the insulation is not in contact with the flue gases and the flue gases will not condense on the casing.

Disadvantages of this system are the need to design the casing for the flue gas temperature. Thermal expansion of the casing is also a concern.

A combination of internal and external insulation could be used. However, difficulty in monitoring the condition of the casing makes this system more difficult to maintain.

3.3.12 Casing and Structural

3.3.12.1 General

Structural steel shall be designed in accordance with the applicable provisions of the applicable codes.

Wind loads and earthquake loads shall be as specified. Wind load from external piping, pipe insulation, platforms, and other attached equipment shall be considered in establishing the net area of wind exposure.

Structures and appurtenances shall be designed for all applicable load conditions expected during shipment, erection, and operation. Cold weather conditions shall be considered, particularly when the HRSG is not in operation. These load conditions shall include, but are not limited to, dead load, wind load, earthquake load, live load, and thermal load.

Design metal temperature of structures and appurtenances should be the calculated metal temperature plus 56°C (100°F), based on the maximum flue gas temperature expected for all operating modes with an ambient temperature of 27°C (80°F) in still air. The effect of elevated design temperature on yield strength and modulus of elasticity should be considered in the design.

3.3.12.2 Structures

The HRSG should be supported on a steel frame independently carrying the full weight of the tubes and headers. The frame should permit lateral and vertical expansion of all parts of the HRSG at design temperatures.

All loads from the tubes and headers should be supported by the structural steel and should not be transmitted into the refractory.

HRSG outer casing should be a minimum of 6 mm ($^1/_4$ in.) thick plate. All casing plate should be sufficiently stiffened against internal design pressure, damage during transport, erection, and vibration. Stiffening should not interfere with expansion.

The outer casing should be seal welded and gas-tight.

The structure should be capable of supporting ladders, stairs, and platforms in locations where installed or where specified for future use.

Flat roof design should allow for runoff of rainwater. This can be accomplished by arrangement of structural members and drain openings, by sloping the roof or with a secondary roof for weather protection. When pitched roofs are provided for weather protection, eaves and gables should prevent the entry of windblown rain.

The casing should have a design pressure based on the maximum operating pressure but not less than 5 kPa(g) (20 in. of water column).

Duct structural systems should support ductwork independent of expansion joints during operation, when idle or with duct sections removed.

Adequate lifting lugs shall be provided to safely lift the equipment for delivery.

3.3.12.3 Access and Inspection Doors

Doors having a minimum clear opening of 600 mm × 600 mm (24 in. × 24 in.) should be provided for each HRSG section.

One access door having a minimum clear opening of 600 mm × 600 mm (24 in. × 24 in.), or 600 mm (24 in.) in diameter should be provided in each stack.

Access doors should be provided to ducts, plenums and at all duct connections to dampers.

3.3.12.4 Ladders, Platforms, and Stairways

Platforms shall be provided as required by the owner for operation, inspection and maintenance purposes per OSHA (29 *CFR* Part 1910) and ANSI 14.3.

3.3.13 Dampers

3.3.13.1 General

Diverter dampers are applied when one or more of the following functions are required:

a. Connection of the turbine exhaust to a bypass stack during start-up of the turbine.
b. Turbine exhaust gas flow regulation for process control purposes.
c. Thermal isolation of the HRSG during turbine operation when process heat is not required or HRSG maintenance.

Stack dampers are not required in the gas turbine exhaust HRSG flue gas stack but they may be used to bottle-up the HRSG during shutdown to keep it warm as long as possible. On vertical HRSGs dampers have been used to keep rain water off the HRSG when it is down.

Damper blades and shafts should be minimum 304 SS material. Damper casings should be constructed of materials comparable to the HRSG ducting.

3.3.13.2 Diverter Dampers

Where a bypass stack is to be provided for start-up purposes, a single blade "flapper type" diverter damper may be used. Where a bypass stack is to be provided for control purposes the diverter damper may be a flapper type or composed of two sets of opposed louver dampers. When two dampers sets are used they must be mechanically linked to prevent closure of both dampers at the same time.

Damper shafts should be solid bar (no pipe shafts allowed). Damper blades should be single thickness solid plate. Damper seals should be metal leaf, low leakage design. Specifically, the design of the shaft and blade should be aimed at the prevention of vibration or fluttering at any blade position under any operating condition.

Damper components should be designed to prevent distortion or deterioration due to corrosive, high temperature or velocity conditions.

The damper operator should be outside of the ducting, so as to be accessible for inspection and maintenance during normal operations.

The damper shaft should extend through the duct wall to external bearings and should be sealed to prevent gas leakage. The damper shaft bearings should be of the self-aligning and non-lubrication type selected based on elevated temperature considering heat transmission from the shaft. Attachment of operators to shafts should be by means of sunk keys or rectangular ends. The shaft should be marked to indicate the blade position.

The damper blade should not move under the effects of gravity or vibration.

Blade seals should be of a material suitable for the turbine exhaust environment. The seals should be designed to accommodate thermal or other movements of the damper casing. The seals should be designed for a maximum leakage of 1% of the total exhaust flow rate against the HRSG design pressure.

Damper shaft drives should have actuators sized for a minimum of 200% of the calculated torque. Dampers should be positively controlled with no counter weights allowed.

The maximum blade travel in both directions should be limited by limit switches. The mounting brackets of the limit switches should be adjustable so as to allow the optimum closing positions of the damper blade to be set.

(Diverter damper should be automatically operated, and its closing/opening speed is critical and should be specified by User. User should specify how the diverter damper operates [e.g., actuated by the low-low level in the steam drum] and the damper closing/opening speed.)

3.3.13.3 Isolation Devices

A bypass stack and an isolation device are required for personnel entrance to the HRSG with the gas turbine in operation. Purchaser should establish the criteria for personnel entry. A guillotine slide gate may be used as an isolation device. A diverter system with a seal air system may also be used for this purpose if approved by purchaser.

Guillotines should have structural channel frames capable of supporting the diverter valve assembly and handling all loads associated with opening and closing the slide gate assembly.

Guillotine blades should be single thickness solid plate.

Guillotine blade seals should be metal leaf type designed to minimize leakage.

Guillotine drive mechanisms should be either chain and sprocket type or worm drive type. The mechanism should drive both sides of the blade (no single point connection allowed).

Preferred guillotine operators are electric type sized for a minimum of 3 times the calculated dead load plus 3 times the friction load.

Guillotines should be supplied with both open and closed limit switches.

3.3.13.4 Seal Air Systems

When specified, a "zero-leakage" seal air system should be provided. The seal air system should be composed of a separate air chamber around the perimeter of the blade as well as a seal air blower with isolation valve. Seal air blower should be designed for the calculated design leakage at a minimum of 2.5 kPa(g) (10 in. W.C.) above the turbine exhaust side operating pressure.

3.3.14 Supplemental Firing

3.3.14.1 General

A supplemental firing system is provided when gas turbine exhaust flow or temperature are insufficient to generate the required superheat temperature or steam flow rate. Increased gas temperature increases the temperature approach, that is, saturated steam or economizer temperature versus flue gas outlet temperature. The LMTD for the HRSG heat transfer surface also increases. Multiple pressure level HRSGs benefit similarly, especially the higher pressure sections. Flue gas heat available is reduced for the lower pressure steam. The effect of supplemental firing is more pronounced with single-pressure level HRSGs than with multi-pressure level HRSGs.

Supplementary firing burners are normally grid type duct burners for fuel gas and sidewall burners for fuel oil. Combination gas and oil firing can be accomplished by using both types of burners. Oil firing is more easily handled with the wall burners than with grid burners. Another style of oil burners is used in the ductwork with the oil gun removable from the side wall. It can also be used for combination firing of oil and gas.

Duct burners utilize excess oxygen in the gas turbine exhaust gas to combust the fuel gas supplied. Flue gas temperature of the turbine exhaust gas (TEG) can be raised from 480ºC – 540ºC (900ºF – 1000ºF) to about 1000ºC (1830ºF) using this excess oxygen. Higher temperatures can be obtained if additional oxygen is provided.

3.3.14.2 Fresh-air Firing

Fresh-air (FA) firing uses ambient air for combustion of the fuel. Forced draft systems are usually required to provide the air at sufficient pressure to overcome the gas pressure in the HRSG.

Fresh-air firing is used to produce steam when the combustion turbine is out of service. Since a significant volume of fresh air would be required to produce the same amount of steam produced with the combustion turbine exhaust, a fresh-air firing system is often designed to generate only 50% of the HRSG steam rated capacity.

Fresh-air firing requires high-temperature dampers in the exhaust gas stream and at the auxiliary burners. A damper and seal air fan is used to prevent exhaust gas leaks through the fan system, or the main combustion air fan must operate.

Fresh-air firing requires special attention in selection of damper and fans.

3.3.14.3 Combustion Air Distribution Grid

A flow distribution grid and flow modeling of the Turbine Exhaust Gas (TEG) or Fresh Air (FA) flow are strongly recommended with grid type duct burners. The grid style duct burner is designed to distribute the fuel evenly across the length of the each burner element and the elements should be spaced evenly over the cross section of the duct. Unless the TEG (or FA) is distributed evenly across the duct cross section in the same manner as the fuel there will be large variations in the temperature of the exhaust gas downstream of the burner.

The design of the distribution grid may also require flow-straightening vanes to remove the residual rotational velocity (created by the turbine) from the TEG before it reaches the duct burner.

3.3.14.4 Velocity/Flow Distribution Across Elements

As a general guide, the maximum velocity variation in the TEG (or FA) flow distribution in the downstream direction over 90% of the duct cross sectional area immediately upstream of the duct burner should be limited to ±15% of the average velocity measured over the whole duct cross section. Also no velocity variation should be greater than ±35% anywhere over the full duct cross section (except adjacent the duct walls, floor, or ceiling).

The proper distribution of fuel gas/oil between the burner runners and along the length of the runners is also important to insure good distribution.

3.3.14.5 Wall Burner

Wall burners are mounted in the duct sidewall, which fire transverse to the main gas flow. These burners are staggered and usually unopposed from the opposite wall allowing for long narrow flames. Flame stabilizing diffuser plates are installed upstream of the flames. The burner and combustion management system is similar to that of the grid burners. This burner may require a fan to supply its primary air.

3.3.14.6 Burner Fouling

There are two types of burner fouling, internal and external. Internal burner fouling typically occurs when the fuel gas composition includes double bonded hydrocarbons (olefins), liquids, or salts. The olefins and liquids in the fuel will create coke deposits if the burner element manifold temperature is over 540°C (1000°F). Insulating the burner manifold pipe will help protect it from the hot TEG and radiant heat from the burner (when firing). The burner elements should be supplied with a cleanout port on one or both ends of each burner element to allow access for inspection and cleaning of the manifold pipe.

External fouling, coking the firing face of the burner element can occur when the fuel gas includes olefins and hydrogen together or when the TEG flow in a local area is too deficient to allow the fuel to burn completely.

3.3.14.7 Flame Length

Burner flame length can vary with the burner design, heat release rate, fuel composition, TEG oxygen content, TEG temperature, and TEG velocity through the burner. Generally the burner flame length will be between 2.7 m – 4 m (9 ft– 13 ft) long depending on the conditions mentioned above. Generally the higher the heat release rate per linear length of burner element the longer the flame length.

The burner flame length can also become elongated in localized areas if the TEG flow is significantly below the average.

Intermediate baffles between the duct burner elements may be required to prevent long flame lengths and flame impingement on the downstream tubes.

3.3.14.8 Duct Burners

Grid type duct burners are multiple fuel headers (elements) installed in a plane normal to the gas flow and fire the same direction as the gas flow. Burners should be equally spaced from each other and extend across the transition duct width. Fuel orifices or nozzles are installed over the length of each fuel burner header and flame stabilization is provided with diffuser plates upstream of the burner nozzle. Flame management systems including pilots and flame scanners are provided for each burner element.

The burner assembly typically consists of the following components:

a. Fuel gas distribution header.
b. Flame scanner assembly including an enclosure and cooling air.
c. Flame scanner cooling air distribution header.
d. Spark ignited gas pilots which may utilize the cooling air supplied to the flame scanners.
e. Ignition transformer.
f. Pilot gas distribution header.
g. Individual isolation valves shall be located close to the element to prevent exhaust gas from condensing in the fuel piping.

In order to specify a duct burner the following data (for the performance range) needs to be passed on to suppliers:

a. Project location.
b. TEG mass flow rate.
c. TEG temperature range.
d. Fired temperature.
e. Burner heat release based on LHV.
f. TEG composition.
g. Maximum design pressure for duct.
h. Primary fuel and secondary fuels if applicable.
i. Fuel composition.
j. Specific gravity.
k. Available pressure.
l. Amount of sulfur in the fuel.
m. Maximum allowable pressure drop in the flue gas over the duct burner.

n. Guaranteed emissions for CO, NO_X, unburned hydrocarbons, and particulate matter (PM-10).
o. Type PLC preferred for BMS.
p. Electrical classifications.
q. Motor power.
r. Control power.
s. Instrument air.
t. Maximum possible TEG flow velocity variation.
u. Burner firing rate turndown.
v. Allowable flame length.
w. Minimum firing duct length.
x. Project site elevation.
y. Project site ambient temperature range.

Following items are typically supplied by HRSG supplier:

a. Interconnecting wiring, view port piping and vent piping.
b. Observation ports.
c. Platforms, ladders and stairs required to access duct burners.
d. Regulated fuel at the required pressure.

3.3.14.9 Duct Burner Supports

Duct burner elements typically require support about every 6 ft over the span of the burner element length to keep the elements from sagging when exposed to the high-temperature TEG and the radiant heat from the burner flame. Two methods are typically used to provide support for the burner elements, using baffles or a truss.

3.3.14.10 Pilot

Individual Class III pilots (defined in NFPA 8502) are typically used on most duct burner applications. Class III pilots offer the most versatility for the burner system and allow individual elements to be brought in and out of service without affecting the remaining burner elements.

An alternate pilot design is a continuous operating strip type Class I (defined in NFPA 8502) pilot that lights all the burner elements at one time. Because the strip pilot design must be run perpendicularly to the elements (in line with the downstream tubes) they are typically limited to smaller turbine applications.

3.3.14.11 Flame Scanners

Optical UV flame scanners are typically used on gas fired grid burner applications. A single scanner can be used to sight the pilot and the main burner flame, however, if the duct burner elements are designed to fire as a group the loss of the scanner signal on any one element will cause the burner to shutdown. Each burner element can be fitted with dual scanners to prevent tripping the burner on the loss of a single flame scanner signal.

It is recommended that the burner elements be fitted with individual automatic element isolation valves to prevent a problem on a single element causing the whole burner to shutdown. Individual automatic isolation valves should also be used on the pilots as well.

Canadian (CSA) safety regulations require that each duct burner element be fitted with two flame scanners, one on each end of the element to prove the flame is stable across the full length of the burner element.

3.3.14.12 Burner Management System (BMS)

A BMS is also included when the HRSG is provided with a duct burner.

The requirements listed below should be considered a minimum, and the BMS should be fully integrated to include both the turbine, plus any auxiliary firing. A comprehensive system description is given in NFPA 8502, which is considered suitable.

This must be fully integrated into the turbine management system and include for full provisions for purging the entire system, together with the necessary safety interlocks, and to be tied in with any environmental systems, such as SCRs.

Prior to start-up, the safety interlocks must be proved, these should include, as a minimum:

a. Turbine running, bypass open, water in drum, feed water system operable, steam generation system operational, feed water pumps running, all fuel valves proven closed, no flames detected.
b. Start-up of system must include a full purge of at least 5 minutes, and 5 volume changes whichever is greater, and at least 8% of turbine full load exhaust flow. Augmented air flow, where applicable must be proved.
c. After completion of purging, exhaust flow can be reduced if required for ignition.
d. Prior to lighting duct burners, turbine exhaust should be increased to at least 25%, or the minimum required for the burner. Duct burners normally operate when the gas turbine is at base load. It is critical to include the operating criteria if the duct burner is to be used at part gas turbine load.
e. Turbine should be started in accordance with manufacturer requirements. Duct burners can be started subject to satisfactory exhaust gas flows and damper positions, with bypass damper open to the HRSG and all duct burner fuel valves closed, and no flame present.
f. Fuels must be at satisfactory temperature and pressure, and atomizing medium, if required, within permitted range. Augmented air system, if included, must be running and proven.
g. All permissives, and interlock requirements must be satisfied, including all steam generator requirements, TEG flows and temperatures. Auxiliary burners must be started as per manufacturer's requirements, and pilot ignition proven within the required time; normally 10 seconds, with 1 minute between restarts. Main burners can be lit at any time after pilot flames are proven but main flames must be proven within 5 seconds of opening of main fuel block valve.
h. Once auxiliary burners are lit, and proven, these must be tripped on incorrect damper position, loss of augmented air supply, or fuel to auxiliary burner trips in addition to turbine trips.
i. Fresh-air firing of the auxiliary burners is acceptable, subject to satisfactory airflows, and all necessary steam and fuel system damper position trips being satisfied.

3.3.15 Expansion Joints

Fabric seal type expansion joints are normally used for accommodating duct and casing expansion. They rely on internal packed insulation to reduce the temperature of the expansion joint fabric and external surface. Expansion joints for HRSGs with internal liners should be designed without heavy metal components extending from the internal liner to the outside casing to avoid local overheating of the external casing plate.

3.3.16 Stack

3.3.16.1 The design and fabrication of HRSG stacks should be in accordance with ASME STS-1 or API 560/ISO 13705, and should satisfy the applicable local wind and earthquake requirements.

3.3.16.2 Exhaust stacks for horizontal HRSGs should be free standing from grade. Exhaust stacks for vertical HRSGs should be mounted on top of the HRSG structure. Bypass stacks may be free standing from grade or supported by the diverter damper structure. In all cases stacks should be self supporting; guyed stacks are not allowed.

3.3.16.3 For stack design flue gas temperatures below 430°C (800°F), unlined carbon steel stacks may be used. For flue gas temperatures above 430°C (800°F), internally lined carbon steel or Type 304 stainless steel stacks are required. External insulation or internal acid resistant coating should be provided if the stack metal temperature falls below the flue gas acid dew point. Personnel protection should be provided on surfaces not externally insulated with metal temperatures above 55°C (130°F).

3.3.16.4 Flue gas sample connections should be provided in accordance with applicable local environmental regulations. Platforms and caged ladders are required for access to sampling points.

3.3.16.5 Each grade supported stack should be furnished with a cleanout door, at least 600 mm × 600 mm (2 ft × 2 ft) in size. The bottom of the door opening should not be more than 1 m (3 ft) above the base of the stack.

3.3.16.6 Concrete foundations should not be directly exposed to hot flue gases. A floor pan should be installed on grade mounted stacks. A minimum NPS 2 stack floor pan drain should be provided to minimize stack floor pan and plate corrosion.

3.3.17 Instrumentation and Controls

The following minimum connections should be supplied:

Temperature (flue gas)

a. Upstream of auxiliary burner (if fitted).
b. Downstream of auxiliary burner (if fitted).
c. Entrance to first steam coils.
d. Exit of each steam generator section of coils.
e. Entrance to bypass stack.
f. Entrance of the exhaust stack.
One of more connections should be provided at the above points dependant upon duct size.

Temperature (water/steam coils)

a. Feed water preheater and economizer coil inlets.
b. Feed water preheater and economizer coil outlets.
c. Desuperheater inlets and outlets.
d. Steam generation coil inlets (if forced circulation).
e. Steam superheat and reheat coil outlets.
f. Tubeskin thermocouples on the first row of tubes after auxiliary burners.

Pressure (flue gas)

a. Turbine exhaust.
b. Upstream and downstream of duct burners (if fitted).
c. Exit of each superheater, reheater, steam generator, economizer and feed water preheater coil.
d. Bypass stack.
e. Exhaust stack.
f. Upstream and downstream of exhaust gas silencers and catalysts.

Pressure (water/steam coils)

a. Feed water preheater and economizer coil inlets.
b. Feed water preheater and economizer coil outlets.
c. Steam generation coils inlet (if forced circulation).
d. Steam superheater and reheater outlets.

Flow water/steam coils

a. Feed water preheater and economizer inlets.
b. Desuperheating water.
c. Superheated steam outlet.

Diverter valve/bypass

a. One limit switch per damper if mechanically interlocked.
b. Two limit switches per damper if not interlocked.

Steam drum

a. Connections are as per Appendix A.

Environmental

a. Analyzers for NO_x, CO, NH_3, etc. as required by local regulations or laws.

3.3.18 Environmental

3.3.18.1 General

Environmental considerations for HRSGs in gas turbine service typically include primary contributors such as NO_x, CO, and noise. Secondary contributors are SO_x, particulate matter, VOCs and UBHCs. The gas turbine and to a lesser degree, the duct burner, are the primary generators of these pollutants. In addition downstream NO_x reduction systems can also add ammonia to this list.

Gas turbines produce NO_x and CO emissions in the following range of 0.155 kg – 0.310 kg NO_x/kW-hr (0.10 lb NO_x/MMBtu – 0.20 lb NO_x/MMBtu) (HHV) and 0.023 kg CO/kW-hr – 0.127 kg CO/kW-hr (0.015 lb CO/MMBtu – 0.082 lb CO/MMBtu) (HHV).

Duct burner emissions firing natural gas are typically 0.155 kg NO_x/kW-hr (0.10 lb NO_x/MMBtu) (HHV) for conventional burner designs and from 0.077 kg NO_x/kW-hr – 0.124 kg NO_x/kW-hr (0.05 lb NO_x/MMBtu – 0.08 lb NO_x/MMBtu) (HHV) for low NO_x designs. CO emissions vary from approximately 0.077 kg CO/kW-hr – 0.155 kg CO/kW-hr (0.05 lb/MMBtu – 0.10 lb/MMBtu) (HHV).

The need to limit these pollutants will depend upon local regulations and permits.

CO oxidation catalytic systems are used to oxidize CO to CO_2 in the presence of a platinum catalyst bed.

Noise is generated by the gas turbine, duct burner, and high exhaust gas flow velocities. The gas turbine can be enclosed in a sound proof building to reduce noise.

Noise may also be generated through acoustic vibration within the tube bank. Discussion and methods for analysis of acoustic vibration are given in TEMA Standard. Detuning baffles are sometimes used to mitigate the problem. Acoustic vibration analysis should be provided by the HRSG vendor for all operating cases.

Inlet ducting and stack exit noise are the main contributors to far field noise. Abatement may be achieved by increasing the thickness of the inlet duct casing or shrouding. Stack exit noise can be reduced by the use of silencing panels inside the stack.

Duct burner NO_x and CO emissions will vary with fuel composition, TEG temperature, the size of the gas turbine, and the HRSG duct. Gas turbines, 20 MW or less, generally have high oxygen content in the TEG and very small HRSG ducting which restricts burner emissions reduction. Generally the emissions generation from a duct burner on this size range of Gas Turbine (GT) system will be about 0.12 kg/MW (0.10 lb/MMBtu) (HHV) of NO_x and CO when firing natural gas.

Medium and large GT systems usually allow for a much larger HRSG duct cross section for the burner and generally produce a lower oxygen content in the TEG than the smaller GTs. In this range of GT and HRSG the NO_x and CO emissions will be generally run about 0.09 kg/MW (0.08 lb/MM Btu) (HHV). Lower emissions may be available on a job-by-job bases.

Very low CO and VOC emissions are generally achievable when burning natural gas with the latest duct burner designs for GT applications. However, these new burner designs often cannot be used with refinery fuels.

The burner fuel composition will also effect the NO_x generation. In general, burning refinery fuel gas will generate higher NO_x emissions than firing natural gas.

3.3.18.2 NO_x Reduction Systems

For NO_x reduction, refer to API RP 536 *Post Combustion NO_x Control for Fired Equipment in General Refinery Services*. There have been many applications of SCR systems installed in HRSG's to reduce NO_x.

As part of Selective Catalytic Reduction systems, a means of injecting ammonia into the HRSG is required. This system normally consists of a storage tank for the ammonia or urea, a pump system, a flow control system, an evaporator, a carrier air system, a static mixer and an ammonia injection grid. The carrier air may be provided by a flue gas recycle fan. Ammonia injection grids may consist of a series of distribution pipes with holes that act as nozzles for spraying the ammonia evenly over the HRSG ductwork. The location of the grid and the uniformity of the distribution should be considered in the flow modeling of the HRSG. Environmental restrictions often limit the amount of excess ammonia being released from the HRSG.

3.3.19 Flow Modeling

The exhaust flow exiting combustion turbines is very turbulent and non-uniform in distribution. Some areas of combustion turbine HRSG inlet ducts may have reverse gas flow. Uniform gas flow is particularly important for satisfactory supplementary firing and superheater performance.

Perforated plates, flow redirection baffles, or other means are used to improve the flow distribution. HRSG inlet ducts may have perforated plates installed upstream of the first bank of tubes. Flow redirection may be necessary for transition ducts diverging more than 30º total included angle.

Flow model tests (cold flow, smoke flow and/or CFD modeling) on combustion turbine HRSGs help predict the gas flow distribution and effectiveness of flow straightening devices. It is important that the test model correctly simulates the combustion turbine exhaust characteristics as well as the HRSG configuration.

3.3.19.1 Tube Vibration

Flow induced vibration is a potential damage mechanism in HRSGs. Discussion and methods for analysis of flow induced vibration are given in TEMA.

Baffles and intermediate tube supports are sometimes used to mitigate the problem. Vibration analysis should be provided by the HRSG vendor for all operating cases. Analysis should be performed for vortex shedding, turbulent buffeting, acoustic resonance, and fluid elastic instability.

3.3.19.2 Turbine Exhaust Gas Distribution

Uniform TEG flow distribution is essential for the best performance from the HRSG and supplemental burner operation. A uniform TEG flow distribution will reduce the amount of temperature variation on the heating surface downstream of the burner and allow the burner to create the lowest emissions.

The general standard for TEG flow distribution over the cross section of the duct work upstream of the burner is: ±15% variation (from the average duct velocity) over at least 90% of the duct's cross sectional area. Ideally, the maximum velocity variation measured anywhere over the duct cross section (except adjacent the duct walls, floor, or ceiling) should be less than ±35% from the average duct velocity.

Depending on the application there may be some leeway with the quality of the flow distribution. Flow distribution becomes more critical the greater the amount of supplemental firing for the size turbine. This is also reflected in the magnitude of the temperature increase of the TEG and the volume percent (wet based) of oxygen remaining downstream of the burner.

One of the simplest ways to see how critical the quality of the flow distribution becomes is to look at its effects on a local area given the maximum variation. Take for example, an LM6000 GT with 280 MM Btu/H (LHV) of supplemental firing. The TEG flow before the burner is 495,600 kg/hr (1,091,700 lb/hr) at 435°C (818°F) with a composition of 13.2% O_2, 7.9% H_20, 3.5% CO_2, 0.9% Ar and balance N_2.

Given a ±15% flow variation, downstream of the burner the conditions would look as follows given ideal mixing:

	–15%	+15%	Expected (ideal)
TEG Temperature:	970°C (1780°F)	840°C (1546°F)	900°C (1646°F)
Residual O_2:	8.05%	9.37%	8.80%

Given a ±25% flow variation the downstream conditions would look as follows given ideal mixing:

	–25%	+25%	Expected (ideal)
TEG Temperature:	1035°C (1896°F)	810°C (1491°F)	900°C (1646°F)
Residual O_2:	7.38%	9.67%	8.80%

In reality, the flue temperature downstream of the duct burner will never achieve a uniform blend. Even with perfect TEG flow distribution to the inlet of the burner, the flue gas downstream directly in line with the burner elements will be hotter than the flue gas located midway between the burner elements. However, without good TEG flow distribution to the inlet to the burner the downstream flue gas temperature variations can become extremely high. The effect of TEG flow variation relative to the available oxygen as shown above can create longer flame lengths and higher emissions.

3.3.19.3 TEG Flow Direction

Although it seems intuitive that the TEG flow direction would be straight ahead (or forward) as it approaches the burner and continues downstream of the burner, very often this is not the case. Unless the distribution grid's design includes flow straightening vanes to stop the rotation of the TEG (the GT exhaust swirl) the exhaust gas flow will be in a helical direct as it moves forward through the ducting, the burner, and into the furnace. This type of flow pattern can cause the burner flames to impinge of the ducting sidewalls immediately downstream of the burner.

On midsize turbines where the turbine exhaust gas discharge is at a 90-degree angle to the gas turbine shaft (side exhaust gas discharge) the TEG flow distribution will be heavily biased to the side of the ducting opposite the turbine. With this type of turbine discharge arrangement the TEG on the turbine side of the ducting may actually be flowing backwards. Correcting the TEG flow distribution on GTs with a side exhaust gas discharge design will require more pressure drop and likely a dual distribution grid system.

Flow modeling results must show the total velocity at a point and total velocity vector direction. Often the flow data collected is only the velocity component normal to the burner plane (normalized velocity). This method ignores the actual TEG velocity, flow distribution, and flow direction and looks only at the component of the flow that is in the ideal direction. Normalized flow model results can mask the distortions in the TEG flow distribution and flow direction.

Ideally the TEG flow direction should be parallel with the axial centerline of the duct (or normal to the burner plane) as it approaches the burner, but this is not possible. However, the true velocity direction of the TEG (the total velocity vector direction) measured at any point should controlled and limited to less than a 25-degree variation from the axial centerline of the ducting. This allows 90% of the total velocity vector to be normal with the burner plane.

3.3.19.4 Firing Duct/Furnace Length

Firing duct/furnace length will also have a major impact on the life the HRSG and the performance of and duct burner. As a general rule of thumb, the longer the furnace, the lower the combustible emissions and the more uniform the flue gas temperature.

The firing duct/furnace should be sized at least 1 m (3 ft) longer than the expected flame length as a minimum. Allowing 2 m (6 ft) of distance beyond the expected flame length or having a furnace length 1.5 times the expected is recommended. The most typical furnace length used by HRSG suppliers for supplemental firing is 4.5 m (15 ft). This length offers reasonable results for the cost. A longer furnace length of 5.5 (18 ft) offers added benefits of increased retention time for lower combustible emissions, better mixing of the flue gases, and lower radiant loading on the HRSG tubes facing the burner. A longer furnace also makes the HRSG design more forgiving of the effects caused by TEG flow variations. Highly fired HRSG applications demand a longer furnace. In general, the higher the fired exhaust temperature, the greater the need for a longer furnace.

3.3.19.5 Flame Length

Typically duct burner flame lengths are between 3 m – 3.7 m (10 ft – 12 ft) depending on the burner and the operating conditions.

The burner flame length is typically a function of the firing capacity per linear foot of active element, the oxygen content in the TEG, burner pressure loss, and the burner design. Generally the active element length is about 0.6 m (2 ft) less than the width of the furnace to prevent the flame from contacting the sidewalls of the ductwork. The duct burner will be normally designed with a capacity between 0.7 MW – 0.9 MW (2.3 MMBtu/hr – 3.0 MMBtu/hr) (LHV) per ft of active element length.

The turbine type and operation will define the TEG temperature and oxygen content that will be available to the duct burner. The burner supplier must evaluate the operating conditions during the highest fired operating cases and the lowest oxygen and/or temperature cases to decide on the burner design.

3.3.19.6 Burner Velocity (Pressure Loss Across Burner)

Grid type duct burners are typically designed with a pressure loss of 6 mm – 13 mm (0.25 in. – 0.5 in.) water column. Burner pressure loss is based on an even distribution of the TEG flow across the duct normal to the plane of the burner face. A typical design TEG velocity across the burner is between 22.5 m/sec – 26 m/sec (75 ft/sec – 85 ft/sec).

3.3.20 Operation and Maintenance Concerns

3.3.20.1 Platforms with stairways and/or ladders should be provided for operation and maintenance of the following:

a. Steam drums.
b. Stop and non-return valves.
c. Safety valves.
d. Vent, drain, blowdown, and shutoff valves.
e. Instruments and control valves.
f. Manhole and handhole covers.
g. Access and observation doors.

h. Electrical equipment.
i. Emissions samplings ports.
j. Duct burners.

Access should be from both sides of valves and instruments, unless otherwise approved by the User.

3.3.20.2 The HRSG should be designed with adequate tube spacing, tube bank depth, cavities, access doors and clear spaces between tube sections for inspection and maintenance access.

3.3.20.3 HRSG design should include optional features to facilitate future repairs, such as plugging of leaking tubes, repair of tube-to-header welds,

3.3.20.4 All components of the HRSG system should be completely drainable. Low point drains should be provided for all enclosures, free standing stacks, ducts, piping, and coil assemblies. All drain connections provided on coil assemblies should be piped together to provide a single collection point for each coil section.

3.3.20.5 Bolted access doors with gaskets, at least 600 mm × 600 mm (2 ft × 2 ft), should be provided as required for entrance to all parts of the HRSG system for inspection, cleaning, repair and replacement of tubes and headers. Access doors should be easy to enter from grade or platforms, and should be clear of all obstructions. Clean out doors should be provided at all places where dust can accumulate. Doors should be pressure tight and insulated as required to prevent erosion. Bolted access doors should be equipped with gaskets manufactured from non-asbestos compressed sheet gasket materials or graphite gasket materials and shall be rated for continuous operation at the temperature of the application.

3.3.20.6 All drums and headers should be equipped with manholes and hinged covers at both ends. Circular manholes should be at least 500 mm (20 in.) in diameter; oval manholes should be at least 355 mm × 455 mm (14 in. × 18 in.). Gaskets in steam service should be spiral wound, Type 304 SS, graphite filled with inner and outer rings or serrated metal 304 SS with graphite facing or corrugated metal 304 SS with graphite facing.

3.3.20.7 Observation ports should be provided to monitor the duct burner elements, pilots, flames and first row of downstream tubes.

3.3.20.8 Liners in internally insulated sections where traffic is anticipated should be adequately designed to withstand the weights of maintenance personnel and equipment.

3.4 FIRED HEATER CONVECTION SECTION HRSG

3.4.1 General

Fired heater convection sections should be designed in accordance with API Std 560/ISO 13705 *Petroleum and natural gas industries—Fired heaters for general refinery service*. This standard expands on those requirements as they apply to forced circulation steam systems in convection sections. It will apply to superheaters, steam generation sections and economizers

Fired heater, convection section HRSGs normally consist of multiple rows of horizontal tubes. The economizer and superheater coils are normally countercurrent to the flow of flue gas. The steam generator coil is normally an upflow coil.

Steam drums are normally separate from the HRSG coils. Additional information on steam drums is provided in Appendix A.

3.4.2 Structure and Casing

The gas path enclosure is normally a rectangular box enclosed on four sides and open on both ends for entry and exit of the flue gas stream. Figure 18 is an example of a fired heater, convection section HRSG layout. An external structural framework integral to the casing plate enclosure supports the steam drums (as applicable) independently from one supporting the tubes and headers. Horizontal tubes may be supported by intermediate (as required) and end tube supports.

3.4.3 Refractory

An internal, refractory insulation system is required to protect the steel casing plate (see API Std 560/ISO 13705).

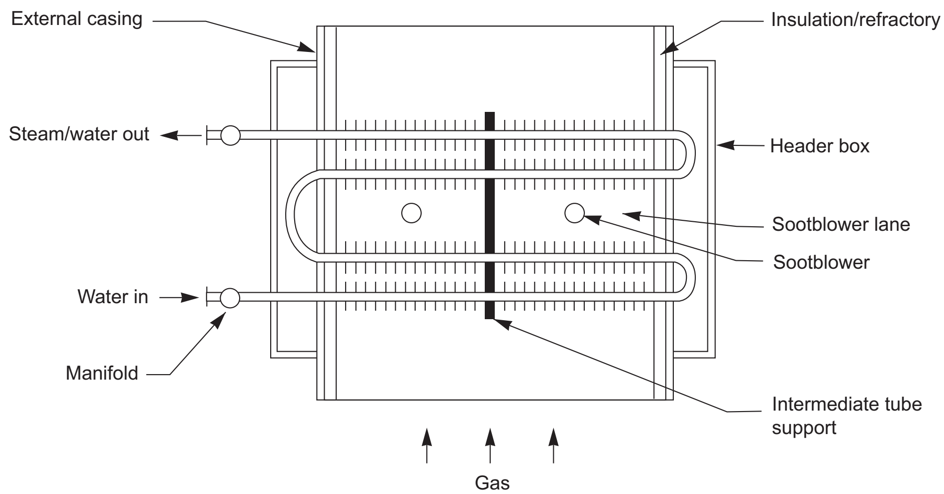


Figure 18—Typical Fire Heater Convection Section HRSG

3.4.4 Tubes

3.4.4.1 Code Considerations

Fired heater, convection section HRSG tubes are normally designed in accordance with Section I, Power Boilers, of the ASME *Boiler and Pressure Vessel Code*. They may be designed in accordance with Section VIII, Pressure Vessels, of the ASME *Boiler and Pressure Vessel Code* or API Std 530/ISO 13704 *Petroleum and natural gas industries—Calculation of heater tube thickness in petroleum refineries*. The choice of the applicable code is often dependent upon the local codes.

3.4.4.2 General

Fired heater convection section HRSGs normally consist of multiple rows of horizontal tubes (bare tubes or tubes with extended surface). The tubes may be arranged into parallel passes. Tubes within the same pass are connected in series by return bends, normally located within header boxes.

The normal spacing between centers of adjacent tubes is two times the nominal tube diameter. The tubes in adjacent rows in the gas path are arranged in a staggered, triangular pattern.

Extended surface (studs or fins attached to the tube outside surface) is used to increase the heat transfer to the tubes. Welded spiral wound solid or serrated fins are normally used. Studs may be used when extreme fouling is expected.

Tubes subject to the hottest flue gases leaving the radiant section of a fired heater are bare. It is desirable to keep the cold end, tube metal temperature above the flue gas dewpoint to prevent acid attack of the metal.

3.4.5 Provisions for Cleaning

Depending on the type of fuel fired, particulate matter may be deposited on the outside surface of the tubes. Limitations of extended surface configurations to allow acceptable tube cleaning are expressed in API Std 560/ISO 13705.

If external tube fouling is anticipated, cleaning provisions as per API Std 560/ISO 13705 should be included. Access panels in the casing side walls should be considered to permit inspection, and cleaning during maintenance shutdown. Reference information on Sootblowers is contained in Appendix C of this document.

3.5 FCC REGENERATOR FLUE GAS HRSG

A fluid catalytic cracking unit (FCCU) in a refinery takes vacuum gas oil and contacts it with fluidized catalyst at elevated temperatures to crack the heavy oil to light products. The cracking process produces coke on the catalyst, which is burned of in the regenerator producing a catalyst-fines laden flue gas. The regenerator operates at range of 620ºC – 730ºC (1150ºF – 1350ºF) and at the pressure of 135 kPa(g) – 275 kPa(g) (20 psig – 40 psig). The HRSG is located downstream of the regenerator and operates at a pressure of 50 mm – 1250 mm of water (2 in. – 50 in. of water). The two types of regenerator operation are referred to as full and partial combustion depending on the ability to completely combust the coke off the catalyst.

This HRSG has special requirements due to the following considerations:

- Catalyst fines.
    - Cause significant fouling requiring robust soot blower systems.
    - Can erode refractory and heat transfer surfaces with high velocity catalyst laden gas.
    - Fall out of catalyst at low velocities causing plugging of heat transfer surfaces.
- Higher operating pressure of the flue gas requiring special casing construction especially with wet scrubbing requirements downstream of the unit.
- Higher casing temperature is required to prevent acid gas corrosion on casing.
- On partial combustion regenerators flue gas composition and temperature can vary significantly requiring special instrumentation on the FCCU HRSG.
- On full combustion regenerators significant temperature excursions, unless accounted for in the design, can cause superheater failures.

3.5.1 FCC Regenerator Flue Gas Applications

3.5.1.1 Types of FCCU Operations

a. Full combustion in regenerator—Flue gas cooler applications.
b. Partial combustion in regenerator—CO boiler/heater applications (supplementary firing is required).

3.5.1.2 Steam generator styles for FCCU operation. (The steam generated in FCCU Applications is usually higher pressure, 3,100 kPa(g) – 4,800 kPa(g) (450 psig – 700 psig), steam and most times includes superheat that is used for large turbine drives such as air blower and wet gas compressor drives.)

a. Forced circulation steam generation.
b. Natural circulation steam generation.
c. Unfired flue gas cooler applications due to lack of temperature control may be integrated into other steam generating systems and externally superheated.
d. Flue gas coolers can have the steam superheater coils located in the shock section when temperature excursions are moderated with others means of protecting the coils.
e. Flue gas cooler can have the steam superheater coils located nested in the steam generation coils to protect them from overheating during temperature excursions.

3.5.2 Process Features for FCCU Operation

3.5.2.1 Full Combustion Operation (Flue Gas Coolers)

The CO content is essentially non-existent and the flue gas is essentially inert.

The inlet temperature to the equipment is in the range of 650ºC – 730ºC (1200ºF – 1350ºF).

The flue gas has catalyst fines entrained within it and has loading of approximately 200 ppm – 400 ppm.

The inlet NO_x value can be widely varied from 50 ppm(v) – 500 ppm(v) based on the regenerator design, capacity, catalyst, promoters used in regenerator and amount of nitrogen and chemically bound nitrogen in the contactor (converter) oil stream's coke deposit on catalyst

For selection of outlet flue gas temperature, the sulfur dewpoint governs. It is usually considered to be in the range of 160ºC – 175ºC (325ºF – 350ºF) due to the catalytic reaction of SO_2 to SO_3 in the regenerator. The actual dewpoint must be determined in the design. It is recommended that the flue gas outlet temperature be 28ºC – 42ºC (50ºF –75ºF) above this dew point. For this reason it is also recommended that the BFW temperature delivered to the Economizer coils be 25ºF above the dewpoint. Another consideration is the downstream environmental equipment's temperature requirements. For instance, wet scrubbers may have a maximum inlet temperature of 230ºC (450ºF) while SCRs perform better at an operating temperature of 315ºC (600ºF).

A minimum velocity of 10.7 m/s (35 ft/s) must be maintained throughout the equipment to keep the catalyst entrained in the flue gas. Sharp turns and other stagnation zones must be minimized in the application. This velocity requirement also requires a review of flue gas induced vibration considerations as well as erosion potential considerations. Outlet hoppers are required on units with flue gas turns.

On FCCUs with power recovery units, a quench system is provided to protect it from regenerator temperature excursions. The steam superheater coil in this equipment can be located in the shock section in this situation with less risk of it receiving a thermal shock from temperature excursions. Note that catalyst loading in these applications is usually lower (80 ppm – 100 ppm) because of the use of third stage separators.

3.5.2.2 Partial Combustion Operation (CO Boilers/Heaters)

The CO content usually ranges from 3% – 9% at full load operation and has a heating value of 280 kJ/kg – 815 kJ/kg (120 Btu/lb – 350 Btu/lb), which contributes significantly to the fuel, needs for the necessary supplemental firing. The full range of flue gas composition (design cases) must be provided as the boiler surface, burner, fan and control system design are all dependant on the CO and other combustibles composition in the flue gas.

The flue gas inlet operating temperature is in the range of 620ºC – 705ºC (1150ºF – 1300ºF).

The catalyst loading is similar to the full combustion operation noted above.

The incoming NO_x values are usually in the same range as in full combustion units, but also have the supplemental firing contribution to consider. Any notable chemically bound nitrogen compounds must be noted in the flue gas composition.

For CO Boilers/Heaters of waterwall construction, as used in package boilers, a higher level of supplementary firing is required due the cold plane combustion characteristics. With combustor style applications, less fuel is required to maintain the adiabatic combustor temperature and destroy the CO. It is recommended that all CO boilers/heaters have some amount of supplemental firing for control and flame out considerations. In some applications with very high CO contents, combustor style units will require additional air to quench the combustor to design refractory temperatures.

The typical operating pressures for these types of HRSG are higher than others due to the backpressure of the downstream equipment. The pressure continues to increase due to environmental issues related to the catalyst and flue gas components. New units are designed for 7.5 kPa(g) – 12.4 kPa(g) (30 in. – 50 in. of water) operating pressure to handle the duct work and pressure losses of SCRs, wet gas scrubbers and electrostatic precipitators (or combinations thereof).

3.5.3 Mechanical Description

3.5.3.1 FCCU Tubes and Coil Design

Due to the catalyst fines and higher flue gas velocities; bare tubes, studded tubes or low-density finned tubes with thick fins are used.

Sometimes, in-line tube pitch instead of triangular pitch is used.

Both above items should be considered when there is a FCCU with very dirty flue gas and low efficiency cyclones. The effectiveness of each to be externally cleaned is a factor to be considered.

Coils can be designed for modular replacement (boiler pendant style) and/or individual replacement (fired heater convection section style). The selection of most waterwall designs preclude the modular replacement of these waterwall tubes.

The steam superheater (SSH) coils may be designed for a “no flow” condition. They may require a higher metallurgy due to the greater tube metal temperature achieved under a “no flow” condition.

The economizer tube metal temperatures must be kept above the sulfur dewpoint. This is more of a concern in an FCCU application than others.

The design flue gas velocity should be reviewed for the economizer section to make sure it does not drop too low to keep the catalyst fines suspended.

3.5.3.2 FCCU Steam Drum

The residence time for FCCU steam drums is usually increased over utility drums because of the process nature of the installation. The FCCU typically requires more time to perform a controlled shutdown or flow diversion than a typical boiler installation. The system is typically not integrated into other boiler systems.

See Appendix A for more information.

3.5.3.3 FCCU Refractory and Casing Design

Castable refractory as a minimum must be used in FCCU applications except where the HRSG is externally lined (i.e., behind waterwall tubes).

The CO Boiler/Heater applications must also consider the CO combustion atmosphere for refractory selection.

Acid dewpoint issues require a higher casing design temperature than in typical gas or liquid-fired HRSGs to avoid condensation issues. Consider a corrosion resistant lining for these applications.

FCCU applications are positive pressure designs and casing must be sufficiently braced and completely welded to prevent leakage.

Sight ports must be pressurized boiler style for CO Boilers/Heaters.

3.5.3.4 Sootblowers and Cleaning Provisions

Sootblowers are required for FCCU applications. The spacing requirements for the sootblowers and the selection of the sootblowers must consider the catalyst loading from the Regenerator. Pressurized wall boxes and/or valves also must be properly selected. A seal air system should be supplied with the sootblower system. The frequency of use is much higher than other applications as a 25ºF rise in outlet temperature is normally reason to begin sootblowing.

Only use retractable sootblowers and only with a proper steam supply pressure. The header must be blown down 2 to 3 minutes prior to sootblowing. Sonic sootblowers have been used but at present they have not always been as effective.

Waterwall boilers sometimes are supplied with dust hoppers in the radiant floor. Considerations for catalyst drop out on the turn from the furnace to convection surfaces are also recommended. These sites are known to promote corrosion of the tubes.

3.5.3.5 Dampers and Expansion Joints

Dampers or guillotines are critical designs due to the elevated pressures. On CO applications the leakage criteria is very critical.

Bypass ducts and diverter valves must also be reviewed for the FCCU applications. A typical fired heater damper would not fit this application.

On CO Boiler/Heater applications, the FD fans ducts require isolation dampers and backflow prevention for redundant fan units and fan protection on loss of a fan. Snuffing steam injection is required due to the positive pressure of the system.

Expansion joints must consider the catalyst fines and have internal liners to prevent drop out in the bellows. A purge may be needed. Dewpoint problems must be considered in material selection.

3.5.3.6 Supplementary Firing (CO Boilers/Heaters)

Oil or gas supplementary firing can be used.

Flame monitoring on each burner is required, not BMS type, continuous flame monitoring system.

Selection of burner sizing and fan sizing must consider the wide range of regeneration gas CO content and any needs for steam production when the regenerator flue gas is not present.

Review need for 100% steam production without FCCU on-line, this is not always required.

3.5.3.7 SCR and Environmental Issues

For FCCU applications, the SCR is not nested in the HRSG, but is located downstream external to the unit.

CO Boilers/Heaters could be candidates for SNCR applications and should be reviewed by proper experts for the NO_x destruction guarantees. SNCR has a better potential of use for a higher destruction efficiency in combustor style units.

3.5.3.8 Flow Distribution and Vibration

Flue gas induced vibration on vertical tube units is more prevalent due to the higher velocities in FCCU applications to entrain the catalyst fines. The use of baffles and intermediate tube guides/supports can be used to eliminate vibration.

The flow distribution transition ducting is important but significantly different than other types due to the higher velocities to entrain the catalyst fines.

3.5.3.9 Stack

Many HRSGs in FCCU applications have no stack since the flue gas must be cleaned up in downstream wet scrubbers, bag houses or electrostatic precipitators.

Most stacks provided are bypass stacks. These have higher design velocities to entrain the catalyst fines.

3.5.4 Operations Description

3.5.4.1 Start-up

Start-up with FCCU in operation is typically not considered and is beyond this discussion.

Under controlled conditions consistent with safe operating practices of boiler operation, purge the unit, ignite a forced air pilot, bring on main burner flame, increase to stable operation before introduction of FCCU regenerator flue gas. On forced circulation units the pumps must be engaged and flow established prior to burner light off.

Robust ignition and pilot systems are necessary to light off CO Boiler burners with the atmosphere and turbulence in this application.

3.5.4.2 Shutdown and Upsets

Operation at turndown rates can result in lower cyclone efficiencies and increase the catalyst carryover.

Since the velocities are lower at turndown and the catalyst loadings may be greater, consider more often sootblowing, to sweep the convection tubes free of fines.

3.5.5 Maintenance and Inspection Issues

HRSG in FCC service normally requires a high level of maintenance. Some typical issues are:

- Sootblowers are frequently used in this severe service.
- Erosion of sootblower poppet valves.
- Seal air system is required on soot blowers for sealing penetration.
- Internal refractory and heat transfer surface erosion.
- Increased corrosion due to catalyst fines catalyzing the formation of SO_3 in the flue gas.
- Optical burner flame detection systems require cleaning.
- Burners and igniters.
- Dampers and baffles.
- Potential use of hoppers for catalyst collection and removal.
- Settled catalyst can cause corrosion of tubes.
- High flue gas pressure operation can cause casing corrosion.
- Higher casing temperatures may be required to prevent casing corrosion which may require external personnel protection systems.
- On supplemental-fired units, the operating pressures can cause the fans to approach blower operating pressures putting them at the edge of the design basis for fans.

APPENDIX A—STEAM DRUMS

A.1 General

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

A.1.1 The steam drum should produce saturated steam approaching 100% quality. There should be minimal water solids carry-over to downstream equipment. It is attached to the steam generating section of a HRSG directly or indirectly through feed water headers, risers, and downcomers.

A.1.2 The drum provides for:

a. Steam separation internal devices.
b. Water storage capacity.
c. Instrumentation connections.
d. Blowdown facilities.
e. Chemical injection facilities.
f. Overpressure protection (safety valves).

A.1.3 A typical steam drum with high purity steam separation internal devices is illustrated in Figure A-1.

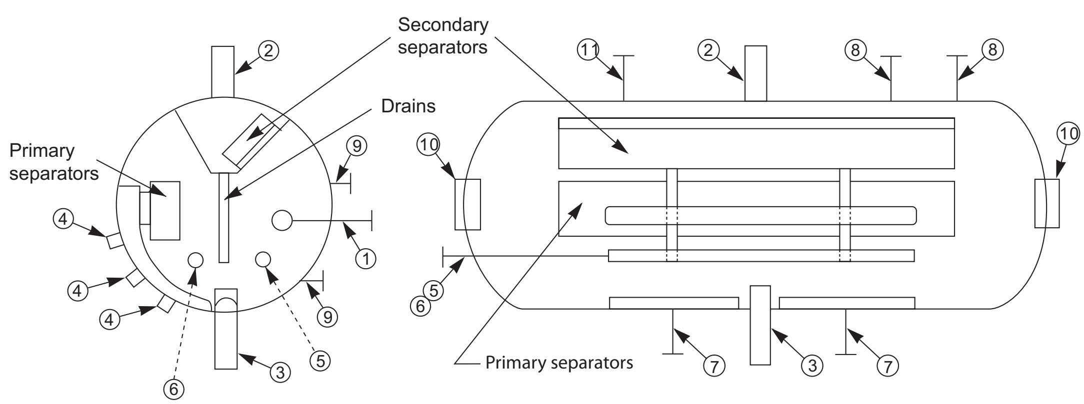
A.1.4 Steam purity is the ratio of the weight of total solids per unit weight of steam produced.

A.2 Application

A.2.1 A steam drum is installed in most HRSGs where the steam must meet specified requirements for steam purity. Steam drums, however, are not required for once-through forced circulation HRSGs.

A.2.2 Several steam pressure levels may be generated in the HRSG. A separate steam drum, including related ancillary facilities, must be supplied for each pressure level.

A.2.3 The steam drum for an HRSG may be shared with other heat recovery systems. These applications are custom designed depending on the heat recovery systems' specific requirements.



KEY

1 Water in
2 Steam out
3 Downcomer
4 Riser
5 Chemical feed
6 Continuous blowdown
7 Intermittant blowdown
8 Safety valve
9 Level gauge connections
10 Manway
11 Vent

Figure A-1—Typical Steam Drum

A.3 Steam Separation

A.3.1 Water and solids leaving the steam drum with the steam is called carryover. Carryover is expressed in either parts per million (ppm) or parts per billion (ppb).

A.3.2 Excessive carryover can lead to serious problems. Acceptable carryover rates depend on the steam use and the composition of the carryover. Detrimental effects of excessive carryover may include:

a. Superheater tube fouling, resulting in tube overheating and corrosion.
b. Reduction of steam turbine efficiency and corrosion resulting from blade and nozzle fouling.
c. Contamination of product or catalyst contacted with the steam.

A.3.3 For steam turbine application or for downstream steam superheating it is prudent to establish limits for boiler water and steam purity. Tables A-1 and A-2 are published by different organizations and are presented as examples.

The following clarifications apply to Table A-1 for drum type boilers:

a. Maximum 0.2 ppm total dissolved solids in the steam at or below 4,140 kPa(g) (600 psig) drum pressure, and 0.1 ppm total dissolved solids maximum above 4,140 kPa(g) (600 psig) are safe limits. Higher levels may be acceptable.
b. Steam purity should be achieved while operating with boiler water total dissolved solids at the high end of the range indicated in Table A-1. The drum supplier specifies the maximum total dissolved solids level in the boiler water at which a specified purity is guaranteed.

A.3.4 Mechanical carryover is the carryover which is dissolved in the entrained water in the delivered steam. Drum internals designed for water removal directly affect the mechanical carryover quantity. Priming is the discharge of steam which contains excessive amounts of entrained water. Priming is a consequence of a high drum water level or foaming.

A.3.5 Steam quality leaving the drum is dependent on the efficiency of the steam/water separation, the solids concentration in the drum water, and on the required steam purity. Acceptable steam quality and purity for process or steam heating applications may be achieved by gravity separation alone. However, multiple stages of steam/water separation are usually necessary to deliver high quality and high purity steam.

Table A-1—Watertube Boilers Recommended Boiler Water Limits and Associated Steam Purity at Steady State Full Load Operation

Drum Pressure kPa gauge (psi gauge)	Maximum Boiler Water Solids[a] (ppm)	Maximum Total Alkalinity[c] (ppm)	Maximum Suspended Solids (ppm)	Maximum FCO, Fractional Carryover[b]	Steam Total Dissolved Solids[b] Corresponding to Max. Boiler Water TDS (ppm)
Drum Boilers					
0 – 2070 (0 – 300)	3500	Note[a]	15	0.0003	1.0
2071 – 3100 (301 – 450)	3000	Note[a]	10	0.0003	1.0
3101 – 4140 (451 – 600)	2500	Note[a]	8	0.0004	1.0
4141 – 5170 (601 – 750)	1000	Note[a]	3	0.0005	0.5
5171 – 6205 (751 – 900)	750	Note[a]	2	0.0006	0.5
6206 – 6895 (901 – 1000)	625	Note[a]	1	0.0007	0.5
6896 – 12410 (1001 – 1800)	100	Not applicable	1	0.001	0.1
12411 – 16200 (1801 – 2350)	50	Not applicable	1	0.002	0.1
16201 – 17930 (2351 – 2600)	25	Not applicable	1	0.002	0.05
17931 – 20000 (2601 – 2900)	15	Not applicable	1	0.003	0.05

[a] 20% of Actual Boiler Water Solids for TDW ≤ 100 ppm, the total alkalinity is dictated by the boiler water treatment.
[b] Does not include vaporous silica carryover.
[c] Expressed as equivalent calcium carbonate in ppm.
Source: American Boiler Manufacturer’s Association Boiler 402, 1 October 2005 Edition.

Table A-2—Suggested Water Quality Limits

Boiler type: industrial watertube, high duty, primary fuel fired, drum type.
Makeup water percentage: up to 100% of feed water conditions: includes superheater, turbine drives, or process restriction on steam purity.
Saturated steam purity target. (9)

Drum Operating Pressure(1)	MPa(g) (psig)	0 – 2.07 (0 – 300)	2.08 – 3.10 (301– 450)	3.11 – 4.14 (451 – 600)	4.15 – 5.17 (601 – 750)	5.18 – 6.21 (751 – 900)	6.22 – 6.89 (901 – 1000)	6.90 – 10.34 (1001 – 1500)	10.35 – 13.79 (1501 – 2000)
Feed water (7)									
Dissolved oxygen (mg/1 O_2) measured before oxygen scavenger addition (8)		<0.04	<0.04	<0.007	<0.007	<0.007	<0.007	<0.007	<0.007
Total iron (mg/1 Fe)		≤0.100	≤0.050	≤0.030	≤0.025	≤0.020	≤0.020	≤0.010	≤0.010
Total copper (mg/1 Cu)		≤0.050	≤0.025	≤0.020	≤0.020	≤0.015	≤0.015	≤0.010	≤0.010
Total hardness (mg/1 $CaCO_3$)		≤0.300	≤0.300	≤0.200	≤0.200	≤0.100	≤0.050	—Not Detectable—	
pH range @ 25ºC		7.5 – 10.0	7.5 – 10.0	7.5 – 10.0	7.5 – 10.0	7.5 – 10.0	8.5 – 9.5	9.0 – 9.6	9.0 – 9.6
Chemicals for preboiler system protection							Use only volatile alkaline materials		
Nonvolatile TOC (mg/1 C)(6)		<1	<1	<0.5	<0.5	<0.5	—As low as possible, <0.2—		
Oily matter (mg/1)		<1	<1	<0.5	<0.5	<0.5	—As low as possible, <0.2—		
Boiler Water									
Silica (mg/1 $S10_2$)		≤150	≤90	≤40	≤30	≤20	≤8	≤2	≤1
Total alkalinity (mg/1 $CaCO_3$)		≤350(3)	≤300(3)	≤250(3)	≤200(3)	≤150(3)	≤100(3)	——Not Specified(4)——	
Free hydroxide alkalinity (mg/1 $CaCO_3$)		——Not Specified——						——Not Detectable(4)——	
Specific conductance (µS/cm) (µsho.cm) @ 25ºC without neutralization		<3500(5)	<3000(5)	<2500(5)	<2000(5)	<1500(5)	<1000(5)	<150	<100

Notes:
1. With local heat fluxes >473.2 kW/m^2 (>150000 Btu/hr/ft^2), use values for the next higher pressure range.
2. Minimum level of OH alkalinity in boilers below 6.21 MPa(g) (900 psig) must be individually specified with regard to silica solubility and other components of internal treatment.
3. Maximum total alkalinity consistent with acceptable steam purity. If necessary, should override conductance as blowdown control parameter. If makeup is demineralized water at 4.14 MPa(g) (600 psig) – 6.89 MPa(g) (1,000 psig), boiler water alkalinity and Conductance should be that in table for 6.90 MPa(g) – 10.34 MPa(g) (1,001 psig – 1,500 psig) range.
4. Not detectable in these cases refers to free sodium or potassium hydroxide alkalinity. Some small variable amount of total alkalinity will be present and measurable with the assumed congruent or coordinated phosphate-pH control or volatile treatment employed at these high-pressure ranges.
5. Maximum values often not achievable without exceeding suggested maximum total alkalinity values, especially in boilers below 6.21 MPa (900 psig) with >20% makeup of water whose total alkalinity is >20% of TDS naturally or after pretreatment by lime-soda, or sodium cycle ion exchange softening. Actual permissible conductance values to achieve any desired steam purity must be established for each case by careful steam purity measurements. Relationship between conductance and steam purity is affected by too many variables to allow its reduction to a simple list of tabulated values.
6. Nonvolatile TOC is that organic carbon not intentionally added as part of the water treatment regime.
7. Boilers below 6.21 MPa(g) (900 psig) with large furnaces, large steam release space and internal chelant, polymer, and/or antifoam treatment can sometimes tolerate higher levels of feed water impurities than those in the table and still achieve adequate deposition control and steam purity. Removal of these impurities by external pretreatment is always a more positive solution. Alternatives must be evaluated as to practicality and economics in each individual case.
8. Values in table assume existence of a deaerator.
9. No values given because steam purity achievable depends upon many variables, including boiler water total alkalinity and specific conductance as well as design of boiler, steam drum internals, and operating condition (see Note 5). Since boilers in this category require a relatively high degree of steam purity, other operating parameters must be set as low as necessary to achieve this high purity for protection of the superheaters and turbines and/or to avoid process contamination.
Source: ASME CRTD 34.

A.3.6 High purity steam drums use several stages of separation. The first stage removes the bulk of the water from the mixture; its design may require the following:

a. Deflectors.
b. Perforated plates.
c. Centrifugal vortex separators.
d. Other proprietary devices.

The steam/water mixture moves through several directional changes, allowing water droplets to fall out. The final stages of separation can employ the following:

a. Wire mesh.
b. Chevron driers.
c. Centrifugal separators.
d. Combinations of items a, b, and c.

The difficulty of steam separation increases as drum pressure increases because the steam and water phase density difference decreases.

A.3.7 Some carryover constituents such as silica dissolve in both the liquid and vapor phases. These constituents tend to increase in concentration in the vapor phase as pressure increases. Liquid phase contaminants can be minimized by efficient steam/water separation. However, vapor phase contaminants can only be controlled by steam washing, by removal of the contaminant through proper treatment of the feed water, or increasing the blowdown rate. Silica carryover at higher pressures [over 6,900 kPa(g) (1,000 psig)] results more from vaporization and solubility of silica in the steam than from entrained water.

In steam washing, the steam and silica vapor are contacted by low solids water, such as steam condensate. The silica in the steam dissolves in the wash water and reduces the silica vapor carryover.

A.4 Water Storage

A.4.1 During transient operation, the steam drum vapor volume will vary. As steam demand is increased the system pressure will decrease. This results in flashing, and an instantaneous increase of steam generation. The water level rises because of the additional steam volume in the water phase. This is called surge or swell. The opposite happens during a reduction in steam demand. A properly tuned control system reestablishes normal water level when steady state operation is reached. Surge volume in the drum should be adequate to avoid either significant water carryover (priming) or low level alarm. This assumes operation initially at normal water level and load swings at a rate of plus or minus 20% of the maximum continuous rating per minute. Low-pressure steam systems are more sensitive to this phenomenon.

A.4.2 The difference in volume between the normal water level and the low-low level is called the storage capacity. Storage provides water to the HRSG if the feed water flow is interrupted or is momentarily inadequate. Typically, drum storage volume is a minimum of 3 minutes of design feed water flow for drum pressures of 5,200 kPa(g) (750 psig) and higher and 5 to 10 minutes at lower pressures. For critical service, steam drum water storage volumes may be higher than those indicated above and is a function of the reliability of boiler feed water supply. Each system should be evaluated on a case-by-case basis. In some cases, surge volume may dictate drum size.

A.5 Mechanical Description

A.5.1 The ASME *Boiler and Pressure Vessel Code*, either Section I or Section VIII, Division 1 is normally applied for the pressure vessel design of the steam drum. If the HRSG is fired, then Section I may apply. If there is no direct firing, Section VIII, Division 1 may be applied, depending on the local requirements. Some users specify Section I design with Section VIII, Division 1 stamping for an unfired HRSG. This establishes more stringent Section I design requirements while avoiding the more frequent system inspection requirements of Section I stamped HRSGs.

Compliance with regulations of local authorities is mandatory.

A.5.2 The layout and size of the drum must allow for internal inspection, maintenance, and repair.

A.5.2.1 The internals should be removable and sized to pass through a manway. A 300 mm (12 in.) by 400 mm (16 in.) minimum sized manway is installed in each drum head. Manway should be equipped with spiral wound gaskets, 304 stainless steel with graphite filler and inner and outer rings or serrated metal gaskets with graphite facing or corrugated metal gaskets with graphite facing.

A.5.2.2 The spacing of internals should allow maintenance personnel to pass around obstructions and work along the complete length of the drum. Baffle plates and other separation devices that cover tubes should be readily removable.

A.5.2.3 The design should permit efficient tube removal and replacement. The area of the tube field must be clear of permanent obstructions to allow space for tube rolling and seal welding.

A.5.2.4 A steam drum is usually not less than 900 mm (36 in.) in diameter in order to provide adequate access and volume.

A.5.3 Steam drum design pressure should be sufficiently above the expected maximum operating pressure to preclude unnecessary discharges from the steam safety valves. The pressure margin is usually a percent of the valve set pressure, and is dependent upon the type of valve. With margins less than 10%, the valve manufacturer should be consulted regarding valve suitability.

A.5.4 Size of steam and water connections must provide acceptable fluid velocities and pressure drop under all operating conditions. The possibility of thermal stresses from relatively cool feed water or chemical feed entering the hot drum must be considered. In thick wall, high-pressure designs, it may be necessary to provide thermal sleeves at the drum wall. A thermal sleeve is a pipe sleeve which penetrates the drum wall through which the feed water or chemical feed pipe is extended.

A.5.5 Vaporfree water should enter the HRSG downcomers. The design and location of the first stage separators relative to the downcomers, and the use of baffles and vortex breakers, can effectively prevent vapor from entering the downcomer nozzles.

A.6 Drum Operating Levels

The key operating levels in the steam drum are:

a. Normal water level.
b. High and low water level.
c. High-high water level.
d. Low-low water level.

A.6.1 Normal water level is the water level which the control system maintains during steady state operation. The normal level is near the drum centerline to enhance moisture separation and to provide adequate water storage volume. This water level may be above the drum centerline for drums which have mechanical steam separators.

A.6.2 High and low water level are those above and below the normal water level which establish the maximum operating range of operating levels to be expected during load swings. The distance between high and low levels and normal level is typically from ±150 mm (6 in.) to ±760 mm (20 in.). Alarms are set for both high and low levels.

A.6.3 High-high water level is the highest level at which the supplier will guarantee the steam purity because of the possibility of water being entrained in the leaving steam.

A.6.4 Low-low water level is the lowest level at which the HRSG should be operated. Below this level the evaporator tubes may be improperly wetted, resulting in tube or drum overheating. Low-low level alarm is also used to shut down duct burners of fired HRSGs, to isolate unfired HRSGs from the hot process gas if equipped with a gas bypass system, or to start unloading the combustion turbine. Depending upon specific conditions, shut down may have to be initiated before low-low level is reached.

A.7 Trim and Instrumentation

A.7.1 The steam drum accommodates pressure safety valves, water level indication; and control, alarm and shutdown instrumentation. Instrumentation must satisfy applicable codes and regulations.

A.7.2 Safety valve(s) installed above the vapor space of the drum provide part or all of the required relieving capacity of the HRSG. If two valves are required, they are either identical or the smaller valve is normally set to lift first. Relief of the full steaming capacity must be provided on the steam drum or in combination with superheater safety valves in accordance with ASME Code.

A.7.3 Level indication is provided by one or more level gauges, level transmitters, or remote level indicators, connected to the drum or water columns. Drum level can be observed by direct vision at the drum platform level. Level indication may also be transmitted to grade or a control room.

Redundancy of instrumentation is desirable to avoid shutdowns for repair. It is helpful on long drums to show endtoend level variations, on the drum, particularly when riser and downcomer connections are not symmetrical along the drum length. The useful range of the level gages should be carefully selected so that the total desired range is obtained. The ASME Code requirements may not provide the desired range of level coverage. Transmitters and other remote indicators generally cover the range from high-high to low-low level and it is desirable to provide similar full range gage glass coverage.

A.7.4 Two-element or three-element systems are used for control.

A.7.4.1 A two-element system monitors the drum water level and the delivered steam flow. A feed-back signal is based on the steam flow, and the demand for changes in the feed water is anticipated before the level actually changes.

A.7.4.2 A three-element system monitors drum water level, discharge steam flow and feed water flow. The steam flow is compared to the water flow and level change is anticipated; the feed water flow is adjusted before the level changes significantly. Three-element control is usually more responsive than two-element control.

A.7.4.3 The level control system can be tuned, or can incorporate computerized programs to minimize the transient effects.

A.8 Control of Water Chemistry

A.8.1 Provisions are incorporated in the steam drum to control the concentration of solids in the drum water. Solids in the drum water will concentrate as steam is generated. If the drum water solids concentration exceeds certain levels, foaming may occur which can lead to entrainment of water and solids in the steam. (Certain organics such as oil and grease in the drum water can also cause foaming.)

Table A-1 (from the American Boiler Manufacturer's Association) contains general recommendations for drum water chemistry. Table A-1 values are exclusive of silica. At pressures above 6,900 kPa(g) (1,000 psig), silica concentration in vapor form increases, requiring special control. Analysis of the steam is necessary to detect carryover. A sample connection using an isokinetic probe per ASTM D 1066 should be installed to extract a representative steam sample. The sample connection should be installed on the steam outlet line or lines.

A.8.2 Solids concentration in the drum water is controlled by removing some of the high solids drum water, which is replenished with low solids feed water. This process is called blowing down. At steady state, the flow balance around the steam drum is:

$$F = S + B$$

where

F = feed water flow rate, in kg per hour (pounds per hour)

S = steam flow rate, in kg per hour (pounds per hour)

B = continuous blowdown flow rate, in kg per hour (pounds per hour)

The total dissolved solids balance is:

$$C_f F = C_S S + C_b B$$

where

C_f = total dissolved solids in feed water, in parts per million

F = feed water flow rate, in kg per hour (pounds per hour)

C_s = total dissolved solids in steam, in parts per million

S = steam flow rate, in kg per hour (pounds per hour)

C_b = total dissolved solids in drum water, in parts per million

B = continuous blowdown flow rate, in kg per hour (pounds per hour)

Using the above relationships and assuming no carryover, the minimum blowdown rate may be determined from the maximum drum water total dissolved solids as follows:

$$B = \left(\frac{C_f}{C_b}\right)F$$

For a particular application, the type of feed water treatment selected establishes feed water solids concentration.

A.8.3 To provide for steam drum water chemistry control, the drum is provided with the following facilities:

a. A feed water pipe to evenly distribute feed water over the length of the drum.
b. The chemical feed pipe, similar in design to the feed water pipe, and usually near the feed water pipe to promote mixing.
c. The continuous blowdown pipe, a perforated pipe located in the drum near the low water level whose function is to control the total dissolved solids level of the boiler water and thereby the steam purity. This area is where drum water solids are judged to be most detrimental to steam purity. If the level drops below the low level, continuous blowdown ceases but level drop rate is reduced. If possible, the continuous blowdown pipe should be located where the boiler water total dissolved solids level is highest to reduce blowdown rates.
d. Intermittent Blowdown: If the drum has undisturbed zones at its bottom, a collector can be used to remove solids which precipitate from the drum water. Otherwise, a mud drum or a low velocity header located at a low elevation in the circulation system can be used for intermittent blowdown location.

APPENDIX B—HEAT FLUX AND CIRCULATION RATIO

B.1 General

Circulation, heat flux and boiling flow regimes are fundamentals applicable to all HRSGs, regardless whether the system is forced or natural circulation, watertube or firetube design.

B.2 Heat Flux

B.2.1 FILM BOILING

Heat flux is the heat transfer rate per unit area of tube surface measured at the surface where boiling occurs. If heat flux is excessive, steam is generated so rapidly that a steam film is formed at the tube wall. This steam film displaces the water and keeps it from rewetting the tube. This phenomenon is known as film boiling or departure from nucleate boiling and results in a sudden increase in the tube metal temperature. This can cause tube failure resulting from high metal temperature.

The heat flux at which departure from nucleate boiling occurs depends on several variables including:

a. Orientation and geometry of the surface.
b. Quantity of steam in the water.
c. Steam/water mixture velocity.
d. Pressure.

The maximum heat flux allowed in HRSG design should be based on the most stringent combination of these variables.

B.2.2 NUCLEATE BOILING

Since boiling heat transfer coefficients are much greater than that of the hot gas side, tube metal temperatures approach that of the saturated water. This assumes nucleate boiling where steam bubbles generated at the tube wall are alternately displaced by water rewetting the tube.

Steam blanketing can also occur at low-heat fluxes with nucleate boiling if the forming steam bubbles are not continuously removed. However, at heat fluxes above 1,262,000 W/m^2 (400,000 Btu/h-ft^2), nucleate boiling changes to film boiling. At this point even the most vigorous circulation cannot prevent the formation of an insulating steam film on the heating surface.

For horizontal boilers, with tube bundles over 900 mm (36 in.) diameter, consideration should be given to providing vertical clear steam lanes within the bundle, together with large shell-to-bundle clearance to prevent steam blanketing.

B.2.3 LOCAL HEAT FLUX

Table B-1 shows typical ranges of maximum allowable local heat fluxes. The maximum heat flux should be calculated in the area of highest temperature difference based on fluid properties at that temperature and under clean conditions. Both tubewall temperature and heat flux should be analyzed to determine the operating limits for HRSG.

Many industrial HRSG designs have much lower local heat fluxes than the maximum specified in Table B-1. This may be due to low-temperature difference or low overall heat transfer coefficients.

B.3 Circulation

B.3.1 CIRCULATION RATIO

Circulation ratio (CR) is the ratio of total steam and water flow in the circuit to the steam flow at the exit of the riser.

$$CR = \frac{\text{total riser steam and water mass flow rate}}{\text{steam mass flow rate at riser outlet}}$$

The designer sets the circulation ratio to maintain nucleate boiling for all operating conditions, that is, to avoid departure from nucleate boiling. However, corrections for two-phase flow regime should be used in conjunction with circulation ratio rather than merely specifying minimum circulation ratio.

Table B-1—HRSG Firetube and Watertube Local Heat Flux

HRSG Type	Maximum Allowable Local Heat Flux W/m^2 (Btu/h-ft^2)	Comments
Firetube		
Kettle	78800 – 94600 (25000 – 30000)	• Pool boiling; circulation pattern is not well defined. • Tube spacing must be carefully considered for larger units.
Horizontal and Vertical Natural or Forced Circulation Thermosyphon	220700 – 315500 (70000 – 100000)	• Separate steam drum, well defined circulation pattern. • May not be applicable to transfer line exchangers in ethylene plants. • Higher fluxes possible in some proprietary designs.
Watertube		
Natural circulation	315500 (100000)	• Vertical tubes prevent flow stratification. • Need to check circulation ratio at the exit of the hottest tube.
Forced circulation	126100 – 157600 (40000 – 5000)	• Design to avoid horizontal tubes stratification. • Need to control high-steam/water mixture velocity.
Forced circulation Once-through [115 mm (4.5 in) max. tube diameter] for enhanced oil recovery	126100 (40000)	• Need to control hardness of water used.
Heat pipe		
Natural circulation	157600 (50000)	• Pool boiling. • Circulation pattern is not well defined

Bubble flow is the required two phase flow regime for HRSG tubes. Bar-Cohen, Ruder, and Griffith found that undesired stratified or plug flow regimes are possible when circulation flow is either too low or heat fluxes too high. Taitel and Dukler present a model predicting flow regimes as a function of tube diameter and orientation, fluid properties and steam/water mass velocity.

B.3.2 NATURAL CIRCULATION

HRSG risers and downcomers form a flow circuit by connecting the steam drum at the top and a water drum or header at the bottom. During operation, the steam/water mixture in the risers is less dense than the water in the downcomers. Flow occurs within the circuit at a rate where the difference in static head between the risers and downcomers balance the resistance to flow. A typical natural circulation circuit (typically, 15:1 to 20:1 circulation ratio) is shown in Figure B-1.

The circulation ratio depends on the static head differences, resistance to flow in the circuit, system pressure, and quantity of steam generated. The designer can increase circulation ratio by raising the height of the steam drum and/or by reducing flow resistance, for example, larger downcomers or increased flow area. A typical performance curve for a particular system is shown in Figure B-2. This curve shows that an increase in the heat transfer and steam generation rate decreases the circulation ratio.

The circulation ratio should be calculated for the anticipated range of operation. Low circulation ratio can result in departure from nucleate boiling and tube overheating. Natural circulation HRSGs generally use vertical or inclined tubes to allow steam to rise freely.

B.3.3 FORCED CIRCULATION

Forced circulation HRSGs use a pump to maintain circulation through the steam generating tubes of the evaporator, steam drum and headers. A typical forced circulation circuit (minimum, typically, 10:1 circulation ratio) is shown in Figure B-3. Water is distributed to parallel tube circuits from an inlet header and the exiting steam/water mixture is collected in an outlet header. The steam/water mixture is returned to the steam drum where the steam is separated and water is recirculated to the evaporator.

Steam generator tubes may have any orientation. Fired heater applications are usually horizontal. Tubes are connected in series in a serpentine arrangement to form each single tube pass. With this arrangement water flows upward and improves flow stability between multipass parallel circuits. The buoyancy of the two phase flow assists the forced circulation and minimizes the potential for steam pocketing.

Forced circulation HRSGs generally have larger tubes, longer tube circuits and higher flow resistance than natural circulation HRSGs.

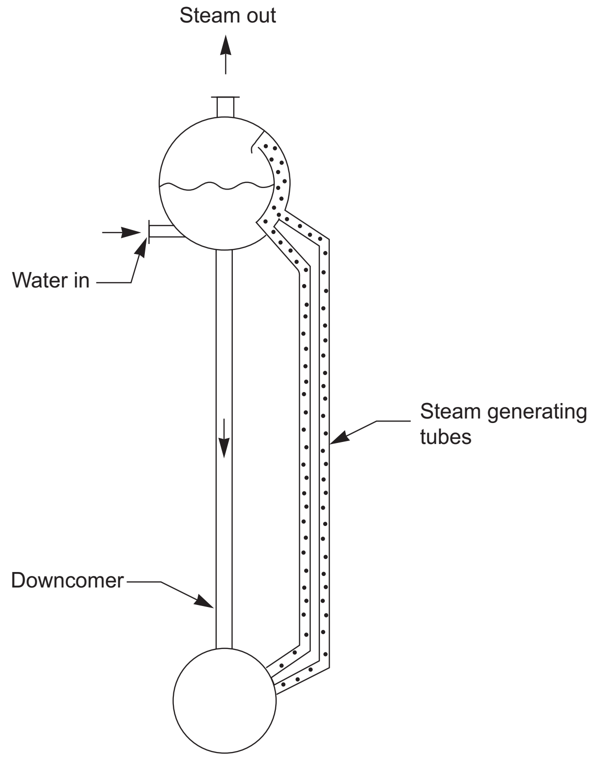


Figure B-1—Typical Watertube HRSG

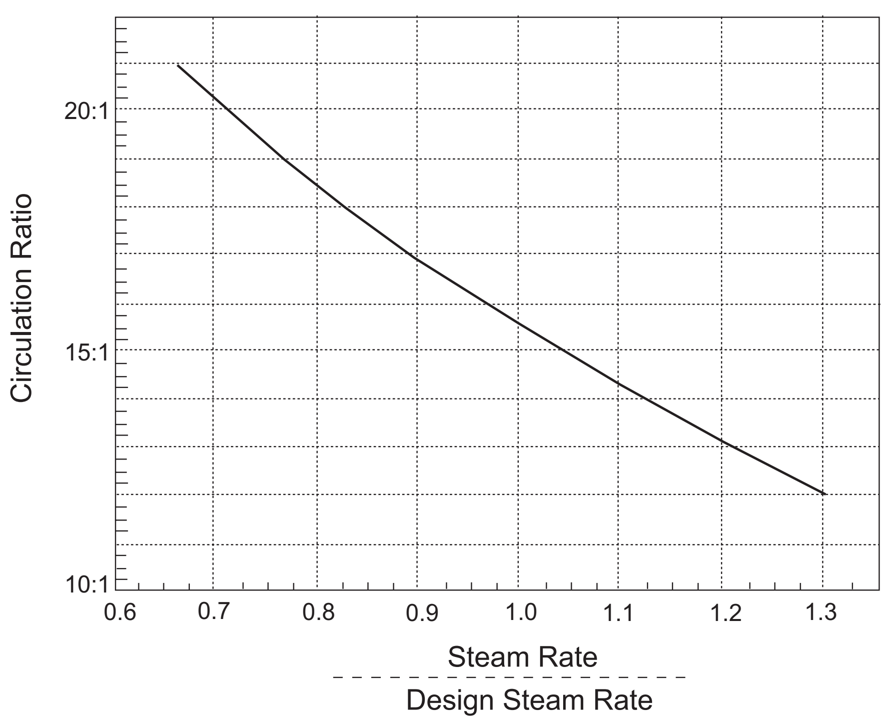


Figure B-2—Typical Circulation Rate

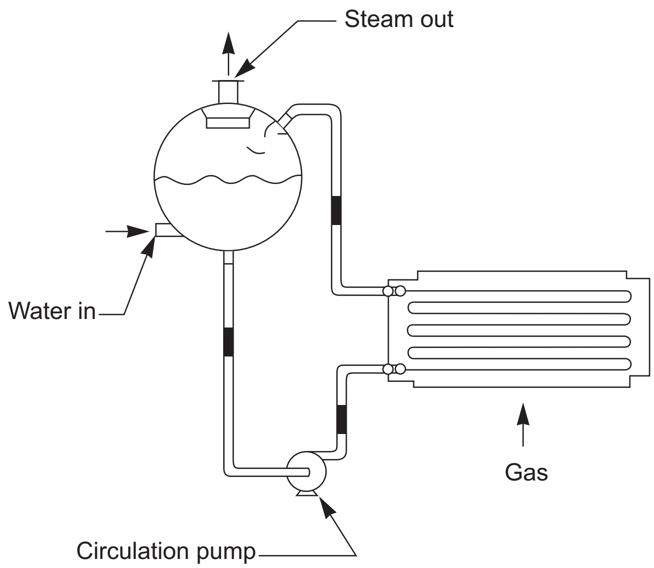


Figure B-3—Typical Forced Circulation System

B.3.4 ADVANTAGES/DISADVANTAGES

B.3.4.1 Natural circulation advantages are:

a. No pumping systems are required.
b. Less maintenance.
c. More reliable.

B.3.4.2 Natural circulation disadvantages are:

a. Usually restricted to vertical or inclined tube applications.
b. Usually installed at grade (more plot space required).
c. Steam drum location requires higher elevation.

B.3.4.3 Forced circulation advantages are:

a. Horizontal or vertical tube arrangements may be used.
b. Forced circulation arrangements can be installed in vertical heater flue gas ducts.
c. Smaller plot requirements. The steam drum location is not restricted.

B.3.4.4 Forced circulation disadvantages are:

a. Pumping systems are required, including standby pump with automatic start.
b. Higher maintenance due to pumps.
c. Vertical tube arrangements require design expertise.

APPENDIX C—SOOTBLOWERS

C.1 General

C.1.1 Flue gas side tube cleaning devices are primarily blowing media cleaners or sootblowers. Sonic cleaning and shot cleaning are seldom used. This appendix will address only sootblowers.

C.1.2 Sootblowers are either fixed position rotary or retractable type. The retractable type may be either fully or partially retractable.

C.1.3 Fixed position rotary sootblowers have a multi-nozzle element permanently located within the flue gas stream. The element is supported at both ends and within the flue gas stream by brackets usually attached to the tubes.

C.1.4 Retractable sootblowers have a lance that normally contains two nozzles, 180º opposed and located at its end. The lance traverses across the tube bank while rotating. The cleaning action is produced by directing the jets of blowing media in a helical path across the tube bank. The lance is retracted outside of the HRSG when not in use. Fully retractable type are not subject to the debilitating effects of temperature and foulants when not in service.

C.1.5 Sootblowers are placed in lanes between rows of tubes. The sootblower lane is the free space between the nearest row of tubes upstream and downstream of the cleaning element. See Figure C-1.

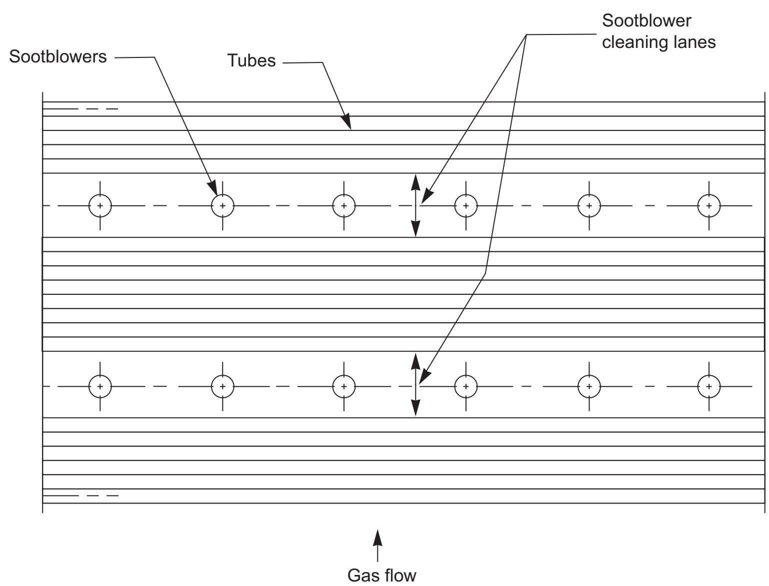


Figure C-1—Sootblower Cleaning Lanes

C.2 Application

C.2.1 Sootblowers are required when heavy oil is fired and extended surface tubes (studs or fins) are present. Provisions for future cleaning are required when heavy oil is fired and only bare tubes are present. Such provisions can include sootblower lanes or mechanical cleaning capability.

C.2.2 Sootblowers are required when catalyst bearing gases are present.

C.2.3 Provisions for future cleaning should be considered when light oil is the heaviest fuel fired.

C.2.4 Fuel gas fired units do not normally require cleaning. The fuel gas composition should be reviewed for fouling potential and future provision for sootblowers made when there is a remote possibility of fouling.

C.2.5 When ammonia and sulfur compounds are present, the potential for fouling and possible sootblower use should be considered.

C.2.6 For temperatures over 540ºC (1000ºF), retractable blowers are desirable. Rotary type is not desirable due to the potential oxidation and drooping of the rotary lance.

C.3 System Considerations

C.3.1 HRSG DESIGN

C.3.1.1 Internal refractories should be protected from damage by the blowing media. Protection may include either metallic shrouds or dense castable lining for either cleaning lane and impingement area or the entire tube bank.

C.3.1.2 Inspection doors should be provided in the lanes to permit inspection of the tube surfaces.

C.3.1.3 Tube arrangement and extended surface choice and orientation should be compatible with the choice of sootblower.

C.3.1.4 The number of rows of sootblowers and the size of the sootblower lanes should accommodate the cleaning characteristics of the sootblower used.

C.3.1.5 The interference of tube supports, guides, baffles, etc. must be considered when laying out cleaning devices.

C.3.1.6 The blowing media may be steam or air. The manufacturer should be consulted as to the optimum pressure. Operation at pressures lower than that recommended by the manufacturer decreases the cleaning ability of the sootblower. Blowing pressure is typically 690 kPa(g) (100 psig) to 2,070 kPa(g) (300 psig).

C.3.2 FIXED POSITION ROTARY SOOTBLOWERS

C.3.2.1 Rotary sootblowers mounted on opposing sides of the tube bank are required if the tube bank exceeds 4.6 m (15 ft).

C.3.2.2 Sootblower lanes should be a minimum of 90 mm (3.5 in.) clear between tube outside diameters for bare tube application, 250 mm (10 in.) between the tips of fins or studs when the sootblower element is parallel to the tubes, 450 mm (18 in.) when the element is perpendicular to the tubes.

C.3.2.3 Sootblower rotation is provided by a pneumatic or electric motor drive. The element, combination gear drive, and cam actuated blowing media admission valve are shown in Figure C-2.

C.3.2.4 Typical gas temperature limits for element materials are:

a. Carbon Steel	425ºC (800ºF)
b. Chrome plated or calorized steel	540ºC (1000ºF)
c. Stainless Steel (22% Cr minimum)	815ºC (1500ºF)

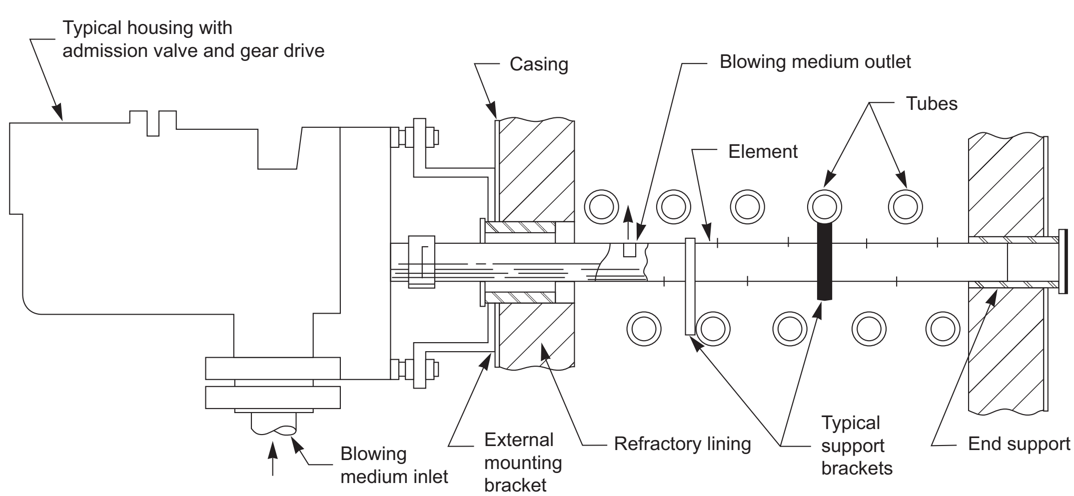


Figure C-2—Typical Fixed Position Rotary Mounting Arrangement

C.3.2.5 Support brackets that are attached to tubes should be of the same material as the element. In the event the bracket temperature exceed 1100ºF and the vanadium content of the fuel exceeds 50 ppm, 50 Cr-50 Ni (Cb) brackets should be used.

C.3.2.6 The support brackets should be independent of the element.

C.3.2.7 Support bracket spacing is a function of flue gas temperature. Typical spacing limitations are as follows:

a. 1000 mm (40 in.) apart: 480ºC (900ºF)
b. 750 mm (30 in.) apart: 815ºC (1500ºF)
c. 500 mm (20 in.) apart: 980ºC (1800ºF)

C.3.2.8 The number of nozzles for an element typically shown by Figure C-2 is based on providing one nozzle per space between tube rows. After establishing the number of nozzles, the blowing media consumption per element may be estimated from Figures C-3 or C-4. Actual consumption rates are a function of sootblower construction details. To provide adequate coverage for most industrial applications, multiple elements are normally installed.

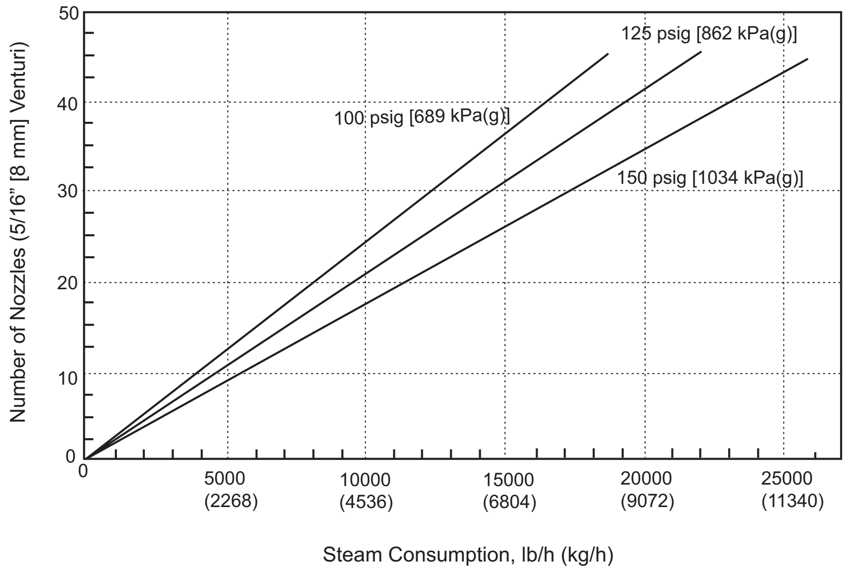


Figure C-3—Typical Steam Flow Rate for Fixed Rotary Soot Blowers

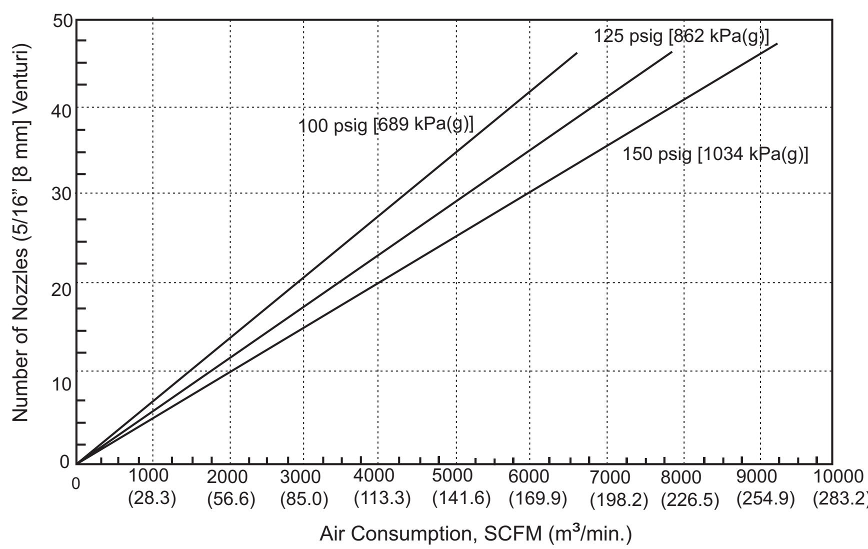


Figure C-4—Typical Air Flow Rate for Fixed Rotary Soot Blowers

C.3.3 RETRACTABLE SOOTBLOWERS

C.3.3.1 Cleaning lanes for bare tubes should be a minimum of 380 mm (15 in.) clear between tube outside diameters. Cleaning lanes for extended surface tubes should be 460 mm (18 in.) between the tips of fins or studs when the sootblower element (lance) is parallel to the tubes and 610 mm (24 in.) when the element is perpendicular to the tubes.

C.3.3.2 The sootblower is supported at the casing wall by a sleeve yoke and from a platform or structure outside the casing near the outboard end. Figure C-5 shows a typical support arrangement.

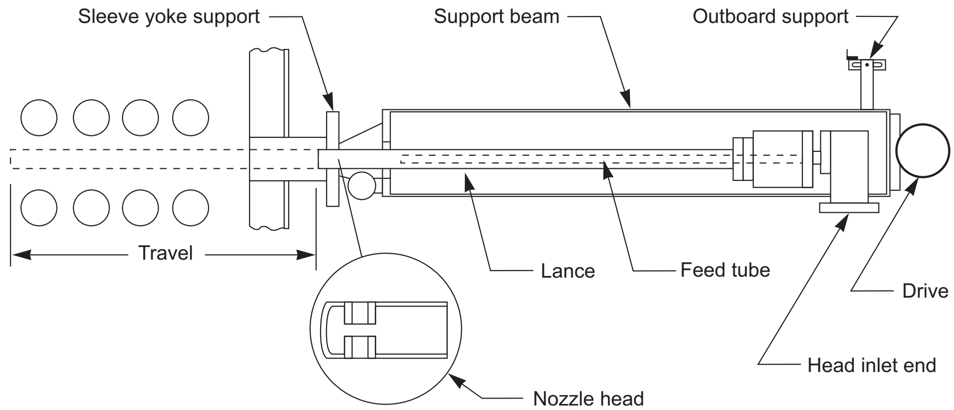


Figure C-5—Typical Retractable Mounting Arrangement

C.3.3.3 Positive pressure wall sleeves with sealing air are required to prevent leakage of flue gases in positive pressure HRSGs.

C.3.4 SOOTBLOWER SPACING

C.3.4.1 The spacing of sootblower elements should be based on the effective cleaning radius. The effective cleaning radius is a function of the following:

a. Tube bank temperatures.
b. Blowing media.
c. Blowing media pressure.
d. Nozzle size and number.
e. Fuel characteristic (potential for soot formation).
f. Tube arrangement (pitch) and size.
g. Extended surface type and orientation.
h. Orientation of sootblower element to tubes.
i. Type of HRSG.

C.3.4.2 Typical Sootblower spacing for staggered tube banks depends on whether the sootblower is a rotary or a retractable one.

For rotary sootblowers, the maximum horizontal or vertical coverage is 900 mm (3 ft) from the element or 3 tube rows, whichever is less.

For retractable sootblowers, the maximum horizontal or vertical coverage is 1200 mm (4 ft) from the element or 4 tube rows, whichever is less.

High fouling fuel will require more sootblowers. The sootblower vendor should be consulted for his recommendations for the specific system and its effective cleaning radii.

Typical blowing steam consumption levels are given in Figure C-6. Air is rarely used in retractable sootblowers.

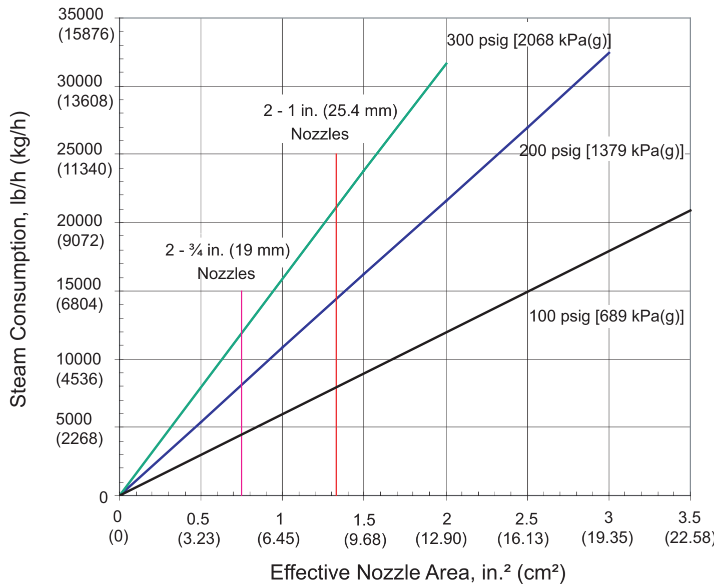


Figure C-6—Typical Steam Flow Rate for Retractable Soot Blowers

C.3.5 EXTERNAL PIPING

Sootblower external piping arrangements should include the following:

a. Individual block valves to each blower.
b. Warm up piping.
c. Steam bleeds.
d. Steam traps.

C.3.6 CONTROLS

Local start/stop push button stations, main steam control valve, and sequential control panel are normally provided by the soot-blower manufacturer.

C.4 Advantages

C.4.1 FIXED POSITION ROTARY SOOTBLOWERS

The advantages of fixed-position rotary sootblowers include:

a. Construction is less complex.
b. External platforms and structure minimized.

C.4.2 RETRACTABLE SOOTBLOWERS

The advantages of retractable sootblowers include:

a. The lance can be used at any flue gas temperature.
b. Internal supports are not required for the lance.
c. More effective cleaning is provided than with fixed position rotary sootblowers.
d. Fewer sootblowers are required than with fixed position rotary sootblowers.

C.5 Disadvantages

C.5.1 FIXED POSITION ROTARY SOOTBLOWERS

The disadvantages of fixed-position rotary sootblowers include:

a. Elements are continually exposed to the flue gases.
b. More frequent maintenance is required than with retractable sootblowers.
c. Cleaning radius is short.
d. Nozzles are subject to plugging.
e. Rotary sootblowers are not recommended when the sootblower element sees temperatures in excess of 1100ºF or fuel oils containing large quantities of heavy metals (over 50 ppm vanadium).
f. Rotary sootblowers may not be suitable when certain high fouling fuels are employed.

C.5.2 RETRACTABLE SOOTBLOWERS

The disadvantages of retractable sootblowers include:

a. Significant platforms and structural supports are required.
b. More routine maintenance is required.
c. Flue gas seals are more susceptible to leakage.
d. More complex construction.

C.6 Operations Description

Sootblowers operation frequency varies depending upon the equipment, the structure and orientation of the tube bank and the fouling tendency of the fuel. Sequential operation of the sootblowers is required to prevent too great a load on utilities, and to prevent unstable operation of the HRSG due to excessive quantities of the blowing media being added to the flue gas.

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